

**STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD**

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants **No. EIB 21-27 (R)**

**ENVIRONMENTAL DEFENSE NOTICE OF INTENT TO PRESENT DIRECT
TESTIMONY**

Environmental Defense Fund (“EDF”), through undersigned counsel, as required by NMAC 20.1.1.302 and the June 8, 2021 Order of Hearing Determination and Hearing Officer Determination, submits its Notice of Intent to Present Direct Testimony in above- captioned matter. As required by applicable regulations, EDF provides the following information in this notice:

1. Identify the person for whom the witnesses will testify:

The four witnesses identified below will testify on behalf of Environmental Defense Fund. EDF is a national membership organization with more than 2.5 million members residing throughout the United States and more than 18,000 residing in the state of New Mexico, many of whom are deeply concerned about the pollution emitted from oil and natural gas sources. EDF brings a strong commitment to sound science, collaborative efforts with industry partners, and market-based solutions to our most pressing environmental and public health challenges.

2. Identify each technical witness the person intends to present, and state the qualifications of that witness, including a description of their educational and work background:

EDF intends to present David Lyon, Senior Scientist; Hillary Hull, Director of Research and Analytics; Tammy Thompson, Senior Air Quality Scientist; and Thomas Alexander, Consultant. Mr. Lyon's educational and work background is set forth in his resume, which is EDF Exhibit B.

Hillary Hull's educational and work background is set forth in her resume, which is EDF Exhibit P. Tammy Thompson's educational and work background is set forth in her resume, which is EDF Exhibit FF. Thomas Alexander's educational and work background is set forth in his resume, which is EDF Exhibit KK.

3. Include a copy of the full direct testimony of each technical witness:

As required by the June 8, 2021 Order of Hearing Determination and Hearing Officer Determination, EDF submits the full written direct testimony of David Lyon in Exhibit RR; Hillary Hull in Exhibit SS; Tammy M. Thompson in Exhibit TT; and Tom Alexander in Exhibit UU.

4. Include the text of any recommended modifications to the proposed regulatory change:

A text of the modification to 20.2.50 NMAC proposed by EDF is attached as Exhibit A.

5. List and attach all exhibits anticipated to be offered by that person at the hearing:

Below is a list of all exhibits to be offered by EDF in support of its direct testimony, which are attached as noted below.

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E	Zhang et al., <i>Quantifying Methane Emissions from the Largest Oil-Producing Basin in the United States from Space</i> , 6 SCI. ADVANCES, Apr. 22, 2020, https://advances.sciencemag.org/content/6/17/eaaz5120 .	47
F	Robertson et al., <i>New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates</i> , 54:21	56

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O	Carbon Limits, <i>Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Program Using Infrared Cameras</i> (Mar. 2015), https://www.catf.us/wp-content/uploads/2014/03/CATF_Pub_CarbonLimitsLDAR.pdf .	293
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II	Final Report: Human Health Risk Assessment for Oil and Gas Operations in Colorado, ICF (Oct. 17, 2019) (submitted to CDPHE), https://drive.google.com/file/d/1pO41DJMXw9sD1NjR_OKyBJP5NCb-AO0I/view .	Stand alone file
JJ	State of New Mexico Environmental Improvement Board, IN THE MATTER OF PROPOSED NEW REGULATION, 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants No. EIB 21-27 (R), Petition for Regulatory Change, https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2021/03/2021-05-06-EIB-21-27-Petition-for-Regulatory-Change-Part-20.2.50-pj.pdf .	N/A
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LL	Pneumatic Controller Task Force Report to the Air Quality Control Commission, Colorado Air Pollution Control Division, (June 1, 2020), https://drive.google.com/file/d/1JStgs0SD2NvZIht1Ti8QQnJAmUZxKgsn/view .	527
MM	Economic Impact Analysis (Final) for Regulation 7, AQCC (Oct. 4, 2017).	
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OO	California Air Resources Board, Standards for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Section 95668(e)(2), https://casetext.com/regulation/california-code-of-regulations/title-17-public-health/division-3-air-resources/chapter-1-air-resources-board/subchapter-10-climate-change/article-4-regulations-to-achieve-greenhouse-gas-emission-reductions/subarticle-13-greenhouse-gas-emission-standards-for-crude-oil-and-natural-gas-facilities/section-95668-standards .	N/A
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Certificate of Service

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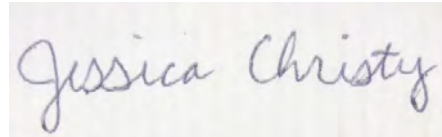
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A handwritten signature in blue ink that reads "Jessica Christy". The signature is written in a cursive style with a large, looped 'J' and a trailing 'y'.

7/28/2021

Jessica Christy

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board.
[20.2.50.1 NMAC – N, XX/XX/2021]

20.2.50.2 SCOPE: This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. Once a source becomes subject to this rule, the requirements of the rule are irrevocably effective unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in this Part.
[20.2.50.2 NMAC – N, XX/XX/2021]

20.2.50.3 STATUTORY AUTHORITY: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021).
[20.2.50.3 NMAC - N, XX/XX/2021]

20.2.50.4 DURATION: Permanent.
[20.2.50.4 NMAC - N, XX/XX/2021]

20.2.50.5 EFFECTIVE DATE: Month XX, 2021, except where a later date is specified in another Section.
[20.2.50.5 NMAC - N, XX/XX/2021]

20.2.50.6 OBJECTIVE: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NO_x) for oil and gas production, processing, and transmission sources.
[20.2.50.6 NMAC - N, XX/XX/2021]

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

A. "Approved instrument monitoring method" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

B. "Auto-igniter" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

C. "Bleed rate" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

D. "Calendar year" means a year beginning January 1 and ending December 31.

E. "Centrifugal compressor" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

F. "Closed vent system" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

G. "Commencement of operation" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

H. "Component" means a pump seal, flange, pressure relief device (including thief hatch or other

opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

I. “Connector” means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, “T’s” or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

J. “Construction” means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

K. “Custody transfer” means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

L. “Control device” means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, air fuel ratio controllers (AFRs), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

M. “Department” means the New Mexico environment department.

N. “Downtime” means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

O. “Drilling” or “drilled” means the process to bore a hole to create a well for oil and/or natural gas production.

P. “Drill-out” means the process of removing the plugs placed during hydraulic fracturing or refracturing. Drill-out ends after the removal of all stage plugs and the initial wellbore cleanup.

Q. “Enclosed combustion device” means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

PR. “Existing” means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

S. “Flowback” means the process of allowing fluids and entrained solids to flow from a well following stimulation, either in preparation for a subsequent phase of treatment or in preparation for cleanup and placing the well into production. The term flowback also means the fluids and entrained solids flowing from a well after drilling or hydraulic fracturing or refracturing. Flowback ends when all temporary flowback equipment is removed from service. Flowback does not include drill-out.

T. “Flowback vessel” means a vessel that contains flowback.

QU. “Gathering and boosting station” means a permanent combination of equipment that collects or moves natural gas, crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage.

V. “Hydraulic fracturing” means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale, coal, and tight sand formations, that subsequently require flowback to expel fracture fluids and solids.

W. “Hydraulic refracturing” means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

RX. “Glycol dehydrator” means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

SY. “Hydrocarbon liquid” means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

FZ. “Liquid unloading” means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

UAA. “Liquid transfer” means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

VBB. “Local distribution company custody transfer station” means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

~~WCC~~. “Natural gas compressor station” means one or more compressors designed to compress natural gas from well pressure to gathering system pressure before the inlet of a natural gas processing plant, or to move compressed natural gas through a transmission pipeline.

~~XDD~~. “Natural gas-fired heater” means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

~~YEE~~. “Natural gas processing plant” means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

~~ZFF~~. “New” means constructed or reconstructed on or after the effective date of this Part.

~~GG~~. “Occupied area” means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

~~HH~~. “Pre-production operations” means the drilling through the hydrocarbon bearing zones, hydraulic fracturing or refracturing, drill-out, and flowback of an oil and/or natural gas well.

~~AAII~~. “Operator” means the person or persons responsible for the overall operation of a stationary source.

~~BBJJ~~. “Optical gas imaging (OGI)” means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

~~CEKK~~. “Owner” means the person or persons who own a stationary source or part of a stationary source.

~~DDLL~~. “Permanent pit” means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

~~EEMM~~. “Pneumatic controller” means an instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature.

~~FFNN~~. “Pneumatic diaphragm pump” means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

~~GGOO~~. “Potential to emit (PTE)” means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

~~HHPP~~. “Produced water” means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

~~HQQ~~. “Produced water management unit” means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

~~JJRR~~. “Qualified Professional Engineer” means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

~~KKSS~~. “Reciprocating compressor” means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

~~LLTT~~. “Reconstruction” means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

~~MMUU~~. “Recycling facility” means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

~~NNVV~~. “Responsible official” means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

~~QQWW~~. “Small business facility” means, for the purposes of this Part, a source that is independently owned or operated by a company that is not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than \$250,000. Employees include part-time, temporary, or limited service workers.

~~PPXX~~. “Startup” means the setting into operation of air pollution control equipment or process equipment.

~~QQYY~~. “Stationary Source” or “source” means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

~~RRZZ~~. “Storage vessel” means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

~~AAA~~. “Vessel measurement system” means equipment and methods used to determine the quantity of the liquids inside a vessel (including a flowback vessel) without requiring direct access through the vessel thief hatch or other opening.

~~SSBBB~~. “Well workover” means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

~~TTCCC~~. “Wellhead site” means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping.

[20.2.50.7 NMAC - N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby.

[20.2.50.8 NMAC - N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose.

[20.2.50.9 NMAC - N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions.

[20.2.50.10 NMAC - N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls.

[20.2.50.11 NMAC - N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New

1 Mexico environment department, air quality bureau.

2 [20.2.50.12 NMAC - N, XX/XX/2021]

3 [The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

4
5 **20.2.23.13-20.2.23.110 [RESERVED]**

6
7 **20.2.50.111 APPLICABILITY:**

8 **A.** This Part applies to crude oil and natural gas production and processing equipment and operations
9 that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or
10 produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering
11 and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local
12 distribution company custody transfer station.

13 **B.** In determining if any source is subject to this Part, including a small business facility as defined in
14 this Part, the owner or operator shall calculate the Potential to Emit (PTE) of such source and shall have the PTE
15 calculation certified by a qualified professional engineer. The calculation shall be kept on file for a minimum of five
16 years and shall be provided to the department upon request.

17 **C.** An owner or operator of a small business facility as defined in this Part shall comply with the
18 requirements of this Part as specified in 20.2.50.125 NMAC.

19 **D.** Oil refinery and transmission pipelines are not subject to this Part.
20 [20.2.50.111 NMAC - N, XX/XX/2021]

21
22 **20.2.50.112 GENERAL PROVISIONS:**

23 **A. General requirements:**

24 **(1)** Sources subject to emissions standards and requirements under this Part shall be operated
25 and maintained consistent with manufacturer specifications, and good engineering and maintenance practices. The
26 owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available
27 upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and
28 maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule
29 sufficient to operate and maintain such units in good working order. The owner or operator shall keep such
30 maintenance schedules on file and make them available to the department upon request.

31 **(2)** Sources subject to emission standards or requirements under this Part shall be operated to
32 minimize emissions of air contaminants, including VOC and NO_x.

33 **(3)** Within two years of the effective date of this Part, owners and operators of a source
34 requiring an Equipment Monitoring Tag (EMT) shall physically tag each unit with an EMT, the format of which
35 shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This
36 unique identifier shall act as an index to the source's record of the data required by this Part. The EMT shall be
37 maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:

38 **(a)** unique unit identification number;

39 **(b)** location of the source;

40 **(c)** type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);

41 **(d)** for each source, the VOC (and NO_x, if applicable) PTE in lbs./hr. and tpy;

42 **(e)** for a control device, the controlled VOC and NO_x PTE in lbs./hr. and tpy;

43 **(f)** make, model, and serial number; and

44 **(g)** a link to the manufacturer's maintenance schedule or repair recommendations.

45 **(4)** The EMT shall be installed and maintained by the owner or operator of the facility.

46 **(5)** The EMT shall be of a format scannable by an owner or operator's authorized
47 representatives and, upon scanning, shall provide unique identifier that shall index the source's record of the data
48 required by this Part.

49 **(6)** The owner or operator shall manage the source's record of data in a database that is able
50 to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or
51 operator's database and submitted to the department upon request. The format of the CDR shall be determined by
52 the department.

53 **(7)** The CDR is a report distinct from the owner or operator's database. The department does
54 not require access to the owner or operator's database, only the CDR.

55 **(8)** If read by the owner or operator's authorized representative, the EMT shall access the
56 owner or operator's database record for that source.

(9) The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:

(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.

(b) data required by this Part shall be maintained in the database for at least five years.

(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.

B. Monitoring requirements:

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation, unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2) An owner or operator may submit for the department's review and approval an equally effective, enforceable, and equivalent alternative monitoring strategy. Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

(3) Each monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of testing, monitoring, or inspection as required under this Part.

C. Recordkeeping requirements:

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

(3) Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for ~~for~~ five years.

D. Reporting requirements: Within 24 hours of a request by the department, the owner or operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

[20.2.50.112 NMAC - N, XX/XX/2021]

20.2.50.113 ENGINES AND TURBINES:

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NO_x and VOC emissions are reduced by at least ninety-five percent per year.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane)
Lean-burn	>1,000	0.50 g/bhp-hr	47 ppmvd @ 15% O ₂ or 93% reduction	0.70 g/bhp-hr
Rich-burn	>1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED, RECONSTRUCTED, OR INSTALLED AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

Engine Type	Rated bhp	NO _x	CO	NMNEHC (as propane)
Lean-burn	>500 - <1,000	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr
Lean-burn	≥1,000	0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control	0.60 g/bhp-hr	0.70 g/bhp-hr
Rich-burn	>500	0.50 g/bhp-hr	0.60 g/bhp-hr	0.70 g/bhp-hr

(4) The owner or operator of a natural gas-fired spark ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NO_x emissions to not more

than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than two years from the effective date of this Part:			
Turbine Rating (bhp)	NO _x (ppmvd @15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane, ppmvd @15% O ₂)
≥1,000 and <5,000	50	50	9
≥5,000 and <15,000	50	50	9
≥15,000	50	50 or 93% reduction	5 or 50% reduction
For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:			
Turbine Rating (bhp)	NO _x (ppmvd @15% O ₂)	CO (ppmvd @ 15% O ₂)	NMNEHC (as propane, ppmvd @15% O ₂)
≥1,000 and <5,000	25	25	9
≥5,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with Control	10 Uncontrolled or 1.8 with Control	5

(8) The owner or operator of a stationary natural gas-fired combustion turbine with NO_x emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

(10) The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine shall meet the minimum manufacturer recommended maintenance schedule. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to manufacturer or supplier recommended maintenance schedules, including replacement of

oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NO_x, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr)} \times \text{Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr)} \times \text{Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption

(a) emissions testing events shall be conducted at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine operated for less than 100 hours per year shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

- (1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:
- (a) the make, model, serial number, and EMT for the engine or turbine;
 - (b) a copy of the engine, turbine, or control device manufacturer recommended maintenance and repair schedule;
 - (c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:
 - (i) the date and time of an inspection, maintenance or repair;
 - (ii) the date a subsequent analysis was performed (if applicable);
 - (iii) the name of the personnel conducting the inspection, maintenance or repair;
 - (iv) a description of the physical condition of the equipment as found during the inspection;
 - (v) a description of maintenance or repair activity conducted; and
 - (vi) the results of the inspection and any required corrective actions.
- (2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine. The records shall include:
- (a) the make, model, serial number, and EMT for the tested engine or turbine;
 - (b) the date and time of sampling or measurements;
 - (c) the date analyses were performed;
 - (d) the name of the personnel and the qualified entity that performed the analyses;
 - (e) the analytical or test methods used;
 - (f) the results of analyses or tests;
 - (g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and
 - (h) operating conditions at the time of sampling or measurement.
- (3) The owner or operator of an emergency use engine operated less than 100 hours per year shall record the total annual hours of operation as recorded by the non-resettable hour meter.
- (4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NO_x and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.113 NM-C - N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:**A. Applicability:**

- (1) Centrifugal compressors using wet seals and located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Centrifugal compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.
- (2) Reciprocating compressors located at tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.114 NMAC. Reciprocating compressors located at wellhead sites are not subject to the requirements of 20.2.50.114 NMAC.

B. Emission standards:

- (1) The owner or operator of an existing centrifugal compressor shall control VOC emissions from a centrifugal compressor wet seal fluid degassing system by at least ninety-five percent within two years of the effective date of this Part. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or a process stream.
- (2) The owner or operator of an existing reciprocating compressor shall, either:
- (a) replace the reciprocating compressor rod packing after every 26,000 hours of

compressor operation or every 36 months, whichever is reached later. The owner or operator shall begin counting the hours of compressor operation toward the first replacement of the rod packing upon the effective date of this Part; or

(b) beginning no later than two years from the effective date of this Part, collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, recovery system, fuel cell, or a process stream.

(3) The owner or operator of a new centrifugal compressor shall control VOC emissions from the centrifugal compressor wet seal fluid degassing system by at least ninety-eight percent upon startup. Emissions shall be captured and routed via a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a new reciprocating compressor shall, upon startup, either:
(a) replace the reciprocating compressor rod packing after every 26,000 hours of compressor operation, or every 36 months, whichever is reached later; or

(b) collect emissions from the rod packing under negative pressure and route them via a closed vent system to a control device, a recovery system, fuel cell or a process stream.

(5) The owner or operator of a centrifugal or reciprocating compressor shall install an EMT on the compressor in accordance with 20.2.50.112 NMAC.

(6) The owner or operator complying with the emission standards in Subsection B of 20.2.50.114 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of a centrifugal compressor complying with Paragraph (1) or (3) of Subsection B of 20.2.50.114 NMAC shall maintain a closed vent system encompassing the wet seal fluid degassing system that complies with the monitoring requirements in 20.2.50.115 NMAC.

(2) The owner or operator of a reciprocating compressor complying with Subparagraph (a) of Paragraph (2) or Subparagraph (a) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall continuously monitor the hours of operation with a non-resettable hour meter and track the number of hours since initial startup or since the previous reciprocating compressor rod packing replacement.

(3) The owner or operator of a reciprocating compressor complying with Subparagraph (b) of Paragraph (2) or Subparagraph (b) of Paragraph (4) of Subsection B of 20.2.50.114 NMAC shall monitor the rod packing emissions collection system semiannually to ensure that it operates under negative pressure and routes emissions through a closed vent system to a control device, recovery system, fuel cell, or process stream.

(4) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a closed vent system or control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) The owner or operator of a centrifugal or reciprocating compressor shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a centrifugal compressor using a wet seal fluid degassing system shall maintain a record of the following:

(a) the location of the centrifugal compressor;

(b) the date of construction, reconstruction, or modification of the centrifugal compressor;

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including the time and date of the monitoring, the personnel conducting the monitoring, a description of any problem observed during the monitoring, and a description of any corrective action taken; and

(d) the type, make, model, and identification number of a control device used to comply with the control requirements in Subsection B of 20.2.50.114 NMAC.

(2) The owner or operator of a reciprocating compressor shall maintain a record of the following:

(a) the location of the reciprocating compressor;

(b) the date of construction, reconstruction, or modification of the reciprocating compressor; and

(c) the monitoring required in Subsection C of 20.2.50.114 NMAC, including:
(i) the number of hours of operation since initial startup or the last rod packing replacement;

(ii) the records of pressure in the rod packing emissions collection system;
and

(iii) the time and date of the inspection, the personnel conducting the inspection, a notation of which checks required in Subsection C of 20.2.50.114 NMAC were completed, a description of problems observed during the inspection, and a description and date of corrective actions taken.

(3) The owner or operator of a centrifugal or reciprocating compressor complying with the requirements in Subsection B of 20.2.50.114 NMAC through use of a control device or closed vent system shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(4) The owner or operator of a centrifugal or reciprocating compressor shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator of a centrifugal or reciprocating compressor shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.114 NM-C - N, XX/XX/2021]

20.2.50.115 CONTROL DEVICES:

A. Applicability: These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NO_x.

(3) The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.

(4) The owner or operator shall inspect control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

(5) The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

(6) The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, ~~or~~ storage vessel, or flowback vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

(7) The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

1 (c) maximum rated capacity for an open flare, ECD/TO, or VRU;
2 (d) gas flow range for an open flare, ECD, or TO; and
3 (e) designed destruction or vapor recovery efficiency.

4 **C. Requirements for open flares:**

5 (1) Emission standards:

6 (a) the flare shall combust the gas sent to the flare and combustion shall be
7 maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare
8 in excess of the manufacturer maximum rated capacity.

9 (b) the owner or operator shall equip each new and existing flare (except those
10 flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an
11 operational auto-igniter, or require manual ignition, and shall comply with the following:

12 (i) a flare with a continuous pilot flame or an auto-igniter shall be
13 equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the
14 flare.

15 (ii) the owner or operator of a flare with manual ignition shall inspect and
16 ensure a flame is present upon initiating a flaring event.

17 (iii) a new flare controlling a continuous gas stream shall be equipped with
18 a continuous pilot flame upon startup.

19 (iv) an existing flare controlling a continuous gas stream constructed before
20 the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date
21 of this Part.

22 (c) an existing flare located at a site with an annual average daily production of
23 equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural
24 gas shall be equipped with an auto-igniter, continuous pilot, or technology (e.g. alarm) that alerts the owner or
25 operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

26 (d) the owner or operator shall operate a flare with no visible emissions, except for
27 periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an
28 observer can, by means of visual observation from the outside of the flare or by other means such as a continuous
29 monitoring device, determine whether it is operating properly.

30 (e) the owner or operator shall repair the flare within three business days of any
31 alarm activation.

32 (2) Monitoring requirements:

33 (a) the owner or operator of a flare with a continuous pilot or auto igniter shall
34 continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using
35 a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative
36 equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a
37 continuous recorder and alarm, if approved by the department;

38 (b) the owner or operator of a manually ignited flare shall monitor the presence of a
39 flame using continuous visual observation during a flaring event;

40 (c) the owner or operator shall, at least quarterly, and upon observing visible
41 emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify
42 compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive
43 minutes;

44 (d) prior to an inspection or monitoring event, the EMT on the flare shall be
45 scanned and the required monitoring data shall be electronically captured during the event in accordance with the
46 monitoring requirements of 20.2.50.112 NMAC; and

47 (e) the owner or operator shall monitor the technology that alerts the owner or
48 operator of a flare malfunction and any instances of technology or alarm activation.

49 (3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record
50 of the following:

51 (a) any instance of alarm activation, including the date and cause of alarm
52 activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting
53 the inspection, and any maintenance activity performed;

54 (b) the results of the U.S. EPA method 22 observations;

55 (c) the monitoring of the presence of a flame on a manual flare during a flaring
56 event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

(4) Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

F. Recordkeeping requirements: The owner or operator of a control device shall maintain a record of the following:

- (1) the certification of the closed vent system as required by this Part; and
- (2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

H. Requirements for flowback vessels and preproduction operations:

(1) Emissions standards:

(a) the owner or operator of a well that begins flowback on or after the effective date of this Part must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to an operating control device that achieves a hydrocarbon control efficiency of at least 95 percent. If a TO or ECD is used, it must have a design destruction efficiency of at least 98 percent for hydrocarbons.

(i) the owner or operator shall use enclosed, vapor-tight flowback vessels with an appropriate pressure relief system to be used only as necessary to ensure safety.

(ii) flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.

(iii) the owner or operator shall use a vessel measurement system to determine the quantity of liquids in the flowback vessel(s).

(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).

(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the vessel measurement system or to add biocides or chemicals is not a violation of 20.2.50.115.H(1)(a)(i) NMAC.

(2) Monitoring

(a) Owners and or operators of a well with flowback that begins on or after the effective date of 20.2.50 NMAC, must conduct daily visual inspections of the flowback vessel and any associated equipment, including

(i) visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.

(ii) visual inspection or monitoring of the control device to ensure that it is operating.

(iii) visual inspection of the control device to ensure that the valves for the piping from the flowback vessel to the control device are open.

(3) Recordkeeping

(a) The owner or operator of each flowback vessel subject to Paragraph (1) of Subsection H of Section 20.2.50.115 NMAC must maintain records for a period of five (5) years and make them available to the NMED upon request, including

(i) the API number of the well and the associated facility location, including latitude and longitude coordinates.

(ii) the date and time of the onset of flowback.

(iii) the date and time the flowback vessels were permanently disconnected, if applicable.

(iv) the date and duration of any period where the control device is not operating.

(v) records of the inspections required in Paragraph (2) of Subsection H of Section 20.2.50.115 NMAC, including the time and date of each inspection, a description of any problems observed,

a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).

[20.2.50.115 NM-C - N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. Applicability: Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC.

B. Emission standards: The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. Default Monitoring requirements: Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be considered a leak; and

(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a facility with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of the following facilities shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for wellhead sites or tank battery facilities:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations:

(i) quarterly at facilities with a PTE less than 25 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 25 tpy VOC.

(c) for wellhead sites within 1,000 feet of an occupied area:

(i) quarterly at facilities with a PTE less than 5 tpy VOC; and

(ii) monthly at facilities with a PTE equal to or greater than 5 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but not more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater

of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.C NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated "Repair delayed," and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO, RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;
 (b) date of inspection;
 (c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);
 (d) name of the personnel performing the inspection;
 (e) a description of any leak requiring repair or a note that no leak was found; and
 (f) whether a visible flag was placed on the leak or not;
 (2) The owner or operator shall keep the following record for any leak that is detected:
 (a) the date the leak is detected;
 (b) the date of attempt to repair;
 (c) for a leak with a designation of "repair delayed" the following shall be recorded:
 (i) reason for delay if a leak is not repaired within the required number of days after discovery;
 (ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;
 (d) date of successful leak repair;
 (e) date the leak was monitored after repair and the results of the monitoring; and
 (f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.
 (3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).
 (4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.
 (2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
 [20.2.50.116 NMAC - N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

A. Applicability: Liquid unloading operations including down-hole well maintenance events at natural gas wells are subject to the requirements of 20.2.50.117 NMAC.

B. Emission standards:

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for liquid unloading.
 (2) The owner or operator of a natural gas well shall use the following best management practices during liquid unloading to minimize emissions, consistent with well site conditions and good engineering practices:
 (a) reduce wellhead pressure before blowdown;
 (b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and
 (c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.
 (3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:
 (a) installation and use of a plunger lift;
 (b) installation and use of an artificial lift engine; or
 (c) installation and use of a control device.
 (4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.
C. Monitoring requirements:
 (1) The owner or operator shall monitor the following parameters during liquid unloading:
 (a) wellhead pressure;
 (b) flow rate of the vented natural gas (to the extent feasible); and

- 1 (c) duration of venting to the storage vessel or atmosphere.
2 (2) The owner or operator shall calculate the volume and mass of VOC vented during a
3 liquid unloading event.
4 (3) A liquid unloading event shall include the scanning of the EMT and monitoring data
5 entry in accordance with the requirements of 20.2.50.112 NMAC.
6 (4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112
7 NMAC.

8 **D. Recordkeeping requirements:**

- 9 (1) The owner or operator shall keep the following records for liquid unloading:
10 (a) identification number and location of the well;
11 (b) date the liquid unloading was performed;
12 (c) wellhead pressure;
13 (d) flow rate of the vented natural gas (to the extent feasible. If not feasible, the
14 owner or operator shall use the maximum potential flow rate in the emission calculation);
15 (e) duration of venting to the storage vessel or atmosphere;
16 (f) a description of the management practice used to minimize release of VOC
17 emissions before and during the liquid unloading;
18 (g) the type of control device used to control VOC emissions during the liquid
19 unloading; and
20 (h) a calculation of the VOC emissions vented during the liquid unloading based on
21 the duration, volume, and mass of VOC.
22 (2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112
23 NMAC.

24 **E. Reporting requirements:** The owner or operator shall comply with the reporting requirements in
25 20.2.50.112 NMAC.
26 [20.2.50.117 NMAC - N, XX/XX/2021]
27

28 **20.2.50.118 GLYCOL DEHYDRATORS:**

29 **A. Applicability:** Glycol dehydrators with a PTE equal to or greater than two tpy of VOC and
30 located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission
31 compressor stations are subject to the requirements of 20.2.50.118 NMAC.

32 **B. Emission standards:**

33 (1) Existing glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall
34 achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still
35 vent and flash tank no later than two years after the effective date. If a combustion control device is used, the
36 combustion control device shall have a minimum design combustion efficiency of ninety-eight percent.

37 (2) New glycol dehydrators with a PTE equal to or greater than two tpy of VOC shall
38 achieve a minimum combined capture and control efficiency of ninety-five percent of VOC emissions from the still
39 vent and flash tank upon startup. If a combustion control device is used, the combustion control device shall have a
40 minimum design combustion efficiency of ninety-eight percent.

41 (3) The owner or operator of a glycol dehydrator shall comply with the following
42 requirements:

43 (a) still vent and flash tank emissions shall be routed at all times to the reboiler
44 firebox, condenser, combustion control device, fuel cell, to a process point that either recycles or recompresses the
45 emissions or uses the emissions as fuel, or to a VRU that reinjects the VOC emissions back into the process stream
46 or natural gas gathering pipeline;

47 (b) if a VRU is used, it shall consist of a closed loop system of seals, ducts and a
48 compressor that reinjects the natural gas into the process or the natural gas pipeline. The VRU shall be operational at
49 least ninety-five percent of the time the facility is in operation, resulting in a minimum combined capture and control
50 efficiency of ninety-five percent. The VRU shall be installed, operated, and maintained according to the
51 manufacturer's specifications;

52 (c) still vent and flash tank emissions shall not be vented to the atmosphere; and

53 (d) the owner or operator of a glycol dehydrator shall install an EMT on the glycol
54 dehydrator in accordance with 20.2.50.112 NMAC.

55 (4) an owner or operator complying with the requirements in Subsection B of 20.2.50.118
56 NMAC through use of a control device shall comply with the requirements in 20.2.50.115 NMAC.

(5) The requirements of Subsection B of 20.2.50.118 NMAC cease to apply when the uncontrolled actual annual VOC emissions from a new or existing glycol dehydrator are less than two tpy VOC.

C. Monitoring requirements:

(1) The owner or operator of a glycol dehydrator shall conduct an annual extended gas analysis on the dehydrator inlet gas and calculate the uncontrolled and controlled VOC emissions in tpy.

(2) The owner or operator of a glycol dehydrator shall inspect the glycol dehydrator, including the reboiler and regenerator, and the control device or process the emissions are being routed, semi-annually to ensure it is operating as initially designed and in accordance with the manufacturer recommended operation and maintenance schedule.

(3) An owner or operator complying with the requirements in Subsection B of 20.2.50.118 NMAC through the use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a glycol dehydrator shall maintain a record of the following:

(a) dehydrator location and identification number;

(b) glycol circulation rate, monthly natural gas throughput, and the date of the most recent throughput measurement;

(c) data and methodology used to estimate the PTE of VOC (must be a department approved calculation methodology);

(d) amount of controlled and uncontrolled VOC emissions in tpy;

(e) type, make, model, and identification number of the control device or process the emissions are being routed;

(f) date and results of any equipment inspection, including maintenance or repair activities required to bring the glycol dehydrator into compliance; and

(g) a copy of the glycol dehydrator manufacturer operation and maintenance recommendations.

(2) An owner or operator complying with the requirements in Paragraph (1) or (2) of Subsection B of 20.2.50.118 NMAC through use of a control device as defined in this Part shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(3) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.118 NMAC - N, XX/XX/2021]

20.2.50.119 HEATERS:

A. Applicability: Natural gas-fired heaters with a rated heat input equal to or greater than 10 MMBtu/hour including heater treaters, heated flash separators, evaporator units, fractionation column heaters, and glycol dehydrator reboilers in use at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.119 NMAC.

B. Emission standards:

(1) Natural gas-fired heaters shall comply with the emission limits in table 1 of 20.2.50.119 NMAC.

Table 1 - EMISSION STANDARDS FOR NO_x AND CO

Date of Construction:	NO _x (ppmvd @ 3% O ₂)	CO (ppmvd @ 3% O ₂)
Constructed or reconstructed before the effective date of 20.2.50 NMAC	30	300
Constructed or reconstructed on or after the effective date of 20.2.50 NMAC	30	130

(2) Existing natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC no later than one year after the effective date of this Part.

(3) New natural gas-fired heaters shall comply with the requirements of 20.2.50.119 NMAC

upon startup.

(4) The owner or operator of a natural gas-fired heater shall install an EMT on the heater in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall:

(a) conduct emission testing for NO_x and CO within 180 days of the compliance date specified in Paragraph (2) or (3) of Subsection B of 20.2.50.119 NMAC and at least every two years thereafter.

(b) inspect, maintain, and repair the heater in accordance with the manufacturer specifications at least once every two years following the applicable compliance date specified in 20.2.50.119 NMAC. The inspection, maintenance, and repair shall include the following:

(i) inspecting the burner and cleaning or replacing components of the burner as necessary;

(ii) inspecting the flame pattern and adjusting the burner as necessary to optimize the flame pattern consistent with the manufacturer specifications and good engineering practices;

(iii) inspecting the AFR controller and ensuring it is calibrated and functioning properly;

(iv) optimizing total emissions of CO consistent with the NO_x requirement, manufacturer specifications, and good combustion engineering practices; and

(v) measuring the concentrations in the effluent stream of CO in ppmvd and O₂ in volume percent before and after adjustments are made in accordance with Subparagraph (c) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC.

(2) The owner or operator shall comply with the following periodic testing requirements:

(a) conduct three test runs of at least 20-minutes duration within ten percent of one-hundred percent peak, or the highest achievable, load;

(b) determine NO_x and CO emissions and O₂ concentrations in the exhaust with a portable analyzer used and maintained in accordance with the manufacturer specifications and following the procedures specified in the current version of ASTM D6522;

(c) if the measured NO_x or CO emissions concentrations are exceeding the emissions limits of table 1 of 20.2.50.119 NMAC, the owner or operator shall repeat the inspection and tune-up in Subparagraph (b) of Paragraph (1) of Subsection C of 20.2.50.119 NMAC within 30 days of the periodic testing; and

(d) if at any time the heater is operated in excess of the highest achievable load plus ten percent, the owner or operator shall perform the testing specified in Subparagraph (a) of Paragraph (2) of Subsection C of 20.2.50.119 NMAC within 60 days from the anomalous operation.

(3) When conducting periodic testing of a heater, the owner or operator shall follow the procedures in Paragraph (2) of Subsection C of 20.2.50.119 NMAC. An owner or operator may deviate from those procedures by submitting a written request to use an alternative procedure to the department at least 60 days before performing the periodic testing. In the alternative procedure request, the owner or operator must demonstrate the alternative procedure's equivalence to the standard procedure. The owner or operator must receive written approval from the department prior to conducting the periodic testing using an alternative procedure.

(4) Prior to a monitoring, inspection, maintenance, or repair event, the owner or operator shall scan the EMT and the required monitoring data shall be captured in accordance with this Part.

D. Recordkeeping requirements: The owner or operator shall maintain a record of the following:

(1) location of the heater;

(2) summary of the complete test report and the results of periodic testing; and

(3) inspections, testing, maintenance, and repairs, which shall include at a minimum:

(a) the date the inspection, testing, maintenance, or repair was conducted;

(b) name of the personnel conducting the inspection, testing, maintenance, or repair;

(c) concentrations in the effluent stream of CO in ppmv and O₂ in volume percent;

and

(d) the results of the inspections and any the corrective action taken.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.119 NMAC - N, XX/XX/2021]

20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

A. Applicability: Hydrocarbon liquid transfers located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.120 NMAC beginning one year from the effective date of this Part.

B. Emission standards:

(1) The owner or operator of a hydrocarbon liquid transfer operation shall use vapor balance, vapor recovery, or a control device to control VOC emissions by at least ninety-eight percent when transferring liquid from a storage vessel to a transfer vessel, or when transferring liquid from a transfer vessel to a storage vessel.

(2) An owner or operator using vapor balance during a liquid transfer operation shall:

(a) transfer the vapor displaced from the vessel being loaded back to the vessel being emptied via a pipe or hose connected before the start of the transfer operation;

(b) ensure that the transfer does not begin until the vapor collection and return system is properly connected;

(c) ensure that connector pipes, hoses, couplers, valves, and pressure relief devices are maintained in a leak-free condition;

(d) check the liquid and vapor line connections for proper connections before commencing the transfer operation; and

(e) operate transfer equipment at a pressure that is less than the pressure relief valve setting of the receiving transport vehicle or storage vessel.

(3) Bottom loading or submerged filling shall be used for the liquid transfer.

(4) Connector pipes and couplers shall be maintained in a leak-free condition.

(5) Connections of hoses and pipes used during liquid transfer operations shall be supported on drip trays that collect any leaks, and the materials collected shall be returned to the process or disposed of in a manner compliant with state law.

(6) Liquid leaks that occur shall be cleaned and disposed of in a manner that prevents emissions to the atmosphere, and the material collected shall be returned to the process or disposed of in a manner compliant with state law.

(7) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator shall visually inspect the transfer equipment during a transfer operation to ensure that liquid transfer lines, hoses, couplings, valves, and pipes are not dripping or leaking. Leaking components shall be repaired to prevent dripping or leaking before the next transfer operation.

(2) The owner or operator of a liquid transfer operation controlled by a control device must follow manufacturer recommended operation and maintenance procedures for the device.

(3) Tanker trucks and tanker rail cars used in liquid transfer service shall be tested annually for vapor tightness in accordance with the following test methods and vapor tightness standards:

(a) method 27 of appendix A of 40 CFR Part 60. Conduct the test using a time period (t) for the pressure and vacuum tests of five minutes. The initial pressure (Pi) for the pressure test shall be 460 mm H₂O (18 inches H₂O), gauge. The initial vacuum (Vi) for the vacuum test shall be 150 mm H₂O (six inches H₂O) gauge. The maximum allowable pressure and vacuum changes (Δp , Δv) are shown in table 1 of 20.2.50.120 NMAC.

Table 1 - ALLOWABLE CARGO TANK TEST PRESSURE OR VACUUM CHANGE

Cargo tank or compartment capacity, liters (gallons)	Allowable vacuum change (Δv) in five minutes, mm H ₂ O (inches H ₂ O)	Allowable pressure change (Δp) in five minutes, mm H ₂ O (inches H ₂ O)
< 3,785 (< 1,000)	64 (2.5)	102 (4.0)
3,785 < 5,678 (1,000 < 1,500)	51 (2.0)	89 (3.5)
5,678 < 9,464 (1,500 < 2,500)	38 (1.5)	76 (3.0)
> 9,464 (> 2,500)	25 (1.0)	64 (2.5)

(b) pressure test the tanker truck or tanker railcar tank's internal vapor valve as follows:

(i) after completing the tests under Subparagraph (a) of Paragraph (3) of Subsection C of 20.2.50.120 NMAC, use the procedures in method 27 to re-pressurize the tank to 460 mm H₂O (18 inches H₂O) gauge. Close the tank's internal vapor valve, thereby isolating the vapor return line and manifold from the tank.

(ii) relieve the pressure in the vapor return line to atmospheric pressure, then reseal the line. After five minutes, record the gauge pressure in the vapor return line and manifold. The maximum allowable five-minute pressure increase is 130 mm H₂O (five inches H₂O).

(4) Owners and operators complying with Paragraph (1) of Subsection B of 20.2.50.120 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(5) Owners and operators shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain a record of the location of the storage vessel and if using a control device, the type, make, and model of the control device:

(2) The owner or operator shall maintain a record of the inspections and testing required in Subsection C of 20.2.50.120 NMAC and shall include the following:

(a) the time and date of the inspection and testing;

(b) the name of the personnel conducting the inspection and testing;

(c) a description of any problem observed during the inspection and testing; and

(d) the results of the inspection and testing and a description of any repair or corrective action taken.

(3) The owner or operator shall maintain a record for each site of the annual total hydrocarbon liquid transferred and annual total VOC emissions. Each calendar year, the owner or operator shall create a company-wide record summarizing the annual total hydrocarbon liquid transferred and the annual total calculated VOC emissions.

(4) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.120 NMAC - N, XX/XX/2021]

20.2.50.121 PIG LAUNCHING AND RECEIVING:

A. Applicability: Pipeline pig launching and receiving operations located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that prevents emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of pig launching and receiving operations shall inspect the equipment for a leak using RM 21 or OGI immediately before the commencement and immediately after the

conclusion of the pig launching or receiving operation, and according to the requirements in 20.2.50.116 NMAC.

(3) An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.121 NMAC - N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. Applicability: Natural gas-driven pneumatic controllers and pumps located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.122 NMAC.

B. Emission standards:

(1) A new natural gas-driven pneumatic controller or pump shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part.

(3) An existing natural gas-driven pneumatic controller at a site with access to commercial line electrical power, and any existing natural-gas driven pneumatic controller at a transmission compressor station or a natural gas processing plant, shall comply with this Section within six months of the effective date of this Part.

(4) At sites that do not have access to commercial line electrical power, owners and operators shall retrofit their fleet of existing natural gas-driven pneumatic controllers according to the following schedule: shall comply with the requirements of 20.2.50.122 NMAC according to the following schedule:

TABLE 1. REQUIREMENTS FOR EXISTING NATURAL GAS-DRIVEN PNEUMATIC CONTROLLERS

<u>Total Historic Percentage of Non-Emitting Controllers</u>	<u>Additional Percentage Required by May 1, 2023</u>	<u>Maximum Percentage Required by May 1, 2023</u>	<u>Additional Percentage Required by May 1, 2025</u>	<u>Maximum Percentage Required by May 1, 2025</u>
<u>> 75 %</u>	<u>+15%</u>	<u>97%</u>	<u>+5%</u>	<u>98%</u>
<u>> 60-75%</u>	<u>+20%</u>	<u>90%</u>	<u>+10%</u>	<u>98%</u>
<u>> 40-60 %</u>	<u>+25%</u>	<u>75%</u>	<u>+20%</u>	<u>95%</u>
<u>> 20-40 %</u>	<u>+35%</u>	<u>65%</u>	<u>+25%</u>	<u>90%</u>
<u>0-20 %</u>	<u>+40%</u>	<u>55%</u>	<u>+35%</u>	<u>90%</u>

Table 1— WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES

<u>Total Historic Percentage of Non-Emitting Controllers</u>	<u>Total Required Percentage of Non-Emitting Controllers by January 1, 2024</u>	<u>Total Required Percentage of Non-Emitting Controllers by January 1, 2027</u>	<u>Total Required Percentage of Non-Emitting Controllers by January 1, 2030</u>

~~>75 %~~	80%	85%	90%
~~>60-75 %~~	80%	85%	90%
~~>40-60 %~~	65%	70%	80%
~~>20-40 %~~	45%	70%	80%
~~0-20 %~~	25%	65%	80%

Table 2—~~NATURAL GAS COMPRESSOR STATIONS AND GAS PROCESSING PLANTS~~

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
~~>75 %~~	80%	95%	98%
~~>60-75 %~~	80%	95%	98%
~~>40-60 %~~	65%	95%	98%
~~>20-40 %~~	50%	95%	98%
~~0-20 %~~	35%	95%	98%

(45) Standards for natural gas-driven pneumatic controllers.

(a) new pneumatic controllers shall have an emission rate of zero.

(b) existing pneumatic controllers at sites with access to commercial line electrical power, and any existing pneumatic controller at a transmission compressor station or a natural gas processing plant, shall have an emission rate of zero.

(c) At sites without access to commercial line electrical power, existing pneumatic controllers shall meet the required percentage of non-emitting controllers within the deadlines in tables 1 ~~and 2~~ of Paragraph (34) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's affected facilities that commenced construction before the effective date of this Part. The total controller count must include all emitting pneumatic controllers and all non-emitting pneumatic controllers, except that pneumatic controllers that are permitted under Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC, necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of tables 1 ~~and 2~~ of Paragraph (34) of Subsection B of 20.2.50.122 NMAC apply and the replacement schedule the owner or operator must meet.

~~(v) if an owner or operator meets at least seventy five percent total non-emitting controllers by January 1, 2025, the owner or operator has satisfied the requirements of tables 1 and 2 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC.~~

~~(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.~~

(d) a pneumatic controller with a bleed rate greater than ~~six standard cubic feet per hour~~ zero is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer.

(56) Standards for natural gas-driven pneumatic pumps.

(a) pneumatic pumps located at a natural gas processing plants shall have an emission rate of zero.

(b) pneumatic pumps located at a wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have an emission rate of zero.

(c) owners and operators of pneumatic pumps located at wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations without access to commercial line electrical power shall reduce VOC emissions from the pneumatic pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device.

(6) The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.

C. Monitoring requirements:

(1) Pneumatic controllers or pumps with a natural gas bleed rate equal to zero are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a pneumatic controller subject to the deadlines set forth in tables 1 and 2 of Paragraph (34) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject controller at each facility.

(3) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall, on a monthly basis, scan the controller and conduct an AVO inspection, and shall also inspect the pneumatic controller, perform necessary maintenance (such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and maintain the pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Paragraph (3) of Subsection C or Subsection D of 20.2.50.116 NMAC. During instrumental inspections, operators shall use Method 21, OGI, or alternative instruments used under Subsection D of 20.2.50.116 to verify that intermittent controllers are not emitting when not actuating. Any intermittent controller emitting when not actuating shall be repaired consistent with Subsection E of 20.2.50.116 NMAC.

(5) The EMT shall be linked to a database that contains the following:

- (a) pneumatic controller identification number;
- (b) type of controller (continuous or intermittent);
- (c) if continuous, design continuous bleed rate in standard cubic feet per hour;
- (d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and
- (e) design annual bleed in standard cubic feet per year.

~~(5)~~ (6) The owner or operator of a pneumatic pump with a bleed rate greater than zero shall, on a monthly basis, scan the pump and conduct an AVO inspection and shall also inspect the pneumatic pump and perform necessary maintenance, and maintain the pneumatic pump according to manufacturer specifications to ensure that the VOC emissions are minimized.

~~(6)~~ (7) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) Pneumatic controllers and pumps with a natural gas bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of the total controller count for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include all emitting and non-emitting pneumatic controllers.

(3) The owner or operator shall maintain a record of the total count of pneumatic controllers necessary for a safety or process purpose that cannot otherwise be met without emitting VOC.

(4) The owner or operator of a pneumatic controller subject to the requirements in tables 1 and 2 of Paragraph (34) of shall generate a schedule for meeting the compliance deadlines for each pneumatic controller. The owner or operator shall keep a record of the compliance status of each subject controller.

(5) The owner or operator shall maintain an electronic record for each pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

- (a) pneumatic controller identification number;
- (b) inspection dates;

(c) name of the personnel conducting the inspection;
 (d) AVO inspection result;
 (e) AVO level discrepancy in continuous or intermittent bleed rate;
 (f) maintenance date and maintenance activity; and
 (g) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(6) The owner or operator of a natural gas-driven pneumatic controller with a bleed rate greater ~~than six standard cubic feet per hour~~zero shall maintain a record in the EMT database of the pneumatic controller documenting why a bleed rate greater than ~~six scfh~~zero is necessary, as required in Subsection B of 20.2.50.122 NMAC.

(7) The owner or operator shall maintain a record in the EMT database for a natural gas-driven pneumatic pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(8) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

(9) The owner or operator of a pneumatic controller with a bleed rate greater than zero shall comply with the requirements in Subsection F of 20.2.50.116 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
 [20.2.50.122 NMAC - N, XX/XX/2021]

20.2.50.123 STORAGE VESSELS

A. Applicability: Storage vessels with an uncontrolled PTE equal to or greater than two tpy of VOC and located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, or transmission compressor stations are subject to the requirements of 20.2.50.123 NMAC.

B. Emission standards:

(1) An existing storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent no later than three years after the effective date of this Part.

(2) An existing storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent no later than one year after the effective date of this Part.

(3) A new storage vessel with a PTE equal to or greater than two tpy and less than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-five percent upon startup.

(4) A new storage vessel with a PTE equal to or greater than 10 tpy of VOC shall have a combined capture and control of VOC emissions of at least ninety-eight percent upon startup.

(5) The emission standards in Subsection B of 20.2.50.123 NMAC cease to apply to a storage vessel if the uncontrolled actual annual VOC emissions decrease to less than two tpy.

(6) If a control device is not installed by the date specified in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC, an owner or operator may comply with Subsection B of 20.2.50.123 NMAC by shutting in the well supplying the storage vessel by the applicable date, and not resuming production from the well until the control device is installed and operational.

(7) The owner or operator of a new or existing storage vessel with a thief hatch shall install a control device that allows the thief hatch to open sufficiently to relieve overpressure in the vessel and to automatically close once the vessel overpressure is relieved. The thief hatch shall be equipped with a manual lock-open safety device to ensure positive hatch opening during times of human ingress. The lock-open safety device shall only be engaged when an owner or operator are present and during an active ingress activity.

(8) The owner or operator of a new or existing storage vessel shall install an EMT on the

storage vessel in accordance with 20.2.50.112 NMAC.

(9) An owner or operator complying with Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the control device operational requirements in 20.2.50.115 NMAC.

C. Storage Vessel Measurement Requirements

(1) The owners and operators of controlled storage tanks at well production facilities, natural gas compressor stations, or natural gas processing plants constructed on or after the effective date of this Part, and at any facilities that are modified on or after the effective date of this Part such that an additional controlled storage vessel is constructed to receive an anticipated increase in throughput of hydrocarbon liquids or produced water, must use a storage vessel measurement system to determine the quantity of liquids in the storage tank(s).

(2) Owners and operators subject to the storage vessel measurement system requirements in this Subsection must keep thief hatches (or other access points to the tank) and pressure relief devices on storage tanks closed and latched during activities to determine the quality and/or quantity of liquids in the storage vessel(s).

(3) Operators may inspect, test, and calibrate the storage vessel measurement system semi-annually, or as directed by the Bureau of Land Management (see 43 CFR Section 3174.6(b)(5)(ii)(B) (November 17, 2016)) or system manufacturer. Opening the thief hatch if required to inspect, test, or calibrate the system is not a violation of Paragraph (1) of this Subsection.

(4) The owner or operator must install signage at or near the storage vessel that indicates which equipment and method(s) are used and the appropriate and necessary operating procedures for that system.

(5) The owner or operator must develop and implement an annual training program for employees and third parties conducting activities subject to this Subsection that includes, at a minimum, operating procedures for each type of system.

(6) Owner or operators must retain records for at least two (2) years and make such records available to the department upon request, including:

(a) Date of construction of the storage vessel or facility;

(b) Description of the storage vessel measurement system used to comply with this

Subsection;

(c) Date(s) of storage vessel measurement system inspections, testing, and calibrations pursuant to Paragraph (3) of this Subsection;

(d) Manufacturer specifications regarding storage vessel measurement system inspections, and/or calibrations, if followed pursuant to Paragraph (3) of this Subsection; and

(e) Records of the annual training program, including the date and names of persons trained.

DE. Monitoring requirements: The owner or operator of a storage vessel shall:

(1) monitor on a monthly basis the total monthly liquid throughput (in barrels) and the upstream separator pressure (in psig). When a storage vessel is unloaded less frequently than monthly, the throughput and separator pressure monitoring shall be conducted before the storage vessel is unloaded;

(2) conduct an AVO inspection on a weekly basis. If the storage vessel is unloaded less frequently than weekly, the AVO inspection shall be conducted before the storage vessel is unloaded;

(3) inspect the vessel monthly to ensure compliance with the requirements of 20.2.50.123 NMAC. The inspection shall include a check to ensure the vessel does not have a leak;

(4) scan the EMT and enter the required monitoring data in accordance with the requirements of 20.2.50.112 NMAC;

(5) comply with the monitoring requirements in 20.2.50.115 NMAC if using a control device to comply with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC; and

(6) comply with the monitoring requirements in 20.2.50.112 NMAC.

ED. Recordkeeping requirements:

(1) The owner or operator shall, on a monthly basis, maintain a record in accordance with 20.2.50.112 NMAC for a storage vessel. The record shall include:

(a) the vessel location and identification number;

(b) monthly liquid throughput and the most recent date of measurement;

(c) the average monthly upstream separator pressure;

(d) the data and methodology used to calculate the PTE of VOC (the calculation methodology shall be department approved);

(e) the controlled and uncontrolled VOC emissions (tpy); and

(f) the type, make, model, and identification number of any control device.

(2) A record of liquid throughput in shall be verified by a dated delivery receipt from the purchaser of the hydrocarbon liquid, the metered volume of hydrocarbon liquid sent downstream, or other proof of transfer.

(3) A record of the inspection required in Subsection C of 20.2.50.123 NMAC shall include:

- (a) the time and date of the inspection;
- (b) the personnel conducting the inspection;
- (c) a notation that the required leak check was completed;
- (d) a description of any problem observed during the inspection; and
- (e) a description and date of any corrective action taken.

(4) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the recordkeeping requirements in 20.2.50.115 NMAC.

(5) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

~~FF.~~ Reporting requirements:

(1) An owner or operator complying with the requirements in Paragraphs (1) through (4) of Subsection B of 20.2.50.123 NMAC through use of a control device shall comply with the reporting requirements in 20.2.50.15 NMAC.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

[20.2.50.123 NMAC - N, XX/XX/2021]

20.2.50.124 WELL WORKOVERS

A. Applicability: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. Emission standards: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. Monitoring requirements:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall keep the following record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the management practices used to minimize release of VOC before and during the workover; and

(g) calculation of the VOC emissions vented during the workover based on the duration, volume, and mass of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

1 **E. Reporting requirements**

2 (1) The owner or operator shall comply with the reporting requirements in 20.2.50.112
3 NMAC.

4 (2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from
5 a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of
6 the well of the planned workover at least three calendar days before the workover event.
7 [20.2.50.124 NMAC - N, XX/XX/2021]

8
9 **20.2.50.125 SMALL BUSINESS FACILITIES**

10 **A. Applicability:** Small business facilities as defined in this Part are subject to the requirements of
11 20.2.50.125 NMAC.

12 **B. General requirements:**

13 (1) The owner or operator shall ensure that all equipment is operated and maintained
14 consistent with manufacturer specifications, and good engineering and maintenance practices. The owner or operator
15 shall keep manufacturer specifications and maintenance practices on file and make them available to the department
16 upon request.

17 (2) The owner or operator shall calculate the VOC and NO_x emissions from the facility on an
18 annual basis. The calculation shall be based on the actual production or processing rates of the facility.

19 (3) The owner or operator shall maintain a database of company-wide VOC and NO_x
20 emission calculations for all subject facilities and associated equipment and shall update the database annually.

21 (4) The owner or operator shall comply with Paragraph (10) of Subsection A of 20.2.50.112
22 NMAC if requested by the department.

23 **C. Monitoring requirements:** The owner or operator shall comply with the requirements in
24 Subsections C or D of 20.2.50.116 NMAC.

25 **D. Repair requirements:** The owner or operator shall comply with the requirements of Subsection
26 E of 20.2.50.116 NMAC.

27 **E. Recordkeeping requirements:** The owner or operator shall maintain the following electronic
28 records for each facility:

29 (1) annual certification that the small business facility meets the definition in this Part;

30 (2) calculated VOC and NO_x emissions from each facility and the company-wide VOC and
31 NO_x emissions for all subject facilities;

32 (3) records as required under Subsection F of 20.2.50.116 NMAC.

33 **F. Reporting requirements:** The owner or operator shall submit to the department an initial small
34 business certification within sixty days of the effective date of this Part, and by March 1 each calendar year
35 thereafter. The certification shall be made on a form provided by the department. The owner or operator shall
36 comply with the reporting requirements in 20.2.50.112 NMAC.

37 **G. Failure to comply with 20.2.50.125 NMAC:** Notwithstanding the provisions of Section
38 20.2.50.125 NMAC, a source that meets the definition of a small business facility can be required to comply with
39 the other Sections of 20.2.50 NMAC if the Secretary finds based on credible evidence that the source (1) presents an
40 imminent and substantial endangerment to the public health or welfare or to the environment; (2) is not being
41 operated or maintained in a manner that minimizes emissions of air contaminants; or (3) has violated any other
42 requirement of 20.2.50.125 NMAC.
43 [20.2.50.125 NMAC - N, XX/XX/2021]

44
45 **20.2.50.126 PRODUCED WATER MANAGEMENT UNITS**

46 **A. Applicability:** Produced water management units as defined in this Part are subject to
47 20.2.50.126 NMAC and shall comply with these requirements no later than 180 days after the effective date of this
48 Part.

49 **B. Emission standards:**

50 (1) The owner or operator shall use best management and good engineering practices to
51 minimize emissions of VOC from produced water management units.

52 (2) The owner or operator shall control VOC emissions from each produced water
53 management unit to less than two tons per year.

54 **C. Monitoring requirements:** The owner or operator shall:

55 (1) calculate the monthly rolling 12-month total of VOC emissions in tons from each unit;

56 (2) monthly, monitor the best management and engineering practices implemented to reduce

emissions at each unit to ensure their effectiveness; and

(3) comply with the monitoring requirements in 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator shall maintain the following electronic records for each produced water management unit:

(a) name or identification of the unit and UTM coordinates of the unit and county;

(b) a description of the best management and engineering practices used to minimize release of VOC at the unit; and

(c) a record of the monthly rolling 12-month total VOC emissions from each unit.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.
[20.2.50.126 NMAC - N, XX/XX/2021]

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION

A. Failure to comply with the emissions standards, monitoring, recordkeeping, reporting or other requirements of this Part within the timeframes specified shall constitute a violation of this Part subject to enforcement action under Section 74-2-12 NMSA 1978.

B. If credible information obtained by the department indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.

C. If credible information provided to the department by a member of the public indicates that a source is not in compliance with the provisions of this Part, the source shall be presumed to be in violation of this Part unless and until the owner or operator provides credible evidence or information demonstrating otherwise.
[20.2.50.127 NMAC - N, XX/XX/2021]

HISTORY OF 20.2.50 NMAC: [RESERVED]

David R. Lyon, Ph.D.

Environmental Defense Fund
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EDUCATION

University of Arkansas, Fayetteville, AR

Ph.D. in Environmental Dynamics (May 2016)

- Dissertation: *Quantifying, Assessing, and Mitigating Methane Emissions from Super-emitters in the Oil and Gas Supply Chain*
- Honors: 4.0 GPA; Doctoral Academy Fellowship

University of Kentucky, Lexington, KY

M.S. in Forestry (May 2004)

- Thesis: *Persistent Effects of Eastern Redcedar on Calcareous Glade Soils and Plant Community*
- Honors: 4.0 GPA; Garden Club of America 2003 Fellowship in Ecological Restoration

Hendrix College, Conway, AR

B.A. in Biology with Chemistry Minor (June 2002)

- Honors: 3.95 GPA; Summa Cum Laude with Distinction; Phi Beta Kappa

WORK EXPERIENCE

Environmental Defense Fund, Austin, TX

Senior Scientist (May 2021 – present)

- Lead EDF's Permian Methane Analysis project using multiple measurement approaches to quantify oil and gas methane emissions and rapidly publish data online

Environmental Defense Fund, Austin, TX

Scientist (March 2014 – April 2021)

- Contribute to the design, planning, execution, and analysis of EDF-sponsored research studies on quantifying methane emissions from the oil and gas supply chain
- Advise internal and external projects on innovative approaches for leak detection and mitigation
- Prepare and review manuscripts for submission to peer-reviewed journals
- Communicate science and advocacy through presentations, briefings, and media interviews
- Provide scientific expertise to other EDF programs and external groups

Environmental Defense Fund, Austin, TX

Research Analyst (June 2012 – March 2014)

- Research, analyze, synthesize, and interpret data related to oil and gas methane emissions
- Analyze, interpret, and communicate data to policymakers, industry, the scientific community, and other stakeholders in support of EDF advocacy on environmental policy
- Write reports, blogs, and other communication materials for general audiences

University of Arkansas at Little Rock, Little Rock, AR

Part-time Lecturer (January 2012 – May 2012)

- Taught senior-level environmental science course *Fundamentals of Air Pollution*

Arkansas Department of Environmental Quality, North Little Rock, AR

Environmental Program Coordinator (January 2009 – May 2012)

- Obtained EPA funding, managed project, and authored report on a study to develop an emissions inventory and monitor air quality impacts of natural gas development in the Fayetteville Shale
- Managed \$500,000 project to develop and implement a web-based emissions inventory reporting system for a multi-state consortium of environmental agencies
- Led the state's air pollution emissions inventory program, which included approximately 175 regulated facilities and several nonpoint emission source categories
- Analyzed emissions data and produced reports for the agency and public
- Analyzed current and proposed federal air regulations to assist agency planning
- Supervised up to four staff

University of Arkansas, Fayetteville, AR

Graduate Assistant (August 2004 – December 2008)

- Performed research on the effects of nutrient enrichment on stream carbon cycling
- Assisted students in general ecology laboratory

University of Kentucky, Lexington, KY

Graduate Assistant (June 2002 – June 2004)

- Performed research in restoration ecology and soil biogeochemistry of calcareous glades
- Taught dendrology and tree species identification to undergraduate students

PUBLICATIONS

Lyon, D. R., Hmiel, B., Gautam, R., Omara, M., Roberts, K. A., Barkley, Z. R., ... & Hamburg, S. P. (2021). Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic. *Atmospheric Chemistry and Physics*, 21(9), 6605-6626.

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GREENHOUSE GASES

Assessment of methane emissions from the U.S. oil and gas supply chain

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Methane emissions from the U.S. oil and natural gas supply chain were estimated by using ground-based, facility-scale measurements and validated with aircraft observations in areas accounting for ~30% of U.S. gas production. When scaled up nationally, our facility-based estimate of 2015 supply chain emissions is 13 ± 2 teragrams per year, equivalent to 2.3% of gross U.S. gas production. This value is ~60% higher than the U.S. Environmental Protection Agency inventory estimate, likely because existing inventory methods miss emissions released during abnormal operating conditions. Methane emissions of this magnitude, per unit of natural gas consumed, produce radiative forcing over a 20-year time horizon comparable to the CO₂ from natural gas combustion. Substantial emission reductions are feasible through rapid detection of the root causes of high emissions and deployment of less failure-prone systems.

Methane (CH₄) is a potent greenhouse gas, and CH₄ emissions from human activities since preindustrial times are responsible for 0.97 W m⁻² of radiative forcing, as compared to 1.7 W m⁻² for carbon dioxide (CO₂) (1). CH₄ is removed from the atmosphere much more rapidly than CO₂; thus, reducing CH₄ emissions can effectively reduce the near-term rate of warming (2). Sharp growth in U.S. oil and natural gas (O/NG) production beginning around 2005 (3) raised concerns about the climate impacts of increased natural gas use (4, 5). By 2012, disagreement among published estimates of CH₄ emissions from U.S. natural gas operations led to a broad consensus that additional data were needed to better characterize emission rates (4–7). A large body of field measurements made between 2012 and 2016 (table S1) has markedly improved understanding of the sources and magnitude of CH₄ emissions from the industry's operations. Brandt *et al.* summarized the early literature (8); other assessments incorporated elements of recent data (9–11). This work synthesizes recent studies to provide an improved overall assessment of emissions from

the O/NG supply chain, which we define to include all operations associated with O/NG production, processing, and transport (materials and methods, section S1.0) (12).

Measurements of O/NG CH₄ emissions can be classified as either top-down (TD) or bottom-up (BU). TD studies quantify ambient methane enhancements using aircraft, satellites, or tower networks and infer aggregate emissions from all contributing sources across large geographies. TD estimates for nine O/NG production areas have been reported to date (table S2). These areas are distributed across the U.S. (fig. S1) and account for ~33% of natural gas, ~24% of oil production, and ~14% of all wells (13). Areas sampled in TD studies also span the range of hydrocarbon characteristics (predominantly gas, predominantly oil, or mixed), as well as a range of production characteristics such as well productivity and maturity. In contrast, BU studies generate regional, state, or national emission estimates by aggregating and extrapolating measured emissions from individual pieces of equipment, operations, or facilities, using measurements made directly at the emission point or, in the case of facilities, directly downwind.

Recent BU studies have been performed on equipment or facilities that are expected to represent the vast majority of emissions from the O/NG supply chain (table S1). In this work, we integrate the results of recent facility-scale BU studies to estimate CH₄ emissions from the U.S. O/NG supply chain, and then we validate the results using TD studies (materials and methods). The probability distributions of our BU methodology are based on observed facility-level emissions, in contrast to the component-by-component approach used for conventional inventories. We thus capture enhancements pro-

duced by all sources within a facility, including the heavy tail of the distribution. When the BU estimate is developed in this manner, direct comparison of BU and TD estimates of CH₄ emissions in the nine basins for which TD measurements have been reported indicates agreement between methods, within estimated uncertainty ranges (Fig. 1).

Our national BU estimate of total CH₄ emissions in 2015 from the U.S. O/NG supply chain is $13 (+2.1/-1.6, 95\% \text{ confidence interval})$ Tg CH₄/year (Table 1). This estimate of O/NG CH₄ emissions can also be expressed as a production-normalized emission rate of 2.3% (+0.4%/-0.3%) by normalizing by annual gross natural gas production [33 trillion cubic feet (13), with average CH₄ content of 90 volume %]. Roughly 85% of national BU emissions are from production, gathering, and processing sources, which are concentrated in active O/NG production areas.

Our assessment does not update emissions from local distribution and end use of natural gas, owing to insufficient information addressing this portion of the supply chain. However, recent studies suggest that local distribution emissions exceed the current inventory estimate (14–16), and that end-user emissions might also be important. If these findings prove to be representative, overall emissions from the natural gas supply chain would increase relative to the value in Table 1 (materials and methods, section S1.5).

Our BU method and TD measurements yield similar estimates of U.S. O/NG CH₄ emissions in 2015, and both are significantly higher than the corresponding estimate in the U.S. Environmental Protection Agency's Greenhouse Gas Inventory (EPA GHGI) (Table 1 and materials and methods, section S1.3) (17). Discrepancies between TD estimates and the EPA GHGI have been reported previously (8, 18). Our BU estimate is 63% higher than the EPA GHGI, largely due to a more than twofold difference in the production segment (Table 1). The discrepancy in production sector emissions alone is ~4 Tg CH₄/year, an amount larger than the emissions from any other O/NG supply chain segment. Such a large difference cannot be attributed to expected uncertainty in either estimate: The extremal ends of the 95% confidence intervals for each estimate differ by 20% (i.e., ~12 Tg/year for the lower bound of our BU estimate can be compared to ~10 Tg/year for the upper bound of the EPA GHGI estimate).

We believe the reason for such large divergence is that sampling methods underlying conventional inventories systematically underestimate total emissions because they miss high emissions caused by abnormal operating conditions (e.g., malfunctions). Distributions of measured emissions from production sites in BU studies are invariably “tail-heavy,” with large emission rates measured at a small subset of sites at any single point in time (19–22). Consequently, the most likely hypothesis for the difference between the EPA GHGI and BU estimates derived from facility-level measurements is that measurements used to develop GHGI emission factors

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undersample abnormal operating conditions encountered during the BU work. Component-based inventory estimates like the GHGI have been shown to underestimate facility-level emissions (23), probably because of the technical difficulty and safety and liability risks associated with measuring large emissions from, for example, venting tanks such as those observed in aerial surveys (24).

Abnormal conditions causing high CH₄ emissions have been observed in studies across the O/NG supply chain. An analysis of site-scale emission measurements in the Barnett Shale concluded that equipment behaving as designed could not explain the number of high-emitting production sites in the region (23). An extensive aerial infrared camera survey of ~8000 production sites in seven U.S. O/NG basins found that ~4% of surveyed sites had one or more observable high-emission rate plumes (24) (detection threshold of ~3 to 10 kg CH₄/hour was two to seven times higher than mean production site emissions estimated in this work). Emissions released from liquid storage tank hatches and vents represented 90% of these sightings. It appears that abnormal operating conditions must be largely responsible, because the observation frequency was too high to be attributed to routine operations like condensate flashing or liquid unloadings alone (24). All other observations were due to anomalous venting from dehydrators, separators, and flares. Notably, the two largest sources of aggregate emissions in the EPA GHGI—pneumatic controllers and equipment leaks—were never observed from these aerial surveys. Similarly, a national survey of gathering facilities found that emission rates were four times higher at the 20% of facilities where substantial tank venting emissions were observed, as compared to the 80% of facilities without such venting (25). In addition, very large emissions from leaking isolation valves at transmission and storage facilities were quantified by means of downwind measurement but could not be accurately (or safely) measured by on-site methods (26). There is an urgent need to complete equipment-based measurement campaigns that capture these large-emission events, so that their causes are better understood.

In contrast to abnormal operational conditions, alternative explanations such as outdated component emission factors are unlikely to explain the magnitude of the difference between our facility-based BU estimate and the GHGI. First, an equipment-level inventory analogous to the EPA GHGI but updated with recent direct measurements of component emissions (materials and methods, section S1.4) predicts total production emissions that are within ~10% of the EPA GHGI, although the contributions of individual source categories differ significantly (table S3). Second, we consider unlikely an alternative hypothesis that systematically higher emissions during daytime sampling cause a high bias in TD methods (materials and methods, section S1.6). Two other factors may lead to low bias in EPA GHGI and similar inventory

Table 1. Summary of this work's bottom-up estimates of CH₄ emissions from the U.S. oil and natural gas (O/NG) supply chain (95% confidence interval) and comparison to the EPA Greenhouse Gas Inventory (GHGI).

Industry segment	2015 CH ₄ emissions (Tg/year)	
	This work (bottom-up)	EPA GHGI (17)
Production	7.6 (+1.9/−1.6)	3.5
Gathering	2.6 (+0.59/−0.18)	2.3
Processing	0.72 (+0.20/−0.071)	0.44
Transmission and storage	1.8 (+0.35/−0.22)	1.4
Local distribution*	0.44 (+0.51/−0.22)	0.44
Oil refining and transportation*	0.034 (+0.050/−0.008)	0.034
U.S. O/NG total	13 (+2.1/−1.7)	8.1 (+2.1/−1.4) [†]

*This work's emission estimates for these sources are taken directly from the GHGI. The local distribution estimate is expected to be a lower bound on actual emissions and does not include losses downstream of customer meters due to leaks or incomplete combustion (materials and methods, section S1.5).

[†]The GHGI only reports industry-wide uncertainties.

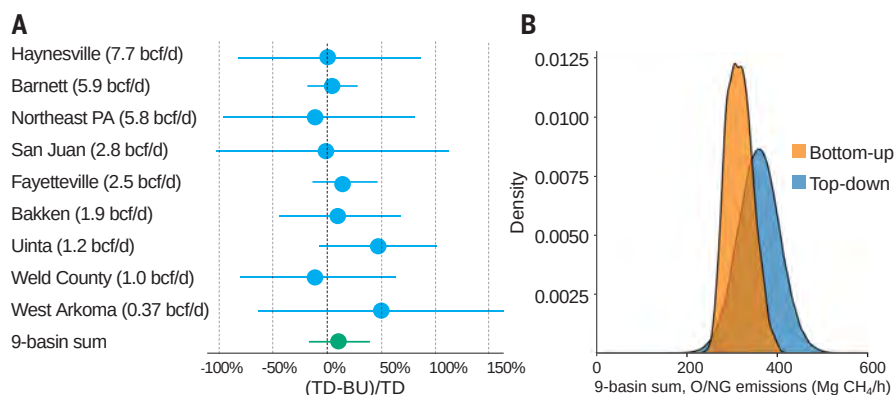


Fig. 1. Comparison of this work's bottom-up (BU) estimates of methane emissions from oil and natural gas (O/NG) sources to top-down (TD) estimates in nine U.S. O/NG production areas. (A) Relative differences of the TD and BU mean emissions, normalized by the TD value, rank ordered by natural gas production in billion cubic feet per day (bcf/d, where 1 bcf = 2.8×10^7 m³). Error bars represent 95% confidence intervals. (B) Distributions of the nine-basin sum of TD and BU mean estimates (blue and orange probability density, respectively). Neither the ensemble of TD-BU pairs (A) nor the nine-basin sum of means (B) are statistically different [$p = 0.13$ by a randomization test, and mean difference of 11% (95% confidence interval of −17 to 41%)].

estimates. Operator cooperation is required to obtain site access for emission measurements (8). Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The potential bias due to this “opt-in” study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with limited or no operator forewarning to construct our BU estimate. Another possible source of bias is measurement error. It has been suggested that malfunction of a measurement instrument widely used in the O/NG industry contributes to underestimated emissions in inventories (27); however, this cannot explain the more than twofold difference in production emissions (28).

The tail-heavy distribution for many O/NG CH₄ emission sources has important implications for mitigation because it suggests that most sources—whether they represent whole facilities or individual pieces of equipment—can have lower emissions when they operate as designed. We anticipate that significant emissions reductions could be achieved by deploying well-designed emission detection and repair systems that are capable of identifying abnormally operating facilities or equipment. For example, pneumatic controllers and equipment leaks are the largest emission sources in the O/NG production segment exclusive of missing emission sources (38 and 21%, respectively; table S3), with malfunctioning controllers contributing 66% of total pneumatic controller emissions (materials and methods, section S1.4) and equipment leaks 60% higher than the GHGI estimate.

Gathering operations, which transport unprocessed natural gas from production sites to processing plants or transmission pipelines, produce ~20% of total O/NG supply chain CH₄ emissions. Until the publication of recent measurements (29), these emissions were largely unaccounted by the EPA GHGI. Gas processing, transmission and storage together contribute another ~20% of total O/NG supply chain emissions, most of which come from ~2500 processing and compression facilities.

Our estimate of emissions from the U.S. O/NG supply chain (13 Tg CH₄/year) compares to the EPA estimate of 18 Tg CH₄/year for all other anthropogenic CH₄ sources (17). Natural gas losses are a waste of a limited natural resource (~\$2 billion/year), increase global levels of surface ozone pollution (30), and substantially erode the potential climate benefits of natural gas use. Indeed, our estimate of CH₄ emissions across the supply chain, per unit of gas consumed, results in roughly the same radiative forcing as does the CO₂ from combustion of natural gas over a 20-year time horizon (31% over 100 years). Moreover, the climate impact of 13 Tg CH₄/year over a 20-year time horizon roughly equals that from the annual CO₂ emissions from all U.S. coal-fired power plants operating in 2015 (31% of the impact over a 100-year time horizon) (materials and methods, section S1.7).

We suggest that inventory methods would be improved by including the substantial volume of missing O/NG CH₄ emissions evident from the large body of scientific work now available and synthesized here. Such empirical adjustments based on observed data have been previously used in air quality management (31).

The large spatial and temporal variability in CH₄ emissions for similar equipment and facilities (due to equipment malfunction and other abnormal operating conditions) reinforces the conclusion that substantial emission reductions are feasible. Key aspects of effective mitigation include pairing well-established technologies and best practices for routine emission sources with economically viable systems to rapidly detect the root causes of high emissions arising from abnormal conditions. The latter could involve combinations of current technologies such as on-site leak surveys by company personnel using optical gas imaging (32), deployment of passive sensors at individual facilities (33, 34) or mounted on ground-based work trucks (35), and in situ remote-sensing approaches using

tower networks, aircraft, or satellites (36). Over time, the development of less failure-prone systems would be expected through repeated observation of and further research into common causes of abnormal emissions, followed by re-engineered design of individual components and processes.

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SUPPLEMENTARY MATERIALS

www.sciencemag.org/content/361/6398/186/suppl/DC1
Materials and Methods
Additional Author Disclosures
Figs. S1 to S11
Tables S1 to S12
References (37–77)
Databases S1 and S2

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ENVIRONMENTAL STUDIES

Quantifying methane emissions from the largest oil-producing basin in the United States from space

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Using new satellite observations and atmospheric inverse modeling, we report methane emissions from the Permian Basin, which is among the world's most prolific oil-producing regions and accounts for >30% of total U.S. oil production. Based on satellite measurements from May 2018 to March 2019, Permian methane emissions from oil and natural gas production are estimated to be $2.7 \pm 0.5 \text{ Tg a}^{-1}$, representing the largest methane flux ever reported from a U.S. oil/gas-producing region and are more than two times higher than bottom-up inventory-based estimates. This magnitude of emissions is 3.7% of the gross gas extracted in the Permian, i.e., ~60% higher than the national average leakage rate. The high methane leakage rate is likely contributed by extensive venting and flaring, resulting from insufficient infrastructure to process and transport natural gas. This work demonstrates a high-resolution satellite data-based atmospheric inversion framework, providing a robust top-down analytical tool for quantifying and evaluating subregional methane emissions.

INTRODUCTION

Methane is a potent greenhouse gas with a relatively short average atmospheric residence time of about a decade and is also a precursor of tropospheric ozone (1). The emission-based radiative forcing for methane (including effects on tropospheric ozone and stratospheric water vapor) is 0.97 W m^{-2} since preindustrial times, which is about 60% of that for CO_2 (2). Roughly a third of the contemporary anthropogenic methane emissions come from the fossil fuel energy sector worldwide (oil, natural gas, and coal) (~100 to 180 Tg a^{-1}) (3, 4, 5). Curbing anthropogenic methane emissions, including those from the oil/gas sector, is considered an effective strategy to slow the rate of near-term climate warming (1). However, the rapid increase in oil and natural gas (O/G) production in the United States since around 2005, driven primarily by hydraulic fracturing and horizontal drilling, has led to major concerns about increasing methane emissions and adverse climate impacts (6). By upscaling data collected from field measurements in some of the largest O/G production basins in the United States, Alvarez *et al.* (7) estimated 13 Tg annual methane emissions from the national O/G supply chain for 2015, which is 60% higher than the official estimates by the U.S. Environmental Protection Agency (EPA) (8). The largest discrepancy was found in the O/G production segment where the estimate by Alvarez *et al.* (7) (7.6 Tg a^{-1}) was more than two times that by EPA, which relies on inventory-based estimates (3.5 Tg a^{-1}) (8).

While field measurements provide in-depth information about a particular site or area, it is often challenging to expand the measurement capacity to observe a diverse set of targets distributed globally over longer periods of time. Additional challenges exist for areas that are difficult to access for technical or proprietary reasons. On the other hand, global satellite observations of column atmospheric methane offer a unique vantage point to identify emission hot spots and quantify regional emissions (9). Using data from Scanning Imaging Absorption spectroMeter for Atmospheric CHartography (SCIAMACHY) satellite observations averaged between 2003 and 2009, Kort *et al.* (10) found large anomalous methane levels from the Four Corners region in the United States, with total methane emissions associated with natural gas, coal, and coalbed sources estimated as $0.59 \pm 0.08 \text{ Tg a}^{-1}$. While the SCIAMACHY data were fairly limited in spatial resolution ($30 \text{ km} \times 60 \text{ km}$) and measurement precision [30 parts per billion in volume or (ppbv)] (9), it was the first time that satellite observations were used to quantify a dense O/G-related methane emission hot spot. This finding also led to several dedicated airborne studies to better understand methane sources in the region (11, 12), which reported methane fluxes comparable to the satellite-based estimate (10).

Here, we demonstrate and exploit the capability of a recent spaceborne sensor, the Tropospheric Monitoring Instrument (TROPOMI), to map atmospheric methane enhancements in the United States and quantify emissions from the Permian Basin (Fig. 1), which has become one of the world's most prolific oil-producing regions in recent years due to advances in drilling technologies. Located in New Mexico and Texas in a region of $\sim 400 \text{ km} \times 400 \text{ km}$, Permian is currently the largest oil-producing basin in the United States. In 2018, the Permian Basin produced $5.5 \times 10^5 \text{ m}^3$ (or 3.5 million barrels) of crude oil and $3.2 \times 10^8 \text{ m}^3$ (or 11 billion feet^3) of natural gas every day (~30 and ~10% of the U.S. national totals, respectively), which was 4 and 2.5 times their corresponding levels in 2007 (around the time of SCIAMACHY observations) (Fig. 2) (13). While the surging production in the Permian Basin and its importance in the U.S. oil boom during the last decade have been widely covered in mass

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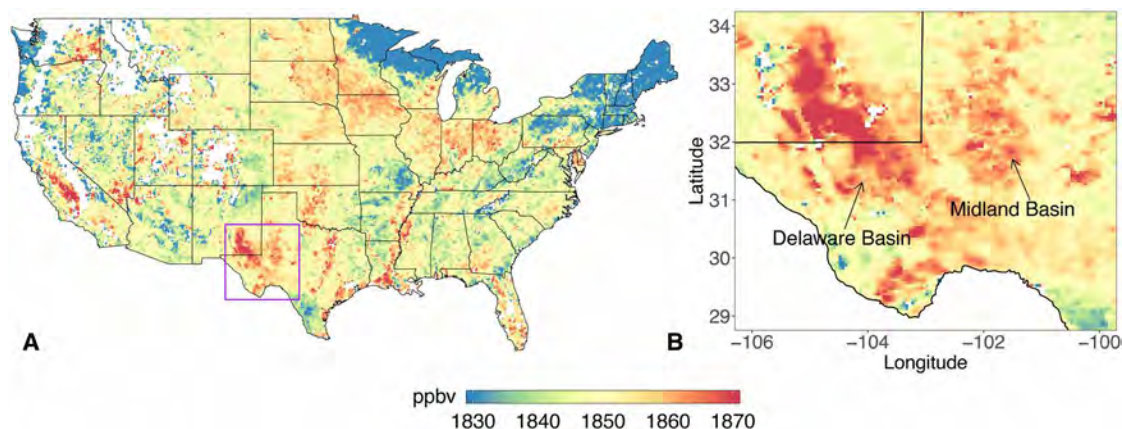


Fig. 1. Satellite observations of the Permian methane anomaly. TROPOMI satellite data derived elevation-corrected column methane mixing ratio for (A) the conterminous United States and (B) the Permian Basin containing the Delaware and Midland sub-basins. White shading represents missing data. Purple boundary in (A) indicates the study domain encompassing the Permian Basin. Methane averages are computed from monthly means of TROPOMI measurements during May 2018 and March 2019.

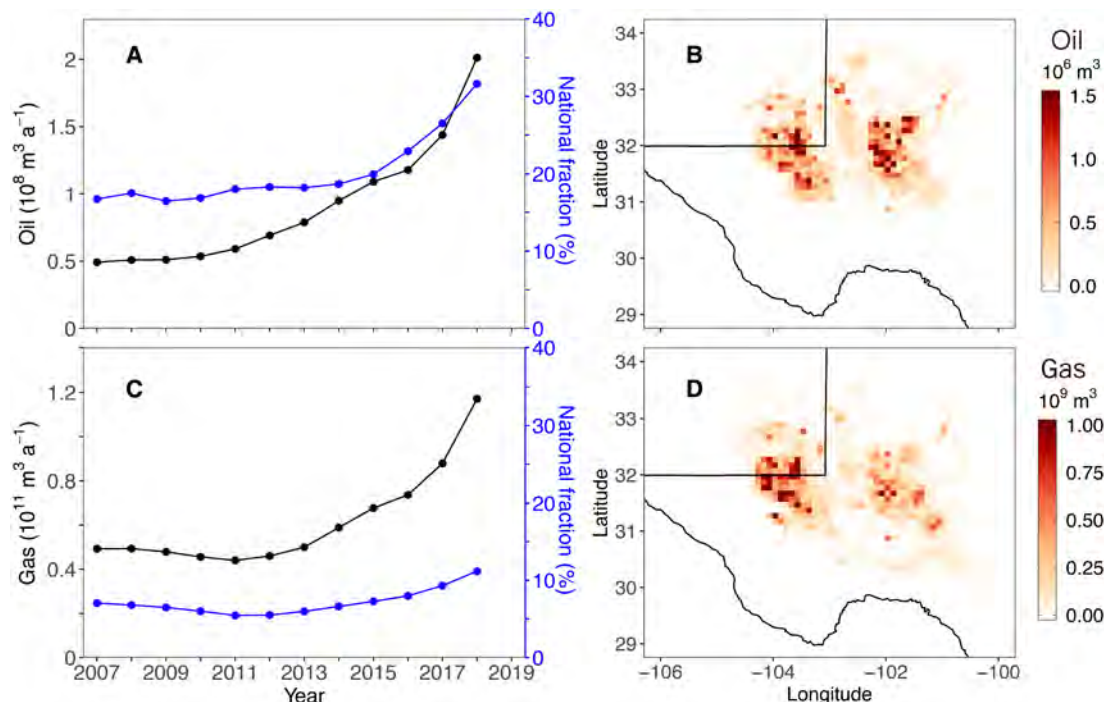


Fig. 2. Oil and gas production in the Permian Basin. (A and C) Time series of annual O/G production in black and the corresponding fractions of total U.S. production in blue [data from the Drilling Productivity Report by EIA (13)]. (B and D) Spatial distribution of oil and gas production for 2018 [data from Enverus Drillinginfo (50)]. Oil production includes both crude and condensate production. Gas production represents gross (before processing) gas production.

media (14), the scale of associated methane emissions from this critical O/G basin is unknown, despite reports of increased flaring and venting activity (15).

Using 11 months of recent data acquired by TROPOMI during 2018–2019, we focus on the distinct methane concentration anomaly over the Permian Basin and quantify the associated methane emissions with a state-of-the-art atmospheric inverse modeling framework. TROPOMI was launched in October 2017 onboard the European Space Agency's Sentinel-5P satellite and provides column atmospheric methane measurements with higher spatial resolution (7 km × 7 km at nadir) and precision (0.6%) than was previously available (16), providing near-daily global coverage with its large 2600-km-wide

swath (17). Our integrated satellite-based approach provides new insights into the dynamic landscape of O/G-related methane emissions in the United States and should pave the way forward toward routine quantification, monitoring, and evaluation of methane emissions from source regions distributed globally.

RESULTS

Satellite observations of the Permian methane anomaly

Figure 1A shows a map of column-averaged dry-air methane mixing ratio over the conterminous United States, retrieved from TROPOMI measurements, with correction for the topography effect (denoted

as XCH_4^t ; see Materials and Methods). The data are averaged from May 2018 to March 2019. Substantial enhancements of XCH_4^t relative to the surrounding background, up to ~ 30 ppbv, are found over the Permian Basin, indicating strong methane emissions. Other notable enhancements are observed in California's central valley, coastal Southeast, and the Mississippi River Valley, likely associated with anthropogenic (agriculture, dairy) and natural (wetland) sources. The elevated methane levels in central California were also seen earlier in the SCIAMACHY analysis (10).

The methane enhancements over the Permian Basin show a characteristic two-branch pattern, which aligns with the two major O/G production sub-basins, the Delaware basin to the west and the Midland basin to the east (Fig. 1B). The enhancement over the Delaware basin, where extensive new exploitation has taken place during the last 5 years (18) (fig. S1), is larger than that over the Midland basin (Fig. 1B). Intensive O/G production activity in these two sub-basins is also captured by satellite observations of radiant heat from gas flaring [Fig. 3A; nighttime observations by the Visible Infrared Imaging Radiometer Suite (VIIRS)] and NO_2 tropospheric column densities (Fig. 3B; daytime observations by TROPOMI). Flaring is a common practice in O/G operations to burn off unwanted or excess gas, and NO_2 is a gaseous pollutant released during gas flaring and other combustion activities in O/G fields (19, 20). On the basis of measurements by the VIIRS instrument onboard the Suomi National Polar-orbiting Partnership satellite, we estimate an average flaring rate of 5.9 ± 1.2 billion $\text{m}^3 \text{a}^{-1}$ during the period of this study, about 4.6% of the gross gas production (see text S1). A fourfold increase in flaring intensity since 2012, observed by the VIIRS instrument, is indicative of the rapid growth in O/G production across the Permian Basin (fig. S1).

Methane emission quantification

We quantify the methane emission rate from the Permian Basin and its spatial distribution with atmospheric inverse modeling, which optimizes spatially resolved methane emission rates by drawing information from TROPOMI observations and the prior emission estimate following the Bayesian rule. The inversion seeks to optimize monthly methane emission rates resolved at $0.25^\circ \times 0.3125^\circ$ horizontal resolution in a study domain containing the Permian Basin and the surrounding region (29° – 34°N , 100° – 106°W). The solution to the

optimization is found analytically with closed-form characterization of the error statistics (3). An atmospheric transport model (a nested version of GEOS-Chem over North America with a $0.25^\circ \times 0.3125^\circ$ horizontal resolution) (21) is used as the forward model to relate atmospheric methane columns with ground-level emissions in the study domain and the contributions from outside the domain. The optimization by the inversion significantly reduces the observation-model mismatch with decreased root mean square error (prior, 23 ppbv; posterior, 14 ppbv) and increased correlation (R ; prior, 0.30; posterior, 0.62) (fig. S2). See Materials and Methods for more details about the configurations of the inverse modeling including error accounting and prior information.

When aggregating monthly spatially resolved posterior emissions to the basin-level annual average, we find a methane emission flux of $2.9 \pm 0.5 \text{ Tg a}^{-1}$ from the Permian Basin (30° – 34°N , 101° – 105°W) (Fig. 4A; see Materials and Methods for the uncertainty analysis). This estimate is more than a factor of 2 larger than the bottom-up estimate based on an extrapolation of EPA greenhouse gas inventory data (EI_{BU} , 1.2 Tg a^{-1} ; see Materials and Methods) (Fig. 4A), suggesting that current methane emissions in the Permian are under-represented in national bottom-up emission inventories (22). Our inversion result is in close agreement with a basin-level estimate based on extrapolation of limited ground-based site-level measurements in the Permian (EI_{ME} , 2.8 Tg a^{-1}) (Fig. 4A). It should be noted that these site-level measurements were primarily conducted in the New Mexico portion of the Permian Basin and covered only a

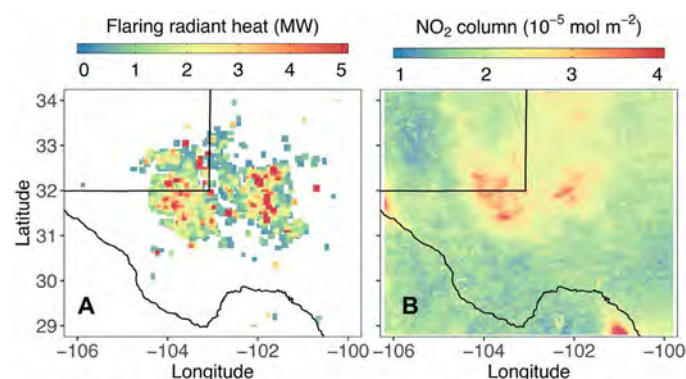


Fig. 3. Satellite observations of gas flaring radiant heat and NO_2 tropospheric column density over the Permian Basin. (A) Gas flaring radiant heat is the annual average of 2018 measured by the VIIRS satellite instrument, and (B) NO_2 tropospheric column density is the 3-month average (June, July, and August of 2018) measured by the TROPOMI instrument, indicating collocated hot spots over the Delaware and Midland sub-basins.

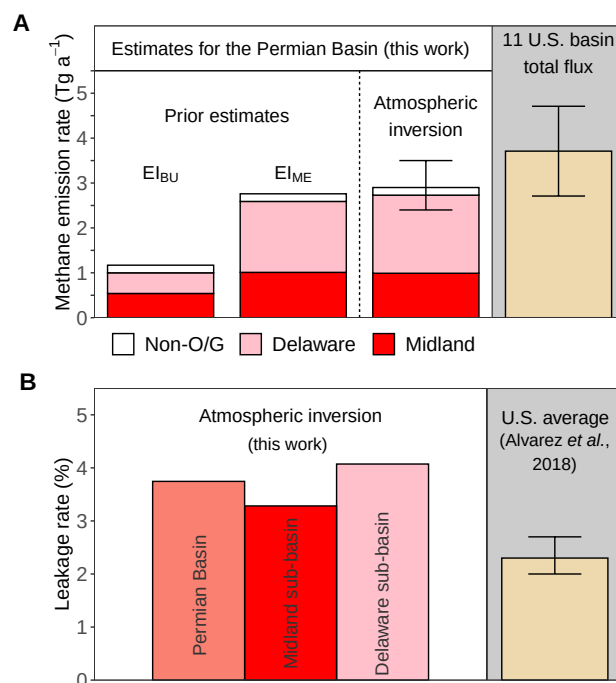


Fig. 4. Methane emission quantification for the Permian Basin. (A) Annual methane emissions from the Permian Basin from two prior emission inventories (EI_{BU} and EI_{ME}), and TROPOMI satellite data-based atmospheric inversion and a mass balance method. The breakdown for Delaware, Midland, and non-O/G sources is shown in pink, red, and white for EI_{BU} , EI_{ME} , and atmospheric inversion, respectively. The estimate for the Permian Basin is compared with total emissions from 11 U.S. basins reported in literature (7, 24, 25) (table S1). (B) Leakage rates for the Permian Basin and two sub-basins, in comparison with the average leakage reported for the entire United States (7).

small fraction of production sites (see Materials and Methods and text S2). As a comparison, we also apply a fast mass balance method following Buchwitz *et al.* (23) to estimate basin-level emissions, which yields an annual mean emission rate of $3.2 \pm 2.0 \text{ Tg a}^{-1}$ for the Permian Basin. This result is consistent with that derived from a full atmospheric inversion. Despite the large uncertainty of the mass balance method, this data-driven approach provides an independent estimate of emissions derived primarily using TROPOMI data (see text S3 for more discussion).

Removing the non-O/G sources (0.2 Tg a^{-1}) from the total flux obtained via the inversion (2.9 Tg a^{-1}), we estimate the methane emissions related to O/G activity to be 2.7 Tg a^{-1} in the Permian Basin. Put in the context of national emissions, this value is approximately one quarter of total emissions from all U.S. oil and gas production areas in 2015 (10.9 Tg a^{-1} , including emissions from production, gathering, and processing, which largely occur in the production areas) (7). Our estimated emission rate for the Permian is significantly higher than those reported in the literature for other major U.S. O/G-producing basins. Table S1 summarizes methane emission estimates for 11 U.S. basins (7, 24, 25) from previous aircraft-based studies [i.e., Haynesville (24, 26), Barnett (24, 27), Northeast Pennsylvania (26, 28), Southwest Pennsylvania (25), San Juan (12), Fayetteville (26, 29), Bakken (24, 30), Uinta (31), Weld (32), West Arkoma (26), Eagle Ford (24), and the Denver Basin (24)]. Our estimate for the Permian (2.7 Tg a^{-1}) is about a factor of 4 higher than the largest methane emissions from these previously reported O/G basins [i.e., Eagle Ford, 0.73 Tg a^{-1} (24)] and is even comparable to the 11-basin sum (3.7 Tg a^{-1}) (Fig. 4A and table S1). This comparison with recent literature indicates that the Permian Basin is likely the largest observed methane-emitting O/G basin in the United States and a substantial contributor to national O/G-related emissions.

Distribution of methane emissions

High-resolution observations from TROPOMI enable us to resolve methane emissions at an unprecedented spatial and temporal resolution, relative to the previous generation of satellite instruments such as the Greenhouse gases Observing SATellite (GOSAT) and SCIAMACHY (9). Figure 5 presents the spatial distribution of methane emissions in the Permian Basin at about a quarter-degree resolution derived from our atmospheric inversion. Compared to the prior inventory El_{BU} , our inversion finds larger methane emissions near the center of the Delaware and Midland sub-basins. Sensitivity inversions further show that this spatial pattern is robust against prior emissions of varied magnitudes and distributions (fig. S3), demonstrating that it is primarily informed by satellite observations.

The spatial distribution of methane emissions derived from inversion is closely correlated with that of gross gas production ($R = 0.78$), but to a lesser degree with that of oil production ($R = 0.53$) and that of the well number density ($R = 0.31$) (fig. S4). Similarly, when we sum up the O/G-related emissions for two sub-basins, the ratio of methane emissions between Delaware and Midland ($1.7/1.0 \text{ Tg a}^{-1} = 1.7$) is closest to the ratio of gas production (1.4), compared to that of oil production (1.0) and well number density (0.7). Because unconventional wells tend to have much higher production per well than conventional wells (33), the dependence of methane emissions on gross gas production rather than the well number density suggests that unconventional wells and infrastructure associated with these wells (e.g., gathering stations), which have been developed recently, are likely the major methane emitters in the Permian Basin.

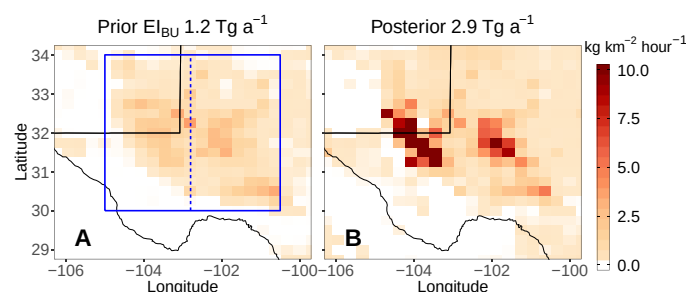


Fig. 5. Spatial distribution of methane emission rates in the Permian Basin. (A) Bottom-up emission inventory El_{BU} extrapolated from EPA greenhouse gas inventory data (prior). (B) TROPOMI observation-derived emissions using Bayesian atmospheric inverse modeling (posterior). The prior and posterior basin-total emissions, indicated on top of the figure, are computed over the area enclosed by the solid blue boundary, with contributions from two sub-basins, the Delaware (left of the dashed line) and Midland (right of the dashed line).

In addition to the spatial distribution, our monthly inversion also provides information about the temporal variation of methane emissions during the 11 months of observation (fig. S5). Although the inversion's ability to resolve the spatial distribution of emissions varies from month to month because of uneven monthly sampling of TROPOMI (fig. S5), our inversion ensemble (table S2 and fig. S5) generally results in consistent monthly basin-level emission estimates (see also uncertainty analysis in Materials and Methods). We speculate that high emissions in December 2018 may be related to a very low in-basin gas price toward the end of 2018, resulting from insufficient gas gathering and transmission capacity in the Permian Basin (33,34). That said, we do not find an apparent increasing trend in methane emissions, although natural gas production from the Permian Basin increased steadily by $\sim 20\%$ during the overlapping 11-month period (fig. S6). Further investigation is required to delineate factors controlling the temporal variations of O/G-related methane emissions.

DISCUSSION

Using an inverse analysis of TROPOMI satellite observations, we estimate a total methane flux of $2.9 \pm 0.5 \text{ Tg a}^{-1}$ in the Permian Basin, with 2.7 Tg a^{-1} coming from O/G-related activity. Methane losses of this magnitude represent a waste of an important resource; for instance, this is enough natural gas to supply 7 million households in the state of Texas (35). Moreover, the 2.7 Tg a^{-1} methane emitted in Permian results in the same radiative forcing as $\sim 260 \text{ Tg a}^{-1} \text{ CO}_2$ over a 20-year time horizon ($86 \text{ Tg CO}_2 \text{ a}^{-1}$ over a 100-year time horizon) (global warming potential of 96 for 20 years and 32 for 100 years) (7, 36), about the same as annual CO_2 emissions from the entire U.S. residential sector ($290 \text{ Tg CO}_2 \text{ a}^{-1}$ in 2017) (22).

Our estimate (2.7 Tg a^{-1}) equates to a production-normalized ($73 \text{ Tg CH}_4 \text{ a}^{-1}$, derived from $127 \text{ billion m}^3 \text{ a}^{-1}$ natural gas production during the study period using 80% methane content by volume) emission rate (or methane leakage rate) of $3.7 \pm 0.7\%$, which is $\sim 60\%$ higher than the national average of $2.3 \pm 0.3\%$ (7) (Fig. 4B). The leakage rate is even higher for the rapidly developing Delaware sub-basin (4.1%). Comparable high leakage rates have also been reported in other oil production-focused basins such as the Bakken (24) (table S1), but these basins produce much lower natural gas than the Permian Basin does. Previous studies summarized in table

S1 show an inverse relationship between the basin-level leakage rate and gas production (24); however, the Permian Basin is an outlier with high oil production, high gas production, and a high leakage rate.

Overall, the high leakage rate in the Permian Basin appears to be associated with insufficient infrastructure for natural gas gathering, processing, and transportation (34, 37), leading to extensive venting and flaring (Fig. 3), which contributes to high methane emissions. The greater profitability of oil production contributes to a lack of investment in natural gas takeaway capacity, which, in turn, has resulted in excessive supply of associated gas and a very low in-basin gas price in the Permian (34). In addition, with the rescinding of U.S. federal requirements on gas capture and fugitive emissions in 2018, current regulations on O/G methane emissions in the Permian Basin are less stringent at both federal and state levels (see text S4). All these factors may increase the incentive for operators to vent and flare their product. On the other hand, the higher-than-average leakage rate in the Permian Basin implies an opportunity to reduce methane emissions in this rapidly growing oil and gas-producing region, through better design, effective management, regulation, and infrastructure development.

MATERIALS AND METHODS

TROPOMI methane observations

We use daily column-averaged dry air column methane mixing ratio (XCH_4) data retrieved from TROPOMI measurements (38) between May 2018 and March 2019. TROPOMI, onboard the polar-orbiting Sentinel-5 Precursor satellite, is a push-broom imaging spectrometer that provides near-daily global coverage with a swath width of 2600 km and a nadir ground pixel size of 7 km $\times$ 7 km at approximately 13:30 local overpass time (17). The retrieval algorithm accounts for the “full physics” of the light path by simultaneously inferring methane concentrations and physical scattering properties, using the oxygen A-band in the near infrared (NIR) and the methane absorption band in the short-wave infrared (SWIR) (39). Only high-quality XCH_4 measurements retrieved under cloud-free conditions are used in this study (as indicated by the retrieval quality assurance flags in TROPOMI data product). These measurements are filtered for solar zenith angle ($<70^\circ$), low viewing zenith angle ($<60^\circ$), smooth topography (1 SD of surface elevation <80 m within 5-km radius), and low aerosol load (aerosol optical thickness <0.3 in NIR) (40).

The TROPOMI XCH_4 product is further corrected for any known retrieval biases (40). The errors in the TROPOMI XCH_4 measurements have been assessed against GOSAT XCH_4 data (38) and were found to correlate with surface albedo. A global bias correction linearly dependent on surface albedo was then derived and applied to the TROPOMI data (40). This bias-corrected TROPOMI XCH_4 product is used in this study. Negligible correlation of errors with other retrieved parameters (e.g., aerosol optical thickness) was found in the assessment. Validation with independent ground-based measurements from the Total Column Carbon Observing Network shows that the bias-corrected TROPOMI XCH_4 has a bias of -4.3 ± 7.4 ppbv, improved upon the uncorrected XCH_4 product (-12 ± 11.5 ppbv) (40). In addition, we also examine the correlation between bias-corrected XCH_4 and other retrieved parameters for the subset of TROPOMI data over the domain of this study. We find no correlation with albedo ($R^2 = 0.00$) and a negligible correlation with aerosol optical thickness ($R^2 = 0.07$), supporting the idea that the XCH_4 enhancement over the Permian Basin (Fig. 1B) is robust.

Figure S7A shows the average XCH_4 over the conterminous United States and the Permian Basin between May 2018 and March 2019 before the topographical correction. We derive the elevation-corrected methane column (XCH_4^t) shown in Fig. 1 by applying a third-order polynomial correction fitted over the U.S. domain following Kort *et al.* (10). The mass balance method uses the elevation-corrected data (XCH_4^t) for emission quantification, while the inversion method uses XCH_4 (bias-corrected) directly obtained from the data product, because the topography effect is taken care of by the atmospheric transport model.

Atmospheric inverse modeling

We perform an inverse analysis of TROPOMI observations to derive optimized estimation of monthly methane emissions at $0.25^\circ \times 0.3125^\circ$ horizontal resolution in the Permian Basin. Quantification of emissions at this combination of relatively high spatial and temporal resolution, not achievable with previous generations of satellite observations such as from GOSAT or SCIAMACHY, is enabled by higher-resolution TROPOMI satellite observations (41). Figure S7B shows that the Permian Basin is well sampled by TROPOMI during the study period, likely because of frequent cloud-free conditions in the region. A total of $\sim 200,000$ TROPOMI XCH_4 retrievals within the study domain (29° – 34°N , 100° – 106°W) between May 2018 and March 2019 are used for the inversion.

Let $\mathbf{x}$ be the state vector that we seek to optimize through inversion, including a gridded ensemble of methane emissions and an additional element representing the regional model bias in XCH_4 . The regional model bias term (a monthly scalar uniform over the inversion domain) is necessary to account for spatially uniform biases caused by imperfect lateral boundary condition and emission errors outside the study domain. The inversion solves for an optimal estimate of $\mathbf{x}$ by minimizing the following cost function

$$J(\mathbf{x}) = (\mathbf{x} - \mathbf{x}_A)^T \mathbf{S}_A^{-1} (\mathbf{x} - \mathbf{x}_A) + (\mathbf{y} - \mathbf{K}\mathbf{x})^T \mathbf{S}_O^{-1} (\mathbf{y} - \mathbf{K}\mathbf{x}) \quad (1)$$

where TROPOMI XCH_4 observations are assembled in $\mathbf{y}$, $\mathbf{x}_A$ is the prior estimate of $\mathbf{x}$, $\mathbf{S}_A$ is the prior error covariance matrix, $\mathbf{S}_O$ is the observational error covariance matrix, and $\mathbf{K}$ is the Jacobian matrix describing the sensitivity of XCH_4 to emissions and the regional model bias ($\partial\mathbf{y}/\partial\mathbf{x}$).

Minimization of Eq. 1 at $\nabla_{\mathbf{x}} J(\mathbf{x}) = 0$ yields the posterior estimation ($\hat{\mathbf{x}}$), the posterior error covariance matrix ($\hat{\mathbf{S}}$), and the averaging kernel matrix ($\mathbf{A}$) (42)

$$\hat{\mathbf{x}} = \mathbf{x}_A + \mathbf{S}_A \mathbf{K}^T (\mathbf{K} \mathbf{S}_A \mathbf{K}^T + \mathbf{S}_O)^{-1} (\mathbf{y} - \mathbf{K} \mathbf{x}_A) \quad (2)$$

$$\hat{\mathbf{S}} = (\mathbf{K}^T \mathbf{S}_O^{-1} \mathbf{K} + \mathbf{S}_A^{-1})^{-1} \quad (3)$$

$$\mathbf{A} = \mathbf{I}_n - \hat{\mathbf{S}} \mathbf{S}_A^{-1} \quad (4)$$

Here, $\mathbf{I}_n$ is an identity matrix where n is the dimension of the state vector $\mathbf{x}$. The trace of $\mathbf{A}$, often called as the degrees of freedom for signal (DOFS), quantifies the number of pieces of information constraining the n -dimensional state vector.

To solve for Eqs. 2 to 4, the prior estimate ($\mathbf{x}_A$) for gridded methane emissions is required. Using different sources of information, we create two gridded emission inventories for the study region: one based on bottom-up information (EI_{BU}) and the other based on extrapolation

of ground-based site-level measurements (EI_{ME}) (see below for descriptions of the inventories). Both emission inventories are time invariant. We use EI_{BU} as the prior estimate in the base inversion, while we use EI_{ME} in a sensitivity inversion to evaluate the impact of the prior estimate ($PI_{EI_{ME}}$; see table S2). We perform further evaluations using prior emissions constructed by disaggregating the total O/G-related emission flux from EI_{BU} with varied spatial proxies (i.e., well count, $PI_{EI_{well}}$, natural gas production, $PI_{EI_{gas}}$, and oil production, $PI_{EI_{oil}}$) (table S2 and fig. S3).

The difference between the EI_{BU} and EI_{ME} (Fig. 5A and fig. S3A) measures the uncertainty of our prior knowledge, and we thus specify prior errors (S_A) for emissions as the absolute difference between EI_{BU} and EI_{ME} . We also specify the prior error for the regional model XCH_4 bias as 10 ppbv. To test the sensitivity to prior errors, we perturb S_A in two sensitivity inversions by doubling ($PE \times 2$) or halving ($PE \times 0.5$) prior errors (table S2). S_O is constructed with the residual error method (43), which results in an error averaged at ~ 11 ppbv. Both S_O and S_A are taken to be diagonal matrices. We also perform a sensitivity inversion to test the impact of error correlations with off-diagonal terms specified following Cusworth *et al.* (44) (OE_Cor; see table S2).

A nested version of the GEOS-Chem chemical transport model (12.1.0) is used as the forward model in the inversion to link XCH_4 to surface emissions. To account for the vertical sensitivity of the satellite instrument, we compute simulated XCH_4 by applying TROPOMI averaging kernels to simulated methane vertical profiles. We construct the Jacobian matrix K , column by column, with simulations perturbing each state vector element independently. The simulations are performed over North America and adjacent oceans driven by GEOS-FP-assimilated meteorological data from the NASA Global Modeling and Assimilation Office on a $0.25^\circ \times 0.3125^\circ$ horizontal grid and 47 vertical layers (~ 30 layers in the troposphere) (21). The boundary conditions for the nested-grid simulation are from a $4^\circ \times 5^\circ$ global simulation from May 2018 to March 2019 driven by GEOS-FP meteorological fields. Note that methane emissions and sinks used in this simulation are optimized with previous-year (2010–2017) GOSAT satellite data following Maasakkers *et al.* (3). Such generated boundary conditions may be biased (i.e., unable to capture the growth of global methane concentrations; see fig. S9), and we account for it by introducing a monthly regional model bias term in the inversion. The retrieved regional model biases may vary with the extent of the inversion domain. To test this sensitivity, we also perform an inversion with a larger spatial domain (27° – 36° N, 98° – 108° W) (Bg_Large; see table S2).

Inversion uncertainty

The posterior error covariance matrix ($\hat{S}$, Eq. 2) and averaging kernel matrix (A , Eq. 3) evaluate the uncertainty of an inversion solution given inversion parameters (e.g., S_A , S_O , forward model). Figure S5 shows monthly posterior errors for basin-level emissions (derived from $\hat{S}$) and corresponding DOFS (trace of A) from our base inversion. Overall, the posterior errors for basin-level emissions are $<5\%$ of the estimated emission flux, and the DOFS are between 5 and 30 for the monthly inversion, indicating that the TROPOMI data are able to constrain basin-level methane emissions and partially resolve the spatial distribution on a monthly basis. The monthly variations in the posterior error and DOFS are mainly driven by uneven data coverage from TROPOMI sampling. For example, poor data coverage

in November 2018 results in a large posterior error and a small DOFS (fig. S5).

We also perform an ensemble of sensitivity inversions by perturbing the configurations and parameters in the base inversion (table S2), aiming to characterize the uncertainties resulting from assumptions made in the inversion not captured by the analytical posterior error. Our results show that all these sensitivity inversions lead to consistent basin-level emission estimates. Annual mean fluxes from sensitivity inversions are within 0.5 Tg a^{-1} of that from our base inversion (table S2), with general agreement in monthly variations as well (fig. S5). Because the uncertainty resulting from sensitivity inversions are significantly larger than that deduced from posterior error covariance matrix (fig. S5), we report the uncertainty of our basin-level emission estimate (0.5 Tg a^{-1}) as half of the range from the inversion ensemble (2.4 to 3.4 Tg a^{-1}).

Furthermore, to assess the uncertainty due to model transport, we compare hourly GEOS-FP 10-m wind speed against measurements at the Midland Airport (MAF) in the Permian Basin during the period of May 2018 and March 2019. Airport wind measurements are not assimilated in the GEOS-FP reanalysis (45), so these observations are independent. We find that the GEOS-FP 10-m wind speed compares well with the airport measurements in both daytime and nighttime (fig. S8), with mean biases of less than 6% in the mean wind speed. We conclude that errors in the model wind fields are unlikely to be a major source of error in the inversion.

We introduced a regional model bias term in monthly inversions to correct for regional background biases in simulated methane concentrations, which result mainly from imperfect boundary conditions. To check our estimate for this regional bias term, we sample the model simulation to compare with independent observations, i.e., surface measurements at the Mauna Loa Observatory (MLO; a Pacific free tropospheric site upwind of the North American continent) (46), tower measurements at Moody, Texas (WKT) (47), and aircraft measurements offshore Corpus Christi, Texas (TGC) (48). The latter two sites are geographically much closer to the Permian Basin (~ 400 km from WKT and ~ 700 km from TGC) than MLO, but can be affected by local emissions that are not optimized in our inversion. Our results show that the model simulation, when corrected with monthly regional model biases (derived from monthly inversions over the Permian Basin), is able to capture the observed monthly variation in methane concentrations, notably the sharp increase from August to October 2018 in MLO and WKT observations (fig. S9), supporting that it is necessary to optimize the regional model bias in the inversion. Better agreement is observed at MLO and TGC compared to WKT (fig. S9), likely because WKT is located closer to local sources that are not fully optimized in the inversion. Overall, most of the differences between the prior simulation and TROPOMI observations can be explained by the regional model biases, except for the mismatch in the vicinity of the Permian Basin (fig. S2). We further perform a sensitivity inversion with a varied spatial domain (Bg_Large). Compared to the base inversion, Bg_Large results in a lower regional methane background (by 3 ppbv on average) and a higher methane emission flux (3.4 Tg a^{-1}) (table S2 and fig. S5), reflecting the error correlation between regional methane biases and methane emissions.

In addition, we note that the inversion cannot fully explain the methane enhancement extending outside the Delaware Basin in the northwest direction (near 33° N, 105° W), although the inversion overall substantially improves the agreement between observations

and model simulations (fig. S2). While our investigations do not attribute an obvious source of emissions causing the northwestern enhancement (whether oil/gas or other sources), the basin-level O/G emission estimates presented here are robust if this enhancement is caused by non-O/G sources, but are conservative if it is caused by O/G sources.

Emission inventory based on bottom-up information

We create a bottom-up methane emission estimate (EI_{BU}) for the study domain starting from the gridded version of the EPA anthropogenic greenhouse gas emission inventory for 2012 (49). Maasakkers *et al.* (49) developed a procedure to spatially and temporally allocate the national sectorial methane emissions reported in the U.S. Inventory of Greenhouse Gas Emissions and Sinks (GHGI) by U.S. EPA on a $0.1^\circ \times 0.1^\circ$ grid, using various databases at the state, county, local, and point-source level. The emission inventory includes methane emissions from agriculture, coal mining, natural gas systems, petroleum (oil) systems, waste, and other minor anthropogenic sources.

To reflect the intensifying exploitation activity in recent years in the Permian Basin, we then make an extrapolation of the methane emissions from the oil and gas production sector, using 2018 Enverus Drillinginfo data on well count, well completion, and production (50). To account for the changes in the national average emission factors, we further scale the subsectorial production emissions using the ratio between the latest GHGI (22) and a previous GHGI that Maasakkers *et al.* (49) was based on (51) for 2013 emissions. The updates result in total methane emissions of 1.2 Tg a^{-1} in the Permian Basin (blue box in Fig. 5A), with 1.0 Tg a^{-1} coming from O/G-related emissions and the remainder mainly from agriculture. We use this updated gridded emission inventory (EI_{BU}) as the prior emission estimate for the inversion. The resulting emissions inventory dataset (EI_{BU} inventory) is publicly available for our study region encompassing the entire Permian Basin (<https://doi.org/10.7910/DVN/NWQGHU>).

Emission inventory based on site-level emission measurements

An alternative prior estimation of methane emissions is obtained by extrapolating ground-based methane emission measurements from a limited sample of oil and gas production sites in the Permian Basin (primarily in the New Mexico portion of the basin) during July and August 2018 (52). The measurements found a wide range of site-level emission rates, which appear to be associated with the complexity of infrastructure, and were classified into emission rates for simple (with only wellheads and/or pump jacks) versus complex sites (also with storage tanks and/or compressors). Extrapolating these site-level emission rates to the entire Permian gave a basin-level methane emission rate of 2.3 Tg a^{-1} from O/G production. Additional emissions from compressor stations and processing plants are estimated to be 0.22 and 0.14 Tg a^{-1} , respectively, using activity data from Enverus Drillinginfo's midstream infrastructure dataset, facility-level emission factors from literature (53, 54), and blowdown event emission factors from GHGI (22). We then disaggregate the basin-level O/G-related emissions to a $0.1^\circ \times 0.1^\circ$ grid by the spatial distribution of gas production (Fig. 2D). To complete the inventory, non-O/G anthropogenic methane emissions (0.2 Tg a^{-1}) are taken from EI_{BU} . This emission inventory (EI_{ME}), based primarily on extrapolation of limited site-level measurements, provides an alternative prior estimate for the inversion and is used to test the sensitivity of the results to the choice of prior information (fig. S3). See text S2 for detailed infor-

mation regarding the site-level measurements and the extrapolation procedure. The resulting emissions inventory dataset (EI_{ME} inventory) is publicly available for our study region encompassing the entire Permian Basin (<https://doi.org/10.7910/DVN/NWQGHU>).

SUPPLEMENTARY MATERIALS

Supplementary material for this article is available at <http://advances.sciencemag.org/cgi/content/full/6/17/eaaz5120/DC1>

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New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates

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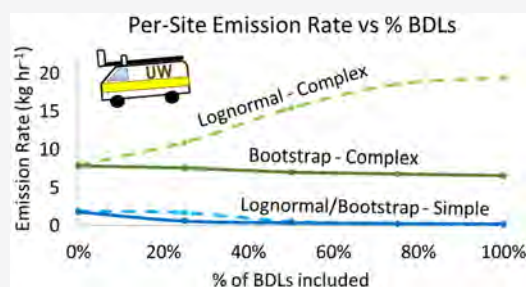


Article Recommendations



Supporting Information

ABSTRACT: Methane emission fluxes were estimated for 71 oil and gas well pads in the western Permian Basin (Delaware Basin), using a mobile laboratory and an inverse Gaussian dispersion method (OTM 33A). Sites with emissions that were below detection limit (BDL) for OTM 33A were recorded and included in the sample. Average emission rate per site was estimated by bootstrapping and by maximum likelihood best log-normal fit. Sites had to be split into “complex” (sites with liquid storage tanks and/or compressors) and “simple” (sites with only wellheads/pump jacks/separators) categories to achieve acceptable log-normal fits. For complex sites, the log-normal fit depends heavily on the number of BDL sites included. As more BDL sites are included, the log-normal distribution fit to the data is falsely widened, overestimating the mean, highlighting the importance of correctly characterizing low end emissions when using log-normal fits. Basin-wide methane emission rates were estimated for the production sector of the New Mexico portion of the Permian and range from ~520 000 tons per year, TPY (bootstrapping, 95% CI: 300 000–790 000) to ~610 000 TPY (log-normal fit method, 95% CI: 330 000–1 000 000). These estimates are a factor of 5.5–9.0 times greater than EPA National Emission Inventory (NEI) estimates for the region.



INTRODUCTION

Production of oil and natural gas in the United States has increased by over 200% and 150%, respectively, since 2005.¹ This boom has primarily been driven by the increased use of hydraulic fracturing combined with directional drilling technologies, allowing the extraction of fossil fuels from formations that were not economically feasible with prior drilling practices. Natural gas has been proposed as a bridge fuel toward a lower carbon economy with less carbon dioxide emissions than coal.² However, natural gas is primarily comprised of methane, a powerful greenhouse gas that has a global warming potential 86 times that of carbon dioxide over a 20 year period.³ According to the most recent estimates from the U.S. Environmental Protection Agency (EPA), natural gas and petroleum systems are the largest anthropogenic source of methane emissions in the United States, accounting for 31% of man-made methane emissions. The production sector alone accounts for over 70% of emissions from natural gas and petroleum systems.⁴

A 2018 study by Alvarez et al.⁵ used observations from several U.S. oil and gas (O&G) basins to determine that observed methane emissions are ~60% higher than EPA emission estimates for the O&G sector, and observed emissions from the production sector alone are 2.2 times higher than EPA estimates, while a study by Howarth et al. suggests even larger underestimates of O&G sector emissions.⁶

One explanation for this low bias in emission inventories is that they do not account for the “heavy-tail” or “fat-tail” of the emission distributions commonly observed in O&G basins. This “fat-tail” is caused by a small percentage of sites, a.k.a., “super-emitters,” that disproportionately account for a large majority of emissions.^{7–15} These high emissions can be the result of routine maintenance (e.g., liquid unloadings, well blowdowns) as well as equipment malfunctions that occur stochastically at any given site.¹³ Due to the random nature of some of these larger leaks, they are difficult to account for in an emission inventory, but recent studies have demonstrated that using a more statistically robust method to estimate O&G emission distributions in emission inventories can successfully represent observed methane emissions.^{5,7}

The Permian Basin is a highly active O&G basin spanning western Texas and southeastern New Mexico. Since 2007, oil and gas production have more than quadrupled and doubled in the basin, respectively. Currently, the basin has the highest oil production in the U.S., and gas production is second only to

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the Marcellus Shale.¹ However, despite it being an important O&G basin, the current study is the first to report ground-based methane flux estimates in the Permian. Aircraft mass-balance flights have not yet successfully estimated a basin-wide emission rate due to the immense size of the basin¹⁶ (~200 000 km²), although current attempts are ongoing. This study examines the use of two different widely used statistical methods (bootstrapping and maximum likelihood log-normal fit) to estimate average emission rates that are then used to scale up facility-level methane emission rates to a basin-level estimate for well pad emissions.

MATERIALS AND METHODS

Mobile Laboratory Platform. Measurements were performed using the University of Wyoming Atmospheric Science Mobile Research Laboratory (Mobile Lab, [Supporting Information \(SI\) Figure S1](#)).^{17–19} A mast extends out beyond the front bumper of the Mobile Lab and is 4 m off the ground to minimize wind interference/wake effects from the body of the vehicle or the ground. The mast houses meteorological instruments, including a 3D sonic anemometer, an AirMar GPS/2D wind sensor, and a 2D compact weather station. An inlet is also attached to the front of the mast which pulls air through approximately 7 m of 1/4 in. Teflon tubing into instruments inside the lab at a rate of 7 LPM. During this project, a Picarro Cavity Ringdown Spectrometer (CRDS) was used to measure methane and water vapor mixing ratios (model G2204, modified by Picarro Inc. to sample at 2-Hz). The calibration of the Picarro was performed by sampling a NIST traceable (±1%) methane in ultrapure air mixture with a methane concentration of 2.576 ppm. The 2-Hz Picarro CRDS calibration fluctuated less than ±6 ppb over the course of the project and was always in agreement with the NIST standard.

Emission Flux Quantification. Methane emission fluxes were calculated using the Gaussian dispersion approach within the U.S. EPA's Other Test Method (OTM) 33A. This method has been described in detail in Brantley et al., Robertson et al., and EPA documentation.^{19–21} The 1-sigma error for OTM 33A, verified by test releases performed under a wide variety of real-world conditions, is ±35% relative to a known release rate, which translates to an error of +54%/–26% for measurement of an unknown emission rate in the field.²² Results using this method have been used in a measurement-based inventory to estimate emissions from other O&G production regions.^{5,12} Briefly, this method uses rapid wind and methane mixing ratio measurements (~2 Hz) downwind of a site to calculate average methane enhancements for each wind direction over a minimum 20 min period. An advantage of OTM 33A is that it does not require site access from operators and therefore can limit the so-called “operator opt-in bias.” During a measurement, as the plume wafts back and forth over the inlet, a plot of the time-averaged in-plume concentrations versus wind direction forms a Gaussian distribution.²³ The peak of a Gaussian fit to the data gives C_{peak} in [eq 1](#) while the horizontal and vertical dispersion parameters (σ_y and σ_z) are determined from a lookup table based on distance from the source and atmospheric stability determined by variation in the horizontal and vertical winds. An emission flux (Q) is calculated by

$$Q = 2\pi \times \bar{U} \times \sigma_y \times \sigma_z \times C_{\text{peak}} \quad (1)$$

Where, $\bar{U}$ is the mean wind speed during the measurement ([SI Section 1.2](#) gives further detail). The limit of detection

(LOD) for the OTM 33A method was empirically determined to be 0.036 kg hr^{–1} (0.01 g/s).²⁰ While we have no empirical evidence that this is not a valid LOD at all distances, we agree that the LOD could vary with distance and meteorological conditions. Therefore, we ran sensitivity tests using varying detection limits (up to an order of magnitude greater, 0.36 kg hr^{–1}), but saw no significant effect on final results (detailed in [SI Section 1.4](#)).

Of the 111 measurements performed in the Permian Basin during this study, 47 yielded a quantified flux estimate with the OTM 33A technique and 29 sites were measured to be below detection limit (BDL) (number of measurements detailed further in [SI Section 7.0](#)). A measurement yields a flux estimate if it passes a series of data quality flags that are part of the OTM 33A analysis method, including flags for atmospheric stability, poor Gaussian fit of the emission plume, excessive wind variance, and others (see [SI Section 1.3](#)). An infrared optical gas imaging camera (FLIR GF300) was used at measurement sites to check for any large conflicting emission sources nearby (such as pipeline leaks) and to pinpoint emission sources on the well pad. A measurement may also be removed from the final data set during postprocessing if satellite imagery (from Google Earth) or analysis of the wind direction during the measurement suggest that there may have been an interfering source upwind.

Study Area. The Permian Basin is located in western Texas (TX) and southeastern New Mexico (NM). The Permian is broken into two main geologic basins: the Midland Basin on the eastern side, and the Delaware Basin (DB) on the western side, separated by the Central Basin Platform ([SI Figure S3](#)). For this study, 111 ground-based, facility-level methane emission measurements were collected in the DB during August 2018. Out of the 111 measurements, 71 were collected in NM and 40 were collected in TX. The sample number was lower in TX mostly due to lighter and more variable winds. Measurements were attempted in the Midland Basin, but due to lack of public road access the measurements were not successful. As of August 2018, there were approximately 144 000 active wells in the Permian Basin, roughly half (73 000) of which were located in the DB.²⁴

Sampling Strategy. Due to the large size of the basin, a clustered random sampling strategy was implemented - clustered by production fields with the densest population of wells in the basin ([SI Figure S4 and S5](#)). This resulted in 8 original clusters, which were then stratified by production magnitude and age of wells to try to obtain a sample set that represented the large age and production range in the basin, including older/low producing wells, newer/high producing wells and those in-between. After a cluster was chosen for the day, we randomly selected sites based on wind direction and downwind road access. This strategy was chosen to minimize transit time between potential sites and to maximize sample size. As the field campaign progressed and the number of measurable sites in each of the original clusters began to dwindle (sites with good downwind road access for given winds had already been measured), 3 more clusters were added in areas that had a sufficient number of well pads that could be targeted. The end result was that the measurements collected in this study leaned more toward the newer/high producing end of the spectrum with an average age of 8 years, average gas production of 680 thousands of cubic feet per day (mcf/d), and average oil production of 170 barrels per day (bpd). Whereas basin-average values for the DB in 2018 were 17 years, 160

mcf/d, and 41 bpd (SI Figure S6). Since newer/higher-producing wells tend to have higher methane emission rates than older/lower-producing wells, this sampling bias may have resulted in an overestimation of the average emission rate per well by up to 20% (details of this analysis are in SI Section 2.3). However, due to the low sample number and limited confidence in the robustness of the relationship between emissions and age/production, as well as the possibility that we may have underestimated the fat-tail (discussed more in the Section “Well Site Classification: Simple Vs Complex”), no correction factor was applied to the data.

Once a site was chosen for measurement, several transects downwind of the site were performed to locate the approximate center of the emission plume, where the Mobile Lab was then parked and the engine turned off to avoid exhaust interference. To check for interfering sources upwind several methods were employed either alone or in combination including performing transects upwind of the site when possible, using the FLIR camera to check pipeline junctions or other nearby sources, and using Google Earth imagery to ensure that there were no large sources nearby that we visually missed. If there was a large site directly upwind of the site of interest and we could not confirm that there were no conflicting emissions coming from that site then we did not measure. Wind direction and speed (10 Hz) and methane mixing ratios (2 Hz) were then measured for a period of at least 20 min to allow the plume to average out into a Gaussian. Sites where the Mobile Lab was clearly downwind, but where no emission plume was detected or emissions were below the detection limit for OTM 33A were recorded as below detection limit (BDL). All measurements were performed within 40–200 m of the source, with distance to source measured using a laser range finder.

Sites Below Detection Limit (BDL). In an effort to make the measurements as representative of the emission distribution in the DB as possible, sites where emissions were below the OTM 33A method's detection limit (0.036 kg hr^{-1}) were also recorded and will be referred to as below detection limit (BDL) sites. A site was recorded as BDL if, while sitting within 150 m downwind, maximum observed methane enhancements were below 50–100 ppb. This is the minimum enhancement distinguishable from background fluctuations that is necessary for an accurate flux estimate. Lofted plumes are a limitation of OTM 33A since measurements are performed from a ground-based vehicle at relatively close distances, so to verify that there were not plumes that were lofted over the inlet at these sites, each site was also verified to have no visible emissions using the FLIR camera from near the edge of the well pad. A site was also only recorded as BDL if the winds were consistent enough to ensure that we were directly downwind of all potential sources on the site. The lowest quantified emission with OTM 33A during this campaign was 0.068 kg hr^{-1} .

To include the BDL sites in the final statistics, first a “success fraction” was applied to the total number of BDL sites. The success fraction represents the fraction of total OTM measurements that passed data quality criteria and is applied to the number of BDL sites to include the same fraction of BDLs as OTM measurements. If this were not done the BDL sites would be statistically over-represented. Not including the success fraction decreases the final basin-level estimate by 5–7%. This success fraction was 72%, resulting in a total of 29 BDL sites counted in the final data set, 17 in NM, and 12 in TX. To estimate the emissions from these sites, values were

chosen randomly with equal probability between 0 kg hr^{-1} and the method minimum detection limit (0.036 kg hr^{-1}). This approach likely underestimates the leakage rate assuming the BDLs actually follow the tail of the data set's log-normal distribution (which would result in the majority of BDL sites having an emission rate close to the LOD), but was chosen to be conservative. One caveat for the number of BDL sites is that the majority of them were measured for less than 5 min, and therefore some low frequency intermittent emissions could have been missed.

Well Site Classification: Simple Vs Complex. The oil and gas extracted at well pads needs to be separated (into oil, gas, and water) and sometimes further processed (e.g., dehydration of the gas), before it is stored on site or sent to a gathering pipeline. Typically, these processes occur at the well pad, where produced water and oil/condensate are sent to atmospheric storage tanks on site that flash gas (though some have controls that combust flashed emissions). However, the majority of sites in the DB have only wellheads or oil pump jacks on site with their production routed offsite to central gathering sites/tank batteries for processing and storage. These “simple” sites therefore have either no, or minimal, liquids storage or processing equipment on site, which have been shown to be the primary emission sources on well pads.^{13,25} During analysis, it became apparent that these “simple” sites have a very different emission profile (median emission rate of 0.03 kg hr^{-1}) than sites with one or more compressors or liquids storage tanks on site (median emission rate of 2.6 kg hr^{-1}). Therefore, sites are broken into two categories for analysis: simple and complex sites. A complex site is defined in this study as any well pad with one or more oil/water storage tank(s) and/or compressor(s) on-site. All other sites are defined as simple, which includes well pads with only one or more wellhead(s), pump jack(s), and/or separator(s)/other simple equipment on-site. Of the 46 sites with flux estimates in NM, 30 were complex and 16 were simple. Of the 25 sites with flux estimates in TX, 17 were complex and 8 were simple.

This classification is especially important when estimating emission distributions and extrapolating facility-level emissions to a basin-level estimate. To extrapolate our measured emissions per site to a basin-level estimate for the NM portion of the DB, the number of wells in the basin during the month of measurement that were actively producing (August 2018:25 000 wells) was divided by the average number of wells per site (1.2) to get an approximate number of sites.²⁴ Wells that were listed as suspended/abandoned/etc. were not included in the scale-up. Then, the number of simple and complex well pads was calculated based on the results from human classification of satellite imagery (Airbus SPOT) that $\sim 2/3$ of the well pads in the NM DB are “simple” with the remaining $1/3$ being “complex” ($\sim 97\%$ of the sites had imagery from 2018 or 2019). This classification only includes well pads with at least one wellhead or pump jack on site. In our sample set, this ratio was reversed, with $\sim 2/3$ of our sites that passed QA/QC being complex sites. A major focus of this field campaign was to capture the high-end of the emission distribution to avoid underestimating the fat-tail, which played into the sampling strategy. There was much less variation in emissions from simple sites (with a large majority of them being BDL) than complex sites so we began preferentially targeting the complex sites to better nail down their contribution to the emission distribution. Importantly, since we estimate average emissions for simple and complex sites

separately, and then scale them up separately to a basin-level estimate, this complex-bias does not contribute to an overestimation of basin-level emissions. Also, although there are twice as many simple sites than complex sites in the basin, emissions from the complex sites dominate the emissions, representing 91% of total emissions.

A similar extrapolation for the TX portion of the basin was not performed due to the lower number of measurements on the TX side, and therefore less confidence in scaling up the data there, and because the classification of satellite imagery was only available for the NM side of the basin. There were only 13 successful site-level measurements (using OTM 33A) and 12 BDL sites from the TX side of the DB (0.05% of active wells in TX DB), as opposed to 29 successful site-level measurements and 17 BDLs on the NM side (0.18% of active wells in NM DB).

It is also important to note that although BDL sites were accounted for and included in the analysis, several sites with large methane enhancements that were either too spread out or too close to the road to sample due to the limitations of OTM 33A¹⁷ were not accounted for/included in the analysis because we do not have approximate mass emission rates for them (similar sites with no emissions were recorded under the BDL category for complex sites). Often, the sites with large observed methane enhancements (15–20 PPM CH₄ from over 100 m away) were gathering facilities/tank batteries that only had tanks and processing equipment on-site but no wells or pump jacks and therefore were not quantified with OTM 33A, identified in the Google Earth analysis, or included in the basin-wide scale up. Since these sites do not have a well or pump jack on-site, they are also not listed in either the NM or TX production databases and there is no publicly available data on their throughput or which wells/pump jacks have production routed to them. Thus, these are likely a significant but currently unaccounted for emission source that requires further study to fully characterize the emissions in the basin. Furthermore, because we have production information for the simple sites but no information on where their production is sent, we may be underestimating their total emissions if their production is being sent to one of these unaccounted for central gathering facilities/tank batteries.

Statistical Techniques for Emission Estimation. Two common methods used for extrapolating facility- or well-level emissions data to a basin-wide estimate are bootstrapping and maximum likelihood best log-normal fit.^{5,7,8,10,12,14,20,26–28} Each of these methods are a way to predict the average emission rate per well/site for a given data set. The average emission rate can then be multiplied by the total number of wells/sites to obtain a total emission rate for a basin or region. One of the objectives of this study is to compare the average emission rate calculated using these two methods and explore how and why they may differ.

Bootstrapping is a proven method used to approximate statistics (and their confidence intervals) of a population without assuming that the data come from any specific distribution. This method estimates statistics of the underlying population by resampling the measured data set (with replacement) a large number of times,²⁹ that is, “pulling the data up by its bootstraps”. For this study, bootstrapping is used to estimate average emission rates per well pad (i.e., per site) and to investigate the production characteristics of different subsections of the DB. The bootstrapping method used in this study is described in detail in Robertson et al. 2017. Briefly, the error distribution for each measurement is first created using a normal distribution with the measured emission rate as the mean and the 1-sigma error estimate for OTM 33A (+54%/–26%)²² as the standard deviation. The measurements with incorporated error are resampled with replacement 100 000 times, creating 100 000 new sample sets of the original sample size (e.g., $n = 71$ for all successful well pad measurements in the DB, $n = 46$ for NM, and $n = 25$ for TX). From these 100 000 sample sets one can calculate 100 000 estimates of the mean and the distribution of all the possible means can be used to determine the 95% CI.

Another popular method to estimate emissions from O&G basins is to assume the data follow a log-normal distribution and use the best log-normal fit to estimate population statistics.^{5,7,12} It has been shown throughout U.S. O&G basins that a small fraction of sites account for a large fraction of the emissions resulting in a “fat-tail”/“heavy-tail” in the emission distribution. However, because this heavy-tail is caused by a small percentage of sites, it is difficult to make enough measurements to capture a significant fraction of these sites during a two- or three-week ground campaign.³⁰ Trying to accurately approximate the heavy-tail of the emissions distribution is critical because it drives the mean emission rate per well/site and therefore the extrapolation to a basin-level estimate. For this reason, studies have fit a log-normal distribution to measured emissions to estimate the heavy-tail. Notably, past studies of O&G basins have revealed that measured emission distributions often exhibit even more extreme distributions than a log-normal fit.⁹ For this study, Matlab’s (version R2018b) log-normal fitting routine, based on maximum likelihood estimation (MLE), was used to evaluate the best log-normal fit to the emission distribution, fitting complex and simple sites as two separate distributions. The lognormality of the data sets is explored more in the [Results and Discussion](#).

Converting Gas Production to Methane Production. Monthly oil and gas production data for measured sites were obtained from the DrillingInfo database.²⁴ The monthly natural gas production (NGP) rates are converted from thousands of cubic feet of natural gas per month (mcf/mo) to kilograms of gross methane produced (GMP) per hour (kg hr^{−1}) using eq 2:

$$\text{GMP} \left(\frac{\text{kg}}{\text{h}} \right) = \text{NGP} \left(\frac{\text{mcf}}{\text{mo}} \right) \times \left[\frac{\left(1000 \frac{\text{ft}^3}{\text{mcf}} \right) \times \left(1.19804 \frac{\text{mol gas}}{\text{ft}^3} \right) \times \left(x \frac{\text{mol CH}_4}{\text{mol gas}} \right) \times \left(0.01604 \frac{\text{kg}}{\text{mol CH}_4} \right)}{(\# \text{days/mo})(24 \text{h/day})} \right] \quad (2)$$

The Permian Basin is a wet gas basin, and publicly available composition data for natural gas produced in the DB is sparse but existing reports cite a methane content (mol CH₄/mol

gas) of 60–75%.^{31,32} For this study, methane content for each site was randomly chosen from a normal distribution centered on 70%, with 95% of values falling between 64 and 76%. This

was done to be as robust as possible with any potential errors involved in the calculation, but pulling random values versus using the same methane content (e.g., 70%) for each measurement had a negligible effect on the final results.

TNMA, ENMA, and Oil Fraction. A throughput-normalized mass average (TNMA) emission, often referred to as the average fraction of methane produced that was emitted to the atmosphere, is calculated following eq 3:

$$\text{TNMA}(\%) = \frac{\sum \text{MMER} \left(\frac{\text{kg}}{\text{h}} \right)}{\sum \text{GMP} \left(\frac{\text{kg}}{\text{h}} \right)} \times 100 \quad (3)$$

Where MMER is the measured methane emission rate (either using OTM 33A or estimated for BDLs), and GMP is the gross methane produced as defined in eq 2. As opposed to separate throughput-normalized emissions for each facility, TNMA represents a basin-average throughput-normalized emission rate.

As mentioned earlier, the DB also produces considerable quantities of oil and therefore all methane emissions from a site cannot be attributed entirely to natural gas production. Average oil fraction, that is, the fraction of total energy production at the site that can be attributed to oil, is calculated as follows:

$$\text{average oil fraction} = \frac{\sum \text{OP} \left(\frac{\text{bbl}}{\text{d}} \right)}{\sum \text{totalBOE} \left(\frac{\text{bbl}}{\text{d}} \right)} = \frac{\sum \text{OP} \left(\frac{\text{bbl}}{\text{d}} \right)}{\sum \left[\text{OP} \left(\frac{\text{bbl}}{\text{d}} \right) + \text{OEGP} \left(\frac{\text{bbl}}{\text{d}} \right) \right]} \quad (4)$$

Where OP is oil production, OEGP is the oil equivalent gas production, and BOE is the barrels of oil equivalent. Gas production is converted to equivalent barrels of oil (OEGP) using the Society of Petroleum Engineer's (SPE) conversion ratio of 5.8 mcf of gas = 1 BOE.³³ Since some sites primarily produce oil with some associated gas, an energy-normalized mass average (ENMA), or the fraction of energy produced (oil plus gas) that is emitted to the atmosphere as methane, is calculated following the same method as Robertson et al. 2017.¹⁹

$$\text{ENMA}(\%) = \frac{\sum \text{MEER} \left(\frac{\text{Btu}}{\text{d}} \right)}{\sum \text{EEP} \left(\frac{\text{Btu}}{\text{d}} \right)} \times 100 \quad (5)$$

where MEER is the measured energy emission rate, and EEP is the equivalent energy production. Total energy production (oil plus gas) was converted to units of Btu using the standard values from the SPE of 5.8×10^6 Btu per barrel of oil and 1×10^6 Btu per mcf of gas.³⁴

RESULTS AND DISCUSSION

Raw Emissions Distribution. Plotting the cumulative emission distribution for measurements of individual well pads using OTM 33A and estimated emissions for BDLs reveals that, similar to results from other basins,^{7–12} the emission distribution in the DB exhibits a skewed, or heavy-tailed, distribution (SI Figure S8). In the DB, the top 15% of emitters had emissions of at least 7 kg hr^{−1} and accounted for over 70% of total emissions. The top 5% of emitters had emissions of at least 20 kg hr^{−1} and accounted for over 30% of total emissions, both in NM and TX. The lognormality of the data set is explored further in the “Per-Site Emission Rate” section.

Bootstrapped Mass Emission Rate, TNMA, Oil Fraction, and ENMA. The results from bootstrapping the emission and production data in the DB are shown in Figure 1

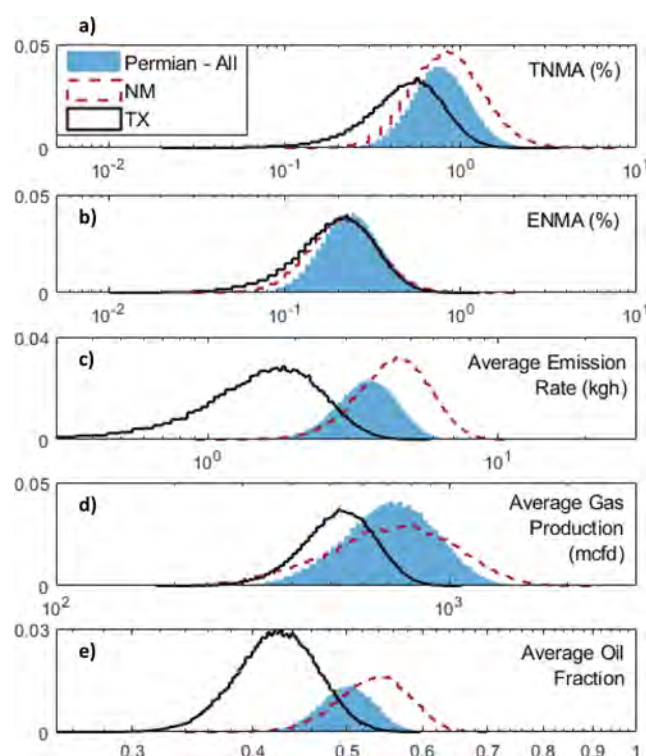


Figure 1. Probability density functions of average emission rates derived by bootstrapping measurements. Panels show all well pads in the DB (blue, filled in), well pads in the NM portion of the DB (red dashed line), and well pads in the TX portion of the DB (black solid line). Panels are (a) throughput-normalized mass average (TNMA, %), (b) energy-normalized mass average (ENMA, %), (c) average mass emission rate per facility (kg hr^{−1}), and (d) average gas production per facility (mcf/d), and (e) average oil fraction per facility.

and Table 1. Measurements performed in NM and TX are separated to compare differences at the state level. Notably, there were only 13 OTM and 12 BDL measurements on the TX side versus 29 OTM and 17 BDL measurements on the NM side (SI Section 7.0), so the results from TX may be skewed by the lower sample size. Statistics are also presented combining measurements from both states, represented as “DB” in Figure 1 and Table 1. To provide context for the current work, results from the DB are compared to statistics from other US basins calculated using the same methods (past work refers to Robertson et al. 2017¹⁹). In these previous studies there was never a statistical reason to separate sites into simple and complex sites. The central estimate for mean TNMA emission rate (Figure 1a) for well pads in the DB is 0.88% (0.42–1.83, 95% CI), which puts the basin midway between previous well pad TNMA emission estimates for the Upper Green River (UGR) Basin and Fayetteville (FV) gas play of 0.1–0.2% and the Denver-Julesburg (DJ) and Uinta Basins of 2–3% (previous estimates shown in SI Figure S9). The central estimate of mean facility-level mass emission rates (Figure 1c) in the DB is 3.8 kg hr^{−1} of methane (2.2–5.7, 95% CI), which is comparable to the average emission rate measured in the Uinta Basin (3.7 kg hr^{−1}), which is the highest we observed from previously measured basins. The

Table 1. Summary of Central Estimates for Facility-Level Mean Emissions (Bootstrapped Distributions Shown in Figure 1)

portion of basin	mean TNMA—% (95% CI)	mean ENMA—% (95% CI)	mean mass emission rate—kg hr ⁻¹ (95% CI)	mean gas production—mcf/d (95% CI)	mean oil fraction (95% CI)
DB	0.89 (0.42–1.83)	0.26 (0.12–0.56)	3.76 (2.24–5.71)	762 (435–1210)	0.50 (0.44–0.57)
NM	1.03 (0.42–2.69)	0.26 (0.11–0.66)	4.74 (2.58–7.61)	818 (377–1470)	0.54 (0.45–0.62)
TX	0.61 (0.22–1.30)	0.25 (0.09–0.55)	1.89 (0.70–3.52)	551 (352–786)	0.43 (0.35–0.51)

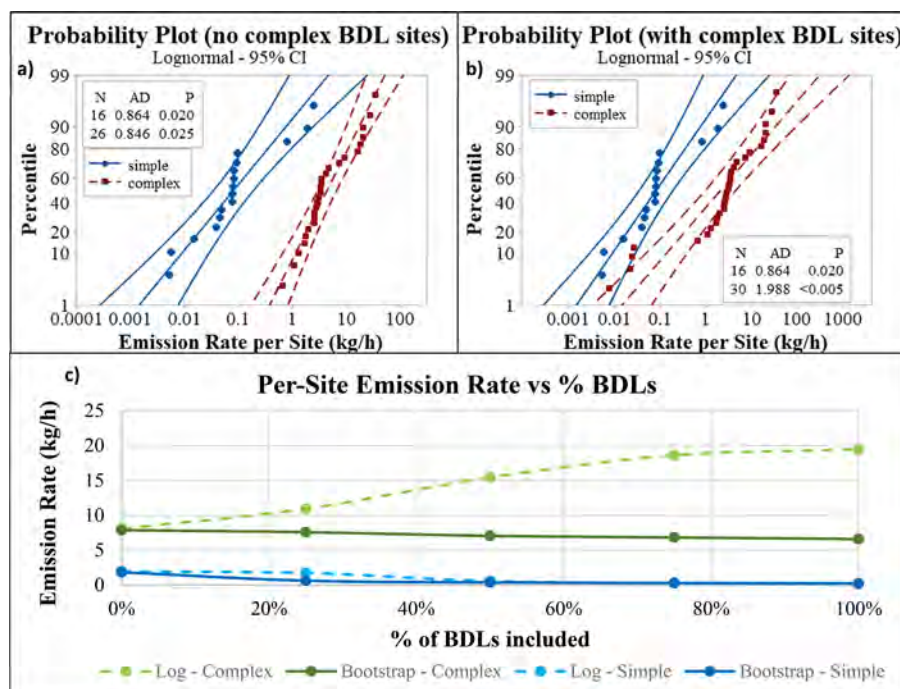


Figure 2. Top two panels show probability plots (emission rate versus percentile) to illustrate how well the measured emission rate data follow a log-normal fit with (a) no complex BDL sites included, and (b) with complex BDL sites included. The distribution for the simple sites is the same in panels a and b (both include BDL sites). The complex BDL sites in panel b are the four data points below 0.1 kg/h, denoted here as kg/h. Blue circle markers are simple sites and red squares are complex sites. The central lines show the best log-normal fit with outside lines showing 95% confidence bounds (solid lines for the simple site distribution, dashed lines for the complex sites distribution). In the legend, N is the sample size, AD is the Anderson-Darling statistic, and P is the corresponding *p*-value, with the values for simple sites on the top row and the values for complex sites on the bottom row. The bottom panel shows estimated per-site emission rate (kg/h) for wells measured in the NM portion of the DB, estimated with both the bootstrapping and log-normal methods using different fractions of the total measured number of below detection limit (BDL) sites. Numbers of BDLs are plotted at increments of 25%, from 0% (0 BDLs) to 100% (28 BDLs).

distributions of measured mass emission rates and TNMA are broken down further into simple and complex sites for both NM and TX in SI Figure S10. Average gas production per well pad (Figure 1d) is approximately 820 mcf/d in NM, similar to the relatively high production rate seen in FV and UGR, and about 50% higher than the average production observed at the TX well pads (550 mcf/d). Well counts for NM and TX well pads were similar with an average of 1.2 and 1.1 wells per site, respectively. Wells in the DB overall have a much higher oil fraction (Figure 1e) than has been observed in other basins with a median value of 0.50 (0.44–0.57, 95% CI). For reference, the DJ Basin in Colorado, which also produces a considerable amount of oil along with its gas production, has an oil fraction of 0.2–0.3. Accordingly, emission rates were also normalized by total energy production (ENMA). The median ENMA (Figure 1b) for the DB is 0.29% (0.14–0.60%, 95% CI).

Per-Site Emission Rate: Lognormal Versus Bootstrapping. To scale measured methane mass emission rates up to a basin-level estimate for the NM portion of the basin, first a per-site emission rate was estimated separately for complex and simple sites using two different methods: (1)

bootstrapping and (2) best log-normal fit. Then, a basin-level estimate was calculated using the number of actively producing simple and complex sites on the NM side of the DB at the time of measurement and their respective average emission rates per site. In August 2018, there were approximately 21 000 active sites in the DB.²⁴ Using the estimate from the manual counting of satellite imagery that ~66% of well pads in the basin were simple and ~33% were complex results in approximately 14 000 simple sites and 7000 complex sites. For the bootstrap method, the per-site emission rate was estimated to be 0.37 kg CH₄ site⁻¹ hr⁻¹ (0.03–0.87, 95% CI) for simple sites, and 7.5 kg CH₄ site⁻¹ hr⁻¹ (4.1–12, 95% CI) for complex sites. Resulting in a basin-level estimate of 520 000 tons per year, TPY (300 000–790 000, 95% CI).

Figure 2 illustrates how well the measured simple and complex sites follow a log-normal distribution. When fitting a log-normal distribution to the simple site emission rates (with estimates for the 13 simple BDL sites included), the resulting *p*-value is 0.02 and the Anderson-Darling (AD) statistic is moderate (0.9), indicating that the null hypothesis that the data come from a log-normal distribution cannot be rejected at the $\alpha = 0.01$ level and that the log-normal assumption is

reasonable for estimating an average emission rate. On the other hand, trying to fit a log-normal distribution to the complex sites (with the four complex BDL sites included), results in a p -value $\ll 0.01$ and a relatively high AD statistic of 2.0 (Figure 2b), indicating that the null hypothesis is rejected and the data do not follow a log-normal distribution. The probability plot (Figure 2b) also suggests that there is a very low probability that the complex BDL sites actually belong on the same distribution as the rest of the complex sites since they are either right on or just outside of the 95% confidence bounds. This may indicate that the complex sites are more likely to have emissions above the detection limit. Undoubtedly, the complex BDL sites are more likely than the simple sites to have intermittent emissions that may have been missed because of the large number of operations occurring on site. The probability plots in Figure 2 also reveal that if the complex BDL sites are included (Figure 2b), it widens the log-normal distribution fit to the data (compared to Figure 2a). Therefore, including these low emitting sites actually increases the mean emission rate for complex sites when estimated using a log-normal distribution. This behavior is explored further in SI Table S1. If the complex BDL sites are excluded from the complex site distribution (Figure 2a), the p -value and AD statistic are similar to those for the simple site distribution, indicating that assuming a log-normal distribution for the emission rates from complex sites is more valid if the complex BDL sites are not included.

As a result, the following analysis will present results using three different approaches: (1) the four complex BDL sites are excluded from the log-normal fit to the complex sites, (2) the four complex BDL sites are excluded from the fit but are factored into the final basin-level emission estimate by assuming the same ratio of BDL complex sites ($4/30 = 13\%$) while using $0.036 \text{ kg CH}_4 \text{ site}^{-1} \text{ hr}^{-1}$ as their emission rate, and (3) the four complex BDL sites are included in the log-normal fit (with BDL values chosen randomly between 0.01 and $0.036 \text{ kg CH}_4 \text{ site}^{-1} \text{ hr}^{-1}$ to match the BDL estimation for simple sites). Note, the third method, as discussed above, results in an invalid log-normal fit but is included here for illustrative purposes.

Using the first approach, the best log-normal fit resulted in per-site emission estimates of $0.43 \text{ kg CH}_4 \text{ site}^{-1} \text{ hr}^{-1}$ for simple sites (0.03–1.93, 95% CI) and $8.8 \text{ kg CH}_4 \text{ site}^{-1} \text{ hr}^{-1}$ for complex sites (4.6–15, 95% CI). The log-normal parameters for the fit to simple sites are $\mu = -3.1$, $\sigma = 1.8$, mode = 0.0016; and for the complex sites: $\mu = 1.5$, $\sigma = 1.1$, mode = 1.4. This results in a basin-level emission estimate of 610 000 TPY (330 000–1 000 000, 95% CI). The log-normal method results in a larger emission estimate than the bootstrapping method (520 000 TPY) since it includes a larger fat-tail in its estimated emission distribution. The second approach results in the same per-site emission rates and log-normal parameters as the first approach, but factoring the fraction of BDL sites into the basin-level roll-up results in a smaller basin-level estimate of 540 000 TPY (290 000–940 000, 95% CI). The third approach results in a similar average per-site emission rate for the simple sites of $0.47 \text{ kg CH}_4 \text{ site}^{-1} \text{ hr}^{-1}$ (0.03–1.7, 95% CI), but a much higher emission rate for complex sites since the log-normal fit is incorrectly widened with the inclusion of the BDL sites: $29 \text{ kg CH}_4 \text{ site}^{-1} \text{ hr}^{-1}$ (7.9–56, 95% CI). Using this approach results in a basin-level estimate of 1 900 000 TPY (540 000–3 600 000, 95% CI).

The sensitivity of the log-normal fit to the number and emission estimates chosen for the BDLs is explored further in Figure 2c and SI Section 6.0. In summary, as an increasing number of BDLs are included in the complex site emission distribution, the best log-normal fit to the data increasingly widens, resulting in larger and larger average emission rates and an increasing divergence from bootstrapping estimates. Therefore, although log-normal fits have been widely used to better characterize the heavy-tail of emission distributions in O&G basins to avoid underestimating total emissions, it is also important to ensure the low end of emissions is representative of the population so that average emission rates are not overestimated when using this approach.

Comparison to EPA Emission Inventories. Since production, and consequently emissions, has changed so drastically in the Permian in the last 5 years, comparisons were only made to the most recently available emission inventories, the EPA's Greenhouse Gas Reporting Program (GHGRP) and National Emission Inventory (NEI). All operators that emit more than 25 000 tons (t) CO_2 -equivalent (CO_2e) per year must report their emissions through the GHGRP. However, although the EPA states that the GHGRP accounts for 85–90% of total U.S. emissions compared to their greenhouse gas inventory (GHGI), the majority of the O&G well pads in the basin likely are not included in the total since they do not meet the 25 000 t CO_2e annual emission threshold. The emission estimate for the O&G production sector (i.e., no gathering, boosting, or transmission) is only reported at the basin-level in the GHGRP. For the Permian Basin in 2018, 68 operators reported their annual production sector emissions for a total of $\sim 216\,000 \text{ TPY CH}_4$. To estimate emissions from just the NM portion of the basin so that our measurements could be more directly compared, total emissions from the Permian were divided based on the fraction of total basin production from NM in 2018 ($\sim 21\%$).²⁴ Taking 21% of the total results in approximately 45 000 TPY of methane from the NM portion of the basin. Comparing this value to our basin-level estimate of 520 000 TPY (using the bootstrapping method) to 610 000 TPY (using the first approach to the log-normal method), suggests that the inventory is over an order of magnitude low for this region.

To generate an estimate from the EPA's NEI 2017 data, the 2017 NEI Production Oil and Gas Tool was used (v1_1). For all O&G production activities in the NM portion of the basin, the NEI 2017 estimates total methane emissions of 91 000 TPY. Excluding truck loading and blowdown emissions from the NEI 2017 estimate, which were not included in our basin-level scale-up, yields a methane emission rate of 67 000 TPY (a factor of 7.8–9.0 times lower than our estimate). However, as mentioned previously, the Permian Basin reported large increases in oil and gas production from 2017 to 2018, with oil production increasing by $\sim 40\%$ and gas production by $\sim 30\%$.³⁵ Because NEI 2018 emissions are not available, we scale the NEI emission estimates by the larger change in production (40%), yielding total methane emissions of 127 000 TPY, and 94 000 TPY if truck loading and blowdown emissions are excluded. Suggesting that the NEI is underestimating methane emissions by a factor of 5.5–6.5.

Comparison to Other Basins. To put methane emissions from the Permian into perspective, estimated basin-wide emissions from only well pads in just the NM portion of the basin (520 000–610 000 TPY CH_4) exceed total basin-wide emissions (i.e., all O&G operations) estimated using aircraft

mass balance techniques in almost every other O&G basin in the U.S. (Alvarez et al. (2018)⁵ demonstrated that bottom-up estimates using OTM 33A give statistically similar results to aircraft mass balance techniques). The one exception is the Eagle Ford Shale region in southern TX with total emissions estimated to be 730 000 (± 190 000) TPY CH₄.¹⁶ The same study that measured the Eagle Ford (Peischl et al. 2018) also estimated basin-wide methane emissions from O&G operations in several other U.S. basins and reported (TPY CH₄): 250 000 (± 61 000) in the Bakken; 370 000 (± 160 000) in Haynesville; and 400 000 (± 260 000) in the Barnett. Basin-wide methane emissions for the Denver-Julesburg Basin were estimated in two separate studies (2012 and 2015) to be 160 000 (± 70 000) – 170 000 (± 60 000) TPY CH₄.^{16,36} Lastly, Karion et al. (2013) estimated emissions from the Uinta Basin to be 480 000 (± 130 000) TPY CH₄.

Future Studies. As this is the first ground-based study of the PB, and only the western portion of the PB, many questions remain and further research is needed to fully characterize emissions in the basin. One important question is how methane emissions in the eastern portion of the basin (Midland Basin) compare to those measured in the DB. Another important question is what fraction of total methane emissions in the basin are contributed by well pad emissions? Comparing our results to a recent satellite study by Zhang et al. (2020) which reported total methane emissions from O&G operations in the DB to be 1.7×10^6 TPY,³⁷ suggests this ratio may be 31–35%. There are several other significant emission sources in the basin not measured in this study, including but not limited to, gathering facilities/tank batteries, compressor stations, leaks along gathering pipelines (including in-line compressors), processing plants, and emissions from unlit or inefficient flare stacks. Emissions from gathering facilities/tank batteries would be particularly informative in trying to gain more information about total emissions from the simple sites measured in this study. Lastly, the measurement of older/low-producing wells should be a priority for future studies to gain a better understanding of the relationship between emissions and age/production of wells in the basin.

■ ASSOCIATED CONTENT

SI Supporting Information

The Supporting Information is available free of charge at <https://pubs.acs.org/doi/10.1021/acs.est.0c02927>.

Details of the OTM 33A methodology; study region and sampling strategy; comparison to previous measurements and subcategories of data presented here; further analysis of the log-normal fit method used; and additional data for all measurements (PDF)

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Notes

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Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic

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20 **Abstract.** Methane emissions associated with the production, transport, and use of oil and natural gas increase the climatic impacts of energy use; however, little is known about how emissions vary temporally and with commodity prices. We present airborne and ground-based data, supported by satellite observations, to measure weekly to monthly changes in total methane emissions in the United States' Permian Basin during a period of volatile oil prices associated with the COVID-19 pandemic. As oil prices declined from ~\$60 to \$20 per barrel, emissions changed concurrently from 3.4% to 1.5% of gas production; as
25 prices partially recovered, emissions increased back to near initial values. Concurrently, total oil and natural gas production only declined by a maximum of ~10% from the peak values seen in the months prior to the crash. Activity data indicate that a rapid decline in well development and subsequent effects on associated gas flaring and midstream infrastructure throughput are the likely drivers of temporary emission reductions. Our results, along with past satellite observations, suggest that under more typical price conditions, the Permian Basin is in a state of overcapacity in which rapidly growing natural gas production
30 exceeds midstream capacity and leads to high methane emissions.



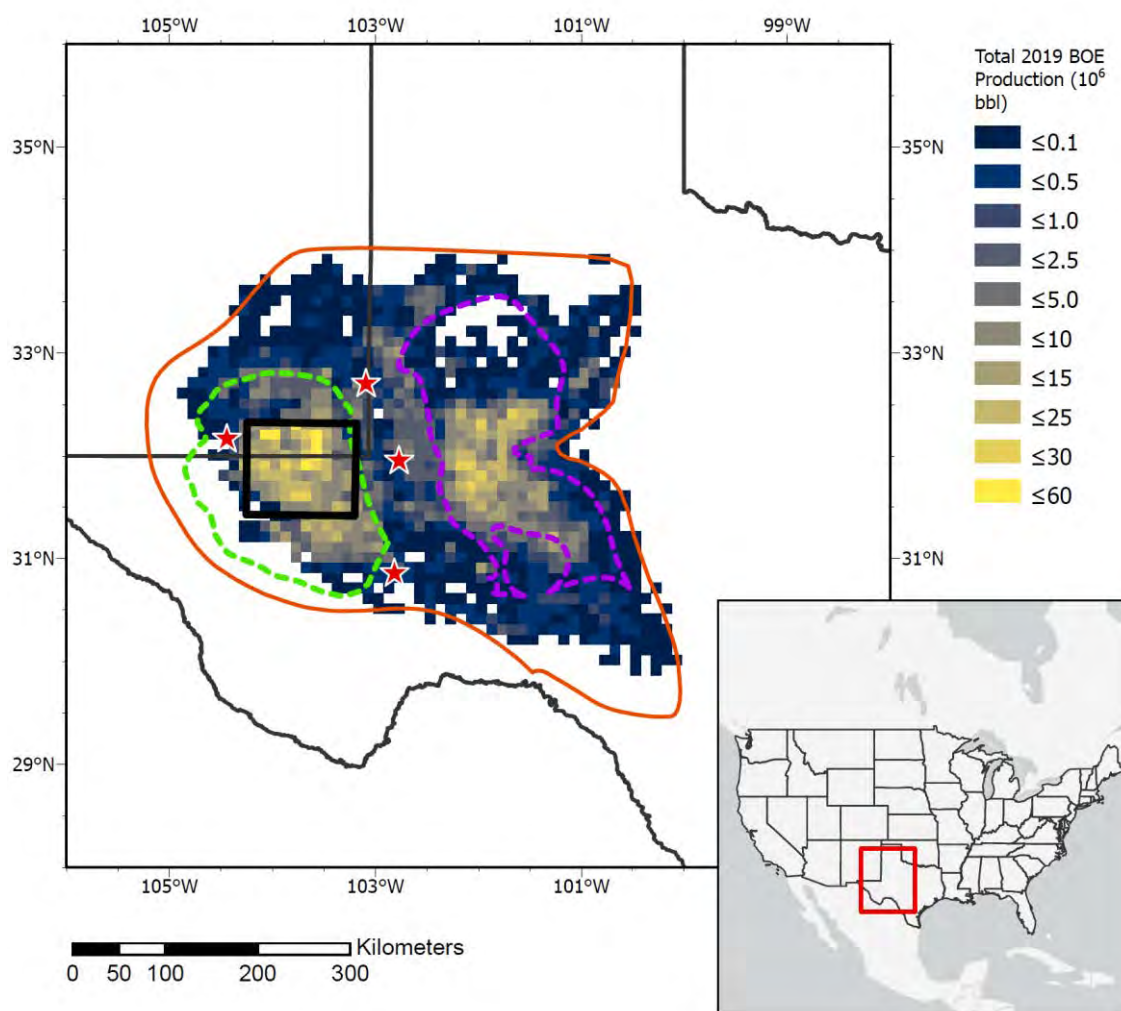
1 Introduction

Accurate quantification of methane (CH_4) emissions from the oil and natural gas (O&G) supply chain is critical for determining the climatic impact of O&G production and use (Alvarez et al., 2012). Alvarez et al. (2018) synthesized over 400 site- and basin-level measurements to estimate United States O&G supply chain emissions at 13 Tg CH_4 in 2015, equivalent to 2.3% of the nation's natural gas production and over 80% higher than the U.S. Environmental Protection Agency (USEPA)'s bottom-up estimate (USEPA, 2020a). There is growing evidence of systematic underestimation of O&G methane emissions when bottom-up methods such as emission factors and engineering equations are used rather than top-down, atmospheric measurements (Allen, 2014; Brandt et al., 2014; Zavala-Araiza et al., 2017). The Permian Basin (Fig. 1) is the largest oil producing basin in the U.S. and rivals the Ghawar Field in Saudi Arabia for the global record (Jacobs, 2019). Although the first oil well was drilled in the Permian Basin nearly 100 years ago, the basin has experienced rapid growth in recent years as directional drilling and hydraulic fracturing allowed production from unconventional reservoirs (Enverus, 2020). In 2019, the Permian Basin had ~600 new wells drilled per month and produced an average of 4.3 million barrels (bbl) oil and 15 billion cubic feet (Bcf) natural gas per day, more than double the 2016 average values (Enverus, 2020). The Permian Basin's limited midstream gathering and processing (G&P) infrastructure for delivering natural gas to market results in high rates of associated gas flaring relative to other U.S. basins. In 2019, average daily flared gas volumes were 0.8 Bcf, 5% of the basin's natural gas production (Appendix A). There is limited methane emissions data from the Permian beyond two recent studies (Zhang et al., 2020; Robertson et al., 2020). Zhang et al. (2020) used satellite observations from May 2018 – March 2019 in an atmospheric inversion to estimate total O&G related emissions in the Permian Basin of 2.7 Tg CH_4 annually, or 3.7% of regional gas production. Robertson et al. (2020) found higher well pad CH_4 emission rates in the Permian Basin compared to most other U.S. basins based on over 70 site-level measurements made in 2018. Alvarez et al. (2018), which pre-dates these studies, had assumed other U.S. basins were representative of the Permian; updating their estimate with the Permian Basin loss rate from Zhang et al. (2020) results in a roughly 10% increase in the U.S. supply chain estimate to 14.2 Tg CH_4 , or 2.5% of total gas production.

In January 2020, oil prices declined as the COVID-19 pandemic triggered a global slowdown in O&G consumption; in March, there was a rapid price drop when the oil oversupply was exacerbated by both the Organization of the Petroleum Exporting Countries (OPEC) failing to reach a deal to cut production and global oil storage capacity reaching its limit (Reed and Krauss, 2020). Spot prices for the U.S. oil benchmark, known as West Texas Intermediate-Cushing (WTI-Cushing), varied dramatically during this period; price per barrel was relatively stable at \$50-60 (USD) for most of 2019, declined to \$20 by late April 2020, briefly dropped below zero on April 20, then recovered to \$40 by early July (USEIA, 2020b). Natural gas spot prices (Henry Hub) were less volatile during this period (\$1.50-2.00 per million British Thermal Units), continuing a gradual downward trend since late 2018 (USEIA, 2020a). Lower commodity prices reduce investment in new well and infrastructure development; in the Permian Basin, the number of active drilling rigs, which had averaged over 400 from April 2019 to March 2020, dropped to approximately 300, 180, and 135 in April, May, and June 2020, respectively (Baker-Hughes, 2020) (Fig. 2).



We hypothesize that the rapid drop in oil price would be associated with a concomitant reduction in methane emissions due to lower rates of well development and a subsequent decline in O&G production. The postulated causal mechanism for this relationship is the effect of natural gas production from new wells on midstream infrastructure throughput. During periods of higher commodity prices, the rapid growth in natural gas production likely exceeds the capacity of the pipelines, compressor stations, and processing plants that deliver and process gas to market, leading to associated gas flaring and anomalous conditions that increase emissions. Such trends were observed in an earlier drilling slowdown in the Bakken, another U.S. unconventional oil formation (Enverus, 2020) (Fig. F1). However, this effect might have been countered in the Permian if lower profit margins led operators to allocate fewer resources to infrastructure maintenance and emissions mitigation, or similarly, restrictions due to COVID-19 reduced the number of field staff performing tasks such as leak detection and repair (LDAR) (Gould et al., 2020).



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Figure 1. Regional map with outlines of the Permian Basin (orange), Delaware and Midland sub-basins (dashed green and purple) and the 100 km x 100 km study area (Black). Locations of the methane measurement tower sites are shown with red stars. A heatmap displays combined gas and oil production from 2019 expressed in barrels-of-oil equivalents (BOE) and gridded to $0.1^\circ \times 0.1^\circ$ resolution (Enverus, 2020).

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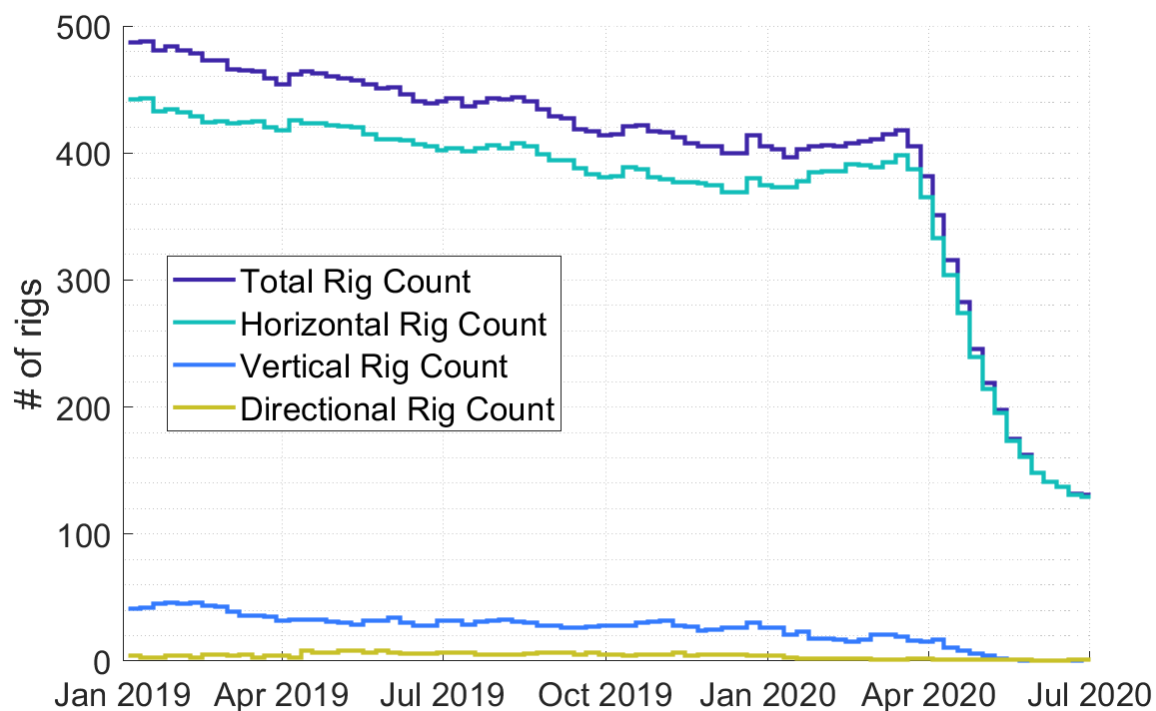


Figure 2. Weekly count of active drilling rigs by type in the Permian Basin between January 2019 and July 2020



2 Study Area and Methods

2.1 Study Area

In January 2020, we began quantifying O&G methane emissions at varying spatiotemporal scales within the Permian Basin with a concentrated effort within a 100 km x100 km area of the Delaware sub-basin along the Texas/New Mexico border (Fig. 1). The 10,000 km² study area includes ~11,000 active wells and accounts for 33% and 43% of the Permian Basin's oil and natural gas production in 2019, respectively (Enverus, 2020). The study area has a high density of midstream O&G infrastructure including 125 gathering and transmission compressor stations, 44 processing plants, and ~32,000 kilometers of gathering pipeline (Enverus, 2020). Based on spatially allocated USEPA inventory data, O&G sources accounted for >90% of methane emissions in the study area in 2012; other sources, dominated by agriculture and waste, were responsible for ~0.5 Mg CH₄ hr⁻¹ (Maasakkers et al., 2016). Since the non-O&G sources account for only a small fraction of total emissions and there have been no major changes in these activities over the past few years, we have assumed all study area emissions are attributable to O&G sources beyond the 0.5 Mg CH₄ hr⁻¹.

2.2 Methods

Between January and August 2020, we used two inversion approaches to quantify total methane emission flux from the study area at a weekly to monthly frequency. The first approach used aircraft-based instruments to measure atmospheric boundary layer (ABL) methane concentration ([CH₄]) along the study area perimeter during six daytime flights (January 22, March 9, March 25, May 4, May 21, and July 13; Sect. 2.22). The second approach continuously quantified [CH₄] from March through August 2020 using sensors installed at three tall towers and one mountaintop station located around the perimeter of the study area ((Richardson et al., 2017); Sect. 2.21). Both approaches estimated study area methane flux on a daily basis by optimizing a prior emissions inventory to minimize model-data differences between observed and simulated regional atmospheric [CH₄] ((Barkley et al., 2017); Sects. 2.21 and 2.23).

We also evaluated satellite-based remote sensing observations of column methane enhancement (ΔXCH_4) for evidence of basin-wide trends (Sect. 2.14). To provide insights about the contribution of natural gas flares to methane emissions, we qualitatively assessed over 300 flares across the basin in February, March, and June 2020 using helicopter-based infrared optical gas imaging (OGI) to visually detect combustion issues ((Lyon et al., 2016); Appendix B). We estimated flare-related methane emissions by applying combustion efficiency assumptions based on survey results to flared gas volume estimates based on satellite observations of flare radiant heat ((Elvidge et al., 2016); Appendix A).

2.2.1 Regional atmospheric [CH₄] reanalysis

An atmospheric reanalysis similar to the system used in previous studies (Barkley et al., 2019; Barkley et al., 2017) was used to create simulated regional atmospheric [CH₄] estimates. The modeling system used Weather Research and Forecasting (WRF) model coupled with Chemistry v3.6 (Skamarock et al., 2008) configured to simulate two domains, an outer 2600 km



x 2100 km domain with 9 km x 9 km horizontal resolution and 50 vertical levels, with about 30 of these levels in the lowest 3 km above ground level, and an inner 830 km x 830 km domain with 3 km x 3 km horizontal resolution and the same vertical layers. The outer domain is nudged to ERA5 wind, temperature and water vapor reanalyses, and the inner domain is nudged to regional observations including ~50 National Weather Service / World Meteorological Organization surface stations, five National Weather Service rawinsonde site soundings launched at 0 and 12 UT, and the meteorological measurements from commercial aircraft-ACARS. Our choice of parameterization schemes within WRF-Chem matches previous studies (Barkley et al., 2019; Barkley et al., 2017).

Only atmospheric [CH₄] from emissions within the model domain are simulated, using techniques demonstrated previously (Barkley et al., 2019; Barkley et al., 2017). Preliminary estimates of surface fluxes of [CH₄] within the domain are taken from the EPA 2012 gridded inventory (Maasakkers et al., 2016), save for the Permian Basin where an updated, production-based inventory is used. This updated inventory is described in detail by Zhang et al. (2020). Briefly, production site CH₄ emission factors were developed using methods in Zavala-Araiza et al. (2015) and based on measurements by Robertson et al. (2020), which accounted for complexity of well site infrastructure and their related CH₄ emissions. Total basin-wide CH₄ emissions were estimated using activity (Enverus, 2020) and disaggregated to individual sites based on their gas production. Additional facility-level CH₄ emissions for gathering and boosting stations, gathering pipelines and processing plants were estimated based on activity data (Enverus, 2020) and CH₄ emission factors from Marchese et al. (2015) and the EPA GHGI (USEPA, 2020a). For the transmission and storage stations, CH₄ emissions were taken from Maasakkers et al. (2016). For the Delaware basin, total CH₄ emissions were estimated at 1.2, 0.11, 0.04, and 0.01 Tg for production sites, gathering and boosting stations, gas processing plants and gas transmission and distribution stations, respectively. These O&G CH₄ emissions were then spatially allocated to a 0.1° x 0.1° grid over the entire basin. This update within the Delaware Basin is important to account for the rapid development within the basin since 2012. Different [CH₄] sources (e.g. oil and gas production, landfills, agriculture) and sources inside and outside the study domain are tagged as independent tracers in the model. Oil and gas emissions outside of the study domain are multiplied by 1.6 to match estimates from Alvarez et al. (2018) and to better account for development in the areas surrounding the study domain. This atmospheric reanalysis system enables us to create a first estimate of atmospheric [CH₄] consistent with the regional meteorology and the preliminary estimate of sources within the outer model domain.

Note that the emissions magnitude from the preliminary [CH₄] emissions estimates are not highly important since the emissions estimate is not a Bayesian inversion that assigns an uncertainty estimate to this preliminary estimate. The spatial pattern of emissions, however, including the relative change in these spatial patterns, is important for the estimate of fluxes. Our assumption that emissions are proportional to gas production should provide a reasonable estimate of the spatial pattern of emissions corresponding to well locations.



2.2.2 Aircraft based methane emission estimates

The total CH₄ emissions from the study area in the Permian Basin study area were determined using airborne data in conjunction with transport modeling. The airborne platform has been deployed and described previously (Conley et al., 2017; Conley et al., 2016; Karion et al., 2015; Smith et al., 2017). In brief, a single-engine Mooney aircraft is outfitted with a Picarro CRDS instrument (G2210-m) to measure in-situ atmospheric CH₄, CO₂, H₂O mole fractions, a differential GPS and aircraft data computer to enable computation of horizontal wind speeds and directions, and a Vaisala probe to measure ambient temperature and relative humidity.

On each flight day, two laps consisting of a box enclosing the 100 km x 100 km study area were flown at 1100 ± 100 ft above ground level (agl), with one complete lap taking ~ 2 h to complete. Two to three vertical profiles were also flown by the aircraft as pairs of ascents/descents between the lowest safe flight altitude (typically 200 to 500 ft agl) and the flight altitude at which significant changes are observed in measured species concentrations (e.g., CH₄, water vapor, relative humidity and potential temperature)- typically 3,000 to 10,000 ft agl. Plots of agl altitude versus these species are used to assess the mixing height of surface emissions. Both CH₄ concentrations along the flight path and the mixing height determined from the airborne vertical profiles are used in transport modeling to determine emissions from the entire study area.

[CH₄] emissions are computed from each complete circuit of the study area by the aircraft. This is done by comparing the observed and simulated [CH₄] enhancement, the increase in [CH₄] downwind of the study area relative to a background value, and adjusting emissions within the study area to minimize the absolute error between the simulated and observed ABL [CH₄].

The 10th percentile of [CH₄] observations in the circuit determines the background. This mole fraction value is subtracted from the observed [CH₄] observations, resulting in an estimate of [CH₄] enhancements. These observed enhancements are then compared to simulated [CH₄] enhancements by matching observation and model at the nearest gridpoints in space and time. Simulated enhancements are split into two categories: study domain enhancements and enhancements originating from outside the study domain. Enhancements associated with sources outside the study domain are subtracted from the observed [CH₄] enhancements, resulting in a set of observations whose enhancements can be directly attributed to emissions within the study domain. The simulated study domain enhancements are then compared to the observed study domain enhancement, and a scalar multiplier is applied to the simulated enhancements to minimize the absolute error between the two datasets. Because the emissions scale linearly with the simulated enhancements, this scalar multiplier, applied to the preliminary emissions estimate within the study area, provides a solution to the emissions within the study domain (Barkley et al., 2017). The solution for each circuit is merged into a single daily estimate.

To test the uncertainty of the emission rate solution for each flight day, a 1000-iteration Monte Carlo uncertainty assessment was performed, adjusting various parameters to test how they impacted the solution. Through the iterations we examine the impact of various possible sources of error, including uncertainty in the background, uncertainty in the assumed influence from sources outside the domain, and uncertainty in the atmospheric transport. For uncertainty in the background, we select a random



180 percentile between 5 and 15 to use as the methane background in a flight lap. For uncertainty in sources outside of the domain
that are subtracted from the observations, we multiply the “other” enhancement tracer by a random factor between 0.5 and 1.5
to account for the possibility that regional emissions may be incorrect. For uncertainty in the transport, the time of the
observations are adjusted by ± 30 minutes. creating perturbations to the model output timeframe used to compare to the
observations. From the 1000 iterations, the 2.5th and 97.5th percentile of solutions are chosen to represent the 95% confidence
185 interval.

2.2.3 Tower-based methane emissions estimates

Atmospheric mole fraction measurements of CH_4 and CO_2 were collected at five locations in the Permian Basin beginning 1
March 2020, using methods similar to those described in Richardson et al. (2017). A map of the measurement locations, along
with oil and gas facilities in the Permian Basin, is shown in Fig. 1. Note that only four of the five planned measurement sites
190 are used in this analysis and shown on Fig. 1 due to instrument malfunctions at the northernmost site. Of these measurement
locations, three were on towers at measurement heights of 91 – 134 m agl and the westernmost site was at a mountaintop
station on a rooftop 4 m agl. The measurements were made with wavelength-scanned cavity ring down spectroscopic
instruments (Picarro, Inc., models G2301, G2401, G2204, and G2132-i). The air samples were dried using Nafion dryers
(PermaPure, Inc.) in reflux mode, with an internal water vapor correction applied for the effects of the remaining water vapor
195 ($< 1\%$). The instruments were calibrated in the laboratory prior to deployment and using quasi-daily field tanks traceable to
the WMO X2004A scale (Dlugokencky et al., 2005; NOAA, 2015). The CH_4 measurement uncertainty (including instrument
noise, uncertainty due to water vapor calibration and tank assignment uncertainty) for the four tower locations was 0.6 ppb
(Carlsbad), 0.6 ppb (Fort Stockton), 3.4 ppb (Hobbs), and 5.4 ppb (Notress), with the differences being attributable to different
instrument type and short Nafion dryer in the case of Hobbs, and laser aging (Notrees).

200 $[\text{CH}_4]$ emissions in the study domain were calculated for each day of tower observations using a similar technique as used with
the aircraft observations. Daily afternoon $[\text{CH}_4]$ at each tower site averaged from 16Z (11 LST) through 22Z (17 LST) was
computed from both the observations and the simulation. A background $[\text{CH}_4]$ value (both for the observations and the model)
is selected based on the lowest measurement from the available tower sites. This background is subtracted from all tower sites
to create an observed CH_4 enhancement. Simulated enhancements from sources outside of the domain are subtracted from the
205 observed enhancements to produce an observed $[\text{CH}_4]$ enhancement associated with sources inside the study domain. A scalar
multiplier is then applied to minimize the absolute error between the observed and modelled enhancements, and a daily
emission rate is solved for in the study domain (Fig. 3).

Figure 4 presents the daily difference between the highest and lowest observed CH_4 measurement across the tower network.
Although though the overall magnitude of the study area plume observed at the tower network can be affected by various
210 meteorological factors (e.g. wind speed, direction, boundary layer height) large changes in the typical size of the observed
plumes can be indicative of sudden shift in behavior of local emissions. From the tower network, we frequently observe large



enhancements >200 ppb in March and mid-April, after which point the enhancement rarely increases above 150 ppb for the remainder of the summer months. It should be noted that a slight decrease in the size of the enhancements would be expected during this period due to increased vertical mixing in a seasonally growing boundary layer; however, modelled results from this timespan exhibit a much smaller magnitude of change. Therefore, the dramatic rechange in behavior CH₄ enhancements coincident with the timing of the price crash is likely due to a change in the emissions rather than a change in the meteorology.

Unlike the aircraft mass balance observations, which are collected on days where meteorological conditions are ideal for measuring emissions from the study domain, the tower dataset is continuous and many days may not be suitable for calculating an emission rate from the study domain. The most useful tower observations for solving for emissions within the study domain are those whose enhancements are influenced primarily by sources within the study domain and contain minimal enhancements from sources outside of the domain. We select for these conditions by retaining days when >50% of the simulated downwind afternoon tower enhancements come from sources within the study domain. This filtering removes 85 of 184 available days, most of which have easterly winds and contain air masses heavily influenced by oil and gas basins in central and eastern Texas. For the remaining 99 days, we remove 5 days whose solutions are more than three median absolute deviations away from the median solution, presumably caused by issues in the model transport. In total, 94 days are used to calculate emissions and trends in the tower dataset between March 1st, 2020 and August 30th, 2020.

Figure 3 presents a timeseries of CH₄ emissions within the 100 x 100 km study area between March 1st, 2020 and June 30th, 2020. This timespan was chosen to focus discussion on the correlations between emissions and activity in the basin during a period of volatile oil prices; accurate activity data is only available through the month of June at the time of manuscript submission (Appendix E). Figure 4 extends the observation of the tower and aerial measurements from Fig. 3 through August 30th 2020 while also presenting monthly mean estimates and 95% CI of the combined results from aircraft and tower-based estimates (Table 1). The 95% CI ranges are derived from twice the standard error of all accepted estimates in each month. Extending the dataset reveals that the mean emissions decreased briefly in July before increasing in August to a similar level as observed in March 2020, albeit with larger uncertainty. Without production or other activity data to relate the observations, we do not have a mechanistic understanding of the reason for the decreased emissions in July, although we note the significant overlap in confidence intervals does not allow for statistically independent estimates between the months of June, July, and August.

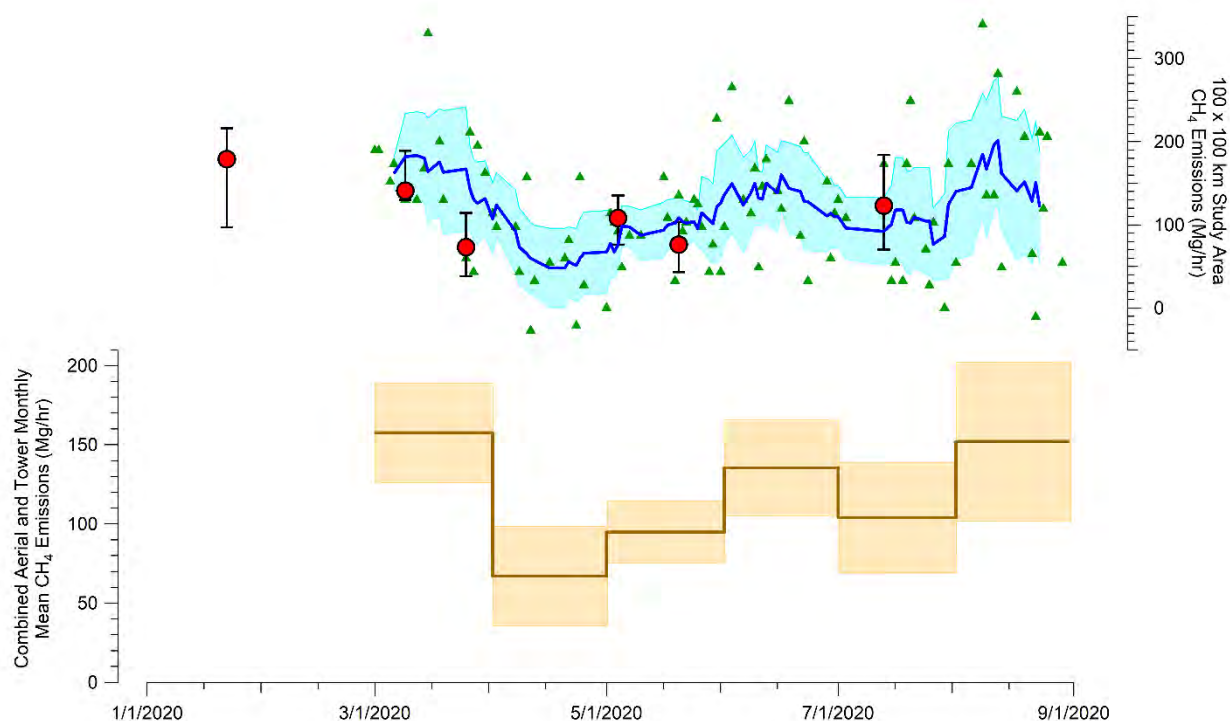


Figure 3. Tower and aerial emission estimates from the 100 x 100 km study area extended for the full available record through August 2020. Individual daily accepted estimates from the tower observations are shown in green triangles while red points represent the aerial estimate and 95% CI and Blue line and shading represent the 7-datapoint moving average of the tower estimates and 95% CI expressed as twice the 7-datapoint moving standard error. Brown line and shading on the lower plot represents the monthly mean estimate and 95% CI from the combination of aerial and tower-based methods.



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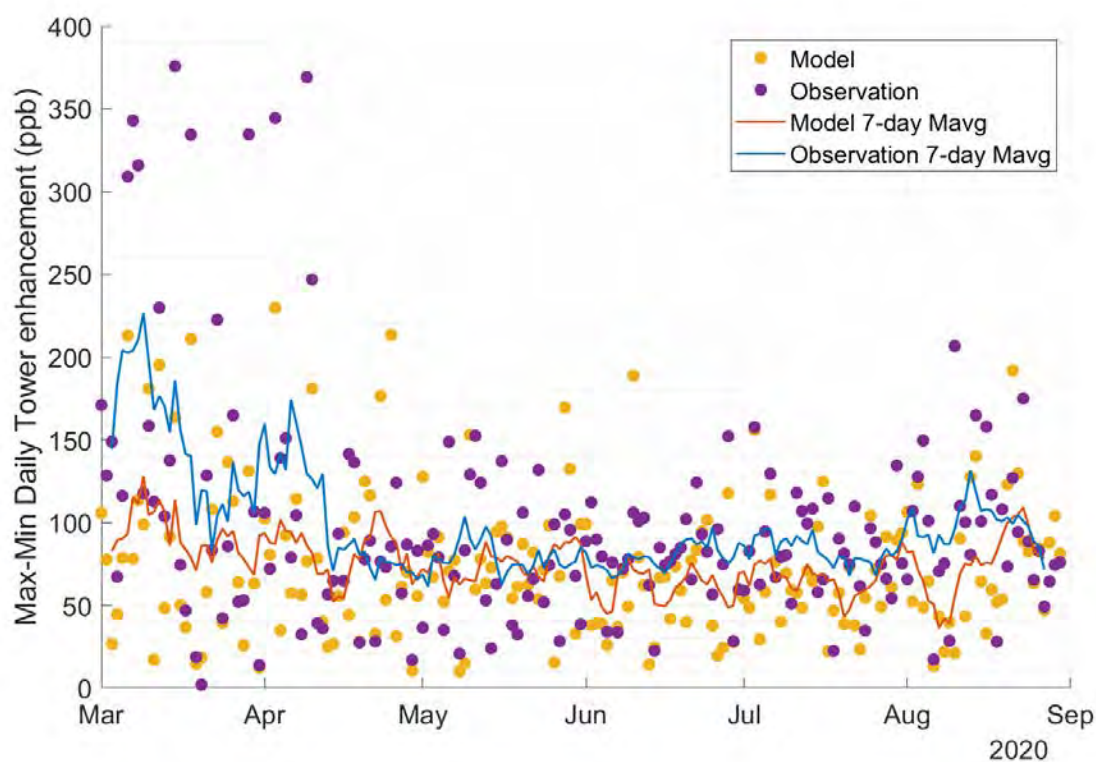


Figure 4. Comparison between modeled and observed differences in the maximum and minimum daily CH_4 enhancement across the tower network. Also shown are the 7-day moving averages of each trend.

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Table 1. Numerical estimates of CH₄ flux from the 100 x 100 km study area derived from the combination of tower and aerial measurements across several temporal ranges.

Time Range	Mean Emissions (Mg/hr)	Standard Deviation (Mg/Hr)	Number of accepted daily tower and aerial measurements	Standard Error (Mg/hr)	95% CI Emission estimate
March 2020	157	66	17	16	126 - 189
April 2020	67	58	13	16	35 - 99
May 2020	95	47	22	10	75 - 115
June 2020	135	64	17	16	105 - 166
July 2020	104	69	15	18	69 - 139
August 2020	152	100	15	26	101 - 202
'Pre-Crash Period' Jan 22 - Mar 19 2020	176	59	12	17	142 - 209
'Emissions Minima' Apr 7 - May 1 2020	55	61	12	17	21 - 89



2.2.4 TROPOMI-derived column-averaged methane mixing ratios

We use column-averaged dry air methane mixing ratios (XCH_4) from the TROPOMI instrument from January to June 2020. TROPOMI was launched in October 2017 onboard the polar sun-synchronous Sentinel-5 Precursor satellite with an $\sim 13:30$ local overpass time. It provides daily global coverage with $7 \text{ km} \times 7 \text{ km}$ pixel resolution at nadir (Hu et al., 2018); the pixel resolution has changed to $\sim 7 \text{ km} \times 5.5 \text{ km}$ at nadir since August 2019. The XCH_4 retrieval uses sunlight backscattered by the Earth's surface and atmosphere in the shortwave infrared (SWIR) spectral range and has near-unit sensitivity down to the surface (Hasekamp et al., 2019). Here we consider only higher-quality XCH_4 measurements (quality assurance value > 0.5).

Figures 5a and 5b show mean methane column enhancements over the Permian basin, observed by TROPOMI in (a) January-February 2020 and (b) April-May 2020. We calculate the daily methane enhancements over the Permian basin from topography-corrected XCH_4 , relative to a regional background column defined by the 10th percentile of XCH_4 across the full Permian domain ($29\text{--}34^\circ\text{N}$, $100\text{--}106^\circ\text{W}$). The topography correction is based on a linear regression of XCH_4 against surface altitude (similar to the methodology presented in (Kort et al., 2014; Zhang et al., 2020), performed across the continental United States ($25\text{--}48^\circ\text{N}$, $66\text{--}125^\circ\text{W}$). Enhancements over the Permian basin appear to be lower in April-May compared to January-February, as indicated by an $\sim 18\%$ reduction in the regional mean between those two periods. This reduction may be due in part to lower spatial coverage after February 2020, likely caused by the introduction in March of a different cloud mask product in the TROPOMI retrieval algorithm (Siddans, 2020). Considering TROPOMI retrievals with quality assurance values of 0.5 or greater, we obtain roughly 6,000–32,000 enhancement measurements per month from January to June 2020 over the full Permian Basin (Fig. 5c). The limited number of satellite observations over our $100 \text{ km} \times 100 \text{ km}$ study area for tower and aircraft measurements (Fig. 3) precludes direct comparison with the suborbital measurements, and therefore we provide here an analysis of TROPOMI methane enhancement over the broader Permian Basin. Coverage is particularly sparse in March and June, so we neglect those two months in the TROPOMI analysis presented here.

Figure 5d shows frequency distributions of methane column enhancements observed by TROPOMI in January, February, April, and May 2020. For these monthly curves we restrict our attention to a smaller Permian domain that closely bounds the methane hotspots seen over the Delaware and Midland sub-basins (dashed lines in Figs. 5a,b; $31\text{--}34^\circ\text{N}$, $101.4\text{--}105.6^\circ\text{W}$). Roughly 5,000–14,000 TROPOMI observations are available per month across this domain, neglecting March and June (Fig. 5c). To mitigate the impact of reduced spatial coverage on our change analysis after February, we manually discard observations from days with little to no coverage of the Delaware and/or Midland sub-basins. Data from 20–40% of observation days in January, February, April, and May (depending on the month) are discarded in this way, but the total number of observations is reduced by only 5%. Permian basin methane enhancements as observed by TROPOMI appear to decrease in early 2020, reaching a minimum in April before beginning to rise again in May.

Repeating our analysis with the background defined at the 25th percentile level (rather than the 10th), we find that these trends are insensitive to the percentile value used. Furthermore, the trends are not explained by seasonal changes in wind speed across



the Permian. Higher winds could lead to lower enhancements, but data from the NASA GEOS-FP meteorological reanalysis
295 product indicate that the daily wind speed averaged over the full Permian basin domain, in the lowest 3 km of the atmosphere,
during the six hours closest to TROPOMI observation time (15:00-21:00 UTC) decreased from a mean of 7.02 m/s in January-
February to 5.48 m/s in April-May.

The trends we identify in TROPOMI methane enhancement analysis across the Permian Basin are broadly consistent with our
findings from tower and aircraft observations of reduced emissions particularly during April in our campaign domain of the
300 Delaware sub-basin, but large uncertainties remain due to the different spatial domains and the reduced satellite coverage after
February 2020. More data and/or more advanced analysis using inverse modelling techniques may be needed to reliably
characterize Permian basin methane emission trends using TROPOMI satellite observations.

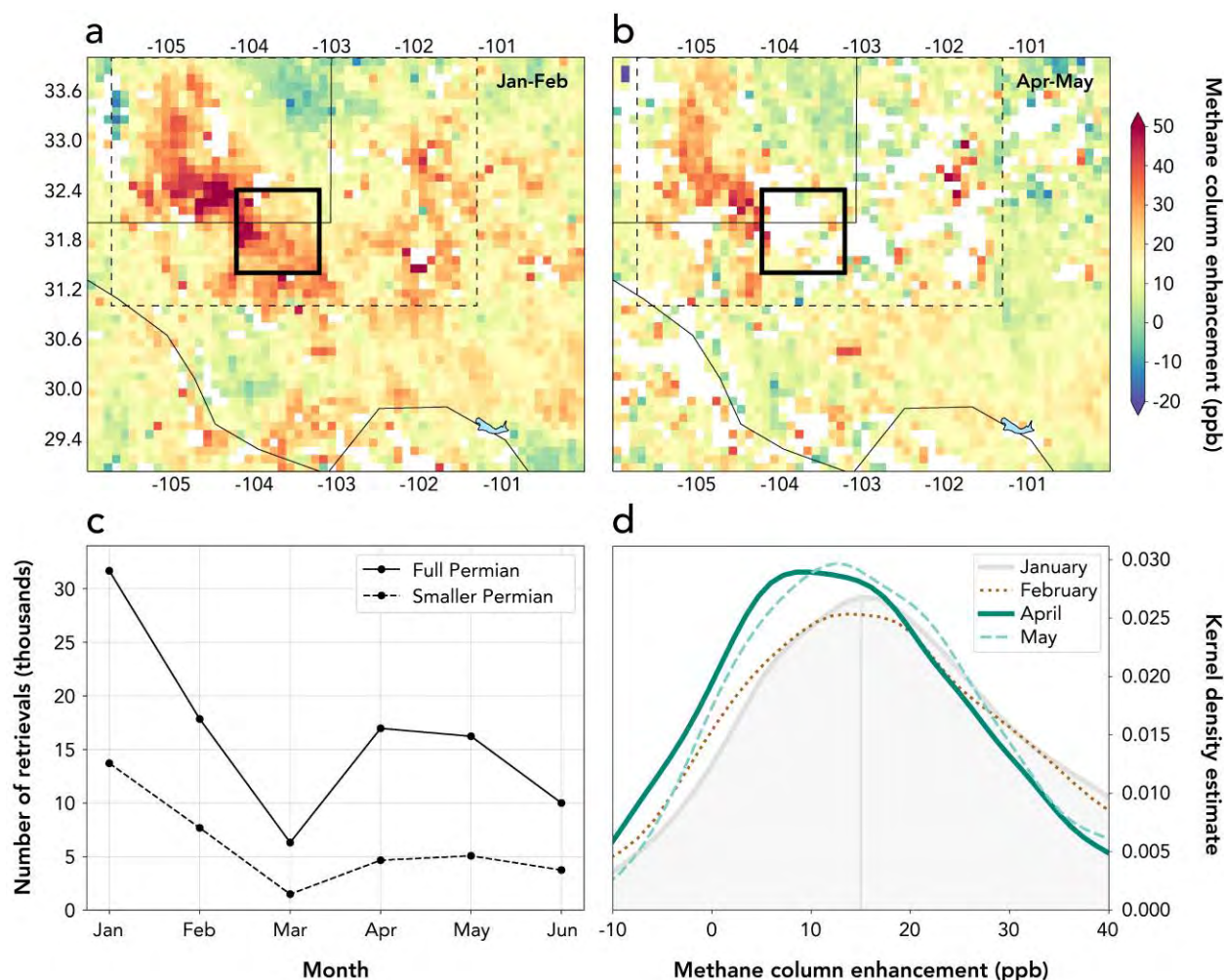


Figure 5. TROPOMI observations of topography-corrected methane column enhancements over the Permian basin, from January to June 2020. a-b: Mean methane column enhancements (ppb) over the Permian basin for the January-February and April-May 2020 time periods, gridded to $0.1^\circ \times 0.1^\circ$ resolution. The thin solid lines indicate state and national borders; the thick solid lines describe the 100 km x 100 km tower and aircraft study region; and the dotted lines trace a smaller Permian domain that closely bounds the methane hotspots seen over the Delaware and Midland sub-basins. c: Number of TROPOMI column retrievals over the full Permian basin domain (29–34°N, 100–106°W) and over the smaller Permian basin domain (31–34°N, 101.4–105.6°W; dashed lines in panels a, b), by month in 2020. d: Frequency distribution plots of methane column enhancements over the smaller Permian domain, by month, after removal of days without coverage of the Delaware and/or Midland sub-basins (see text). The gray vertical line indicates the distribution maximum for January.



3 Results

Both aircraft and tower-based methane flux data show consistent trends of declining then rebounding methane emissions in our Permian Basin study area during March – June 2020 (Fig. 6). Between January 22 and March 19, 2020, Emissions were 176 Mg CH₄ hr⁻¹ (95% confidence interval range: 142 – 209 Mg CH₄ hr⁻¹). Following the rapid decrease in oil price, emissions between April 7 and May 1, 2020 reached a minimum of 55 Mg CH₄ hr⁻¹ (95% CI range: 21 – 89 Mg CH₄ hr⁻¹). After the oil price mostly recovered, emissions for the month of June had increased to 135 Mg CH₄ hr⁻¹ (95% CI range 105 – 166 Mg CH₄ hr⁻¹) and by August had recovered largely to pre-crash levels at, albeit with higher uncertainty (152 Mg CH₄ hr⁻¹; 95% CI range 101 – 202 Mg CH₄ hr⁻¹, Fig. 3). Combining the monthly tower estimates with reported gas production (Enverus, 2020), we calculate a March 2020 loss rate of 3.4% of total gas production (95% CI range: 2.7 – 4.1%), slightly lower but within the uncertainty of previously reported basin wide estimates from 2018 – 2019 (3.7 ± 0.7 (1 σ) %) (Zhang et al., 2020). The minimum loss rate calculated for April 2020 was 1.5% of gas production (95% CI range: 0.8 – 2.2%); the loss rate of later months is uncertain due to incomplete gas production data (Appendix E). In the full Permian Basin, orbital observations of XCH₄ indicate lower methane column enhancements in April – May versus January – February 2020, consistent with the aircraft and tower-based flux data (Fig. 5).

Well pad development in the study area proceeded at an average rate of 71 new sites per month between August 2019 and March 2020, then dropped to a monthly average of 24 sites between April and July 2020 (Appendix C, Fig. 7). The number of well completions per month declined from 134 to 53 between January and April 2020 (Enverus, 2020); completion counts are higher than well pad development rates due to multiple wells being located on a single pad. After rising steadily throughout 2019, oil and gas production peaked in March 2020 and then declined 9 and 8%, respectively, in April. Based on adjusted, incomplete production data for May and June, gas production stayed relatively steady after April while oil production dropped an additional 3% (Appendix E). The relative decline in O&G production between March and April 2020 was much greater among wells in the first two months of production, decreasing 50 and 45%, for oil and gas, respectively (Appendix E).

The three flare surveys between February and June 2020 consistently found that 11% of flares had combustion issues, with 5% unlit and emitting hydrocarbons. Even when using conservative assumptions of greater combustion efficiency, we estimate a basin-wide flare combustion efficiency of 93%, with the remaining gas (assuming 80% methane content) being emitted to the atmosphere (Appendix B). Satellite observations of radiant heat indicate that flared gas volumes were cut in half from 7.6 to 3.2 Bcf between January and April 2020 (Fig. 8).

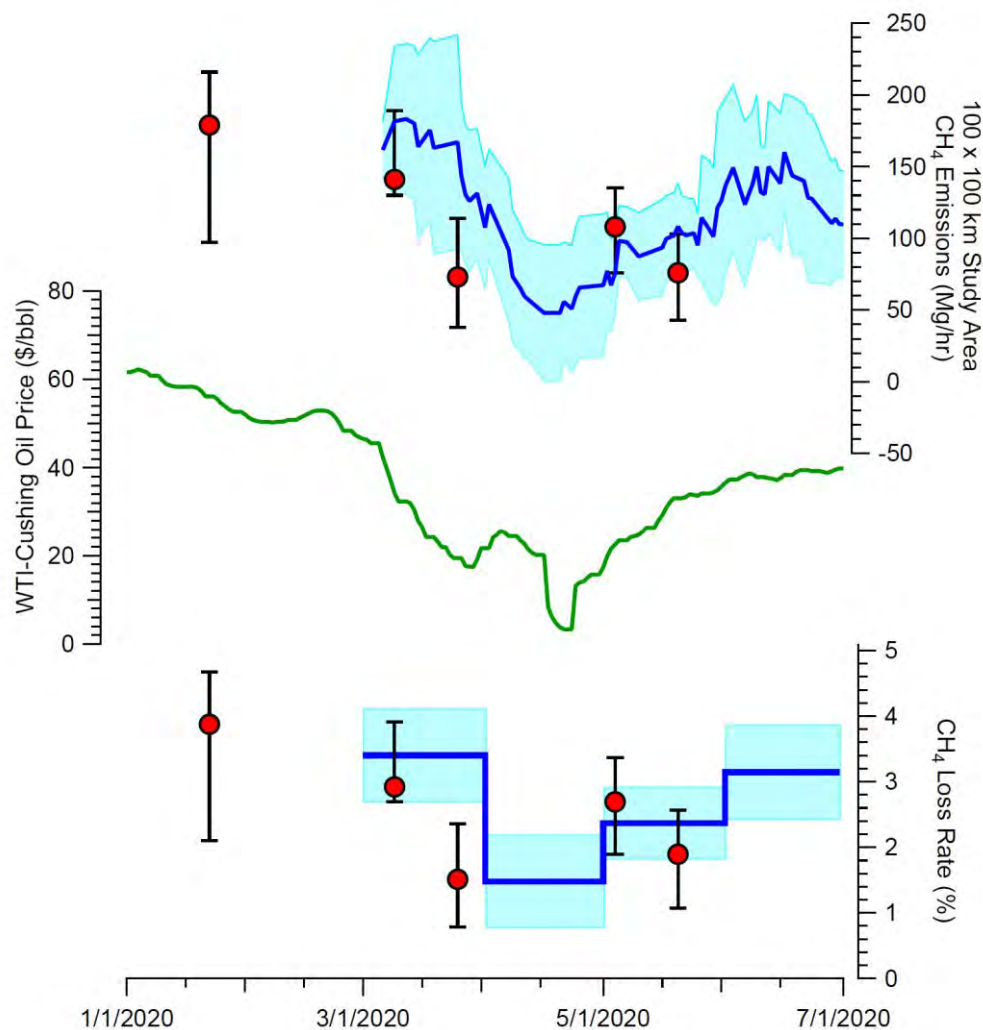


Figure 6. Temporal variation in methane emissions and crude oil price. Top: Aerial (red circles with 95% CI error range) and tower based 7-point moving average and 95% CI (blue line and shading) atmospheric estimates of 100 km x 100 km study area CH_4 emissions. Middle: 7-day moving average of WTI-Cushing daily oil price. Bottom: Resulting CH_4 loss rate from aerial and monthly mean tower-based measurements utilizing published monthly gas production within the study area (Enverus, 2020).

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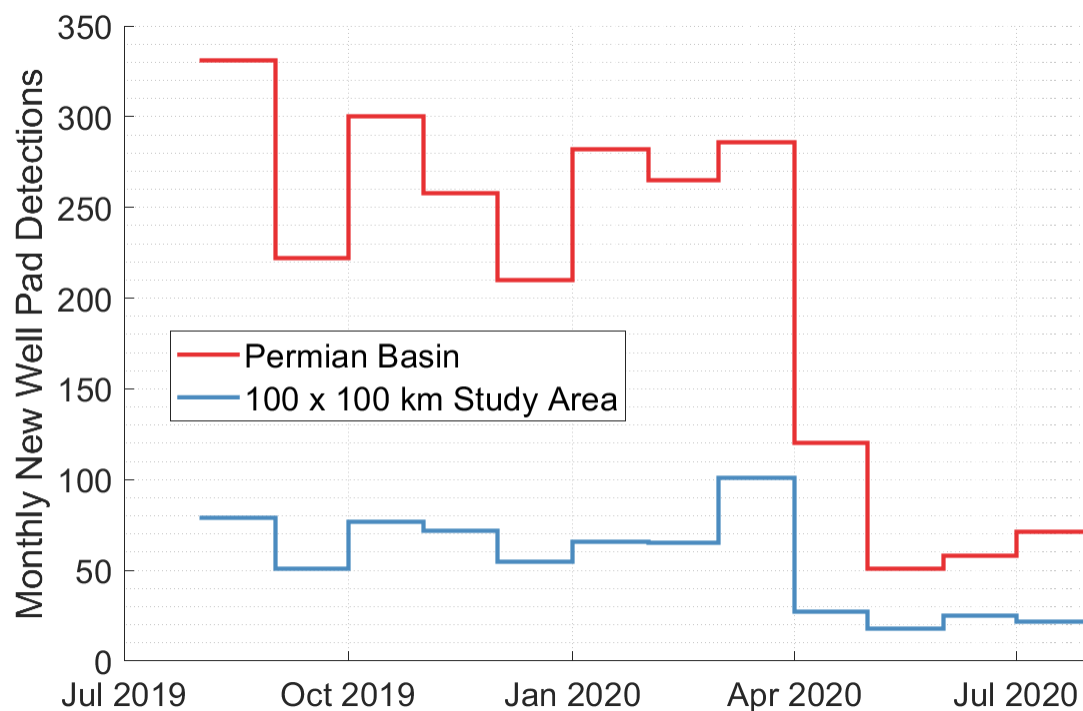


Figure 7. Number of new well pads constructed per month between August 1, 2019 and August 1, 2020.

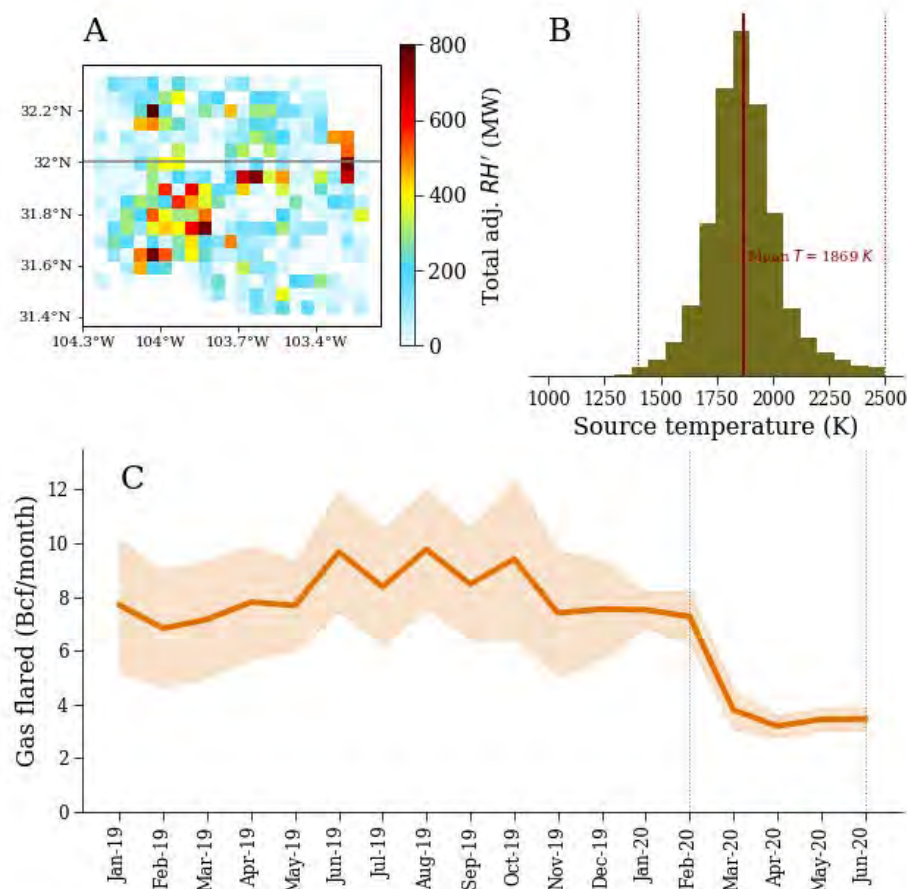


Figure 8. VIIRS-derived gas flaring in the study region. (A) Spatial distribution of the cumulative adjusted radiant heat over the period between January 2019 and June 2020 aggregated over a $0.05 \times 0.05^\circ$ grid resolution. (B) Histogram of VIIRS-derived source temperatures. Dotted lines show the temperature regime characteristic of gas flaring sources (1400–2500 K). (C) Monthly trend in VIIRS-derived gas flared volumes. The mean estimate is shown in solid line and the 95% CI on the mean is shown in the shaded area.



4 Conclusions

The pandemic-related oil price crash provided an unexpected opportunity to assess temporal variability in methane emissions during a period of volatile oil prices and associated operational changes. In support of our hypothesis that methane emissions would decline with oil price, we observed a three-fold reduction in Permian Basin study area methane emissions that was strongly correlated to the average daily oil price. The relative decline in O&G production during this period was less than 10%; accordingly, loss rate temporarily decreased from 3.4% to 1.5% of gas production between January 22 – March 19 and April 7 – May 1, 2020 (Appendix E). It is important to note that even the minimum observed loss rate of 1.5% is several times higher than the performance targets committed to by major O&G companies accounting for about one-third of global oil production, including some with operations in the Permian Basin (OGCI, 2020). We hypothesize that total methane emissions are positively correlated with oil price due to three interrelated factors associated with well development: 1) well completion rates, 2) associated gas flaring volumes, and 3) indirect impacts of new gas production on the gathering and processing (G&P) system.

Lower oil prices directly led to reduced emissions by decreasing well development activities, as we observed for rig count, new site construction, and well completions following the price crash. Well development activities are an intermittent source of methane emissions, particularly completion flowback, the typically multi-day period following hydraulic fracturing when fluids, excess proppant, and entrained gas are expelled from the wellbore (Allen et al., 2013). We estimate that the ~80 fewer well completions in April versus January 2020 caused average potential flowback emissions in our study area to decline from 9 to 2 Mg CH₄ hr⁻¹ (Appendix D). At the time of the study, U.S. federal regulations mandated the use of reduced emission completions to control emissions in most situations; however, operator reported data suggest actual emissions (1 – 2.5 Mg CH₄ hr⁻¹) are of similar magnitude to our estimate of potential emissions. ((USEPA, 2019, 2020b); Appendix D).

The observed two-fold reduction in flared gas volumes between January and April 2020 was likely the result of the large drop in gas production from new wells. Unconventional wells tend to have high initial gas production followed by steep declines. With lower rates of well development and new gas production in the area, competition for limited gas pipeline capacity likely was abated, leading to less flaring of stranded associated gas. Assuming a combustion efficiency of 93%, we estimate flare-related methane emissions in our study area were approximately 8 and 3 Mg CH₄ hr⁻¹ in January and April 2020, respectively (Appendix A). Our combustion efficiency assumption, which is based on repeat observations of over 300 flares, is conservatively high and therefore our emission estimate represents a lower bound. However, even with worst-case assumptions of flare combustion efficiency it is unlikely that January and April flare-related emissions would have exceeded 20 and 7 Mg CH₄ hr⁻¹, respectively (Appendix B).

Our estimates of well completion and flare-related methane emissions account for less than 20% of the observed total reduction between pre-crash and minimum price conditions; therefore, we theorize that the primary driver of emission reductions is indirect improvements to G&P system performance resulting from reduced inputs of gas from new wells. This result suggests



that the high methane emission rate observed in the Permian Basin in recent years is in large part due to insufficient capacity
 400 of G&P infrastructure for handling and delivering rapidly growing rates of natural gas production (Zhang et al., 2020). The
 drastic decline in flared gas volumes during the oil price crash suggests that the reduction in new gas production relieved G&P
 capacity issues. A similar pattern was observed in the Bakken formation during the oil price decline of 2015-2016: price drops
 caused only a small decrease in total production but a large decrease in drilling and flaring rates (Appendix F). Our study
 provides the first direct evidence of reduced methane emissions resulting from an apparent abatement of infrastructure capacity
 405 limitations.

The high methane emission rate observed in the Permian Basin during periods of higher commodity prices is likely a
 consequence of associated gas production increasing at a faster rate than midstream infrastructure capacity, which leads to
 extensive flaring and anomalous conditions related to excess gas throughput (e.g. pressure relief venting). Our observations of
 emissions declining concurrently with new well development suggest that methane emissions could be mitigated in the Permian
 410 Basin and similar oil-producing fields by better aligning development rates of wells and midstream infrastructure. For example,
 regulations could prohibit the drilling of wells in areas without sufficient capacity to transport newly produced gas to market.
 Our findings suggest that policies which tie the maximum rate of well development to infrastructure capacity, in addition to
 other approaches such as requiring high frequency or continuous monitoring to detect large emission sources (Alvarez et al.,
 2018), can facilitate lower methane emissions that reduce the climatic impact of oil and gas production.

415 **Appendix A. VIIRS-derived flared natural gas volumes**

We assess the monthly trends in the volumes of natural gas flared in the study region using nighttime fire and flare data
 observed by the Visible Infrared Imaging Radiometer Suite (VIIRS) instrument onboard the Suomi National Polar-Orbiting
 Partnership satellite. Specifically, we use the VIIRS NightFire V3.0 data product to support our analysis (Elvidge et al., 2013)
 For the study region and for the period between January 2019 and June 2020, we retrieved 49,885 individual VIIRS detections
 420 for which it was possible to estimate flaring source temperatures based on Planck curve fitting of the source radiances Elvidge
 et al. (2013). During this period, the mean VIIRS-derived source temperature was 1869 K. The histogram of source
 temperatures is shown in Fig. 8b, indicating a strong gas flaring signal in the characteristic temperature regime of between
 1400 and 2500 K. Elvidge et al. (2015) developed a correlation between the VIIRS-derived radiant heat and reported gas flared
 volumes and derived the relationship:

$$425 \quad V_a = 0.0274 RH' (R^2 = 0.86)$$

where V_a is the annual volume of gas flared (in billion cubic meters) and RH' is the modified radiant heat for each individual
 flare, adjusted to account for the observed non-linear relationship between flared gas volume and radiant heat and was
 430 computed as: $RH' = \sigma T^4 S^{0.7}$, where σ is the Stefan-Boltzmann constant ($5.67 \times 10^{-8} \text{ W m}^{-2} \text{ K}^{-1}$), T and S are the source
 temperature and area, respectively, and the exponent (0.7) was empirically developed by Elvidge et al. (2015) to address non-



linearity. Figure 8a shows the spatial distribution of the cumulative RH' in the study region over the period between January 2019 and June 2020, as aggregated over a $0.05^\circ \times 0.05^\circ$ grid resolution. To estimate monthly gas flared volumes (V_m in billion cubic feet) for the study area, we modify equation the equation above, assuming the relationship holds over monthly intervals:

$$V_m = 0.0274 RH' \times \frac{1}{12} \times 35.315 \left[\frac{Bcf}{Bcm} \right]$$

We use the equation above to compute the mean monthly gas flared volumes (and 95% CI on the mean) in the study area based on the daily RH' aggregated from individual detected flares. The trend in the monthly gas flared volumes is shown in Fig. 8c.

The average flaring rate in 2019 was 8.2 ± 2.2 Bcf/month. From February 2020, a sharp decline in the mean gas flaring rate was observed, with the lowest estimated flaring rate of 3.2 ± 0.4 Bcf in April. Following a similar procedure for the entire Permian region, the estimated mean monthly flaring rate declined from a mean of 23 ± 5 Bcf/month in 2019 to 8.1 ± 1.7 Bcf in May 2020. Thus, the lowest estimated monthly gas flared volumes in 2020 were a factor of 2.6 and 2.8 times lower than the monthly mean observed in 2019 for the 100 km x 100 km study region and full Permian Basin, respectively.

Appendix B. Aerial flare performance survey

We compiled a list of potential locations of recently active flares in the Permian Basin (Delaware and Midland sub-Basins) based on a geospatial analysis of the SkyTruth Global Flaring Dataset, which is derived from heat sources detected by the Visible Infrared Imaging Radiometer Suite (VIIRS) instrument on the NOAA Suomi NPP satellite; SkyTruth has applied several filters to the VIIRS data including removing heat sources $<1,500^\circ\text{C}$ and with <3 detections per month (Skytruth, 2020). To account for spatial uncertainty of SkyTruth flare locations, we spatially joined their individual flare detections between October 1, 2019 and January 31, 2020 using a 100-meter buffer distance; the centroid latitude/longitude of the 1,014 joined detections were defined as likely locations of recently active O&G flares. Leak Surveys, Inc. (LSI), a leak detection company specializing in aerial optical gas imaging, was provided a list of 573 potential active flare locations from the original set of 1,014. The site selection methodology balanced representativeness and survey efficiency by defining one contiguous, high flare density area in each sub-basin that could be surveyed over the course of approximately five days. For the Delaware sub-Basin, we selected 323 locations located within our main study area (NW and SE corners are 32.325°N , 103.822°W and 31.417°N , 103.202°W , respectively). For the Midland sub-Basin, we selected 250 locations from the two counties (Midland and Martin) with the highest flare counts from the analysis of VIIRS data. LSI surveyed these locations with a custom infrared camera (IR) deployed in a R44 helicopter. Potential flare locations were identified with spatial coordinates and a unique flare ID.

LSI performed three surveys of the potential flare locations during the weeks of February 17, March 23, and June 22, 2020 (EDF, 2020). At each potential flare location, LSI determined if one or more flares was present at the spatial coordinates, and



465 if so, observed the flare(s) for operational status. For flares with apparent combustion issues, LSI recorded 30 – 60 seconds of
infrared and visual video footage of the flare plume to provide visual evidence of flare status. For each flare, LSI assigned a
qualitative assessment of the apparent flare status at the time of survey from four categories: inactive and unlit with no
emissions (inactive); active, lit, and operating properly (operational); active and lit but with operational issues such as
incomplete combustion or excessive smoke (malfunction); or active, unlit, and venting methane (unlit). For survey 1, LSI
470 observed 337 flares from the random selection of potential locations. For surveys 2 and 3, a random subset of the 337 flares
was selected for re-survey, prioritizing locations that had previously observed issues. We observed similar flare performance
in each of the three surveys: 11% of active flares had observed malfunctions, including 5% that were unlit and venting (Table
B1).

475 To estimate methane emissions from flaring, we used our qualitative flare performance data and conservatively high
assumptions about the combustion efficiency of operational, malfunctioning, and unlit flares to estimate overall combustion
efficiency, and then applied combustion efficiency to estimated flared volumes in 2019 based on an analysis of VIIRS data
(Appendix B). We assume that operational flares perform at the EPA default combustion efficiency of 98% (Regulations,
2016). The 5% of flares that were unlit and venting were assumed to have a combustion efficiency of 0%. The 6% of flares
480 that were lit with apparent combustion issues were assumed to have 90% combustion efficiency. If we assume flared gas
volumes are proportional to the observed fraction of flares by performance, then the overall combustion efficiency of active
flares in the Permian Basin is 93%, which means 7% of flared methane is emitted. Applying 93% combustion efficiency to the
280 Bcf of gas flared in the Permian in 2019 (assuming 80% CH₄ content) results in annual methane emissions of
approximately 300,000 Mg CH₄ from flaring in the Permian; unlit flares account for about 65% of these emissions, while
485 operational and poorly combusting flares account for about 15 and 10%, respectively. As a sensitivity analysis, we use
alternative combustion efficiency assumptions of 90%, 50%, and 0% for operational, malfunctioning, and unlit flares,
respectively; this leads to an overall combustion efficiency of 83% and 2.3x more flare-related methane emissions than our
conservatively low assumptions.

490 EPA publishes two separate estimates of Permian flaring methane emissions, which incorporates the 98% combustion
efficiency but different gas flared data. The 2020 Greenhouse Gas Inventory (USEPA, 2020a) reports 2018 Permian Basin
methane emissions of 12,100 Mg CH₄ from associated gas flaring, plus 8,500 and 4,600 Mg CH₄ from associated gas venting
and miscellaneous production flaring, respectively. The Greenhouse Gas Reporting Program (USEPA, 2020b) reports 18,800
Mg CH₄ from Permian Basin onshore production facilities.

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Table B1. The operational performance of Permian Basin flares as observed during three helicopter-based infrared optical gas imaging surveys.

Surveyed Flares	Survey 1	Survey 2	Survey 3	Average
Operational	276	147	237	
Inactive	25	0	62	
Combustion Issue	23	9	18	
Unlit and Venting	13	10	12	
Total	337	166	329	
Malfunctioning (% of active)	11.5%	11.4%	11.2%	11.4%
Unlit and Venting (% of active)	4.2%	6.0%	4.5%	4.9%

500 Appendix C. Satellite imagery and machine learning based estimates of well pad development

We mapped new well pad construction in the Permian Basin using a two-step machine learning and remote sensing approach. First, well pad candidates were identified in satellite imagery with a convolutional neural network (CNN) model in individual scenes. The model predictions were then compared between the beginning and end of each month to identify the locations of newly constructed well pads. Second, by differencing before/after model outputs, persistent false-positives in the model were removed. The resulting model was deployed on imagery over the Permian Basin on a monthly cadence between August 1, 2019 and July 1, 2020.

We assessed the monthly trends in new well pad construction in the Permian Basin using a combination of satellite imagery from the European Space Agency Sentinel-2 satellite (ESA, 2020) and the National Aeronautics and Space Administration (NASA) Landsat-8 satellite (USGS, 2020). Imagery from Sentinel-2 has a pixel resolution of 10m, sufficient to clearly identify well pads, and is collected approximately once every 5 days for any location, providing an average of 6 collects per month. While this is generally sufficient for monthly monitoring, some areas experience high cloud cover in all the scenes, causing well pads to be missed. Imagery from Landsat-8 was used to fill in for such cloudy scenes. Despite the slower 16-day revisit rate and coarser (30m) pixel resolution of Landsat-8, well pads are still easily detectable. The combined use of these two satellites provided at least one cloud-free scene for all of the Permian Basin for each month within the time period we monitored. We use six spectral bands from both Sentinel-2 and Landsat-8: "red", "green", "blue", "NIR", "SWIR1", and "SWIR2".



520 New well pad construction was detected in a two-step approach. Well pad candidates were first identified with a convolutional neural network (CNN) model in individual scenes. The model predictions were compared between the beginning and end of each month, and new well pads were identified. Well pads were detected using a semantic segmentation approach. We used a UNet architecture with a six-band input layer with shape (*height, width, 12*) and output predicting the presence or absence of well pads in each pixel. Landsat-8 imagery was resampled to 10m to match the resolution of Sentinel-2 imagery.

525 The model was trained on a ground-truth dataset taken from well pads detected with a separate machine learning model run on high resolution (1.5m) imagery. We generated ~7000 training tiles, each of size 512 x 512 pixels and containing 0 to 400 well pads each. The dataset was split into sets with 70 % for training, 10% for validation, and 20% for testing. Examples of image-target pairs are shown in Fig. C1.

530 New well pads were detected by comparing model output heatmaps between the beginning and end of sequential monthly time periods (Fig. C2). Intuitively, pixel values in satellite imagery change frequently in irrelevant ways, so it is more effective to identify change in the model output. The heatmap from the earlier time was subtracted from the later time. A threshold operator followed by a morphological opening operation were applied to these difference maps. New well pad detections were identified in the resulting binary map as shown in Fig. C3.

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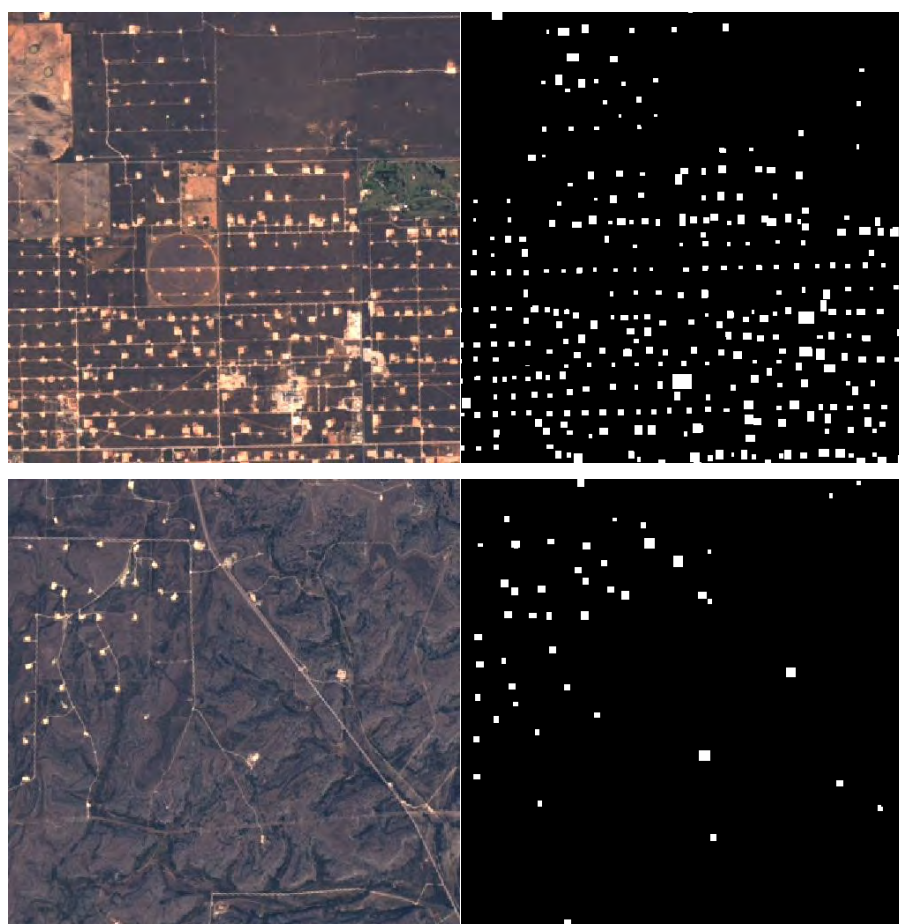
To further remove false positives, we require that new well pad candidates should not have existed in multiple months leading up to the construction date, and should continue to exist for several months after. We thus used the three months before and the two months after to remove candidates that fail this condition. While the 10m resolution of the imagery makes it difficult to confirm with certainty that candidates contain oil and gas infrastructure, we suspect that the Permian Basin region is unlikely to experience a high volume of unrelated ground clearing for development. We confirm this with manual inspection, see details below.

540 The CNN and change detection pipeline was run over the Permian Basin on monthly imagery composites between August 1, 2019 to July 1, 2020. The deployment was done using the Descartes Labs platform. Tiled imagery was drawn on-the-fly, model inference was performed in a cloud-native kubernetes infrastructure, and results were stored in the commercial cloud. Finally, the authors hand-verified the candidates for each month.

550 The change detection analysis has a precision of ~100%, since the final results have been hand-verified. It is infeasible to measure the model accuracy or recall directly, as these would require identifying a substantial number of newly constructed well pads as well as false negatives (newly constructed well pads that were missed by the model), which would require extensive hand-labeling; additionally, the model performance may vary across geographies, making a single metric less useful. Instead, we estimated the recall using a dataset of well pads identified with a separate machine learning model in high-



resolution imagery; we measured the fraction of these well pads that are detected as well pads by the UNet in single mosaics. Any well pads missed in this step will not be identified as new well pads. We measured this recall on four separate monthly
 555 mosaics, and found a recall of 90.0%, with a statistical uncertainty of less than a percent. Finally, the number of newly constructed well pads per month are shown in Fig. 7 with examples presented in Figs. C4 and C5.



560

Figure C1. Examples of image-target pairs: (left) Sentinel-2 RGB imagery (ESA, 2020); (right) Ground truth



565

Figure C2. CNN model example, showing Sentinel-2 imagery (left; ESA, 2020) and model output heatmap over the same area (right).



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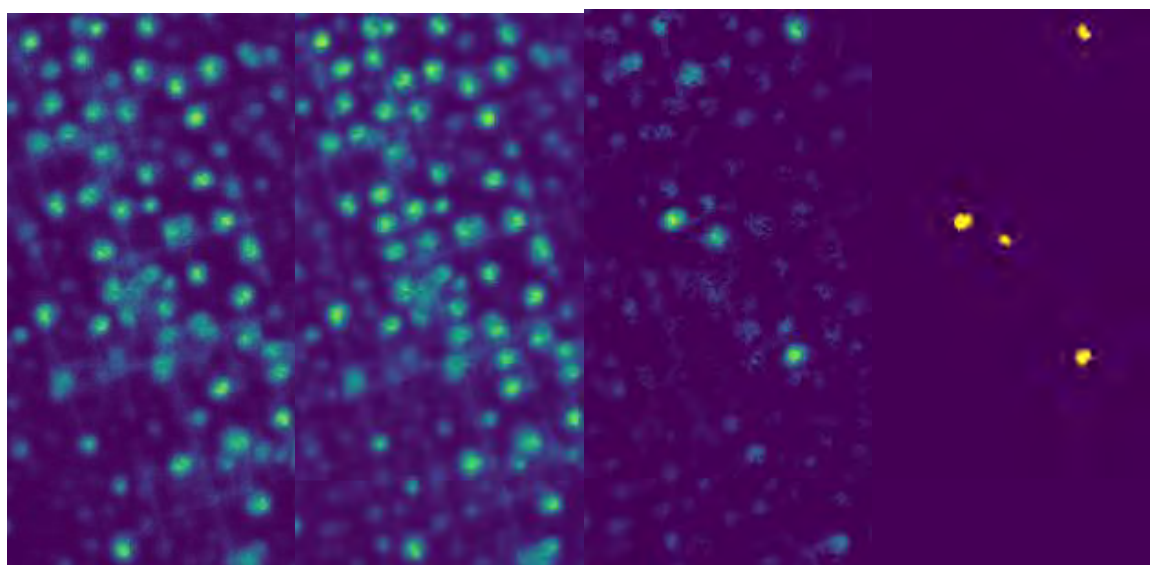


Figure C3. Before (top-left) and after (top-right) medium-resolution imagery (ESA, 2020). Same area in model output
 575 (bottom, left to right): 1. before, 2. after, 3. difference, 4. detected new well pads.



580 **Figure C4.** Example of an area where new development was found, before (top) and after (bottom) shown in Sentinel-2
imagery (ESA, 2020). Points in yellow indicate the locations of new well pad development.

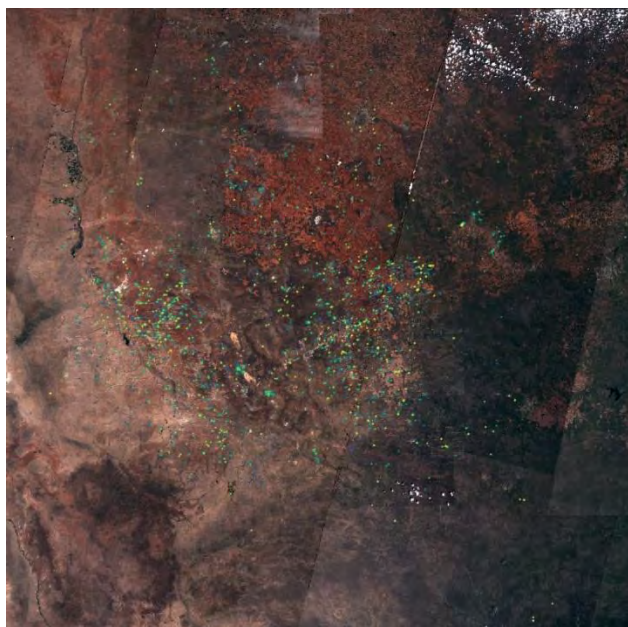


Figure C5. Number of new well pads constructed per month between August 1, 2019 and July 1, 2020 overlaid on Sentinel-2
585 imagery over a subset of the Permian Basin (ESA, 2020).



Appendix D. Well completion emission estimates

Well completion flowback refers to the unconventional well development period following hydraulic fracturing in which water, proppant, and entrained natural gas flow out of the wellbore to prepare a well for production (Allen et al., 2013). As of 2015, U.S. federal regulations require all oil and gas wells except exploratory and low-pressure wells to utilize reduced emission completions (RECs), which separate the natural gas and send to a pipeline as soon as technically feasible (USEPA, 2019); occasionally, flaring or a combination of REC and flaring is used to partially control emissions. Previous research has demonstrated that RECs control flowback emissions by an average of 99% (Allen et al., 2013). To estimate monthly completion-related methane emissions within our 100 km x 100 km study area during the study period, we compiled a list of every well located within our study area with a completion date between January 1 and April 30, 2020 (Enverus, 2020) and applied two approaches to estimate potential and actual emissions. The first approach estimated actual emissions by applying an emission factor (total methane emitted per well completion) based on 2018 data from 3,359 completions in the Permian Basin reported to the EPA Greenhouse Gas Reporting Program, which operators estimate with a choice of measurements or engineering equations (USEPA, 2019, 2020b). To convert total emissions into an hourly emission rate, we assumed that completions emit at a constant rate over 4 days, the average duration from Allen et al. (2013). The second approach, which estimated potential emissions, assumes that wells emit their initial gas production for 4 days following the completion date; we assumed 80% methane content of natural gas and used the daily average production rate from the first complete month of gas production (referred to as PracIP by (Enverus, 2020)).

The number of well completions per month in the study area dropped from 134 in January to 53 in April 2020. Based on our first approach, January and April 2020 completion-related actual emissions were 2.5 and 1 Mg CH₄ h⁻¹, respectively, with an average emission factor of 19 kg CH₄ h⁻¹ per completion and 93% of completions utilizing a REC or REC plus flaring (Table D1). Based on the second approach, the average potential emission rate per completion was 61 kg CH₄ h⁻¹ in January and 23 kg CH₄ h⁻¹ in April 2020; this results in total study area completion-related emissions of 9.3 and 1.9 Mg CH₄ h⁻¹ in January and April, respectively (Table D2).



Table D1. Estimate of Permian Basin well completion emission factors based on US EPA Greenhouse Gas Reporting Program data.

	Permian Basin Annual Completions (#)	Total Methane Emissions (Mg CH ₄)	Average Emissions (Mg CH ₄ completion ⁻¹)	Average Emission Rate assuming 4 day duration (kg CH ₄ completion ⁻¹)
Reduced Emission Completion (REC)	1,162	376	0.3	3
REC & Flared	1,955	4,673	2.4	25
Uncontrolled	14	35	2.5	26
Flared	228	1,202	5.3	55
<i>Total</i>	<i>3,359</i>	<i>6,287</i>	<i>1.9</i>	<i>19</i>



625 **Table D2.** Estimate of average monthly potential completion-related emissions from our study area from January 2019 – April 2020 based on initial production data and the assumption of 4 day completion duration.

Year	Month	Average Ongoing Daily Well Completions (wells)	Average Aggregate Completion-Related Emissions (Mg CH ₄ h ⁻¹)
2019	1	435	7.1
2019	2	616	15.2
2019	3	570	12.3
2019	4	706	12.0
2019	5	595	11.0
2019	6	569	9.3
2019	7	762	14.7
2019	8	884	13.6
2019	9	492	12.1
2019	10	658	10.5
2019	11	720	14.6
2019	12	461	9.4
2020	1	505	9.3
2020	2	335	7.7
2020	3	259	3.7
2020	4	212	1.9



630 **Appendix E. Oil & Gas production data and assessment of database completeness**

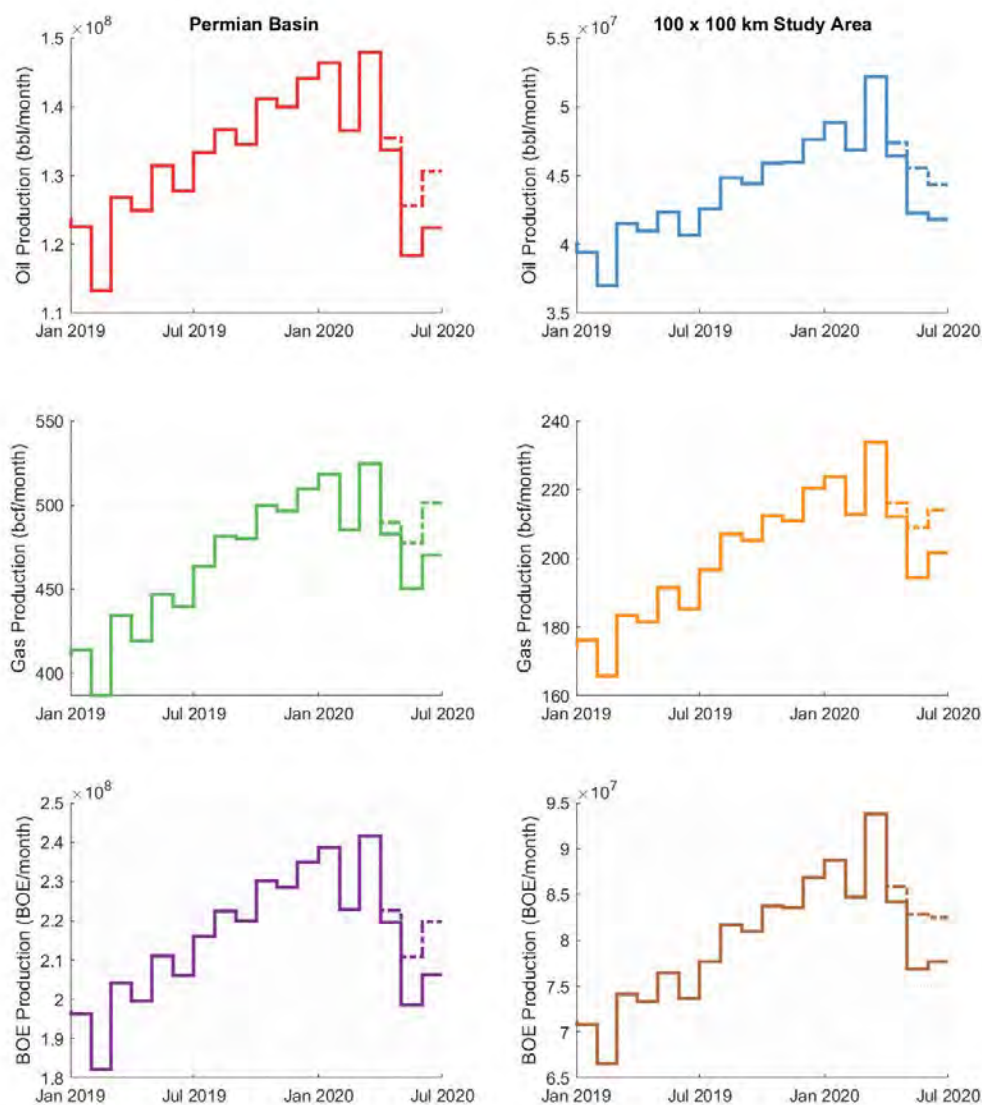
Production quantities of oil and gas from individual wells is reported to public state databases (RRC, 2020; NMOCD, 2020); however, the best results are achieved by analyses from an external database (Enverus, 2020) which filters and aggregates all of the publicly available datasets from all reporting agencies. Oil and Gas production data from New Mexico is updated on a monthly cadence, while data from Texas is updated twice each month but still only at monthly resolution. Timeseries of Oil, Gas and combined barrels-of-oil equivalent (BOE) production within the greater Permian basin and 100 x 100 km study area are presented in Fig. E1. Similarly, Fig. E2 presents a timeseries of the number wells reporting production each month within the basin and 100 x 100 km study area as well as timeseries of the number of wells exhibiting their first month of Oil and Gas production and their as their spud date: the date at which the subsurface drilling commences within the process of well development. The typical lag in data reporting is at least 3 months (Enverus, 2020) (e.g. O&G production during the month of June is available on or shortly after the 1st of September); however in practice reporting delays upwards of 6 months have been observed. We anticipate additional delays in the reporting of production data related to the global COVID-19 pandemic, thus here we attempt to broadly assess the incompleteness of the production dataset and its related impact on our estimates of the study area CH₄ loss rate.

The number of active wells reporting production was relatively constant in the Permian basin was relatively consistent through March 2020, only exhibiting a drop from the trend in April 2020 suggesting that new wells were coming online at roughly the same rate of older, depreciated wells being shut in. Alternatively, in the smaller 100 x 100 km study area which represents $7.4 \pm 0.3\%$ (1σ) of the total Permian basin active well count for January 2019 – March 2020, the number of wells reporting production each month was increasing at a rate of 102 ± 58 (1σ) wells per month between January 2019 and March 2020. During the same time span in the study area, the rate of new well production (168 ± 27 wells/month, 1σ) significantly outpaced the rate of depreciated wells being shut in by roughly a factor of 3.

Therefore, to estimate the complete dataset of total monthly production in the April-June 2020 under the timeframe of the observations of CH₄ emissions presented in Fig. 2, we extrapolate the average well count for January to March 2020 to the subsequent three months as the dotted line on the Orange and Red traces of Fig. E2. We assume the deficit in wells reported represent the same distribution of oil and gas reported from each well present in the database; therefore, we linearly scale the production upwards by this factor as shown in the dotted lines in Fig. E1. This assessment suggests that that production largely plateaued during the height of the COVID-19 pandemic, rather than the <10% decrease observed by the reported data at time of submission. Therefore, using the projected gas production estimates, we calculate a projected loss rate in the basin from both the monthly mean tower data and May aerial measurements the as the purple dotted line and yellow points respectively in Fig. E3.



665 This approach discussed above likely overestimates the oil and gas production due to the reduced activity observed from satellite well pad detection (Fig.7) and the reduced rate of new well development (Fig. E2). Therefore, we consider this to be an upper limit on the study area gas production and therefore a lower limit on the CH₄ loss rate, with the actual value likely falling between the two estimates. Regardless, the adjusted loss rate represents a minimal adjustment within the 95% CI estimate expressed by the aerial and tower data temporal and analytical uncertainty that we do not consider it to differ significantly from the reported result in Fig. 6.



670

Figure E1. Monthly Timeseries of monthly Oil, Gas and Barrels of Oil Equivalent production (Top, Middle and Bottom respectively) in both the Permian Basin (left) and 100 x 100 km Study Area (Right). Dotted lines for April-June 2020 represent adjusted production to assess incompleteness of the dataset.



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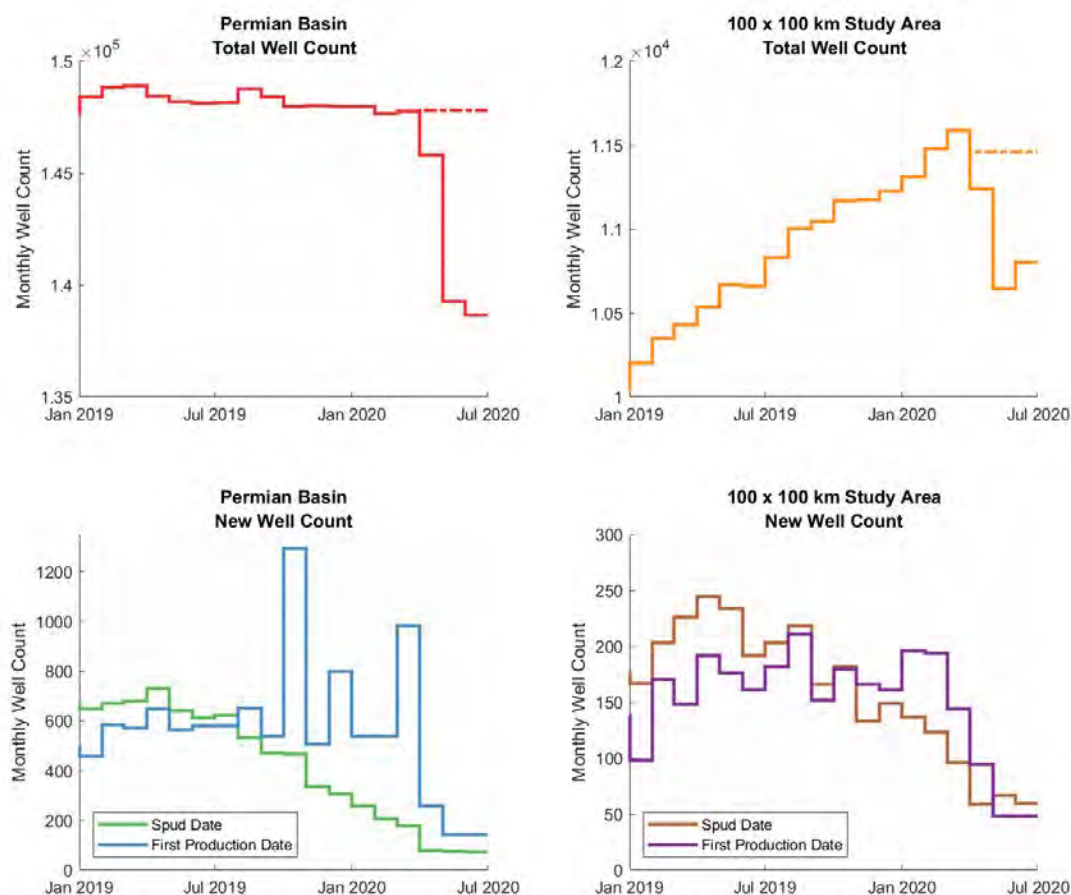


Figure E2. Monthly Timeseries of Active wells (top) and newly produced wells by spud date and month of first production (bottom) in both the Permian Basin (left) and 100 x 100 km Study Area (right). Dotted lines for April-June 2020 represent adjusted well counts to assess incompleteness of the dataset

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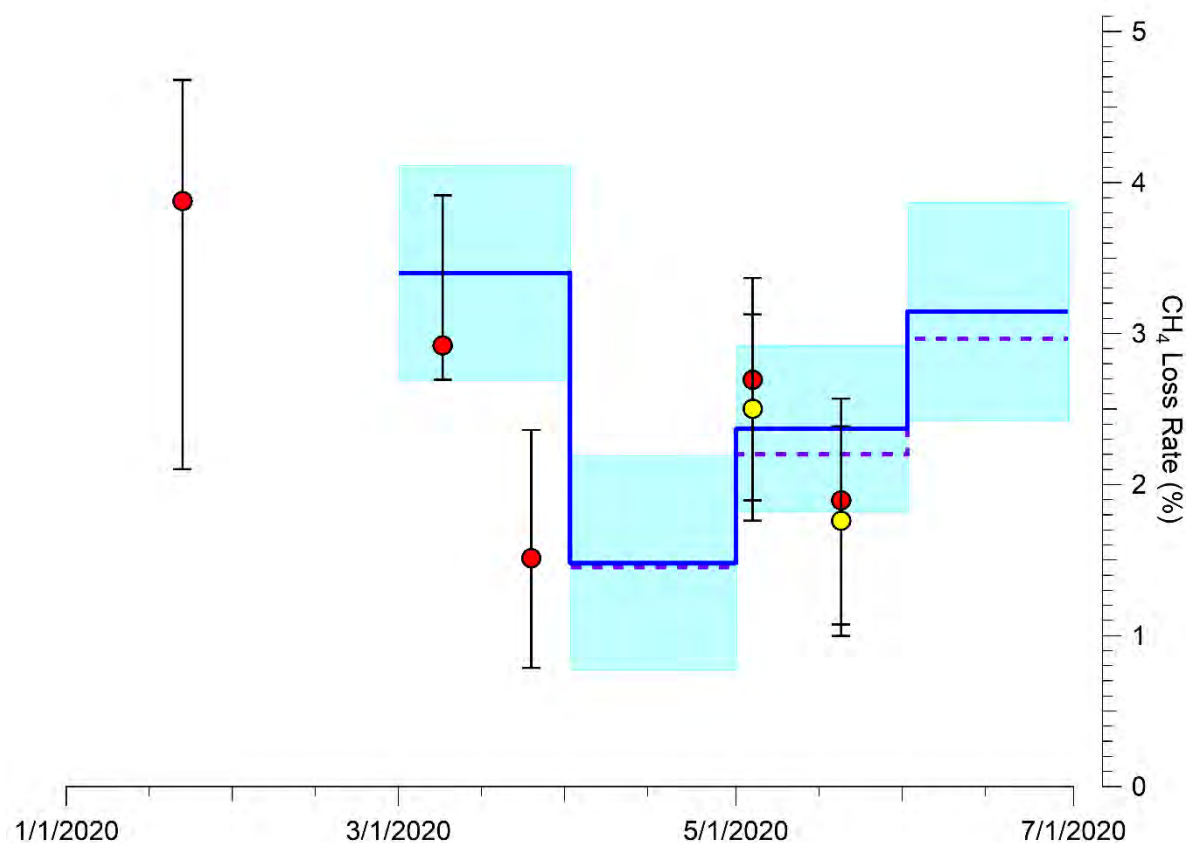


Figure E3. Gas production normalized loss rate in the 100 x 100 km study area following the same formatting as presented in Figure 6. Dotted purple line and yellow points reflect the adjusted tower and aerial based loss rates respectively after considering the incompleteness of the production database.



Appendix F. Supplementary data from Bakken Shale



690 **Figure F1.** Number of wells drilled versus fraction of total gas production flared in the Bakken region (North Dakota, U.S.A.) from 2012 - 2017. Similar to trends observed in the Permian, there was a strong correlation between wells drilled and fraction of gas flared with both values decreasing rapidly when oil prices crashed in 2014.



Data Availability

695 Data are available for download at <https://www.permianmap.org/>

Author Contribution

D.R.L., B.H., A.R.B., M.K., E.A.K., A.J.M., and S.P.H. contributed to study conceptualization. D.R.L., B.H., R.G., M.O., K.R., Z.R.B., K.J.D., N.L.M., V.C.M., S.J.R., S.C., M.L.S., D.J.J., L.S., D.V.V., A.D., X.R., N.S., and K.T.S. contributed to methods development and data analysis. D.R.L., B.H., M.O., Z.R.B., K.J.D., M.L.S., D.J.V., and K.T.S. wrote the original
700 draft and all authors reviewed and edited the manuscript

Competing Interests

A.R.B., E.A.K., M.K., and A.J.M. serve on the PermianMAP scientific advisory panel. Authors declare no other competing interests.

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710 Monitoring System. Computations for this research were performed on The Pennsylvania State University's Institute for Computational and Data Sciences' Roar supercomputer.



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Intermittency of Large Methane Emitters in the Permian Basin

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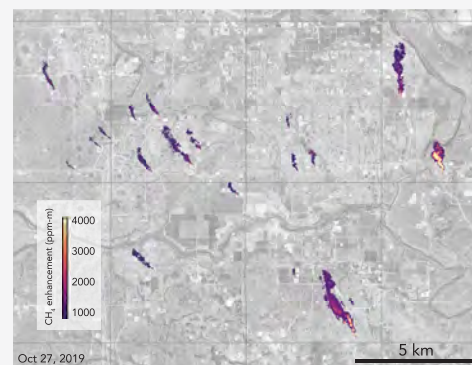


Article Recommendations



Supporting Information

ABSTRACT: The Permian Basin is the largest and fastest growing oil and gas (O&G) producing region in the United States. We conducted an extensive airborne campaign across the majority of the Permian in September–November, 2019 with imaging spectrometers to quantify strong methane (CH_4) point source emissions at facility-scales, including high frequency sampling to evaluate intermittency. We identified 1100 unique and heavy-tailed distributed sources that were sampled at least 3 times (average 8 times), showing 26% average persistence. Sources that were routinely persistent (50–100%) make up only 11% of high emitting infrastructure but 29% of quantified emissions from this population, potentially indicative of leaking equipment that merits repair. Sector attribution of plumes shows that 50% of detected emissions result from O&G production, 38% from gathering and boosting, and 12% from processing. This suggests a 20% relative shift from upstream to midstream compared to other US O&G basins for large emitters. Simultaneous spectroscopic identification of flares found that 12% of detected Permian CH_4 plume emissions were associated with either active or inactive flares. Frequent, high-resolution monitoring is necessary to accurately understand intermittent methane superemitters across large, heterogeneous O&G basins and efficiently pinpoint persistent leaks for mitigation.



INTRODUCTION

Methane (CH_4) is a major constituent of gas emitted from oil and gas (O&G) infrastructure and is the second most important anthropogenic greenhouse gas.¹ Multiple field campaigns across US O&G basins have shown that CH_4 emissions resulting from these operations follow a heavy-tailed distribution, where a handful of so-called “super-emitters” dominate the point-source emission budget for the region^{2–4} and can make up 20–50% of the total regional budget.⁵ Superemitters exist across O&G sectors (e.g., production, gathering, processing) and can result from expected activity (e.g., venting, liquids unloadings, etc) as well as leaks and malfunctions (e.g., pipeline leaks, unlit flares, well control loss). An accounting of emissions from the latter category could increase the U.S. Environmental Protection Agency’s (EPA) CH_4 O&G emission inventory by as much as 60%.⁶ There is considerable uncertainty in the persistence of superemitters due to sparse temporal sampling and/or limited spatial coverage common in many measurement campaigns. This complicates focused detection and remediation and underscores the need for regular monitoring from observing systems with sufficient sensitivity to detect anomalous emissions.

The Permian Basin in western Texas and southeastern New Mexico is both the largest and fastest growing O&G producing basin in the United States. The Energy Information Administration (EIA) reports that from 2014 to 2019 oil and gas production in the Permian increased by 390% and

350%, respectively, and the basin accounted for approximately 38% of total US oil production and 17% of total US natural gas production in late 2020.⁷ Hence, quantifying CH_4 emissions from these expanded operations is of tremendous interest. Using column-averaged dry-air mixing ratio (XCH_4) measurements from the Tropospheric Monitoring Instrument⁸ (TROPOMI), onboard the Sentinel-5P satellite, Schneising et al.⁹ and Zhang et al.¹⁰ both estimated Permian basin-wide leakage rates of 3.7%, with the former finding an energy basis loss rate of 1.3%, with natural gas constituting 35% of the energy produced in the basin. Given that TROPOMI’s $7.0 \times 5.5 \text{ km}^2$ spatial resolution is generally too coarse for detecting and quantifying individual point source emissions in most O&G fields,¹¹ this complicates partitioning leakage rates to specific segments of the O&G supply chain.

In this study, we map and quantify strong CH_4 point sources in the Permian Basin using the same airborne imaging spectrometer technology that was successfully deployed in previous studies.^{4,5} This technology allows for rapid, high

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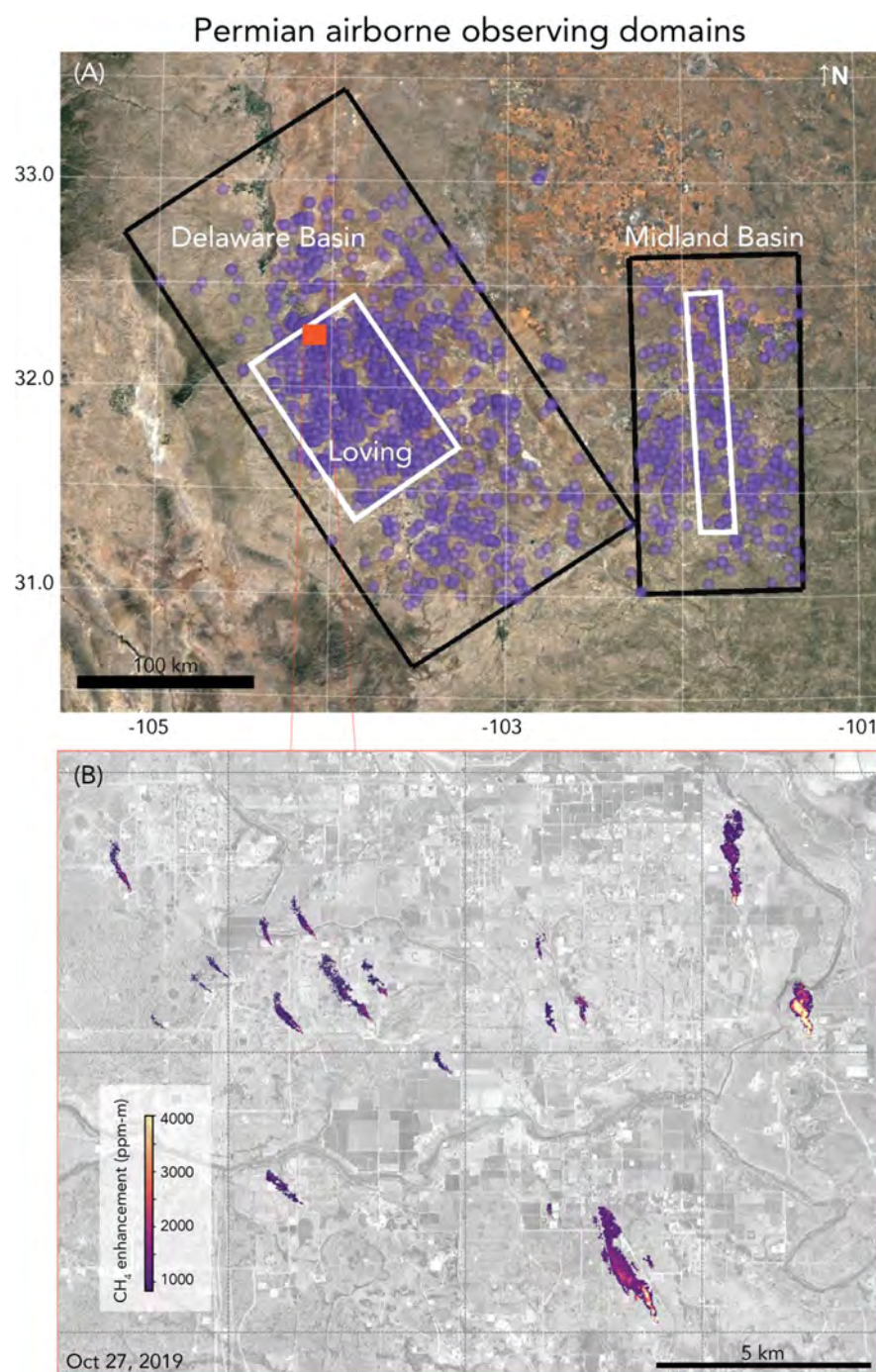


Figure 1. Domains surveyed by AVIRIS-NG and GAO during the airborne campaign from Sep–Nov 2019 (panel A), covering 55000 km² of total area, including 39000 km² in the Delaware Basin and 16000 km² in the Midland Basin. Black boxes represent the area surveyed at least once by the Global Airborne Observatory (GAO) instrument. White boxes represent where sites were revisited with the AVIRIS-NG instrument at least seven times during the campaign. Purple dots represent detected methane emission sources. Panel B shows methane plumes detected by GAO during a ~30 min interval on Oct 27th in the orange box in panel A, illustrating typical emissions from strong point sources in the Permian. Basemap images are from Google Earth.

spatial resolution mapping of large areas for strong CH₄ emission sources whose locations and timing are often unpredictable. Studies have shown that emissions from O&G operations can be intermittent (i.e., highly variable or stochastic) or persistent (i.e., continuously emitting).^{12,13} We quantify the persistence of strong point sources across the Permian through multiple overflights and find many sources to be highly intermittent (average 26% persistence). We attribute

each source to an emission sector (production, gathering and boosting, processing) to assess the supply chain distribution for strong superemitting point sources above the instrument detection limit (10–20 kg CH₄h^{−1}).

This measurement and quantification approach complements previous field studies that employed measuring systems with lower detection limits, but these were limited to surveys of only hundreds of production sites and/or a limited degree of

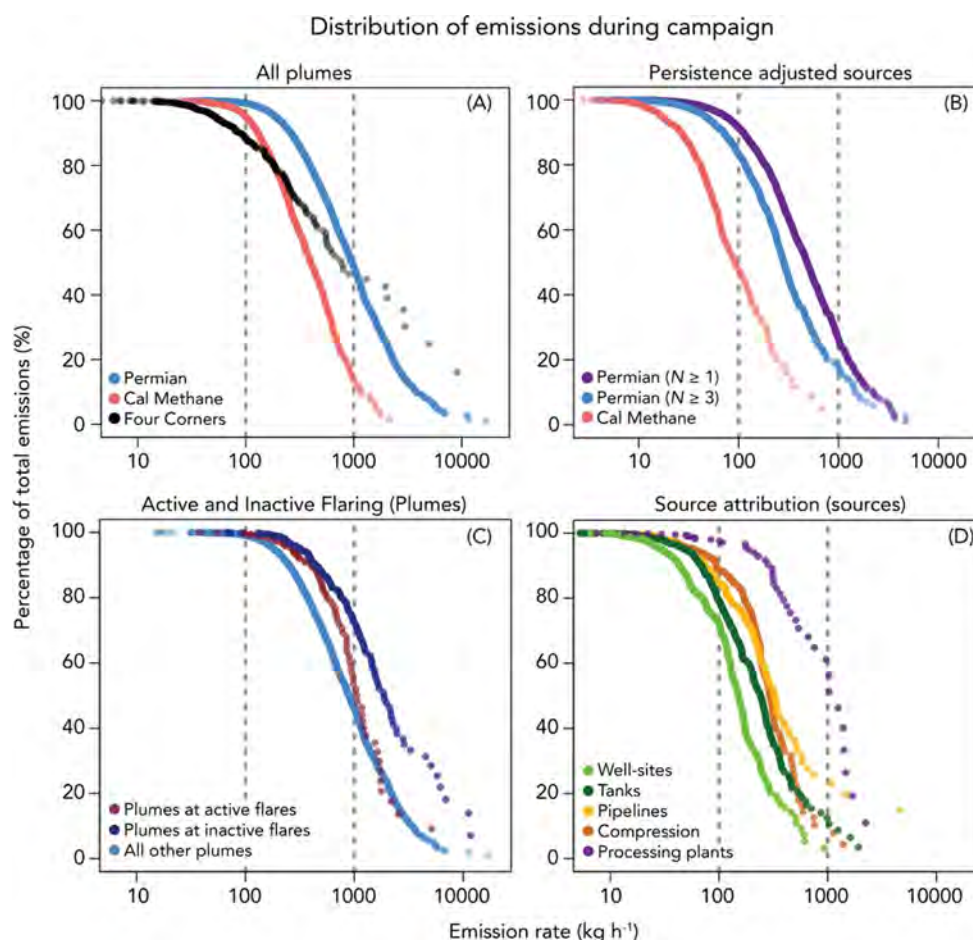


Figure 2. Distribution of CH_4 emissions quantified during the campaign by AVIRIS-NG/GAO ($10\text{--}20\text{ kg h}^{-1}$ detection limit). Panel A shows the distribution of all plumes quantified during the campaign and compares them against the distribution plumes from the oil and gas sector of the California Methane Survey (Duren et al., 2019) and the Four Corners survey (Frankenberg et al., 2016). Panel B shows persistence-adjusted source emissions, where sources are defined as locations where a unique set of methane plumes are colocated within 150-m of one another. In panel B, the curve with $N \geq 3$ samples is from a subset of the full survey domain represented by the $N \geq 1$ curve. Panel C shows individual plumes that were associated with active or inactive flares, with flares determined from measured emitted radiance and visible imagery, and include flares contained at well-sites, compressor stations, or processing plants. Panel D shows a representative subset of sources (Panel B; $N \geq 3$) that were classified into infrastructure categories using visible imagery.

temporal sampling.^{14,15} Though our airborne platforms have higher detection limits than some mobile measuring systems, they are lower than what has been cited as a superemitter threshold (26 kg h^{-1}).¹⁶ Additionally, we were able to cover 55000 km^2 of area within the Permian, allowing for quantification of any strong point sources above the instrument detection limit for thousands of upstream and midstream elements. This wide-area airborne approach with rapid repeat sampling allows for deeper characterization of strong point source emissions and their temporal variability across an entire basin, shedding more light into the distribution and dynamics of heterogeneous O&G fields, and helping prioritize mitigation.

MATERIALS AND METHODS

We designed this airborne survey to quantify strong (i.e., superemitter) CH_4 point sources in the Permian Basin and their persistence, and attribute sources to specific sectors or supply chain segments. From September to November, 2019, we deployed two remote sensing airborne platforms to map the region: the Next-Generation Airborne Visible/Infrared Imaging Spectrometer¹⁷ (AVIRIS-NG) and the Global Airborne

Observatory¹⁸ (GAO). The GAO imaging spectrometer is identical to the AVIRIS-NG instrument (both were constructed by the NASA Jet Propulsion Laboratory around the same time) and has the same performance. GAO is also equipped with a digital modular aerial camera (DIMAC) bore-sighted with the imaging spectrometer that provided simultaneous very high resolution (VHR) visible imagery with $\sim 60\text{ cm}$ ground pixel resolution during this study. Survey domains are shown in Figure 1: 39000 km^2 was mapped at least once in the Delaware basin and 16000 km^2 in the Midland basin. Detailed descriptions of survey design, CH_4 retrieval, emission quantification, uncertainties, detection limits, and controlled release experiments are described in the Supporting Information (SI).

We define a methane emission source as a location where a unique set of methane plumes are colocated within 150-m of one another (e.g., a typical lateral distance of a well pad) over the course of the campaign. This allows us to attribute temporally asynchronous plumes to unique facilities for persistence calculations. We visually inspected each identified source location using VHR imagery and designated it as production, gathering and boosting, or processing supply chain

segments. Source identification protocols are described in Section S2. For the production segment, we differentiated tank batteries from other production-related sources such as well heads. For the gathering and boosting segment, we labeled sources as either gathering pipelines or “compression”, with compression specifically referring to infrastructure within a midstream compressor station’s footprint. We categorized processing sources as those emanating from any infrastructure contained within the processing plant’s spatial footprint.

Given potential variability in CH₄ emissions at a particular source location, we apply persistence weighting for each CH₄ source detected in the survey. This is estimated by accounting for the frequency ($f = M/N$) in which a plume was detected, where M is the number of detected plumes at that source location during the campaign and N is the number of overflights over that location during the campaign. We calculate the persistence-weighted mean emission rate (q) for each source ($q = f \times \bar{q}$), where $\bar{q}$ is the average of all plumes detected at that source. We require a minimum of at least three overflights during the campaign for inclusion into our point source summary statistics (Table S3). We choose $N \geq 3$ overflights as a threshold, as this assumes probabilistically that we are confident in capturing the persistence of a source, i.e., the probability of a capturing a detectably 25% persistent source with three overflights is greater than 50%, or explicitly $p = 1 - (1 - 0.25)^3 > 0.5$.

■ RESULTS AND DISCUSSION

Figure 1b shows a representative mosaic of 19 retrieved CH₄ plumes seen by GAO over a 168 km² subsection of the Delaware Basin on October 27th, 2019. Multiple plumes of various sizes, emission rates, and source categories are clearly visible across the scene, each with a downwind extent consistent with southeasterly winds. Overall, we detected a total of 3067 unique plumes emanating from 1756 distinct sources during the course of the campaign. For analysis, we further reduced this population to 1100 distinct sources with at least 3 overflights per source (average: 8 overflights). The plume emission distribution is shown in Figure 2a (Delaware + Midland Basins) and compared against CH₄ plume distributions quantified in O&G sector during the California Methane Survey⁵ and the Four Corners airborne survey.⁴ Like California and Four Corners, individual Permian plume emissions follow a heavy-tailed distribution; however, the Permian distribution is shifted toward higher emissions compared to both California O&G and Four Corners. For example, 36% of all Permian plumes are greater than 500 kg CH₄ h^{−1}, compared to only 14% of all California O&G plumes and 8% of all Four Corners plumes.

We compare detected Permian persistence-adjusted point source emissions to O&G emissions from the California Methane Survey where sufficient overflights allowed for persistence weighting (Figure 2b). Even with accounting for intermittent plumes, the source distribution is still heavy-tailed, with 20% of sources constituting 60% of detected point source emissions in the Permian. Again, the distribution of point source emissions is shifted toward higher emission rates when compared with the California O&G sector. The mean persistence of sources with at least three airborne overflights is $f = 0.26$, which is close to the persistence observed in California ($f = 0.23$, Figure S3a). Too few overflights can affect persistence calculations. Figure S4a shows mean persistence as a function of number of overflights. Between $N = 1$ to $N = 3$

overflights, the average persistence declines, but it then stabilizes within 1σ of $f = 0.26$ for $N \geq 3$. Along with our confidence in persistence probability calculation, the result in Figure S4a justifies the use of the $N \geq 3$ threshold to adequately capture the emission dynamics of intermittent sources. For comparison, Figure 2b also shows the persistence-adjusted source emission distribution if we include all detected sources (i.e., $N \geq 1$). The distribution is significantly shifted toward higher emissions: a possible result of not having sufficient overflights to confidently assess persistence for $N = [1, 2]$ sources. Sources covered with $N \geq 3$ overflights also represent a smaller area than the full survey domain, so additional revisits of these sparsely sampled regions would enable a better assessment of the basin’s source distribution.

Differentiation between highly persistent and highly intermittent emission sources can be helpful for identifying discrepancies in assumed emission factors for key sectors and potentially for informing mitigation action. Table S4 shows mean emission rates for various persistence levels for $N \geq 3$ overflights. Highly intermittent sources ($0 < f \leq 0.25$) may be attributable to routine process or maintenance emissions that are readily predictable. We find that these operations constitute 66% of all sources and are responsible for 48% of all point source emissions in our population (average 113 kg h^{−1}). Conversely, more persistent sources ($0.50 < f \leq 1$) may be attributable to persistent leaks or malfunctions requiring operator intervention to curb emissions. We find that these operations constitute only 11% of all sources in our population but are responsible for 29% of quantified emissions in that population (average 638 kg h^{−1}). Similarly, we show how intermittency is distributed as a function of source emission rates (for $N \geq 3$ overflights) in Table S6. Detected sources with low persistence-adjusted emissions (0–100 kg h^{−1}) represent 56% of all detected source infrastructure and are highly intermittent (mean $f = 0.17$). In contrast, detected sources above 500 kg h^{−1} represent just 5% of detected infrastructure but are much more persistent (mean $f = 0.52$). Prioritization of the identification of this small population of relatively persistent sources could potentially enable a sizable reduction in emissions. To put this in context, if that subpopulation of potentially anomalous superemitters could be repaired, we estimate a mitigation equivalent to 28% of California’s entire 1.59 Tg a^{−1} methane inventory for 2018.¹⁹

We performed wall-to-wall mapping of a 6600 km² subdomain in the Delaware basin near Loving, TX (6600 km²; Figure 1a) with AVIRIS-NG seven times (each in a single 4 h flight day) during the campaign and detected 725 unique CH₄ emission sources in this subdomain. Figure S4b shows the detected point source emissions we quantified for each mapping day: they range from 0.54 to 1.04 Tg a^{−1} (mean 0.77 Tg a^{−1}). The 1σ variability in emissions over this subdomain is 0.21 Tg a^{−1}, which is almost a factor of 2 larger than the total detected point source emissions from California’s O&G sector (0.12 ± 0.04 Tg CH₄ a^{−1}). The large variability in this domain’s emissions stems directly from the intermittency and variability that we observed at the source scale (Figure S3). In other words, we show explicitly that the activity and emission factors at the source level follow a broad distribution. Therefore, although a single basin-scan of CH₄ plumes technically represents an unbiased sample or a snapshot of emissions, frequent, wide-area high resolution remote sensing observations are needed for a more robust accounting of variability.

Table 1. Source Attribution for Persistent CH₄ Point Sources with at Least 3 Overflights

Type		# Sources Identified ^a		Percent of identified sources (%)		Quantified emissions (Tg a ⁻¹) ^{b,c}		Percent of quantified emissions (%)	
Production	Well site ^d	703	314	65	29	0.74 ± 0.24	0.26 ± 0.08	50	17
	Tank Batteries		389		35		0.48 ± 0.16		33
Gathering and Boosting	Gathering pipelines	353	176	31	16	0.55 ± 0.19	0.27 ± 0.09	38	19
	Compression ^e		177		16		0.28 ± 0.10		19
Processing ^f	Processing plants	43	43	4	4	0.18 ± 0.05	0.18 ± 0.05	12	12

^aCH₄ emission sources were visually identified using DIMAC, AVIRIS-NG/GAO RGB channels, and Google Earth imagery. Only sources where we were confident of their emission persistence (i.e., at least three overflights with AVIRIS-NG or GAO) are summarized. ^bError bars represent aggregated uncertainties from point source emissions (Section S1). ^cEmissions are summed only for $N \geq 3$ sources, which does not represent the entire survey domain. ^dAny CH₄ sources from production facilities that were not associated with tank batteries were marked “Well-site” (e.g., pumpjacks, well heads, etc.). ^eAny CH₄ sources emanating near midstream compressor stations, but not at processing plants or gathering pipelines, are marked “Compression”. ^fAny CH₄ emissions emanating within a processing plant’s footprint (vents, flares, compressors, tanks, etc.) are marked “Processing plants”.

Sector attribution of detected CH₄ sources using VHR imagery allows for further supply chain contextualization of emissions (Table 1; Figures S5, S6). We find that 64% of CH₄ sources occurs at production sites, 32% at gathering and boosting infrastructure, and the remaining 4% at processing plants. However, the point source emissions from each sector do not follow the same distribution (Figure 2d), with 50% of identified point source emissions resulting from production, 38% resulting from gathering and boosting, and 12% resulting from processing. These results do not vary significantly with overflight frequency (e.g., $N \geq 1$ compared to $N \geq 3$; Table S5). Alvarez et al. estimated that the emission breakdown among the production, gathering, and processing sectors in U.S. O&G is 70%, 24%, and 7%, respectively.⁶ The fact that our results diverge from this estimate may indicate that Permian gathering and processing capacity during the September–November 2019 was unable to keep pace with the rapid growth of production, leading to excess venting and inefficient flaring at gathering and processing stations. An independent assessment of the Permian using ground-based, airborne, and satellite information during 2019–2020 led to the conclusion that during 2019, the Permian was in a state of overcapacity, with gas production exceeding midstream capacity.²⁰ We also see significant emissions from gathering pipelines (19% of quantified emissions), which may be due to corrosion, material defects, or joint and fitting failures.²¹

We compare the number of detected point sources to bottom-up estimates of production infrastructure within our flight domain. Using the Climate Action Engine bottom-up global information system (GIS) database (<https://rmi.org/cae>), the Texas portion of the Delaware GAO flight box (Figure 1) contains 19000 active O&G wells. At the time of this study, we only had access to Texas data, but if we assume a similar density of infrastructure pertaining to the New Mexico portion of the Delaware Basin, we estimate a total coverage of 39000 O&G wells. If we combine these with the O&G wells contained within the Midland GAO flight box (33000), we estimate coverage of 72000 O&G wells during our campaign. Comparing with our source attribution list for production sites, this means we detected CH₄ emissions at approximately 1.48% of all covered production sites. This again highlights the nature of superemitters which has been seen in previous studies,^{2–5} i.e., superemitters represent a small fraction of infrastructure but in aggregate, represent a large source of emissions (Table 1). Even though 1.48% represents a small percentage of O&G production sites in the Permian, the California Methane Survey

identified CH₄ emissions at only 0.2% of active O&G production sites. This fact highlights significant differences that exist between basins. The Permian and California O&G production are similar in terms of average persistence for detected sources, but the Permian contains more detected sources whose emissions are on average 3 times greater than California O&G emissions (Table S3).

The shortwave infrared responsivity of the AVIRIS-NG and GAO spectrometers also enables flare detection (Section S3). Since flaring can occur at upstream or midstream infrastructure, we add any additional flag to our sector attribution if we detect active (lit) or inactive (unlit) flares (e.g., Figure S4c,f,g). We find that CH₄ plumes associated with both active and inactive flares represent 7.4% of all detected plumes and 12.1% of all detected plume emissions during the campaign. This suggests that CH₄ emissions associated with flaring are higher on average than the rest of the CH₄ plume population (Figure 2c). CH₄ plumes attributed to inactive flaring are particularly skewed, as these emissions can often represent large gas volumes that were diverted to a flare stack, but remained unlit due to equipment malfunction or other operator-related issues. However, Figure 2c also shows that though lower, the tail of the CH₄ plume distribution associated with active flares is still large, with 17 plumes having emission rates greater than 1000 kg h⁻¹. The U.S. EPA assumes 98% flaring efficiency for typical O&G operations;²² however, field studies in other basins have shown this efficiency number to pertain to a right-skewed distribution,²³ meaning that many flares operate at much lower efficiency than 98% efficiency. The population of large CH₄ emissions that were visibly colocated with active flares lends additional evidence that flaring is not uniformly efficient across O&G operations within a basin, and that suboptimal flares contribute significantly to the basin’s point source emission budget. Finally, among quantified CH₄ emissions associated with active/inactive flaring, VHR source attribution shows that 51% of emissions are associated with production, 12% with gathering and boosting, and 37% with processing. This again supports the hypothesis that the ~ 20% relative shift from upstream to midstream emissions (Table 1) is perhaps due to limitations in the haul-away capacity of gas produced in the Permian.

In summary, high spatially and temporally resolved CH₄ observations can contribute actionable information to help operators and regulators, especially when contextualized with visible imagery. Outside the Permian, few global O&G basins have sufficient measurement networks or field campaigns

capable of quantifying intermittent point source emissions. An emerging potential for point source quantification of global CH₄ superemitters is through high resolution satellite remote sensing. Through a more coordinated targeting of priority basins, recently launched and planned satellite imaging spectrometer missions may collectively provide sufficient sensitivity^{24,25} and temporal sampling to offer robust estimates of global, strong point source persistence. This information, when combined with complementary coarser resolution, regional mapping satellites (e.g., TROPOMI), and sustained facility scale measurements, has the potential to constrain aggregate regional budgets and sources with lower emission rates, can help improve global CH₄ budgets, national and regional inventories, and potentially inform mitigation decisions by operators worldwide.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at <https://pubs.acs.org/doi/10.1021/acs.estlett.1c00173>.

Georeferenced plume list (XLSX)

Georeferenced source list (XLSX)

(PDF)

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Notes

The authors declare no competing financial interest.

All plume imagery, emission estimates, and uncertainties are available for download from our data portal (methane.jpl.nasa.gov).

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ENVIRONMENTAL STUDIES

Satellite-based survey of extreme methane emissions in the Permian basin

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Industrial emissions play a major role in the global methane budget. The Permian basin is thought to be responsible for almost half of the methane emissions from all U.S. oil- and gas-producing regions, but little is known about individual contributors, a prerequisite for mitigation. We use a new class of satellite measurements acquired during several days in 2019 and 2020 to perform the first regional-scale and high-resolution survey of methane sources in the Permian. We find an unexpectedly large number of extreme point sources (37 plumes with emission rates $>500 \text{ kg hour}^{-1}$), which account for a range between 31 and 53% of the estimated emissions in the sampled area. Our analysis reveals that new facilities are major emitters in the area, often due to inefficient flaring operations (20% of detections). These results put current practices into question and are relevant to guide emission reduction efforts.

INTRODUCTION

Methane (CH_4) is the second most important anthropogenic greenhouse gas and a precursor for tropospheric ozone, which acts as both greenhouse gas and air pollutant. Due to methane's strong radiative forcing potential and its short lifetime in the atmosphere (9 ± 1 years) (1), the reduction of methane emissions is being prioritized as an effective climate change mitigation measure on decadal time scales (2).

Methane levels in the atmosphere have almost tripled since pre-industrial times (3). Along with agriculture, oil and natural gas (O&G) production operations are one of the primary causes for this increase, but the magnitude, dynamics, spatial distribution, and driving mechanisms of methane emissions from O&G production remain poorly understood. This is especially concerning for the United States, which is the world leader in O&G production, owing to its rapid growth in the last two decades. Alvarez *et al.* (4) estimated that $13 \text{ Tg CH}_4 \text{ a}^{-1}$ was emitted from the U.S. national O&G supply chain in 2015, which is 78% higher than the most recent estimates by the U.S. Environmental Protection Agency (EPA) for that year, and represents an important fraction of the 68- to $92\text{-Tg CH}_4 \text{ a}^{-1}$ range estimated globally for upstream and downstream

O&G sectors in the 2008–2017 decade (5). This large share of methane emissions from the U.S. O&G sector is increasing. For example, Jackson *et al.* (6) reported that fossil fuel-related methane emissions in the United States increased between 3.4 and $4.0 \text{ Tg CH}_4 \text{ a}^{-1}$ from 2000–2006 to 2017, which is approximately 80% of the total increase of methane emissions for North America in that period.

Methane emissions from O&G production originate mainly from point sources including wells, gathering stations, compressor stations, storage tanks, pipelines, processing plants, and flares. There may be thousands of these individual point sources in a typical O&G field (7). A small fraction of facilities are responsible for a large share of total emissions at any given time, which may be caused by intentional venting of wells and storage tanks, inefficient flaring, or leaks from malfunctioning equipment (7). O&G production in the Permian basin, located in New Mexico and Texas, has been growing rapidly over the past decade, and the Permian is now the largest O&G-producing basin in the United States. This was covered by a recent study by Zhang *et al.* (8), which combined satellite observations from the Tropospheric Monitoring Instrument (TROPOMI) onboard the Sentinel-5P satellite with atmospheric modeling methods to find Permian methane emissions from O&G production to be $2.7 \pm 0.5 \text{ Tg CH}_4 \text{ a}^{-1}$. This number represents the largest methane flux ever reported from a U.S. O&G-producing region; it is more than twice the bottom-up estimates for the Permian, and a factor of 4 higher than estimates for any other United States O&G basin.

Better characterizing the nature, intensity, and dynamics of methane point emissions from the world's O&G basins, and in particular from the Permian, is not only critical to close the gap between bottom-up and top-down anthropogenic emission estimates but also to facilitate emission reductions. Better emission characterization is also crucial for understanding the contribution of the O&G production sector to the acceleration of the methane growth rate in the atmosphere. Airborne measurement methods, through either mass balance (9, 10) or imaging spectroscopy (11–16), are a powerful approach to detect and monitor methane point sources

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over large O&G regions. In particular, so-called imaging spectrometers offer a unique observational configuration to map methane point emissions with simultaneously high accuracy and spatial sampling. These instruments produce images of the solar radiation reflected by the Earth surface at hundreds of wavelengths, including those in the shortwave infrared region of the electromagnetic spectrum sampling the strong methane absorption band around 2300 nm (see fig. S1). High-resolution maps of methane plumes (up to 3 to 4 m for airborne instruments) can be inferred from these observed spectra using atmospheric retrieval techniques (see Materials and Methods).

Satellite remote sensing represents a critical means for systematic monitoring of point emissions from O&G-producing regions around the world (17). The Sentinel-5P/TROPOMI mission, launched in 2017, is a crucial step toward the monitoring of methane emissions from space (18–21), but its 7-km pixel size does not generally allow sampling of individual point sources (22). Instead, high-resolution (~30-m) methane retrievals can be performed using satellite imaging spectrometers (23), which trade TROPOMI's fine spectral resolution for fine spatial resolution. This trade-off does not allow retrieval of small methane sources but is ideal for detecting large point sources, as demonstrated with the EO-1/Hyperion during the Aliso Canyon methane blowout (24). The GHGSat-D private satellite has also shown capability of retrieving large methane sources at 50-m spatial resolution (25, 26).

In this study, we take advantage of the rapid development of spaceborne imaging spectroscopy technology and data processing methods to perform the first satellite-based large-scale and high-resolution survey of methane point emitters in the Permian basin. Our dataset was acquired by three satellite missions launched between 2018 and 2019: two versions of the Advanced Hyperspectral Imager (AHSI) onboard China's Gaofen-5 (GF5) and ZY1 satellites (27) and the imaging spectrometer onboard Italy's PRISMA mission (see Materials and Methods). We cover a ~150 km-by-200 km area in the Delaware sub-basin of the Permian basin with a total of 30 images acquired within several days, but mostly on four different dates: 15 May 2019, 1 November 2019, 29 December 2019, and 8 February 2020 (see table S1 and fig. S2). We generate maps of methane concentration enhancements (ΔCH_4), from which we detect methane plumes through visual inspection (fig. S3). We calculate emission flux rates (Q) for each plume using the integrated methane enhancement (IME) method and large eddy simulations performed specifically for our satellite observations (fig. S4). See Materials and Methods for further information on the derivation of methane plumes and the conversion to emission rates. We evaluated the sensitivity of our satellite measurements to methane enhancements and the uncertainties in methane flux calculation by means of simulation-based studies (texts S1 and S2 and figs. S5 to S8). The 30-m spatial sampling of our survey allows us to map individual methane plumes and to attribute emissions to specific infrastructure. Our core objective is to identify, characterize, and quantify the largest point emissions in the area, with the overarching motivation of assisting future emission reduction efforts.

RESULTS

Imaging extreme methane point sources

Figure 1 shows the location and intensity of the 37 methane plumes that we have detected over the Delaware sub-basin of the Permian

after the processing of our satellite imaging spectroscopy dataset. The detected point emissions have Q typically between 500 kg hour⁻¹ (which we assume as both our detection limit and our definition of an "extreme emission") and 6000 kg hour⁻¹. Most plumes are located in the 31.0° to 32.5°N, 103.3° to 104.2°W subregion. This matches the area of highest methane fluxes revealed by top-down estimates by Zhang *et al.* (8) but is less well aligned with the bottom-up emission inventory based on the U.S. EPA greenhouse gas inventory (28) updated to account for 2018 infrastructure using well-level information from Enverus DrillingInfo (fig. S9) (29).

Subpanels around the main panel of Fig. 1 show examples of individual methane plumes (see table S1 and fig. S10 for details on plume locations, intensity, and type of emitting facility). There is a relatively large variability in both emission rates and source types. For example, plume a corresponds to a large emission ($Q = 3590 \pm 1220$ kg hour⁻¹) from an area devoid of visible infrastructure elements such as well pads and storage tanks; plume b ($Q = 2119 \pm 608$ kg hour⁻¹) is associated with the incomplete combustion of a flare from a tank battery; plume f is a strong emission ($Q = 4385 \pm 1296$ kg hour⁻¹) that we attribute to the venting of a gas well; plumes g and j are two very large emissions (Q of 5952 ± 2556 and 5472 ± 2159 kg hour⁻¹, respectively) from compression stations. Last, plume c is a special case. It corresponds to an emission of an abnormally high magnitude ($Q = 18,492 \pm 6570$ kg hour⁻¹) from an unknown source. The absence of correlation between the spatial distribution of the methane enhancement and surface brightness and composition indicates that this is a real methane plume and not the result of a processing artifact (see fig. S11 for maps of the surface and its mineralogy) (30). We attribute it to a large transient release, potentially from one of the large natural gas gathering pipelines in the area. A strong methane enhancement is seen by TROPOMI at the same location in the days around this event (fig. S12), but we are not able to determine what fraction of the enhancement is actually due to this particular emission.

We do not find multiple plume detections from any of the methane sources in our satellite dataset, which may be due to the relatively high detection limit of our measurements (~500 kg hour⁻¹, see text S1) and the limited temporal sampling of our data: 32 of 37 plumes are derived from four different overpasses between 15 May 2019 and 8 February 2020, with 19 of them corresponding to the same GF5-AHSI overpass (see table S1 and fig. S2). However, we do find correspondence between our detections and highly accurate ΔCH_4 maps from an independent airborne AVIRIS-NG imaging spectrometer campaign sampling over some areas in the Permian included in our large-scale satellite survey (see fig. S13 for examples).

Strength of point emissions in the Permian basin

The distribution of flux rates from all the detected emissions in the Permian is shown in Fig. 2. Of 37 detected plumes, 29 have fluxes larger than 1000 kg hour⁻¹. To our knowledge, the Delaware sub-basin of the Permian therefore contains the highest number of extreme point emitters ever observed across a single O&G-producing basin. For example, the magnitude of the emission rates in the Permian is substantially higher than the one previously cataloged in the Barnett Shale basin, where only 5 of 17,400 well pads were found to emit more than 300 kg hour⁻¹ (31, 32). Moreover, only seven emissions larger than 1000 kg hour⁻¹ were found over the Four Corners natural gas-producing region from a total of 250 plumes identified during a comprehensive campaign using the AVIRIS-NG airborne

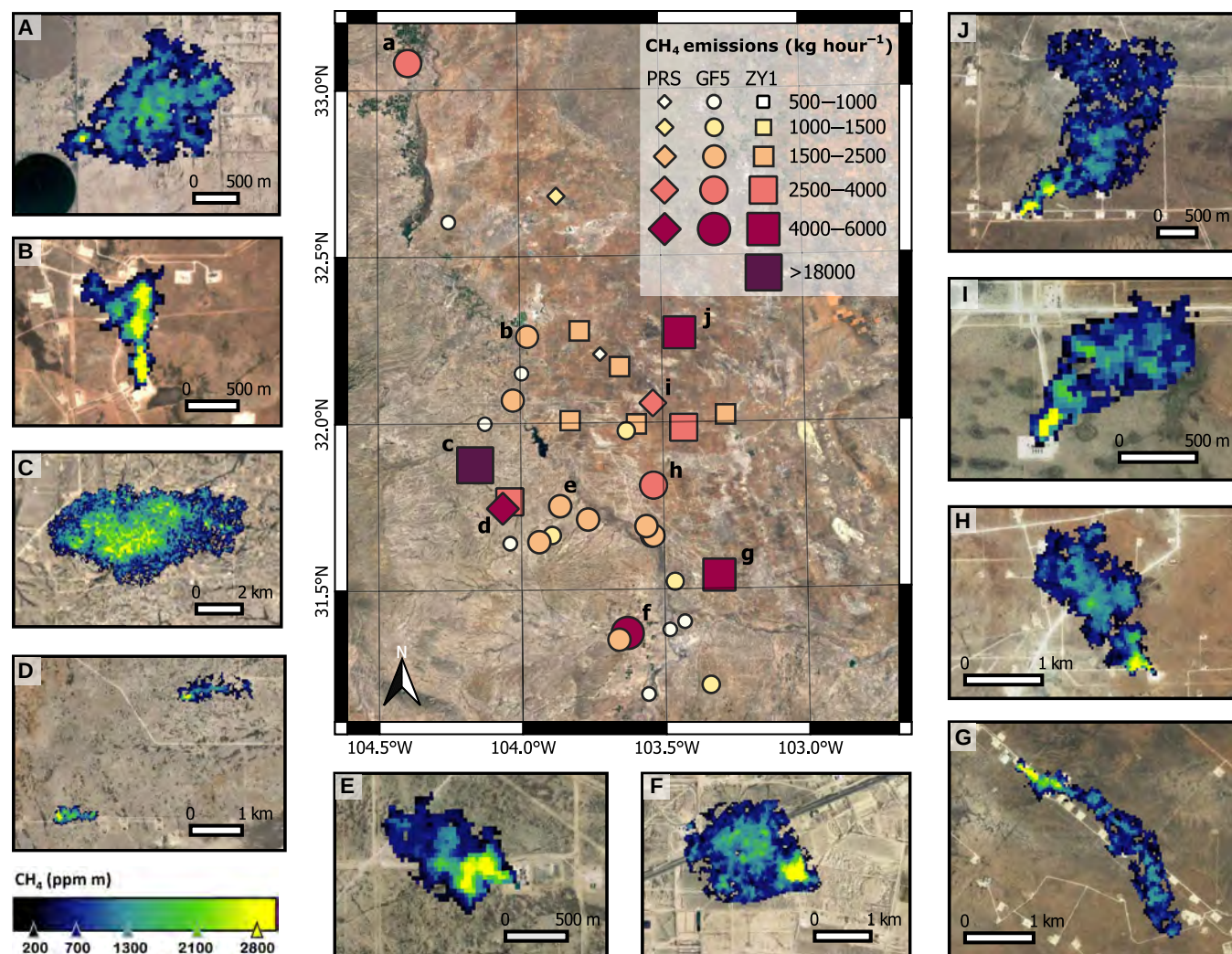


Fig. 1. Extreme methane emissions detected in the Permian basin from satellite imaging spectroscopy data. A map with the identified methane plumes is shown in the central panel. Emissions are coded according to their flux rate and to the source of data (GF5-AHSI, GF5; ZY1-AHSI, ZY1; PRISMA, PRS). The small panels (A to J) around the main figure show examples of the detected plumes.

imaging spectrometer, which is similar to the satellite instruments used in this study (14). It must be noted, though, that the area sampled by airborne instruments in the Four Corners region was also smaller (~60 km by 50 km) than the one we have been able to cover in the Permian basin with satellite imaging spectrometers (~150 km by 200 km). This implies that it is the total number of extreme emitters, and not the spatial density of sources, that makes the Permian to be such an outstanding case.

Despite the fact that some of the emissions detected at Four Corners are due to coal mine vents rather than to O&G extraction facilities, we consider the Four Corners dataset as the best reference for our Permian survey, as their use of airborne imaging spectrometers to detect and quantify emissions inherently leads to a systematic survey of high point emitters. Integrated emission estimates for the two regions are shown in the inset of Fig. 2. The emission rate reported for Four Corners corresponds to the sum of all ~250 plumes detected from the dataset collected in the airborne campaign, for which a detection limit of ~2 to 5 kg hour⁻¹ was estimated

(14). In the case of the Permian basin, we consider only the 19 plumes detected from one single overpass of the GF5-AHSI system on 8 February 2020, as GF5-AHSI has the highest sensitivity and measurement accuracy (see text S1 and figs. S5 and S6). The flux rates estimated for those 19 plumes are aggregated and scaled from per-hour to per-year units for direct comparison with the per-year amounts given by Frankenberg *et al.* (14) for Four Corners. The resulting integrated flux from the Permian plumes is 0.28 Tg a⁻¹ (0.20 to 0.35 Tg a⁻¹ 95% confidence interval), which is close to the 0.3 Tg a⁻¹ (0.23 to 0.39 Tg a⁻¹ 95% confidence interval) reported for Four Corners, despite the much smaller number of plumes detected from our satellite data. Although our total emission rate and its confidence interval are calculated from a small dataset, we estimate them to have a 1- σ uncertainty below 13% (see text S3 and fig. S14). This simple comparison with the Four Corners dataset illustrates the outstanding strength of the methane emissions currently occurring in the Permian basin. Measurement differences between the two datasets (most important, spatial resolution and detection limit) prevent a more detailed analysis.

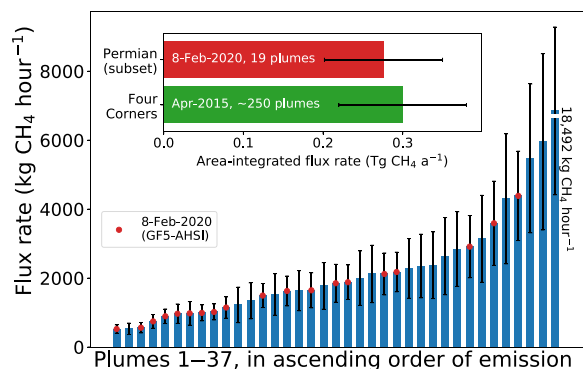


Fig. 2. Distribution of emission rates for the 37 methane plumes detected over the Permian basin with satellite imaging spectroscopy. The last bar corresponds to the massive emission displayed in Fig. 1C, whose flux rate exceeds the plot range. The inset plot shows a comparison of area-wide flux estimates from the integration of single emissions detected over the Permian on 8 February 2020 by the GF5-AHSI system (emissions marked as red circles in the main plot) and over the Four Corners region during the April 2015 AVIRIS-NG airborne campaign described in (14). Vertical error bars correspond to 1- σ precision errors in flux rate calculations, and horizontal error bars correspond to the 95% confidence interval in areal flux estimates calculated through bootstrapping for the two datasets.

We have also compared our detected point emissions with area-integrated emission estimates generated through top-down inversions of TROPOMI satellite concentrations using the method described by Zhang *et al.* (8). This comparison of single-point emissions with area-integrated emissions is only intended to provide further context for the magnitude of the extreme point emissions that we have detected. Top-down area integrated emission estimates give 0.73 Tg a^{-1} for the Permian area sampled by GF5-AHSI on 8 February 2020 on the basis of a February 2020 (monthly) inversion run. The single point emissions sampled by GF5-AHSI on 8 February 2020 represent then a 38% (31 to 53% confidence interval) of that areal emission. This “tail-heavy” nature of O&G methane emission distributions has been previously reported (4, 33). For example, our numbers are roughly consistent with a 2015 Barnett Shale inventory, which found that fat-tailed emissions made up 19% of regional O&G emissions (31), whereas $>500\text{-kg hour}^{-1}$ emissions represented about 50% of the total 2015 Four Corners emission rate from point sources (14). Our plume detections only represent snapshots in time of those emissions with an intensity higher than 500 kg hour^{-1} at the time of the satellite overpass, and our scaling from per-hour to per-year units is done for comparison on a common basis. Because most of the emissions are intermittent, we assume that the detected sources provide a statistical sampling of large emitters on the regional level to scale up to a representative annual estimate.

Breakdown of emission sources

The high spatial resolution of our data allows us to directly attribute the detected plumes to specific infrastructure (see Materials and Methods and fig. S15). A breakdown of the characteristics of the 34 plumes for which information on the emitting infrastructure could be found is presented in Fig. 3 (see table S1 for more details). We classify emissions in terms of the emission source (flaring, compressor station, tank battery, or wellheads) and the age of the emitting infrastructure.

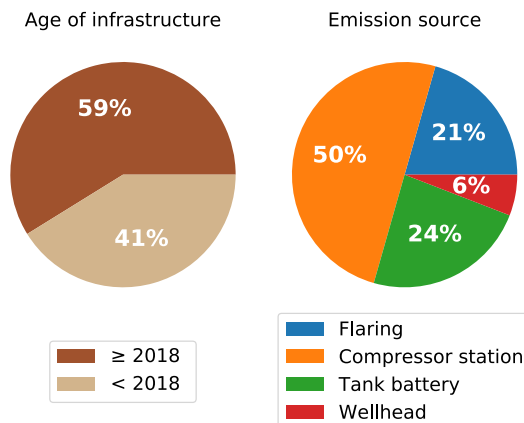


Fig. 3. Breakdown of satellite-detected extreme methane emissions ($>500 \text{ kg hour}^{-1}$) over the Permian basin. Emissions are classified in terms of the year in which the infrastructure started production (left) and of the emission source (right). The data represent the percentage of plumes detected in each category as a function of the total number of plumes for which source information was available.

The first important result from this analysis is that we detect more extreme emissions from facilities starting production in 2018 or later than from older ones, irrespective of whether we base the calculation on the number of detected plumes (59 to 41%) or on the amount of methane emitted by them (51 to 49%). This is unexpected if we take into consideration that the number of wells producing before 2018 represents 65% of active wells in our study area (see Materials and Methods). According to these numbers, extreme emissions occur 2.6 times more frequently for new facilities (those from 2018 or after) than from old facilities, and the amount of methane emitted by new facilities is twice the one emitted from the older ones. This finding agrees with the results from a large helicopter-based emission survey over seven U.S. basins, which found that well pads in their first 2 months of production were five times more likely to have detected emissions (7). This result supports the speculation that recently developed wells and infrastructure associated with these wells are the major methane emitters in the Permian basin (8), which is likely due to a faster development of gas extraction methods than of storage and processing capabilities. We do not rule out the possible contribution of exploratory drilling to these large emissions from new facilities, as uncontrolled methane emissions during the drilling of new wells can be large.

Second, we find a surprisingly high share of emissions (21%, in terms of both number of plumes and amount of emitted methane) from active flaring processes (see fig. S15 for an example of a large methane plume being emitted during flaring). The flux rates of the detected emissions from flaring are between 1640 and $2640 \text{ kg hour}^{-1}$ (see table S1). Although this range is in the lower half of our emission distribution (Fig. 2), such high emission rates can only be explained by inefficient or malfunctioning flaring operations (7, 34). This finding agrees with a study in the Bakken Shale, which estimated that incomplete combustion from flares contributed almost 20% of the total field emissions of methane, most of which was due to a small number of low-efficiency flares (35). We note that all seven detected flaring-related emissions are from new well pads and

tanks, namely, one infrastructure element from 2017, four from 2018, and two from 2019 (see table S1). This reinforces the hypothesis that the higher extraction potential of new infrastructure might not be matched by an equal development in gathering, processing, and transportation facilities.

DISCUSSION

Our space-based high-resolution mapping approach has enabled a first large-scale survey of methane point emitters in the Permian basin, one of the top O&G-producing regions of the world. The 30-m resolution and wide area coverage of the newly developed satellite technology used in this work has proven to be an effective means to detect, quantify, and classify strong methane point emissions. From satellite data acquired during several days in 2019 and 2020, we find a large number of extreme point sources, with flux rates typically ranging from 500 to 6000 kg hour⁻¹ and a recent massive emission of >18,000 kg hour⁻¹. Our analysis of emission sources reveals that new facilities (starting production in 2018 or later) are major emitters, which could be caused by a limited ability of storage, processing, and transportation facilities to cope with the high production of unconventional wells. This is supported by the high fraction of emissions from flaring (21%, all of them from new wells), as it has recently been reported in mass media (36). This finding has strong implications for the design and regulation of O&G production activities in the Permian basin, and could be extrapolated to other O&G-producing regions.

We have demonstrated that spaceborne high-resolution imaging spectroscopy has a great potential for both operational surveillance of fugitive or unpermitted emissions from O&G activities and for the improvement of bottom-up emissions inventories. However, further work is needed on both spaceborne imaging spectrometer technology and data processing methods to lower the 500 kg hour⁻¹ detection limit that we estimate for our data and to improve spatial and temporal coverage. A number of satellite high-resolution imaging spectroscopy missions with similar characteristics to the ones used in this work will be launched in the next years. These include, first, a new version of the GF5-AHSI system, the German EnMAP mission (37), and NASA's EMIT, planned for launch in the next couple of years, and, later, European Space Agency's (ESA's) CHIME and NASA's SBG missions in the 2025–2030 time frame. The latter two will combine a high measurement sensitivity, a global coverage at 30-m sampling, a 2- to 3-week revisit time, and an open data policy. In combination with TROPOMI's daily revisit and high-accuracy measurements, to be soon complemented by the upcoming MethaneSAT mission, high-resolution imaging spectroscopy missions have a strong promise for operational, unbiased, open-access, and cost-effective monitoring of methane point sources. It can be anticipated that this global scenario for high-resolution methane mapping will be complemented by private satellite missions, of which the GHG-Sat-D mission is currently the best example, and by multispectral missions with spectral coverage of the 2300-nm spectral feature such as Sentinel-2, sensitive to large methane emissions over spatially homogeneous targets (38).

Our results suggest that the rapid installation of new O&G production facilities in the Permian basin might not be counterbalanced by sufficient parallel development of gas gathering and processing infrastructure, which would lead to a high concentration of extreme emissions in the region due to issues such as unlit associated gas

flares (39). This situation could be affected by environmental regulations, which have been recently weakened at the federal level (40). We argue that satellite-based methods are valuable to detect and monitor potential changes in methane point emissions in O&G-producing regions, which will also enable the industry to efficiently reduce emissions by identifying and repairing problems causing extreme, but sometimes intermittent, emissions that are often unnoticed by traditional leak detection approaches.

MATERIALS AND METHODS

Satellite imaging spectroscopy data

Imaging spectroscopy, also known as hyperspectral imaging, is a remote sensing technique in which images of the solar radiation reflected by the Earth are produced in hundreds of spectral channels between the visible and the shortwave infrared part of the electromagnetic spectrum (roughly 400 to 2500 nm). This dense spectral sampling enables the use of spectroscopic techniques to detect and quantify the Earth's surface and atmosphere constituents based on their spectral signatures.

We use data from three new hyperspectral satellite missions, each one carrying an imaging spectrometer as payload. These are two versions of the AHSI onboard the GF5 and ZY1 platforms (China, launched in May 2018 and September 2019, respectively) (27) and the core instrument onboard PRISMA (Italy, launched in March 2019). These instruments sample the 400- to 2500-nm spectral window with a pixel size of 30 m. AHSI images cover an area of 60 km by 60 km, whereas PRISMA images cover areas of 30 km by 30 km. Measurements in the short-wave infrared spectral region from 2000 to 2500 nm sample absorption features from water vapor, carbon dioxide, and methane. The 2100- to 2450-nm window is especially sensitive to methane (see fig. S1) and is therefore the one we use for our methane retrievals.

In our study, we have combined a total of 30 images acquired from all three systems to cover a 150 km-by-200 km area in the Permian basin (see fig. S2). These missions are operated through sporadic pointing at selected targets, so they do not acquire data systematically over every single point on Earth (as opposed to global coverage missions such as TROPOMI). The acquisitions used in this work were mostly taken between May 2019 and August 2020, and most of the detections are from images acquired on four different days (15 May 2019 and 8 February 2020 for GF5-AHSI, and 1 November 2019 and 29 December 2019 for ZY1 AHSI) (see table S1). In particular, 19 plumes were detected from a single overpass of GF5-AHSI on 8 February 2020.

Retrieval of methane concentration enhancements

We calculate methane concentration enhancements (i.e., increments above background levels in the amount of methane present in the atmospheric column, ΔCH_4) using a so-called matched filter image processing technique applied to spectra in the 2110- to 2450-nm spectral fitting window. Matched filter methods have been widely tested for methane retrieval from airborne imaging spectroscopy data (12, 41) and on one occasion with spaceborne data (24). These methods seek to detect a target spectrum (in our case, a methane absorption spectrum) across a hyperspectral image using statistics extracted from the data. We use radiative transfer simulations to generate a unit absorption spectrum, which represents the change in radiance for a 1-ppm (part per million) increase in methane

concentration over a pathlength of 1 m. The matched filter uses this unit absorption spectrum to convert changes in radiance into ΔCH_4 in ppm-m units. Assuming a scale height of 8 km, 10,000 ppm-m translate to a ΔCH_4 of 1.25 ppm (24). The statistics needed by the matched filter (mean spectrum and covariances) are calculated on a per-column basis to account for across-track changes in the instrument's radiometric and spectral response usually occurring in imaging spectrometers. The retrieval is run for all pixels of the image to produce ΔCH_4 maps with a 30-m sampling.

We have evaluated the performance of the matched filter retrieval with our satellite data through a simulation-based sensitivity analysis optimized for the Permian conditions. Details are provided in text S1. From this analysis, we conclude that the retrieval is not biased, that GF5-AHSI is substantially more sensitive to ΔCH_4 than ZY1-AHSI and PRISMA, and that representative ΔCH_4 1- σ precision errors are 63, 101, and 149 ppb (parts per billion) for GF5-AHSI, ZY1-AHSI, and PRISMA, respectively (figs. S5 and S6).

Estimation of emission rates from methane concentration enhancement maps

From the resulting ΔCH_4 maps, we detect emission plumes through visual inspection of the data. We search for methane enhancements within the image with the typical shape of a gas plume from a point emitter (i.e., higher concentrations at the source and progressive decrease downwind). We compare the plume direction with that of the wind as further evidence to conclude that the enhancement is from a real emission and not a retrieval artifact.

For each of the detected plumes, we apply a 200-ppm-m threshold to define the background signal and manually define a polygon to mask it out from the background (see fig. S3). With the pixels included in the plume mask, we calculate an IME as the total mass of methane contained in the plume (14). The IME is typically expressed in kilograms and represents the total mass of excess methane within the plume structure. After Varon *et al.* (42), we link the IME to the emission flux rate Q as

$$Q = \frac{U_{\text{eff}} \cdot \text{IME}}{L} \quad (1)$$

where U_{eff} is an effective wind speed and L is the plume length scale (square root of the plume mask area). For the calculation of U_{eff} , we use large eddy simulations to establish the following empirical relationships between U_{eff} and the measurable 10-m wind speed U_{10} (see fig. S4)

$$U_{\text{eff}} = 0.34 \cdot U_{10} + 0.44 \quad (2)$$

These simulations were specifically performed for a spatial resolution and measurement uncertainty compatible with our data using the methodology described by Varon *et al.* (42). Our processing takes U_{10} data from the GEOS-FP dataset for the time and location of each detected plume.

Assessment of uncertainties in the estimated emission rates

For the estimation of the associated flux rate uncertainties, we have implemented an uncertainty propagation formalism similar to the one proposed by Cusworth *et al.* (16). We assume errors in the input 10-m wind speed U_{10} and the IME derived from the ΔCH_4 maps. We choose a conservative 50% uncertainty estimate in GEOS-FP U_{10} data consistent with the ~ 1.5 -m/s error SD in wind

speed given by Varon *et al.* (26). A random distribution of U_{10} values is generated around the actual GEOS-FP U_{10} value for each plume. A distribution of Q values is calculated for each plume from the U_{10} distribution using Eqs. 1 and 2 with the actual values of IME and L . The SD of the resulting Q ensemble is taken as the precision error (1- σ) of the estimated flux for each plume.

The resulting absolute and relative 1- σ uncertainties for the 37 plumes detected in this study are presented in fig. S7. Relative precision errors are in the range of 20 to 45% and are strongly dominated by the contribution of U_{10} uncertainties on the flux calculation (~ 18 to 40%), whereas uncertainties from retrieval noise in the IME calculation are typically between 2 and 7%. The ranges for the uncertainty contributions from wind and retrieval noise are roughly consistent with the study by Varon *et al.* (26) for the GHGSat-D satellite (16 to 27% for the wind contribution and 7% for the retrieval, for a total error of 40 to 45%) despite the much finer spectral resolution of GHGSat-D than the imaging spectroscopy mission used in this study. Uncertainties in flux rate estimation from satellite imaging spectroscopy data were also analyzed by Cusworth *et al.* (23). They estimated a relative random error in the range of 15 to 25% for bright surfaces such as in the Permian, although the absolute flux rates were underestimated by $\sim 35\%$ in the case of a bright surface and 900 kg hour⁻¹ source, which is the closest scenario to the observation conditions of our Permian study. According to the authors, one of the causes for this underestimation could be the fact that the $U_{10} - U_{\text{eff}}$ relationship was not explicitly derived for the spatial resolution and retrieval sensitivity of the imaging spectroscopy missions under evaluation, which is not the case in our study.

The magnitude of our estimated plume-level emission rates has been further assessed through a simulation-based study with the Weather Research Forecast model version 3.9.1 coupled with Chemistry in Large Eddy Simulation mode (WRF-Chem-LES) (43). Three of the observed plumes (k, l, and x) have been simulated with WRF-Chem-LES and wind data from National Oceanic and Atmospheric Administration's High-Resolution Rapid Refresh (HRRR) model. The results from this analysis confirm the extreme magnitude of the estimated Q as well as the validity of our precision error estimates derived from the propagation of wind uncertainties. On the other hand, this analysis has revealed that assumptions of the IME-based Q estimation model, not included in our precision error estimates, can also represent an important source of uncertainty. See text S2, fig. S8, and table S2 for further details.

Attribution of plumes to emitting infrastructure elements

The 30 m-by-30 m spatial sampling of our satellite imaging spectroscopy data enables the identification of methane point sources (see fig. S15), even within oil and gas extraction platforms, and storage tank or compressor station platforms, which have a typical size between 60 and 600 m² in the Permian. We use high-resolution Google Earth (GE) images co-registered with the methane enhancement maps to attribute sources to emissions. Sentinel-2 10-m images were used instead of GE images in those cases in which the GE data were not available for the time and location of the detected methane plume.

Some details on platform type (oil or gas well or tank battery), extraction start year, and status (active/inactive) have been collected from the interactive PermianMAP (44) of the Environmental Defense Fund (EDF), which offers data generated by the Railroad Commission of Texas (45) and New Mexico's Department of Energy, Minerals, and Natural Resources (46). Other data not available in

PermianMAP have been obtained through visual interpretation of the satellite images and the information provided by the Sentinel-2 historical record. Using this information, we can identify the emission source of most of the detected plumes, being these compressor stations, tank batteries, wellheads, or emissions derived from flaring. The latter are easily identified by the high signal emitted by the torch flame at ~2300 nm (34) and by the location of the plume above the chimney (see fig. S15).

Regarding the information on well age, we extracted well information from Enverus DrillingInfo (29) for all wells in New Mexico and Texas reporting production in 2020. We calculate statistics for wells in the region with most plume detections (31.0° to 32.5°N, 103.3° to 104.2°W). In this count, the term “wells” refers to well pads that may contain multiple wells and infrastructure elements. To see when wells were finished, we use their month of first production as completion date. Because wells that have been active for a long time but hardly produce anymore (stripper wells) can skew the average, we also calculate mean well ages for the subset of wells with substantial production (defined as 10% of the mean production per well). The count has resulted in a total number of wells of 6993, with 4516 of them producing since before 2018 (65% of the total). The average year of start of production for these wells with substantial production in the area of interest is 2015.35.

SUPPLEMENTARY MATERIALS

Supplementary material for this article is available at <http://advances.sciencemag.org/cgi/content/full/7/27/eabf4507/DC1>

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Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings

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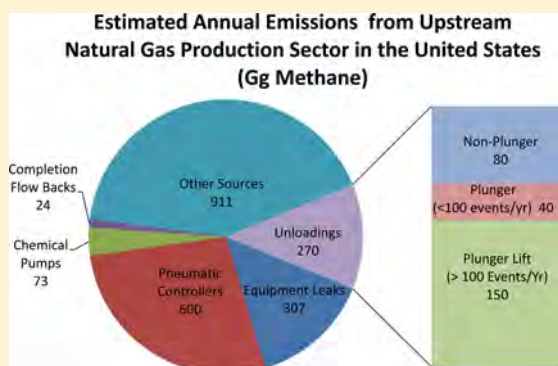
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Supporting Information

ABSTRACT: Methane emissions from liquid unloadings were measured at 107 wells in natural gas production regions throughout the United States. Liquid unloadings clear wells of accumulated liquids to increase production, employing a variety of liquid lifting mechanisms. In this work, wells with and without plunger lifts were sampled. Most wells without plunger lifts unload less than 10 times per year with emissions averaging 21 000–35 000 scf methane (0.4–0.7 Mg) per event (95% confidence limits of 10 000–50 000 scf/event). For wells with plunger lifts, emissions averaged 1000–10 000 scf methane (0.02–0.2 Mg) per event (95% confidence limits of 500–12 000 scf/event). Some wells with plunger lifts are automatically triggered and unload thousands of times per year and these wells account for the majority of the emissions from all wells with liquid unloadings. If the data collected in this work are assumed to be representative of national populations, the data suggest that the central estimate of emissions from unloadings (270 Gg/yr, 95% confidence range of 190–400 Gg) are within a few percent of the emissions estimated in the EPA 2012 Greenhouse Gas National Emission Inventory (released in 2014), with emissions dominated by wells with high frequencies of unloadings.



INTRODUCTION

Natural gas production in the United States is increasing, driven by increased use of horizontal drilling and hydraulic fracturing.¹ As natural gas production has increased, interest has increased in the emissions of greenhouse gases along the natural gas supply chain.^{2–10} Methane, the primary component of natural gas, is a potent greenhouse gas, and a variety of sources contribute to methane emissions along the natural gas supply chain. For some of these sources, emission measurements are sparse, including measurements of emissions from pneumatic controllers and liquid unloadings.¹¹ Measurements of emissions from pneumatic controllers have been described in a companion manuscript.¹² This work reports on emissions from gas well liquid unloadings.

A liquid unloading may be necessary when a gas well that also produces oil or water accumulates liquids in the well bore. The liquids accumulation may be due to a variety of causes, including decreases in gas velocity in the well, decreases in reservoir pressure, or changing gas to liquid ratios. As liquids accumulate, well production can decline and an operator may choose to unload the liquids from the well to restore production. Liquids can be unloaded in a variety of ways. For example, the well tubing can be modified to increase gas velocity or a pump may be installed to remove downhole

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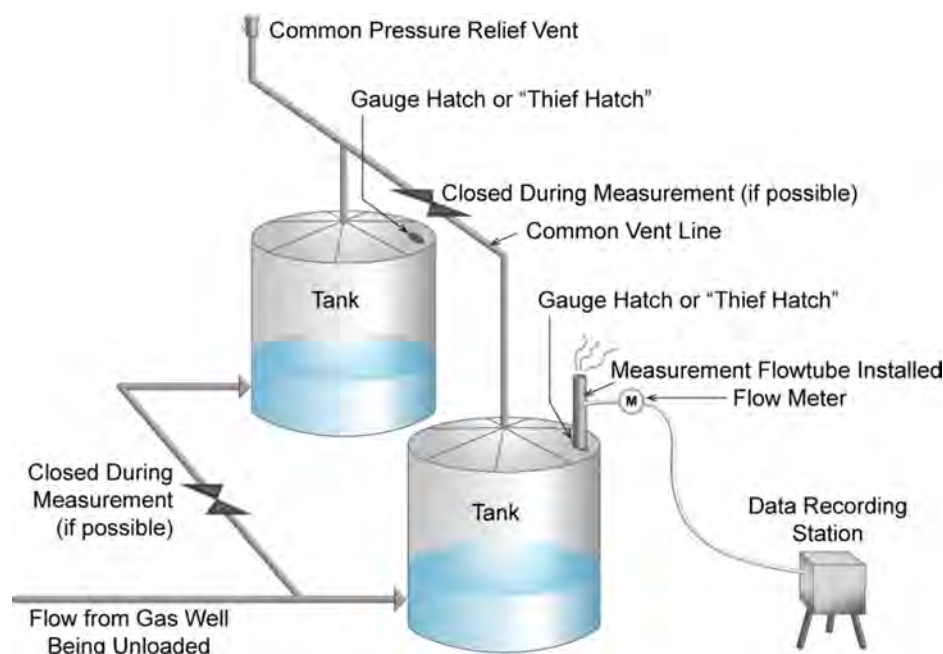


Figure 1. Conceptual diagram of a tank layout on a well site and the positioning of the temporary stack used to measure volume of gas vented during a liquid unloading.

liquids. Neither of these methods lead to venting emissions. Other unloading methods, such as temporarily diverting the flow from the well to an atmospheric vent, do lead to emissions. This work focuses on unloadings that result in emissions.

In the most recent national inventory of greenhouse gas emissions (for calendar year 2012, released in 2014, referred to here as the EPA 2012 GHG NEI),¹³ the EPA estimates that 60 810 natural gas wells, out of an estimated 470 913 natural gas wells in the United States (not including oil wells with associated gas production), have liquid unloadings that result in methane emissions. This represents 13% of gas wells in the EPA 2012 GHG NEI. Collectively, liquid unloadings from these wells are estimated to emit 273.6 Gg of methane per year (14.2 billion standard cubic feet, bcf), or approximately 14% of the estimated 1992 Gg of methane emissions from the natural gas production portion of the natural gas supply chain.

The estimates of methane emissions from liquid unloadings in EPA 2012 GHG NEI are generally consistent with more recent information collected through the EPA's Greenhouse Gas Reporting Program (for calendar year 2012, released in 2013, referred to here as the EPA 2012 GHGRP).¹⁴ The GHGRP reports approximately 276 Gg of methane emissions from liquid unloadings at facilities that meet threshold reporting requirements. Information for 58 663 wells that have unloading emissions was reported in 2012. In October 2014, GHGRP data were released for reporting year 2013 as well as revised data for reporting year 2012. In the 2014 data release, the number of wells with methane emissions from unloadings was reported as 55 491 for 2013, a 5.4% decrease from the number of wells originally reported for 2012. The number of wells with methane emissions from unloadings in 2012 was revised from 58 663 (released in October 2013) to 59 162 (released in October 2014). In this work, the 2012 data are used in order to allow comparisons with the 2012 GHG NEI. The originally released data are used since changes in reporting for 2012, as reflected in the well count, were relatively minor. Some changes were more significant, however, so a

sensitivity analysis, using revised 2012 and 2013 GHGRP data, is reported in Supporting Information (SI). The liquid unloading emission estimates from the EPA GHGRP are shown, by production region, in SI (Section S1).

Emissions from liquid unloadings of natural gas wells are not uniformly distributed in time or space. Estimated emissions from liquid unloadings are spatially concentrated in Rocky Mountain production regions. Wells in the Rocky Mountain region account for more than half of estimated emissions from liquid unloadings in the 2012 GHGRP. Temporal distributions also vary. Some wells release unloading emissions several times per day while others may release unloading emissions only once per year or once during the well's production life cycle. Wells may only release unloading emissions for a portion of their production lifetime, leading to a dependence of unloading emissions on well age. In addition to spatial and temporal variability in emissions of wells that vent, both estimates and measurements indicate that a small fraction of wells that vent account for a majority of emissions. For example, for one type of well with unloading emissions (wells without plunger lifts, see definition later in text), emission estimates reported by the American Petroleum Institute/America's Natural Gas Alliance (API/ANGA), indicate that three percent of wells accounted for half of emissions from this type of well and half of the wells accounted for more than 90% of emissions.¹⁵ In a limited number of measurements of methane emissions from a single type of well with unloading emissions (wells without plunger lifts—see definition later in text), Allen et al.¹¹ found that 95% of the emissions came from less than half of the wells.

Emission estimates, and a limited number of measurements of methane emissions from liquid unloadings, both suggest that a small fraction of wells, in particular geographical regions, and at particular times in the well's life cycle, account for a large fraction of liquid unloading emissions. These characterizations of unloadings emissions are primarily based on emission estimates, however, and there are few data in the scientific literature to test the reliability of emission estimates. This leads

to potentially large uncertainties in the emissions from this source category. More measurement data are needed, along with a better understanding of the relationships between well characteristics and unloading emissions.

This work reports measurements of methane emissions from 107 natural gas wells with emissions associated with liquid unloading. These data represent the most extensive set of measurements of emissions from liquid unloadings in the scientific literature. The relationships between emissions magnitude, unloading event frequency and other well characteristics are explored.

MATERIALS AND METHODS

Emission Measurements. The liquid unloadings reported in this work are grouped as plunger-lift unloadings and unloadings of wells without plunger lifts.

In a manually triggered unloading of a well without a plunger lift, an operator manually diverts the well's flow from a production separator, which typically operates at pressures of multiple atmospheres, to an atmospheric pressure tank. This allows the well to temporarily flow to a lower pressure destination (the atmospheric pressure tank or vent, rather than the pressurized separator). The resulting higher pressure gradient allows more gas to flow, increasing velocity in the production tubing and entraining and lifting liquids out of the well. Gas is discharged through the tank vent to the atmosphere until liquids are cleared. In a small number of wells (~0.1% of wells reported by companies participating in this work), this process is automated, resulting in two subcategories of unloadings for wells without plunger lifts, manual and automatic. All of the measurements reported in this work for wells without plunger lifts are for wells that had unloadings that were manually triggered; no wells without plunger lifts were observed in the sampling that had automated unloadings.

Emissions from unloadings of wells without plunger lifts were measured in this work by directing flow through a temporary stack installed on top of the vent. Figure 1 shows a conceptual diagram of a tank layout on a well site and the positioning of the temporary stack. Grounded metal or metal lined tubing was used to construct the temporary stack, to prevent static discharge. Flow rate through the temporary stack was measured continuously, near the centerline of the temporary stack, using a thermal gas mass flow meter. The thermal meter was extended into the middle of the temporary stack, which was between two and eight inches in diameter, with the diameter depending on the anticipated flow rate. Since the width of the meter's probe was approximately 3.5 cm (1.4 in.), the thermal meter recorded a centerline velocity. Total volumetric flow was calculated by multiplying the product of the measured gas velocity and the cross-sectional area of each stack by a correction factor to convert the centerline velocity in the stack to an estimated average velocity in the stack, accounting for the change in velocity profile from friction near the stack walls and accounting for the cross sectional area of the stack obstructed by the flow meter (see SI Section S2). In some well configurations (31 of the 107 wells on which measurements were made), measurement through a temporary stack on the atmospheric tank was not technically feasible. In these cases, measurements were made by inserting a segment of pipe (with the thermal gas mass flow meter in the pipe) into the process line between the separator and the atmospheric tank in order to measure the flow into the tank.

The methane fraction of the vented gas was assumed to be equal to the methane fraction in the normally produced gas. This was presumed to be a more accurate indicator of total methane emissions than measurements of the gas composition made through the temporary stack. The gas exiting through the temporary stack during the unloading period is a combination of the unloaded gas from the well and the gas initially in the vapor space of the tank (typically much lower in methane than the site's produced gas). At the end of the unloading, the tank will contain more methane, from the unloading, than was in the tank at the start of the unloading. This methane, which is associated with the unloading event, will eventually be released as part of normal tank operations. Multiplying the measured vented gas volume by the methane fraction of the produced gas captures these emissions that occur because of the unloading but that are not released during the period when the tank is actively venting.

Uncertainty in these measurement methods is estimated at 10–20% of the measured emissions and this estimate is dominated by the assumed uncertainty in the flow, which includes both uncertainties in the stack gas volumetric flow measurement, and determining when flows return to zero. Variability in the gas composition from the well is expected to be much less than 10%. As described in the Results section, these measurement uncertainties are small compared to the combined measurement uncertainty and uncertainty introduced by selecting only a subpopulation of wells for measurement (sampling uncertainty), which are 50% or more of measured emissions.

Liquids can also be unloaded from a well using a plunger lift system. This liquid removal operation holds a plunger at the top of the well, and either manually or by automation occasionally closes (shuts-in) the well and releases the plunger, allowing it to fall down the well bore below the accumulated liquids. The well is then reopened, allowing the gas to push the plunger and the liquid back up the well bore as a slug of liquid. If the plunger returns to the top and the liquid and gas flow to the separator, there is no venting and all gas from the separator is routed to sales. In some cases, if the plunger does not return to the surface as expected, the plunger controller may bypass the separator and direct the flow to an atmospheric pressure vent, such as a vented tank. Directing flow to the lower pressure vent causes the plunger to return to the surface but also allows gas to vent. Plunger cycles may be initiated manually, on a timed interval, or based on certain well parameters such as a reduced gas flow. In this work, measurements were made on both wells in which the unloading was automated through use of a controller (automatically triggered), and wells in which the plunger lift cycle was manually initiated by an operator (manually triggered).

In both the manually triggered plunger lift unloadings and the automatically triggered plunger lift unloadings, the volume of vented gas was measured using the same procedures as used for the wells without plunger lifts. For the automatically triggered unloadings, the measurement equipment was typically left in place for one to several days, making measurements continuously. This allowed automated plunger unloading venting events to be measured only when and if they occurred in routine operation, without artificially triggering the events. For all the plunger lift unloading events, the composition of the vented gas was assumed to be the same as the composition of the gas produced by that well. Produced gas composition was provided by site operators.

Table 1. Unloading events measured in this work. Wells with manual unloadings typically had one event per well, while automated Plunger Lift Unloadings Had Multiple Events Per Well; A Mapping of Region Boundaries is Provided in Supporting Information

type of well	initiation system	wells with unloadings sampled				
		U.S. total	Appalachian	Rocky Mountain	Gulf Coast	Mid-Continent
plunger	auto	25	0	20	1	4
	manual	50	7	29	1	13
non- plunger	manual	32	4	2	14	12
total		107	11	51	16	29

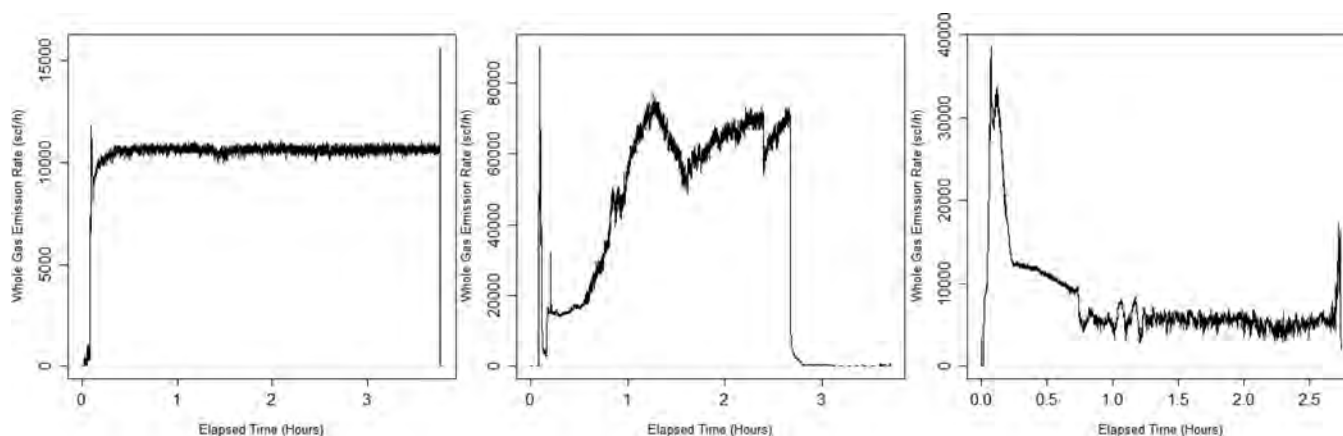


Figure 2. Representative time series of methane flow rates during manually triggered liquid unloadings from wells without plunger lifts (USH-47-0201 left; USH-47-0701 middle; UCG-03-0301 right); Note differences in horizontal and vertical scales.

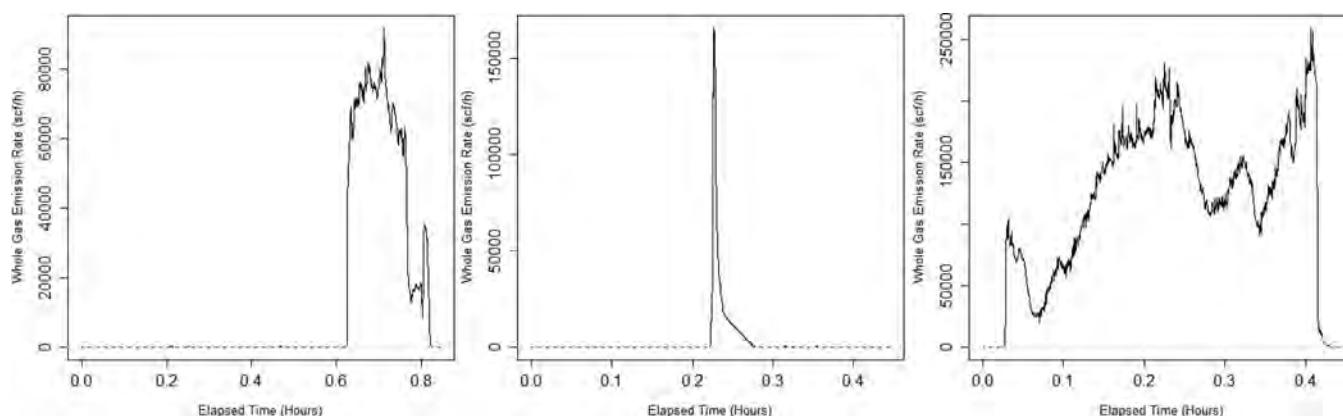


Figure 3. Representative time series of methane flow rates during manually triggered liquid unloadings from wells with plunger lifts (UBB-45-0101 left; UJR-46-0601 middle; USH-45-0202 right); Note differences in horizontal and vertical scales.

Sampling Strategies. Emission estimates reported through the EPA 2012 GHGRP¹⁴ indicate that a small fraction of wells, in particular geographical regions, account for a large fraction of emissions from liquid unloadings. The sampling strategy employed in this work was to sample most extensively in regions that were likely to dominate emissions (SI, Section S1). Details of the sampling approach are provided in SI. Briefly, the sampling team would visit a region for one or multiple weeks and sample a randomly selected subset of those wells that were unloading during that period. Consequently, more samples were collected on wells that unloaded more frequently. The features of these sample collection methods (preferential sampling in regions with high estimated emissions from unloadings and sampling of wells that tended to have high unloading frequencies) are important to consider when the data

presented in this work are used to establish national emission estimates.

RESULTS AND DISCUSSION

Methane emissions from liquid unloadings were measured at 107 natural gas wells. A summary of the geographical locations of the wells sampled is provided in Table 1.

For the 32 wells without plunger lifts (manually unloaded) sampled in this work, one event was typically sampled for each well; a few wells had more than one event sampled and for these wells, average values are reported. The unloadings of wells without plunger lifts sampled in this work had durations that lasted between 0.17 and 4.5 h, and vented methane volumes that ranged between 550 and 135 000 standard cubic feet (scf) of methane per event (0.011–2.6 Mg). Representative time series for the methane emissions from wells without

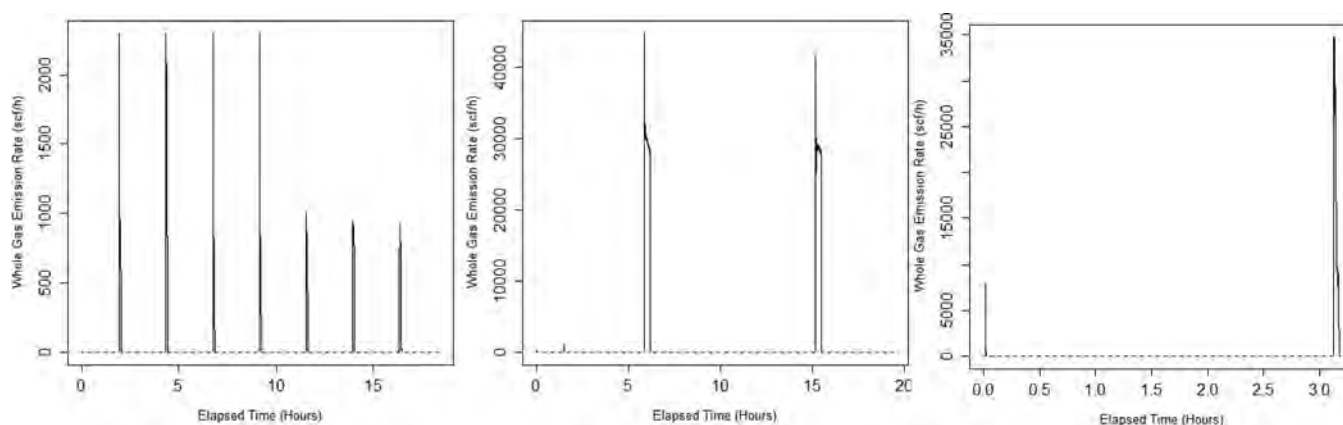


Figure 4. Representative time series of methane flow rates during automatically triggered liquid unloadings from wells with plunger lifts (UBB-42-0401 left; UBB-42-0201 middle; UEF-49-0501 right); Note differences in horizontal and vertical scales.

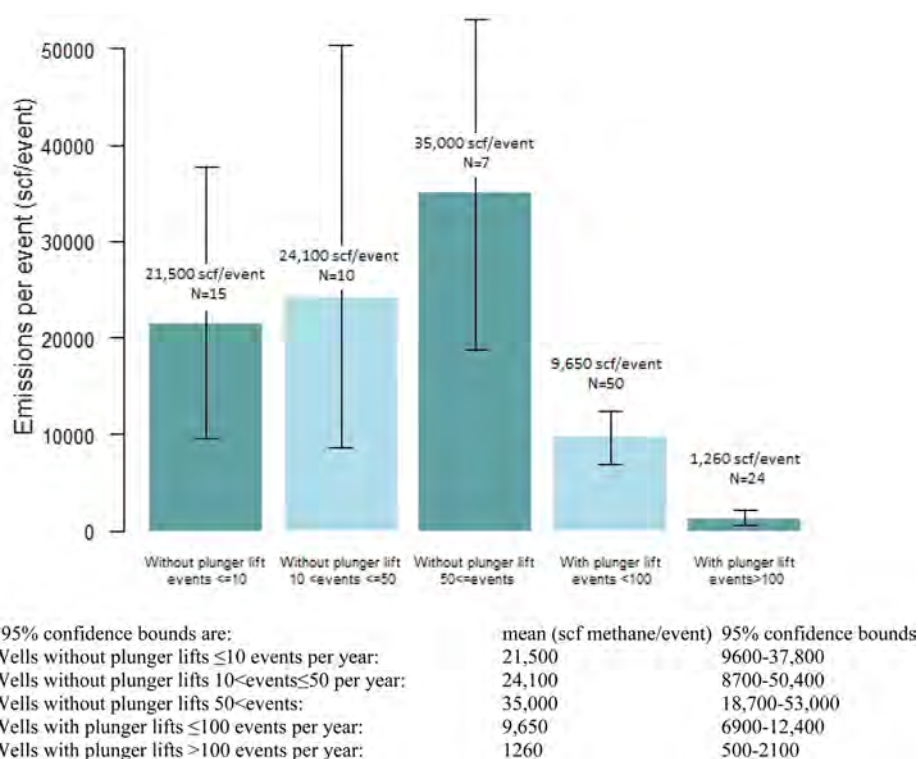


Figure 5. Average emissions per event for wells with and without plunger lifts, sorted by frequency of events (events per year per well).

plunger lifts are shown in Figure 2. These three events shown had durations that ranged from 2.72 to 3.75 h. Vented volumes for these three events shown ranged between 21 000 and 135 000 scf methane (0.40–2.6 Mg). As illustrated by these representative time series, some manual unloadings without plunger lift rapidly rose to a high flow rate, then maintained a steady flow throughout the event; others rose more slowly to a peak flow, then had variable flow during the event; still others rapidly rose to a peak flow, then had declining flows throughout the event. This complex flow behavior makes it difficult to generalize about the flow characteristics for manually triggered unloadings of wells without plunger lifts.

For the 50 plunger lift wells with manually triggered unloadings, one event was typically sampled for each well. The manual unloadings of wells with plunger lifts sampled in this work had durations that lasted between 0.03 h and more than 3 h, and had vented methane volumes that ranged

between approximately 200 and 49 000 scf methane per event (0.004–0.94 Mg). Representative time series for the methane emissions from a manual unloading are shown in Figure 3. These three events shown had durations that ranged from 1.2 to 20 min. Vented volumes ranged between 1220 and 27 000 scf methane for the three events shown (0.02–0.52 Mg). As illustrated by these representative time series, some manually triggered unloadings with plunger lift rapidly rose to a high flow rate, then almost immediately fell rapidly, leading to a relatively short duration event; others rose rapidly to a peak flow that was maintained for 5–10 min or more; still others had complex flow patterns over an event lasting 10 min or more. As was the case for manually triggered unloadings without plunger lifts, this complex flow behavior makes it difficult to generalize about the flow characteristics.

For automated plunger lift wells, the sampling equipment was left in place for one to several days at each well, and

typically more than one event was sampled for each well. The automatically triggered unloadings (with plunger lift) sampled in this work had durations that lasted between <1 min and more than 20 min, and vented methane volumes that ranged from 50 scf methane to more than 8000 scf methane per event) (0.001–0.15 Mg). The numbers of events sampled per well ranged from 2 to more than 70; average values of emissions per event were used when multiple events were recorded. Representative time series for the methane emissions from automated plunger lift unloadings are shown in Figure 4. Individual unloading events for these three wells had durations that ranged from 2 to 20 min. Vented volumes per event ranged between 60 and 8600 scf methane for the three wells shown (0.001–0.15 Mg). As illustrated by these representative time series, some plunger lift wells with automated unloadings had emissions per event that were quite similar, and that occurred with a regular frequency. In contrast, however, some automated plunger lift wells had events that had qualitatively different emissions and/or variable event frequencies.

SI (Section S3) provides details of the unloading emissions and well characteristics for each of the 107 wells sampled in this work. A summary is provided in Figure 5. A relatively small number of wells have high emissions and most wells have much lower emissions. For example, 20% (6 of 32) of the wells account for 83% of the annual emissions for wells without plunger lifts, where annual emissions are estimated by multiplying the emission for an unloading event, measured in this work, by the number of times that well unloaded during calendar year 2012 or 2013 (whichever was the most recent report available), as reported by the well operator. The six wells that account for 83% of the annual emissions of wells without plunger lifts vent 6% of their collective annual production. For manually and automatically triggered plunger lift wells, 20% of the wells account for 65% and 72% of the annual emissions, respectively. These wells vent 2% and 20% of their collective annual production, for manually and automatically triggered wells, respectively.

Because the distributions of event emissions are not normally distributed about a mean, uncertainties in the average values of emissions per event are reported based on the results of a bootstrapping method, rather than as a simple standard deviation of the data set. In the bootstrapping procedure, the original data set of each type of well was recreated by making random event selections, with replacement, from the data set. A total of 1000 of these resampled data sets were created and the mean value of the emissions for each resampled data set was determined. The 95% confidence intervals for the emission estimates represent the 2.5% and 97.5% percentiles of the means in the 1000 resampled data sets. So, for example, for the 25 automatically triggered plunger lift wells, a mean value for emissions per event, for each well, was calculated by selecting 25 emission measurements, at random and with replacement. This mean was tabulated and the process was repeated 1000 times to generate 1000 mean values. The 2.5% and 97.5% percentiles were determined to be 538 and 2085 scf methane per event, and these values are the 95% confidence bounds for the mean value of the measurements (in this case 1260 scf methane/event). The bootstrapping procedure leads to a combined sampling and measurement uncertainty. This uncertainty has a much larger range (typically 50% or more of the mean value, see Figure 5) than would be estimated from the uncertainty associated with the measurement alone (approximately 10–20% of the measured value) and is a

reflection of the heterogeneity of well characteristics in the data sets and the underlying population of wells with unloading emissions.

Statistical analyses were conducted to identify well and unloading event characteristics that could explain the variability in the measured emission data. Variables that were considered included well pressures, well bore volumes, well ages, unloading event durations and unloading frequencies. The variable that explained the largest amount of variability in the observed annual well emissions was unloading frequency, although there was also a positive correlation of event frequencies with well age (older wells had more unloading events per year than younger wells) and a negative correlation of annual emissions with well depth (deeper wells, which were generally newer, had lower annual emissions than shallower, generally older, wells). Correlations with emissions per event were generally weaker than for annual emissions. Additional details are provided in SI (Section S4). As shown in Figure 5, for wells without plunger lifts, average emissions for individual unloading events range between 21 000 and 35 000 scf methane per event, if the events are binned into wells that have less than 10 events per year, between 11 and 50 events per year, and 51 or more events per year. The differences in annual emissions from manually unloaded wells without plunger lifts are largely due to the frequency of events, rather than the volume of gas emitted per event. For wells with plunger lifts, Figure 5 reports average emissions in two frequency bins. Manually triggered plunger lift wells were binned as a single group; all had less than 100 events per year (maximum observed value of 52 events per year). Automatically triggered plunger lift wells were also considered as a single category since all of these wells had more than 180 unloadings per year (average of 1870 unloadings per year in the sampled population). Plunger lift wells that were manually triggered had average emissions per event of 9650 scf methane. Plunger lift wells with automated triggering of the unloading had average emissions of 1260 scf methane per event.

The measured emissions per event were compared to predictions made using emission estimation methods commonly used in EPA GHGRP reporting. For wells with plunger lifts, the emission estimates averaged 4500 scf/event as compared to an average of 8000 scf/event for the study measurements (difference is statistically different, $p = 0.004$). Despite the differences in mean predicted and observed emission rates, the paired measurements and estimates were weakly, but statistically significantly correlated. For wells without plunger lifts, the emission estimates averaged 31 000 scf/event as compared to an average of 27 000 scf/event for the measurements (difference is not statistically significant), however, while the averages are similar, the estimates were not well correlated with the observations. See SI (Section S4) for more details.

Implications for National Emission Estimates. National emissions, based on the measurements made in this work, are estimated by multiplying an emission factor, based on the measurements, by an activity factor. Emission event counts, stratified into categories based on emission events per year per well, were chosen for the activity factor because of the process used for selecting wells to be sampled and because annual emission estimates for wells with unloadings depended most strongly on event frequency.

As documented in SI (Section S1), the measurement team typically visited production Basins for approximately a week, and sampled randomly selected wells that had scheduled (for

manually triggered wells) or anticipated (for automatically triggered wells) unloading events for that week of sampling. This meant that the study team was far more likely to sample wells that unloaded weekly or more frequently, rather than wells that unloaded just a few times per year. This sampling approach resulted in a representative distribution of events, but not a representative distribution of wells. For example, 85% of the wells, without plunger lift, that have unloading emissions and that are operated by the companies that provided sampling sites in this work, had fewer than 10 emission events per year (See SI, Section S5). In the measurements performed for this work, 15 of the 32 wells without plunger lift (47%) had 10 or less events per year. These wells are therefore under-represented in the measurement data, relative to their presence in the participating companies' overall well population. Because of differences in the distributions of event frequency between the sampled wells and the national population of wells, it would not be appropriate to choose an emission factor of emissions per well per year and an activity factor of number of wells, without adjusting for this difference in event frequency distribution.

An additional reason for stratifying wells by frequency of events in the activity factor is the data shown in Figure 5, which indicate a reasonable degree of consistency in per event emissions. Wells without plunger lifts had measured mean values of 21 000–35 000 scf methane/event. Wells with plunger lifts had measured mean values of 1000–10 000 scf methane/event, but much larger ranges of event frequencies. For the calculations reported in this work, national, rather than regional averages of emissions per event will be used, due to the limited number of observations in individual regions.

In this work, national estimates of numbers of unloading events were based on a survey of the participating companies (see SI, Section S5). Data on event counts from the EPA GHGRP were not used since event counts for plunger and nonplunger wells are either partially reported or of uncertain quality. The national event counts were assumed to have the same distributions as reported in the participant survey. Based on this survey, it was estimated that the 32 225 wells with plunger lifts (based on data from the 2012 GHGRP) have a total of 6.8 million events per year. Only 206 500 of these 6.8 million events are associated with wells that vent less than 100 times per year. Total annual emissions from plunger lift wells are estimated at 10 billion cubic feet of methane per year (bcf/yr) (190 Gg/yr), with 80% of those emissions associated with wells that vent more than 100 times per year (additional details in SI, Section S5). For wells that vent more than 100 times per year, the average emissions per well per year are 1 400 000 scf per well per year (27 Mg/yr) with 95% confidence bounds of 600 000–2 500 000 scf (10–50 Mg, based on the confidence bounds in the emissions per event).

For wells without plunger lifts, it was estimated that 26 438 wells (based on data from the 2012 GHGRP) vent a total of 177 000 times per year, with total emissions of 4.4 bcf/yr (84 Gg/yr). Again, the wells that vent with highest frequency have the highest emissions per well. The 1.1% of wells that vent more than 50 times per year have average emissions of 3.2 million scf methane/yr. For wells without plunger lifts, however, these wells account for only 1.1% of the wells with unloading emissions, so the emissions from these wells venting at high frequency account for only 25% of emissions from wells without plunger lifts. Additional details are provided in SI, Section S5).

The overall emission estimate for liquid unloadings (plunger and nonplunger wells), based on the measurements made in this work, is 270 Gg (14 bcf/yr), which is within a few percent of the national emissions estimated in either the 2012 GHG NEI (273 Gg/yr) or the 2012 GHGRP (276 Gg/yr). The 95% confidence range for this estimate is 190–400 Gg/yr, based on the reported confidence ranges in the per event emission factors, but not accounting for uncertainties in event counts. SI (Section S5) reports sensitivity analyses that suggest uncertainties in event count estimates may be large, up to a factor of 2 or more, which could have a significant impact on national emission estimates. Regardless of the exact national total of emissions, however, wells with high frequencies of unloadings have annual emissions that are a factor of 10 or more greater than the annual emissions of wells with low frequencies of unloadings.

■ ASSOCIATED CONTENT

■ Supporting Information

Additional material as described in the text. This material is available free of charge via the Internet at <http://pubs.acs.org>.

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Notes

The authors declare the following competing financial interest(s): Lead author David Allen serves as chair of the Environmental Protection Agency's Science Advisory Board, and in this role is a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality, the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. Adam Pacsi and Daniel Zavala-Araiza, who were graduate students at the University of Texas at the time the work in this paper was done, have accepted positions at Chevron Energy Technology Company and Environmental Defense Fund, respectively. John Seinfeld served as a consultant for Shell in 2012. A. Daniel Hill owns ExxonMobil, BP, and ConocoPhillips stock, serves on the Advisory Board for Sanchez Oil and Gas, for which he is compensated, and has been a consultant for Schlumberger and numerous oil and gas operating companies..

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Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry



Executive Summary

Pneumatic devices powered by pressurized natural gas are used widely in the natural gas industry as liquid level controllers, pressure regulators, and valve controllers. Methane emissions from pneumatic devices, which have been estimated at 51 billion cubic feet (Bcf) per year in the production sector, 14 Bcf per year in the transmission sector and <1 Bcf per year in the processing sector, are one of the largest sources of vented methane emissions from the natural gas industry. Reducing these emissions by replacing high-bleed devices with low-bleed devices, retrofitting high-bleed devices, and improving maintenance practices can be profitable.

Natural Gas STAR Partners have achieved significant savings and methane emission reductions through replacement, retrofit, and maintenance of high-bleed pneumatics. Partners have found that most retrofit investments pay for themselves in little over a year, and replacements in as little as 6 months. To date, Natural Gas STAR Partners have saved 36.4 Bcf by retrofitting or replacing high-bleed with low-bleed pneumatic devices, representing a savings of \$254.8 million worth of gas. Individual savings will vary depending on the design,

condition and specific operating conditions of the controller.

Technology Background

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. Control devices can be powered by electricity or compressed air, when available and economic. In the vast majority of applications, however, the gas industry uses pneumatic devices that employ energy from pressurized natural gas.

Natural gas powered pneumatic devices perform a variety of functions in all three sectors of the natural gas industry. In the production sector, an estimated 400,000 pneumatic devices are used to control and monitor gas and liquid flows and levels in dehydrators and separators, temperature in dehydrator regenerators, and pressure in flash tanks. In the processing sector, about 13,000 gas pneumatic devices are used for compressor and glycol dehydration control in gas gathering/booster stations and isolation valves in processing plants (process control in gas processing plants is predominantly instrument air).

Economic and Environmental Benefits

Economic and Environmental Benefits								
Method for Reducing Natural Gas Losses	Volume of Natural Gas Savings (Mcf/year)	Value of Natural Gas Savings (\$/year)			Implementation Cost (\$)	Payback (Months)		
		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf		\$3 per Mcf	\$5 per Mcf	\$7 per Mcf
Replacement								
Change to low-bleed device at end of life.	50 to 200	\$150 to \$600	\$250 to \$1,000	\$350 to \$1,400	\$210 to \$340 ^a	4 to 27	3 to 17	2 to 12
Early-replacement of high-bleed unit.	260	\$780	\$1,300	\$1,820	\$1,850	29	17	13
Retrofit	230	\$690	\$1,150	\$1,610 per year	\$675	12	7	5
Maintenance	45 to 260	\$135 to \$780	\$225 to \$1,300	\$315 to \$1,820	Negligible to \$500	Immediate to 8	Immediate to 5	Immediate to 4
General Assumptions: ^a Incremental cost of low-bleed over high-bleed equipment.								

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

Definition of High-Bleed Pneumatic

Any pneumatic device that bleeds in excess of 6 scfh (over 50 Mcf per year) is considered a high-bleed device by the Natural Gas STAR Program.

In the transmission sector, an estimated 85,000 pneumatic devices actuate isolation valves and regulate gas flow and pressure at compressor stations, pipelines, and storage facilities. Non-bleed pneumatic devices are also found on meter runs at

distribution company gate stations for regulating flow, pressure, and temperature.

As part of normal operation, pneumatic devices release or bleed natural gas to the atmosphere and, consequently, are a major source of methane emissions from the natural gas industry. The actual bleed rate or emissions level largely depends on the design of the device.

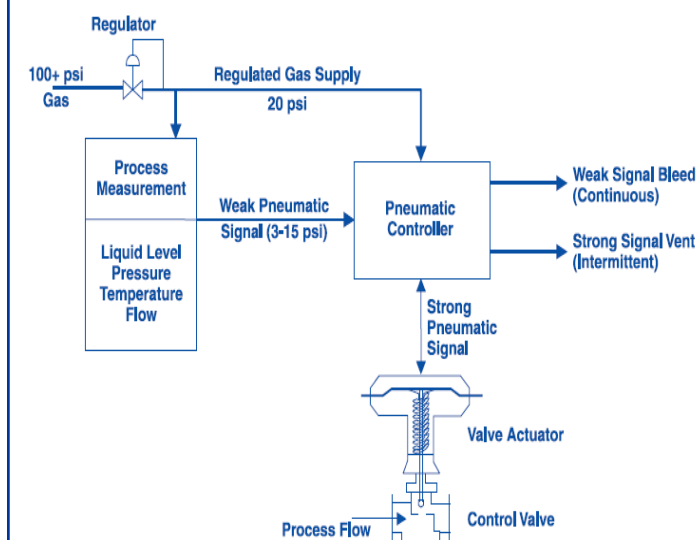
Exhibit 1 shows a schematic of a gas pneumatic control system. Clean, dry, pressurized natural gas is regulated to a constant pressure, usually around 20 psig. This gas supply is used both as a signal and a power supply. A small stream is sent to a device that measures a process condition (liquid level, gas pressure, flow, temperature). This device regulates the pressure of this small gas stream (from 3 to 15 psig) in proportion to the process condition. The stream flows to the pneumatic valve controller, where its variable pressure is used to regulate a valve actuator.

To close the valve pictured in Exhibit 1, 20-psig pneumatic gas is directed to the actuator, pushing the diaphragm down against the spring, which, through the valve stem, pushes the valve plug closed. When gas is vented off the actuator, the spring pushes the valve back open. The weak signal continuously vents (bleeds) to the atmosphere. Electro-pneumatic devices use weak electric current instead of the weak gas stream to signal pneumatic valve actuation.

In general, controllers of similar design usually have similar steady-state bleed rates regardless of brand name. Pneumatic devices come in three basic designs:

- ★ **Continuous** bleed devices are used to modulate flow, liquid level, or pressure and will generally vent gas at a steady rate;
- ★ **Actuating or intermittent** bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed or as they throttle gas flows; and

Exhibit 1: Pneumatic Device Schematic



- ★ **Self-contained** devices release gas into the downstream pipeline, not to the atmosphere.

To reduce emissions from pneumatic devices the following options can be pursued, either alone or in combination:

1. Replacement of high-bleed devices with low-bleed devices having similar performance capabilities.
2. Installation of low-bleed retrofit kits on operating devices.
3. Enhanced maintenance, cleaning and tuning, repairing/replacing leaking gaskets, tubing fittings, and seals.

Field experience shows that up to 80 percent of all high-bleed devices can be replaced with low-bleed equipment or retrofitted. Exhibit 2 lists the generic options applicable for different controller requirements.

In general, the bleed rate will also vary with the pneumatic gas supply pressure, actuation frequency, and age or condition of the equipment. Due to the need for precision, controllers that must operate quickly will bleed more gas than slower operating devices. The condition of a pneumatic device is a stronger indicator of emission potential than age; well-maintained pneumatic devices operate efficiently for many years.

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

Exhibit 2: Options for Reducing Gas-Bleed Emissions by Controller Type

Action	Pneumatic Types		
	Level Controllers	Pressure Controllers	Positioners/ Transducers
<u>Replacements</u>			
High-bleed with low-bleed	X	X	X (electro-pneumatic)
<u>Retrofits</u>			
Install retrofit kits	X	X	X
<u>Maintenance</u>			
Lower gas supply pressure/replace springs/re-bench	X	X	X
Repair leaks, clean and tune	X	X	X
Change gain setting	X	X	
Remove unnecessary positioners			X

Economic and Environmental Benefits

Reducing methane emissions from high-bleed pneumatic devices through the options presented above will yield significant benefits, including:

- ★ **Financial return from reducing gas-bleed losses.** Using a natural gas price of \$7.00 per thousand cubic feet (Mcf), savings from reduced emissions can range from \$315 to \$1,820 or more per year per device. In many cases, the cost of implementation is recovered in less than a year.
- ★ **Increased operational efficiency.** The retrofit or complete replacement of worn units can provide better system-wide performance and reliability and improve monitoring of parameters such as gas flow, pressure, or liquid level.
- ★ **Lower methane emissions.** Reductions in methane emissions can range from 45 to 260 Mcf per device per year, depending on the device and the specific application.

Decision Process

Operators can determine the gas-bleed reduction option that is best suited to their situation, by following the decision process laid out below. Depending on the types of

devices that are being considered, one or more options for reducing pneumatic gas bleed may be appropriate.

Step 1: Locate and describe the high-bleed devices.

Partners should first identify the high-bleed devices that are candidates for replacement, retrofit, or repair. The identification and description process can occur during normal maintenance or during a system-wide or facility-specific pneumatics survey. For each pneumatic device, record the location, function, make and model, condition, age, estimated remaining useful life, and bleed rate characteristics (volume and whether intermittent or continuous).

The pneumatic device's bleed rate can be determined through direct measurement or from data provided by the manufacturer. Direct measurement might include bagging studies at selected instruments, high-volume sampler measurements (see "Directed Inspection and Maintenance at Compressor Stations" Lessons Learned) or the operator's standard leak measurement approach. Operators will find it unnecessary to measure bleed rates at each device. In most cases, sample measurements of a few devices are sufficient. Experience suggests that manufacturers' bleed rates are understated, so measurement data should be used when it can be acquired.

Appendix A lists brand, model, and gas bleed information—as provided by manufacturers—for various pneumatic devices. This is not an exhaustive list, but it covers the most commonly used devices. Where available, actual field data on bleed rates are included.

Step 2: Establish the technical feasibility and costs of alternatives.

Nearly all high-bleed pneumatic devices can be replaced or retrofitted with lower-bleed equipment. Consult your pneumatic device vendor or an instrumentation specialist for availability, specifications and costs of suitable devices. Low-bleed devices can be requested by specifying bleed rates less than 6 standard cubic feet per hour (scfh). It is important to note that not all manufacturers report bleed rates in the same manner, and companies should exercise

Five Steps for Reducing Methane Emissions from Pneumatic Devices:

1. Locate and describe the high-bleed devices;
2. Establish the technical feasibility and costs of alternatives;
3. Estimate the savings;
4. Evaluate the economics; and
5. Develop an implementation plan.

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

caution when making purchases of low-bleed devices.

Appendix B lists cost data for many low-bleed pneumatic devices and summarizes the compatibility of retrofit kits with various controllers. This is not an exhaustive list, but it covers the most commonly used devices.

Maintenance of pneumatics is a cost-effective method for reducing emissions. All companies should consider maintenance as an important part of their implementation plan. Cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals, can save 5 to 10 scfh per device. Tuning to operate over a broader range of proportional band often reduces bleed rates by as much as 10 scfh. Eliminating unnecessary valve positioners can save up to 18 scfh per device.

Some high-bleed devices, however, should not be replaced with low-bleed devices. Control of very large valves that require fast and/or precise response to process changes often require high-bleed controllers. These are found most frequently on large compressor discharge and bypass pressure controllers. EPA recommends contacting vendors for new fast-acting devices with lower bleed rates.

Step 3: Estimate the savings.

Determine the quantity of gas that can be saved with a low-bleed controller, using field measurement of the high-bleed controller and a similar low-bleed device in service. If these actual bleed rates are not available, use bleed specifications provided by manufacturers.

Gas savings can be monetized to annual savings using \$7.00 per Mcf and multiplying bleed reduction, typically specified in scfh, by 8,670 hours per year.

Gas Savings = (High-bleed, scfh) — (Low-bleed, scfh)

Annual Gas Savings = Gas Savings (scfh) * 8,760 hrs/yr * 1 Mcf/1000scf * \$7.00/Mcf

Step 4: Evaluate the economics.

The cost-effectiveness of replacement, retrofit, or maintenance of high-bleed pneumatic devices can be evaluated using straightforward economic analysis. A cost-benefit analysis for replacement or retrofit is appropriate unless high-bleed characteristics are required for operational reasons.

Exhibit 3 illustrates a cost-benefit analysis for replacement of a high-bleed liquid level controller. Cash flow over a five-year period is analyzed by showing the magnitude and timing of costs (shown in parenthesis) and benefits. In this example, a \$513 initial investment buys a level controller that saves 19 scfh of gas. At \$7.00 per Mcf, the low-bleed device saves \$1,165 per year. Annual maintenance costs for the new and old controllers are shown. The maintenance cost for the older high-bleed controller is shown as a benefit because it is an avoided cost. Net present value (NPV) is equal to the benefits minus the costs accrued over five years and discounted by 10 percent each year. Internal rate of return (IRR) is the discount rate at which the NPV generated by the investment equals zero.

Exhibit 3: Cost-Effectiveness Calculation for Replacement

Type of Costs	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5
Implementation Costs, \$ (Capital Costs) ^a	(513)					
Annual Savings, \$ (New vs. Old) ^b		1,165	1,165	1,165	1,165	1,165
Maintenance Costs, \$ (New Controller) ^c		(34)	(34)	(34)	(34)	(34)
Avoided Maintenance, \$ (Replaced Controller) ^c		70	70	70	70	70
Net Benefit	(513)	1,202	1,202	1,202	1,202	1,202
NPV ^d = \$4,042 IRR = 234%						
Notes: ^a Quoted cost of a Fisher 2680 device. Adjusted to 2006 equipment costs. See Appendix B. ^b Annual savings per device calculated as the change in bleed rate of 19 scfh x 8,760 hrs/yr = 167 Mcf/yr at \$7/Mcf. ^c Maintenance costs are estimated. ^d Net Present Value (NPV) based on 10% discount rate for 5 years.						

Exhibit 4 illustrates the range of savings offered by proven methods for reducing gas bleed emissions. For simplicity, it is assumed that the cost of maintenance of the pneumatic device will be the same before and after the replacement, retrofit, or enhanced maintenance activity.

As seen in Exhibit 4, sometimes more than one option to reduce gas bleed may be appropriate and cost-effective for a given application. For the listed options, please note that the payback period with respect to implementation cost can range from less than one month to two years.

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

Exhibit 4: Economic Benefits of Reducing Pneumatic Device Emissions

Action	Cost ^a (\$)	Bleed Rate Reductions ^b (Mcf/yr/device)	Annual Savings ^c (\$/year)	Payback Period (months)	IRR ^d (%)
Replacement					
Level Controllers					
High-bleed to low-bleed	513	166	1,165	6	226
Pressure Controllers					
High-bleed to low-bleed	1,809	228	1,596	14	84
Airset metal to soft-seal	104	219	1,533	<1	>1,400
Retrofit					
Level Controllers					
Mizer	675	219	1,533	6	226
Large orifice to small	41	184	1,288	<1	>3,100
Large nozzle to small	189	131	917	3	>450
Pressure Controllers					
Large orifice to small	41	184	1,288	<1	>3,100
Maintenance					
All types					
Reduce supply pressure	207	175	1,225	3	>500
Repair leaks, retune	31	44	308	2	>900
Level Controllers					
Change gain setting	0	88	616	Immediate	—
Positioners					
Remove unnecessary	0	158	1,106	Immediate	—

^a Implementation costs represent average costs for Fisher brand pneumatic instruments installed.

^b Bleed rate reduction = change in bleed rate scf/hr x 8,760 hr/yr.

^c Savings based on \$7.00/Mcf cost of gas.

^d Internal rate of return (IRR) calculated over 5 years.

The case studies in Exhibit 5 on the next page present analyses performed and savings achieved by two Natural Gas STAR Partners who installed retrofit kits at gas production facilities.

Step 5: Develop an implementation plan.

After identifying the pneumatic devices that can be profitably replaced, retrofitted or maintained, devise a systematic plan for implementing the required changes. This can include modifying the current inspection and maintenance schedule and prioritizing replacement or retrofits. It may be most cost-effective to replace all those devices that meet the technical and economic criteria of

your analysis at one time to minimize labor costs and disruption of operation.

Where a pneumatic device is at the end of its useful life and is scheduled for replacement, it should be replaced with a low-bleed model instead of a new high-bleed device whenever possible.

When assessing options for replacement of high-bleed pneumatic devices, natural gas price may influence the decision making process. Exhibit 6 shows an economic analysis of early replacement of a high bleed pneumatic device with a lower bleed device at different natural gas prices.

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

Exhibit 5: Case Studies on Retrofit To Reduce Gas Leaks at Natural Gas STAR Partner Sites

Study	Implementation Costs (\$)	Emissions Reductions (Mcf/yr)	Annual Savings (\$/year)	Payback (months)	IRR (%)
Company 1:					
Platform 1	8,988	2,286	16,002	7	177
Platform 2	13,892	3,592	25,144	7	180
Retrofit Liquid-level controllers	5,452	1,717	12,019	6	220
Company 2:					
Per device	702	219	1,533	6	218

Other Technologies

Instrument air, nitrogen gas, electric valve controllers, and mechanical control systems are some of the alternatives to gas powered pneumatics implemented by Partners.

- ★ **Instrument Air.** These systems substitute compressed, dried air in place of natural gas in pneumatic devices, and thus eliminate methane emissions entirely. Instrument air systems are typically installed at facilities where there is a high concentration of pneumatic control valves and fulltime operator presence (for example, most gas

Nelson Price Indexes

In order to account for inflation in equipment and operating & maintenance costs, Nelson-Farrar Quarterly Cost Indexes (available in the first issue of each quarter in the *Oil and Gas Journal*) are used to update costs in the Lessons Learned documents.

The "Refinery Operation Index" is used to revise operating costs while the "Machinery: Oilfield Itemized Refining Cost Index" is used to update equipment costs.

To use these indexes in the future, simply look up the most current Nelson-Farrar index number, divide by the February 2006 Nelson-Farrar index number, and, finally multiply by the appropriate costs in the Lessons Learned.

Exhibit 6: Gas Price Impact on Economic Analysis

	\$3/Mcf	\$5/Mcf	\$7/Mcf	\$8/Mcf	\$10/Mcf
Value of Gas Saved	\$780	\$1,300	\$1,820	\$2,080	\$2,600
Payback Period (months)	29	18	13	11	9
Internal Rate of Return (IRR)	31%	64%	95%	110%	139%
Net Present Value ($r=10\%$)	\$1,107	\$3,078	\$5,049	\$6,035	\$8,006

processing plants use instrument air for pneumatic devices). The major costs associated with instrument air systems are capital and energy. Instrument air systems are powered by electric compressors, and require the installation of dehydrators and volume tanks to filter, dry and store the air for instrumentation use. Generally, Partners have found that cost-effective implementation of instrument air systems is limited to field sites with available utility or self-generated electrical power. The Lessons Learned study, "Covert Gas Pneumatic Controls to Instrument Air," provides a detailed description of the technical and economic decision process required to evaluate conversion from gas pneumatic devices to instrument air.

- ★ **Nitrogen Gas.** Unlike instrument air systems that require capital expenditures and electric power, these systems only require the installation of a cryogenic liquid nitrogen cylinder, that is replaced periodically, and a liquid nitrogen vaporizer. The system uses a pressure regulator to control the expansion of the nitrogen gas (i.e., the gas pressure) as it enters the control system. The primary disadvantage of these systems stems from the cost of liquid nitrogen and the potential safety hazard associated with using cryogenic liquids.
- ★ **Electric Valve Controllers.** Due to advances in technology, the use of electronic control instrumentation is increasing. These systems use small electrical motors to operate valves and therefore do not bleed natural gas into the atmosphere. While they are reliant on a constant

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

Methane Content of Natural Gas

The average methane content of natural gas varies by natural gas industry sector. The Natural Gas STAR Program assumes the following methane content of natural gas when estimating methane savings for Partner Reported Opportunities.

Production	79 %
Processing	87 %
Transmission and Distribution	94 %

supply of electricity, and have high associated operating costs, they have the advantage of not requiring the utilization of natural gas or a compressor to operate.

- ★ **Mechanical Control Systems.** These devices have been widely used in the natural gas and petroleum industry. They operate using a combination of springs, levers, flow channels and hand wheels. While they are simple in design and require no natural gas or power supply to operate, their application is limited due to the need for the control valve to be in close proximity to the process measurement. Also, these systems are unable to handle large flow fluctuations and lack the sensitivity of pneumatic systems.

Each of these options has specific advantages and disadvantages. Where Natural Gas STAR Partners do install these systems as replacements to gas powered pneumatic devices, they should report the resulting emissions reductions and recognize the savings.

One Partner's Experience

Union Pacific Resources replaced 70 high-bleed pneumatic devices with low-bleed pneumatic devices and retrofitted 330 high-bleed pneumatic devices. As a result, this Partner has estimated a total reduction of methane emissions of 49,600 Mcf per year. Assuming a gas price of \$7 per Mcf, the savings corresponds to \$347,200. The costs of replacing and retrofitting all the devices, including materials and labor, is \$166,300 at 2006 costs, resulting in a payback period of less than one year.

One Partner's Experience

Marathon Oil Company surveyed 158 pneumatic control devices at 50 production sites using the Hi-Flow Sampler to measure emissions. Half of these controllers were identified as non-bleed devices (e.g., weighted dump valves, spring operated regulators, enclosed capillary temperature controllers, non-bleed pressure switches). High-bleed devices accounted for 35 of 67 level controllers, 5 of 76 pressure controllers, and 1 of 15 temperature controllers. Measured gas emissions were 583 scfh total; 86 percent of emissions came from level controllers, with leaks up to 48 scfh, and averaging 7.6 scfh. Marathon concluded that “control devices with higher emissions can be identified qualitatively by sound prior to leak measurement, making it unnecessary to quantitatively measure methane emissions using technologically advanced equipment.”

Lessons Learned

Natural Gas STAR Partners offer the following Lessons Learned:

- ★ Hear it; feel it; replace it. Where emissions can be heard or felt, this is a sign that emissions are significant enough to warrant corrective action.
- ★ Control valve cycle frequency is another indicator of excessive emissions. When devices cycle more than once per minute, they can be replaced or retrofitted profitably.
- ★ Manufacturer bleed rate specifications are not necessarily what users will experience. Actual bleed rates will generally exceed manufacturer's specifications because of operating conditions different from manufacturer's assumptions, installation settings and maintenance.
- ★ Combine equipment retrofits or replacements with improved maintenance activities. Do not overlook simple solutions such as replacing tubes and fittings or rearranging controllers.
- ★ The smaller orifices in low-bleed devices and retrofit kits can be subject to clogging from debris in corroded pipes. Therefore, pneumatic supply gas piping and tubing should be flushed out before retrofitting with

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

smaller orifice devices, and gas filters should be well maintained.

- ★ When replacing pneumatic control systems powered by pressurized natural gas with instrument air or other systems, do not forget to account for the savings from the resulting methane emission reductions.
- ★ Include methane emission reductions from pneumatics in annual reports submitted as part of the Natural Gas STAR Program.

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Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

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Appendix A

The following chart contains manufacturer-reported bleed rates. Actual bleed rates have been included whenever possible. Discrepancies occur due to a variety of reasons, including:

- ★ Maintenance.
- ★ Operating conditions.
- ★ Manufacturer vs. operating assumptions.

It is important to note that manufacturer information has not been verified by any third party and there may be large differences between manufacturer-reported bleed rates and those found during operations. Until a full set of information is available, companies should be careful to compare bleed rates in standard units (CFH) when comparing manufacturers and models. During this study we found that manufacturers reported information in a wide range of different units and operating assumptions.

Gas Bleed Rate for Various Pneumatic Devices			
Controller Model	Type	Consumption Rate (CFH)	
		Manufacturer Data	Field Data (where available)
High-Bleed Pneumatic Devices			
**Fisher 4100 Series	Pressure controller (large orifice)	35	
**Fisher 2500 Series	Liquid-level controllers (P.B. in mid range)	10-34	44-72
*Invalco AE-155	Liquid-level controller		44-63
*Moore Products—Model 750P	Positioner	42	
*Invalco CT Series	Liquid-level controllers	40	34-87
**Fisher 4150/4160K	Pressure controller (P.B. 0 or 10)	2.5-29	
**Fisher 546	Transducer	21	
**Fisher 3620J	Electro-pneumatic positioner	18.2	
Foxboro 43AP	Pressure controller	18	
**Fisher 3582i	Electro-pneumatic positioner	17.2	

**Fisher 4100 Series	Pressure controller (small orifice)	15	
**Fisher DVC 6000	Electro-pneumatic positioner	14	
**Fisher 846	Transducer	12	
**Fisher 4160	Pressure controller (P.B. 0.5)	10-34	
**Fisher 2506	Receiver controller (P.B. 0.5)	10	
**Fisher DVC 5000	Electro-pneumatic positioner	10	
**Masoneilan 4700E	Positioners	9	
**Fisher 3661	Electro-pneumatic positioner	8.8	
**Fisher 646	Transducer	7.8	
**Fisher 3660	Pneumatic positioner	6	
**ITT Barton 335P	Pressure controller	6	
*Ametek Series 40	Pressure controllers	6	

Low- or No-Bleed Pneumatic Devices			
**Masoneilan SV	Positioners	4	
**Fisher 4195 Series	Pressure controllers	3.5	
**ITT Barton 273A	Pressure transmitter	3	
**ITT Barton 274A	Pressure transmitter	3	
**ITT Barton 284B	Pressure transmitter	3	
**ITT Barton 285B	Pressure transmitter	3	
**Bristol Babcock Series 5457-70F	Transmitter	3	
**Bristol Babcock Series 5453-Model 624 -II	Liquid-level controllers	3	
**Bristol Babcock Series 5453-Model 10F	Pressure controllers	3	
**Bristol Babcock Series 5455 Model 624 -III	Pressure controllers	3	
**ITT Barton 358	Pressure controller	1.8	

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

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**ITT Barton 359	Pressure controller	1.8	
**Fisher 3610J	Pneumatic positioner	16	
**Bristol Babcock Series 502 A/D	Recording pneumatic controllers	<6	
**Fisher 4660	High-low pressure pilot	<5	
**Bristol Babcock Series 9110-00A	Transducers	0.42	
Fisher 2100 Series	Liquid-level controllers	1	
**Fisher 2680	Liquid-level controllers	<1	
*Norriseal 1001 (A) (snap)	Liquid-level controller	0.2	0.2
*Norriseal 1001 (A) ('Envirosave')	Liquid-level controller	0	0
*Norriseal 1001 (A) (throttle)	Liquid-level controller	0.007	0.007
**Becker VRP-B -CH	Double-acting pilot pressure control system (replaces controllers and positioners)	0-10	
**Becker HPP-5	Pneumatic positioner (Double-acting)	0-10	
**Becker EFP-2.0	Electro-pneumatic positioner	0	
**Becker VRP-SB	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker VRP-SB GAP Controller	Replaces pneumatic "gap" type controllers	0	
**Becker VRP-SB-PID Controller	Single-acting pilot pressure control system specifically designed for power plant type feeds (replaces controllers and positioners)	0	
**Becker VRP-SB-CH	Single-acting pilot pressure control system (replaces controllers and positioners)	0	
**Becker HPP-SB	Pneumatic positioner (Single-acting)	0	

Actuator Model	Size	Manufacturer Data	Field Data
*Shafer RV-Series Rotary Vane Valve Actuators	33" x 32"	1,084	
	36" x 26"	768	
	26" x 22"	469	
	25" x 16"	323	
	20" x 16"	201	
	16.5" x 16"	128	
	14.5" x 14"	86	
	12.5" x 12"	49	
	12" x 9"	22	
	11" x 10"	32	
	9" x 7"	12	
	8" x 6.5"	8	
	6.5" x 3.5"	6	
	5" x 3"	6	
Actuator Model	Size	Number of Snap-acting Strokes per CF	Number of Throttling Strokes per CF
**Fisher Valve Actuators	20	21	39
**Fisher Valve Actuators	30	12	22
**Fisher Valve Actuators	34/40	6	10
**Fisher Valve Actuators	45/50	3	5
**Fisher Valve Actuators	46/50	2	3
* Last updated in 1996.			
** Last updated in 2001.			

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)

Appendix B

Controllers Compatible with MIZER Retrofits	
Type	Brand / Model Number
Liquid-level controllers	C.E. Invalco — 215, 402, AE-155
	Norriseal — 1001, 1001A
Pressure controllers	Norriseal — 4300
Suggested Retail Prices for Various Brand Low-Bleed Pneumatic Devices (Estimates Based on Best Information Available at Time of Publication)	
Brand / Model	Price per Device
**ITT Barton 335P (pressure controller)	\$920
**ITT Barton 273A (pressure transmitter)	\$1,010
**ITT Barton 274A (pressure transmitter)	\$1,385
**ITT Barton 284B (pressure transmitter)	\$1,605
**ITT Barton 285B (pressure transmitter)	\$1,990
**ITT Barton 340E (recording pressure controller)	\$1,400
**ITT Barton 338E (recorder controller)	\$2,800
**Ametek Series 40 (pressure controllers)	\$1,100 (average cost)
**Becker VRP-B-CH	\$1,575.00
**Becker HPP-5	\$1,675.00
**Becker VRP-SB	\$1,575.00-\$2,000.00
**Becker VRP-SB-CH-PID	\$2,075.00
**Becker VRP-SB-CH	\$1,575.00
**Becker HPP-SB	\$1,675.00
**Mizer Retrofit Kits	\$400-\$600
**Fisher 67AFR (airset regulators)	\$80
**Fisher 2680 (liquid-level controllers)	\$380
**Fisher 4195 (pressure controllers)	\$1,340
**Bristol Babcock Series 9110-00A (transducers)	\$1,535-\$1,550
**Bristol Babcock Series 5453 (controllers)	\$1,540
**Bristol Babcock 5453 40 G (temperature controllers)	\$3,500
**Bristol Babcock Series 5457-624 II (controllers)	\$3,140
**Bristol Babcock Series 502 A/D (recording controllers)	\$3,000
**Bristol Babcock Series 5455-624 III (pressure controllers)	\$1,135
**Bristol Babcock Series 5453-624 II (liquid level controllers)	\$2,345
**Bristol Babcock Series 5453-10F (pressure controllers)	\$1,440
* Last updated in 1996.	
** Last updated in 2001.	

Options For Reducing Methane Emissions From Pneumatic Devices In The Natural Gas Industry

(Cont'd)



**United States
Environmental Protection Agency
Air and Radiation (6202J)
1200 Pennsylvania Ave., NW
Washington, DC 20460**

October 2006

EPA provides the suggested methane emissions estimating methods contained in this document as a tool to develop basic methane emissions estimates only. As regulatory reporting demands a higher-level of accuracy, the methane emission estimating methods and terminology contained in this document may not conform to the Greenhouse Gas Reporting Rule, 40 CFR Part 98, Subpart W methods or those in other EPA regulations.

Corrections

PERSPECTIVE

Correction for “Theory of mass-independent fractionation of isotopes, phase space accessibility, and a role of isotopic symmetry,” by Rudolph A. Marcus, which appeared in issue 44, October 29, 2013, of *Proc Natl Acad Sci USA* (110:17703–17707; first published June 28, 2013; 10.1073/pnas.1213080110).

The author notes that, on page 1, middle column, lines 11–16 “Fewer accidental resonances mean less energy sharing and so less statistical behavior with a consequence that they are in equilibrium with the population of accessible states of O_3^* at low pressures, as discussed later.” should instead appear as “Fewer accidental resonances mean less energy sharing and so less statistical behavior with a consequence of a shorter lifetime of O_3^* at low pressures, as discussed later.”

On page 2, middle column, first full paragraph, lines 11–14 “This major difference in the pressure effect indicates a difference in the role of the collisions in these two distant phenomena.” should instead appear as “This major difference in the pressure effect indicates a difference in the role of the collisions in these two distinct phenomena.”

On page 3, middle column, first paragraph, lines 4–7 “The overall deviation from statistical theory for the recombination rate constant was (N. Ghaderi) perhaps a factor of 2.” should instead appear as “The overall deviation from statistical theory for the recombination rate constant was (N. Ghaderi) less than a factor of 2.”

On page 3, middle column, first full paragraph, lines 22–26 “Any chaos in the form of higher-order resonances within a volume element h^N would be coarse grained and so presumably contribute to quantum chaos.” should instead appear as “Any chaos in the form of higher-order resonances within a volume element h^N would be coarse grained and so presumably not contribute to quantum chaos.”

Both the online article and the print article have been corrected.

www.pnas.org/cgi/doi/10.1073/pnas.1315099110

ENVIRONMENTAL SCIENCES

Correction for “Measurements of methane emissions at natural gas production sites in the United States,” by David T. Allen, Vincent M. Torres, James Thomas, David W. Sullivan, Matthew Harrison, Al Hendler, Scott C. Herndon, Charles E. Kolb, Matthew P. Fraser, A. Daniel Hill, Brian K. Lamb, Jennifer Miskimins, Robert F. Sawyer, and John H. Seinfeld, which appeared in issue 44, October 29, 2013, of *Proc Natl Acad Sci USA* (110:17768–17773; first published September 16, 2013; 10.1073/pnas.1304880110).

The authors note that upon publication their conflict of interest statement was not complete. The updated disclosure statement is as follows, “Jennifer Miskimins holds a joint appointment with Barree & Associates and the Colorado School of Mines. She has also served as an advisor to Nexen in 2012. David T. Allen served as a consultant for the Eastern Research Group and ExxonMobil in 2012, and is the current chair of the Science Advisory Board for the EPA. John H. Seinfeld has served as a consultant for Shell in 2012. David T. Allen, Matthew Harrison, Charles E. Kolb, and Robert F. Sawyer variously serve as members of scientific advisory panels for projects supported by Environmental Defense Fund and companies involved in the natural gas supply chain. These projects are led at Colorado State University (on natural gas gathering and processing), Washington State University (on local distribution of natural gas), and the University of West Virginia (on CNG fueling and use in heavy duty vehicles).”

Both the online article and print article have been corrected.

www.pnas.org/cgi/doi/10.1073/pnas.1318658110

PHYSIOLOGY

Correction for “mitoBK_{Ca} is encoded by the *Kcnma1* gene, and a splicing sequence defines its mitochondrial location,” by Harpreet Singh, Rong Lu, Jean C. Bopassa, Andrea L. Meredith, Enrico Stefani, and Ligia Toro, which appeared in issue 26, June 25, 2013, of *Proc Natl Acad Sci USA* (110:10836–10841; first published June 10, 2013; 10.1073/pnas.1302028110).

PNAS notes that a conflict of interest statement was omitted during publication. PNAS declares that “The editor, Ramon Latorre, is a recent coauthor with the authors of this publication, having published a paper with them in 2012.”

Additionally, the authors note:

“Although Figs. 1 and S1 display the same sequence template, the analyses of LC/MS/MS data were performed against the respective databases, rat for Fig. 1, and mouse for Fig. S1. Sequence

alignment of rat (NCBI:Q62976.3; UniProtKB: Q62976-1 V.3, which differs by 3 amino acids near the N terminus with that of Figs. 1 and S1) and mouse (NCBI: NP_001240298.1) isoforms show 98.9% amino acid identity with differences circumscribed to the extreme N and C termini. Peptides identified by LC/MS/MS have the exact sequence in rat and mouse as shown in Figs. 1 and S1.”

“In published Fig. 7, panels *E* and *F* show slices of the same heart in each condition; to better display the infarcted vs. healthy portions, these images were scaled to approximately the same size. We noticed that some data points in panel *G* were slightly moved during figure preparation. The revised Fig. 7 now shows heart slices at their original magnification (*E* and *F*) and the correct panel *G*. The corrected figure and its legend appear below.”

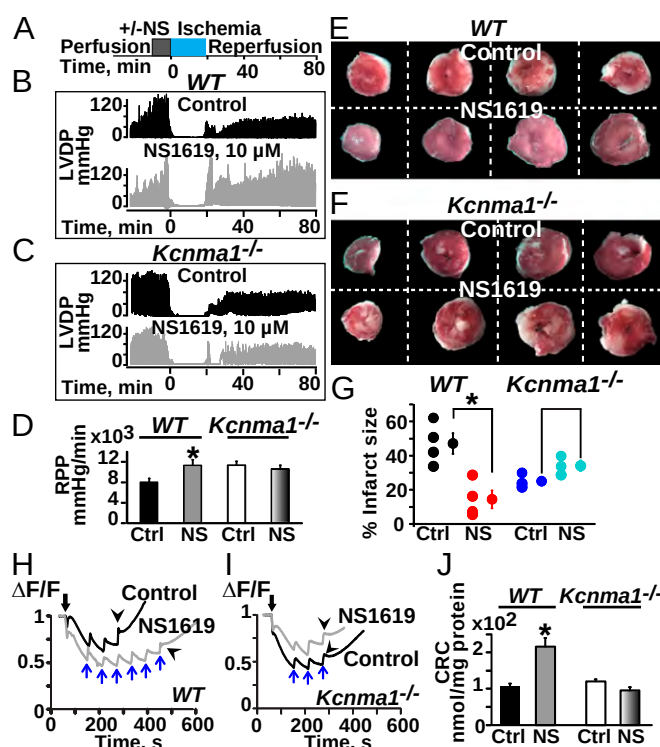


Fig. 7. BK_{Ca} protects the heart from ischemic injury. (A) Ischemia/reperfusion protocol. (B and C) Function traces of hearts preconditioned with vehicle (DMSO, control) or with NS1619 (10 μM) in WT and *Kcnma1*^{-/-} mice. (D) NS1619 significantly improved mean RPP in WT but not in *Kcnma1*^{-/-} mice. (E and G) WT hearts preconditioned with NS1619 exhibited less infarct size (white) compared with the control. (F and G) In *Kcnma1*^{-/-}, infarct size was not reduced with NS1619. (H–J) Mitochondrial Ca²⁺ uptake. NS1619 preconditioning increased the amount of Ca²⁺ needed to induce a large Ca²⁺ release in WT but not in *Kcnma1*^{-/-} samples. Black arrows, addition of mitochondria. Blue arrows, 40 nmol Ca²⁺ pulses. Arrowheads, massive release of Ca²⁺. **P* < 0.05 vs. control (Ctrl); CRC, Ca²⁺ retention capacity.

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Measurements of methane emissions at natural gas production sites in the United States

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Edited by Susan L. Brantley, Pennsylvania State University, University Park, PA, and approved August 19, 2013 (received for review March 20, 2013)

Engineering estimates of methane emissions from natural gas production have led to varied projections of national emissions. This work reports direct measurements of methane emissions at 190 onshore natural gas sites in the United States (150 production sites, 27 well completion flowbacks, 9 well unloadings, and 4 workovers). For well completion flowbacks, which clear fractured wells of liquid to allow gas production, methane emissions ranged from 0.01 Mg to 17 Mg (mean = 1.7 Mg; 95% confidence bounds of 0.67–3.3 Mg), compared with an average of 81 Mg per event in the 2011 EPA national emission inventory from April 2013. Emission factors for pneumatic pumps and controllers as well as equipment leaks were both comparable to and higher than estimates in the national inventory. Overall, if emission factors from this work for completion flowbacks, equipment leaks, and pneumatic pumps and controllers are assumed to be representative of national populations and are used to estimate national emissions, total annual emissions from these source categories are calculated to be 957 Gg of methane (with sampling and measurement uncertainties estimated at ± 200 Gg). The estimate for comparable source categories in the EPA national inventory is $\sim 1,200$ Gg. Additional measurements of unloadings and workovers are needed to produce national emission estimates for these source categories. The 957 Gg in emissions for completion flowbacks, pneumatics, and equipment leaks, coupled with EPA national inventory estimates for other categories, leads to an estimated 2,300 Gg of methane emissions from natural gas production (0.42% of gross gas production).

greenhouse gas emissions | hydraulic fracturing

Methane is the primary component of natural gas and is also a greenhouse gas (GHG). In the US national inventories of GHG emissions for 2011, released by the Environmental Protection Agency (EPA) in April 2013 (1), 2,545 Gg of CH₄ emissions have been attributed to natural gas production activities. These published estimates of CH₄ emissions from the US natural gas industry are primarily based on engineering estimates along with average emission factors developed in the early 1990s (2, 3). During the past two decades, however, natural gas production processes have changed significantly, so the emission factors from the 1990s may not reflect current practices. This work presents direct measurements of methane emissions from multiple sources at onshore natural gas production sites incorporating operational practices that have been adopted or become more prevalent since the 1990s.

Horizontal drilling and hydraulic fracturing are among the practices that have become more widely used over the past two decades. During hydraulic fracturing, materials that typically consist of water, sand and, additives, are injected at high pressure into low-permeability formations. The injection of the hydraulic fracturing fluids creates channels for flow in the formations (often shale formations), allowing methane and other hydrocarbon gases

and liquids in the formation to migrate to the production well. The well and formation is partially cleared of liquids in a process referred to as a completion flowback, after which the well is placed into production. Production of natural gas from shale formations (shale gas) accounts for 30% of US natural gas production, and this percentage is projected to grow to more than 50% by 2040 (4).

Multiple analyses of the environmental implications of gas production using hydraulic fracturing have been performed, including assessments of water contamination (5–8), criteria air pollutant and air toxics releases (9–11), and greenhouse gas emissions (11–18). Greenhouse gas emission analyses have generally been based on either engineering estimates of emissions or measurements made 100 m to a kilometer downwind of the well site. This work reports direct on-site measurements of methane emissions from natural gas production in shale gas production regions.

Significance

This work reports direct measurements of methane emissions at 190 onshore natural gas sites in the United States. The measurements indicate that well completion emissions are lower than previously estimated; the data also show emissions from pneumatic controllers and equipment leaks are higher than Environmental Protection Agency (EPA) national emission projections. Estimates of total emissions are similar to the most recent EPA national inventory of methane emissions from natural gas production. These measurements will help inform policymakers, researchers, and industry, providing information about some of the sources of methane emissions from the production of natural gas, and will better inform and advance national and international scientific and policy discussions with respect to natural gas development and use.

Author contributions: D.T.A. and M.H. designed research; D.T.A., V.M.T., J.T., D.W.S., M.H., A.H., and S.C.H. performed research; C.E.K., M.P.F., A.D.H., B.K.L., J.M., R.F.S., and J.H.S. analyzed data; and D.T.A. wrote the paper.

Conflict of interest statement: J.M. holds a joint appointment with Barree & Associates and the Colorado School of Mines. She has also served as an advisor to Nexen in 2012. D.T.A. served as a consultant for the Eastern Research Group and ExxonMobil in 2012, and is the current chair of the Science Advisory Board for the EPA. J.H.S. has served as a consultant for Shell in 2012. D.T.A., M.H., C.E.K., and R.F.S. variously serve as members of scientific advisory panels for projects supported by Environmental Defense Fund and companies involved in the natural gas supply chain. These projects are led at Colorado State University (on natural gas gathering and processing), Washington State University (on local distribution of natural gas), and the University of West Virginia (on CNG fueling and use in heavy duty vehicles).

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because of regulatory or voluntary emission reductions. In the current national inventory, emission reductions are roughly one-half of potential emissions (*SI Appendix*). In this work, net or measured emissions for the total of all 27 completions are 98% less than potential emissions. This large difference between the net emissions measured in this work and the net emissions estimated in the national inventory is due to several factors. First, consistent with emerging regulatory requirements (21) and improved operating practices, 67% of the wells sent methane to sales or control devices. Second, for those wells with methane capture or control, 99% of the potential emissions were captured or controlled. Finally, the wells with uncontrolled releases had much lower than average potential to emit. Of the nine wells in this work that had uncontrolled venting of methane, the average potential to emit was 0.83 Mg, which is 0.55% of the average potential to emit in the national inventory. The relative importance of these factors is discussed in *SI Appendix*.

Unloadings. Gas wells often produce liquid hydrocarbons and water along with natural gas. In most new wells, the velocity of natural gas up the production tubing of the well is sufficient to lift any produced water out of the well with the gas. As gas production declines, the velocity may no longer be sufficient to lift the liquids, which begin to accumulate in the wellbore and eventually restrict gas flow from the producing formation. Liquids accumulation therefore needs to be removed to allow the well to continue to produce gas at optimal rates.

There are multiple methods of unloading a gas well, some of which do not result in emissions. In this work, sampling was performed for unloadings in which an operator manually bypasses the well's separator. Unlike automated plunger lift methods, these manual unloading events could be scheduled, allowing the study team adequate time to install measurement equipment. As the flow to the separator, which typically operates at pressures of multiple atmospheres, is bypassed, flow is diverted to an atmospheric pressure tank. This diversion allows the well to flow to a lower pressure destination (the atmospheric pressure tank, rather than the pressurized separator). This lower pressure end point allows more gas to flow, increasing velocity in the production tubing and lifting the liquids out of the well. Gas is discharged from the tanks through the tank vent, unless the tanks have an emissions control system such as a combustor.

The nine unloading events reported in this work were varied in their characteristics. Methane emissions ranged from less than 0.02 Mg to 3.7 Mg. Some unloadings lasted 2 h (or more) and had relatively uninterrupted flow. Other unloadings were as short as 10–15 min with uninterrupted flow, and still others had intermittent flow for short periods and periods of no flow for much of the unloading period. Some of the wells sampled only unloaded once over the current life of the well, whereas others were unloaded monthly. The average emission per unloading event was 1.1 Mg of methane (95% confidence limits of 0.32–2.0 Mg). If the emissions per event for each well are multiplied by the event frequency (events per year) reported by the well operators, the average emission per well per year was 5.8 Mg (an average of 5.9 events per unloaded well per year). The sampled population reflected a wide range of emission rates, with a population of high emitting wells and a population of low emitting wells. When emissions are averaged per event, emissions from four of the nine events contribute more than 95% of the total emissions. *SI Appendix* provides more information about individual unloading events.

Because the characteristics of the unloading events sampled in this work are highly variable, and because the number of events sampled is small, extrapolating the results to larger populations should be done with caution. One source of data on larger populations of wells with unloadings, to which the population sampled in this work can be compared, is a survey reported by

the American Petroleum Institute and America's Natural Gas Alliance (API/ANGA) (22). In this survey, more than 20 companies provided data and well characteristics for 40,000–60,000 wells (with the number in the sample depending on the type of emission event). These API/ANGA data were used by the EPA to arrive at 2011 national inventory emission estimates for 35,828 wells without plunger lift and 22,866 with plunger lift, which vent for unloading. Unloading emissions for the wells in the API/ANGA survey were estimated based on well characteristics such as well bore volume, well pressure, venting time, and gas production rate (3). For the unloading events without plunger lift, 100 of the 2,901 wells (3%) in the survey account for 50% of the estimated emissions. Ninety percent of the estimated emissions in the API/ANGA survey are due to one-half of the wells. Because a small population of wells (3%) accounts for one-half of the emissions, if this relatively small population of high emitting wells is not adequately sampled, it is not possible to accurately estimate national emissions. The wells sampled in this work unloaded relatively infrequently. In contrast, some wells in the API/ANGA survey, including some of the highest emitting wells, unload with a daily or weekly frequency. An average frequency of unloading for the wells in the API/ANGA survey is 32.57 events per year, compared with an average observed in this work of 5.9.

Because a small number of unloading events accounts for a large fraction of emissions in the API/ANGA survey (22), and because some of these wells had frequencies of unloading higher than any of the events observed in this work, the sample set of nine events reported in this work is not sufficient for accurately estimating emissions from unloading at a national scale. Nevertheless, the data reported here provide valuable insights for the design of future sampling campaigns.

One important result from the measurements reported here is that current EPA estimation methods overpredict measured emissions. If the emission estimation method (3) used in the API/ANGA survey is applied to the events sampled in this work, estimates are 5 times higher than measured emissions. Estimates of the emissions for the nine events are 5.2 Mg per event versus measured emissions of 1.1 Mg per event. Emissions were overestimated for every event. The percentage by which emissions are overestimated increases as emissions per event decrease (*SI Appendix*). Possible causes of the overestimate include the assumptions in the estimation method that the entire well bore volume is released in an unloading and that the gas flow during an unloading is continuous.

Overall, the implication of all of these issues is a large uncertainty bound in the national emissions from gas well unloading. If the per well annual emissions from this work are used, a national emission estimate based on counts of wells that undergo unloading is in reasonable agreement with emissions in the EPA national inventory (1). In contrast, another estimate of unloading emissions, based on the per event emissions observed in this work and an estimate of national unloading events (22), would lead to a national estimate five times the estimate based on well counts. This estimate is not supported by the available data, given that the national event count is dominated by high frequency unloading events and the wells observed here unloaded far less frequently with much higher emission estimates per event. A lower estimate of unloading emissions could be suggested based on national well counts, emission estimates, and the finding that emission estimation methods, used in many EPA inventory estimates, overestimate observations made in this work by a factor of 5. All of these methods, however, assume a single scalar value represents a wide range of unloadings; the data presented in this work and in the API/ANGA survey (22) suggest that refined emission estimation methods, taking into account well and unloading characteristics, will be required. Additional measurements of unloading emissions are needed, both to resolve the

^aEmissions from EPA national inventory are based on reported potential emissions less reductions; when reductions are reported for combined source categories, identical percentage reductions of potential emissions are assumed to apply across source categories (*SI Appendix, section S5*).

[†]Emission factors used to estimate national inventories are designed to be representative of the participating companies' activities and practices, but not necessarily all activities and practices.

[‡]National emissions based on a regionally weighted average (*SI Appendix, section S5*).

[§]Ranges are based on 95% confidence bounds of emission factors; activity factors are identical to those used in EPA inventory. Uncertainties in activity factors (e.g., device counts) are not included. Uncertainties associated with whether regional or national averaging is performed are included in the uncertainty estimate (*SI Appendix, section S5.4*).

[¶]Sampling in this work included compressors on well sites, but not all gathering compressors. Well site and gathering compressors are combined in the national inventory. Range reported for national inventory for equipment leaks and "other" sources reflect uncertainty in attributing compressor emissions from national inventory to a specific source category.

[#]Uncertainty bound assumes uncertainties for completion flowbacks, pneumatic pumps and controllers and leaks are independent, and consequently, the combined uncertainty is the square root of the sum of the squares of the individual uncertainties.

^{**}US total gross gas production (oil and coal bed, gas, and shale, onshore and offshore): 547,000 Gg.

Emissions for equipment on well sites, in routine production, that were targeted for measurements had much narrower uncertainty bounds than well completion flowbacks or well unloadings. Emissions from pneumatic chemical injection pumps measured in this work averaged 3.7 ± 1.6 g of methane per minute per pump, 9% lower than the EPA emission factor (*SI Appendix, section S2*). Intermittent and low bleed pneumatic devices measured in this work averaged 5.9 ± 2.4 and 1.7 ± 1.0 g

Table 3. Measurement methods used in the study

Source	Direct measurement methods	Mobile downwind sampling
Well completions	Measurements from flowback tanks made by using enclosures and temporary stacks with measurements of flow rate and composition	Downwind tracer ratio methods: Metered release of C ₂ H ₂ and N ₂ O on site and downwind measurements of methane to C ₂ H ₂ and methane to N ₂ O concentration ratios
Gas well unloading	Temporary stack with measurements of flow rate and composition	
Well workovers	Measurements from flowback tanks made by using enclosures and temporary stacks with measurements of flow rate and composition	
Production sites	Infrared (FLIR) camera surveys of sites and flow rate measurements using a HiFlow device	Metered release of C ₂ H ₂ and N ₂ O on site and downwind measurements of methane to C ₂ H ₂ and methane to N ₂ O concentration ratios

of natural gas per device per minute, 29% and 270% higher than EPA emission factors, respectively (*SI Appendix, section S2*). No high bleed pneumatic devices were identified at the sampling sites, and the average emission rate for the population of pneumatic controllers sampled in this work was 3.36 ± 0.65 g of methane per min (3.8 ± 0.69 g of natural gas per min). Equipment leaks measured in this work averaged 1.23 ± 0.44 g of methane per minute per well, which can be compared with an EPA estimate of potential emissions (no regulatory or voluntary emission reductions) of 1.37–1.67, derived from EPA's inventory for similar equipment types (wellheads, separators, heaters, meters/piping, and dehydrator fugitives), with the range reflecting whether small compressors are added to the comparison (*SI Appendix, section S5*). Comparing to net emissions is challenging because EPA does not assign emission reductions to specific equipment categories. Additional information is provided in *SI Appendix*.

There was significant geographical variability in the emissions rates from pneumatic pumps and controllers, but these regional differences were not as pronounced for equipment leaks. Emissions per pump from the Gulf Coast are statistically significantly different and roughly an order of magnitude higher than from pumps in the Midcontinent. Emissions per controller from the Gulf Coast are highest and are statistically significantly different from controller emissions in the Rocky Mountain and Appalachian regions. Emissions per controller in the Rocky Mountain region are lowest and an order of magnitude less than the national average (*SI Appendix*).

Implications for National Emission Estimates. If the average emissions reported in this work for well completion flowbacks, pneumatic devices, and equipment leaks are assumed to be representative of national populations and are applied to national counts of completions, pneumatic devices, and wells in EPA's national inventory, emissions from these source categories would be calculated as 957 Gg (with sampling and measurement uncertainties estimated at ± 200 Gg), compared with 1,211–1,250 Gg methane per year in the 2011 EPA national inventory (1) for the same source categories. A large emissions decrease associated with completion flowbacks is partially offset by emission increases from pneumatic controllers and equipment leaks. Reasons for these differences are described in *SI Appendix*.

The estimated uncertainty in the national emission estimates based on this work is $\sim 20\%$ (200 Gg). The sources of uncertainty include measurement uncertainty, uncertainty introduced by the selection of sites, and uncertainty due to choices in performing regional or national averaging of equipment counts and emission factors. These components of the quantified uncertainty are described in *SI Appendix*. The uncertainty estimate does not

include factors such as uncertainty in national counts of wells or equipment and the issue of whether the companies that provided sampling sites are representative of the national population.

The 957 ± 200 Gg in emissions for completion flowbacks, pneumatics, and equipment leaks, coupled with national inventory estimates for other categories, leads to an estimated 2,300 Gg of methane emissions from natural gas production (0.42% of gross gas production). A summary is provided in Table 2, and details of the calculations are available in *SI Appendix*.

Total emissions estimated based on measurements in this work (2,300 Gg) are comparable with the most recent EPA national GHG inventory (2,545 Gg in the 2011 inventory, released in April 2013) (1). Table 2 also compares emissions in specific source categories, estimated based on the measurements made in this work, to EPA estimates of the same categories in the national inventory (1). For some emission categories, such as completion flowbacks and pneumatic controllers, conclusions can be drawn from the comparisons. Specifically, measured emissions from completion flowbacks are roughly 600 Gg lower than the completion flowback emissions in the current inventory; measured emissions from pneumatic controllers are 150–500 Gg higher than in the current inventory. For other emission categories, such as equipment leaks and pneumatic pumps, however, drawing conclusions is more difficult. For these source categories, the national inventory reports potential emissions for each category, but aggregates emission reductions, creating uncertainty in the net emissions in these categories (see *SI Appendix, section S5.5* for more details).

It should also be noted that the national inventory has changed in recent years based on evolving regulations (21) and understanding of emission sources. In this work, comparisons are made to the most recent release of the inventory (2011 final version, released in April 2013) and back casts to previous years by using consistent calculation methodologies. Emissions were estimated as 2,545 Gg in 2011, compared with 2,948 Gg in 2009 and 2,724 Gg in 2010. The work presented here suggests practices such as combusting or capturing emissions from completion flowbacks, as required by New Source Performance Standards subpart OOOO and the revised National Emission Standards for Hazardous Air Pollutants subpart HH (21), are resulting in reduced methane emissions. Other source categories require more data to produce national emission estimates, and adjustments in the inventory may emerge as more emission measurements are performed. Emission estimates may be adjusted downward if workovers with hydraulic fracturing are found to have emissions per event that are similar to completion flowbacks and may be adjusted either upward or downward as more emissions data are collected for liquids unloading or pneumatic devices.

Finally, an emissions intensity of 0.42% is reported in Table 2. The intensity expresses a methane emission per unit of gross gas production. This intensity should be interpreted with caution, because it includes only production operations and implicitly attributes all methane emissions from natural gas wells to natural gas production, although natural gas wells produce substantial amounts of natural gas liquids and oil. The intensity is reported here because it facilitates comparisons with other analyses that have appeared in the literature (23).

Methods

Multiple independent and complementary techniques were used to measure methane emissions. The primary procedures involved direct measurements of CH_4 emissions at their source. A variety of different procedures were used for direct source measurements, depending on the type of source being sampled and the type of natural gas production equipment being used. Table 3 summarizes the direct source methods used in the study; detailed descriptions of the methods are provided in *SI Appendix*.

In addition to direct source measurements, tracer ratio measurements, designed to estimate the total methane emissions from a site, were made at 20% of the well completion flowbacks and 13% of the production sites. The tracer release method was developed in the 1990s to quantify methane emissions from a wide range of natural gas system components (24, 25). Sites for tracer releases were selected for their steady, moderate winds and downwind access. Measurements for sites without downwind access could not be made. Table 3 also summarizes these measurement methods, which are described in detail in *SI Appendix*. In brief, tracer compounds were released at a known rate on-site; downwind measurements of methane (minus

background) and the tracer (minus background) were assumed to be equal to the ratio of emission rates, allowing methane emissions to be estimated. These measurements were performed for a subset of the sampling locations that had relatively open terrain and steady winds, producing well-defined emission plumes downwind of the sites. The tracer studies allowed for an independent measurement of emissions that were also measured by using direct source methods. For completion flowbacks, emission estimates based on the downwind measurements were generally within a factor of 2 of the direct source measurements, supporting the conclusion that emissions from completion flowbacks are roughly 97% below the most recent national estimates and that emissions from completion flowbacks without methane control or recovery equipment, observed in this work, are well below the average potential emissions in current national inventories (1). For the production sites, emissions estimated based on the downwind measurements were also comparable to total on-site measurements; however, because the total on-site emissions were determined by using a combination of measurements and estimation methods, it is difficult to use downwind measurements to confirm the direct source measurements. Tracer study results are summarized in *SI Appendix*.

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3.0 Point Source Testing

ERG subcontracted the point source testing task to Sage Environmental Consulting LP (Sage). This section discusses how the point source testing task was conducted and the results that were obtained.

This section has seven sub-sections:

- 3.1 Introduction – Provides a summary of the purpose of the point source study, the scope of work, and the project timeline.
- 3.2 Point Source Survey Sampling Equipment – This section describes the field instrumentation.
- 3.3 Point Source Survey and Sampling Procedures – This section discusses survey procedures, documentation of emission points, the collection of emission data, canister sampling, and data archival procedures.
- 3.4 Emissions Calculation Procedures – The development of canister-derived emissions, the application of correlation equations, the creation of surrogate tank and non-tank emissions profiles, the use of EPA default-zero emissions factors, the use of engine emissions tables, and the calculation of Screening Emissions Factors are discussed in this section.
- 3.5 Point Source Emissions Results – The results of the point source study are provided in the charts and tables of this section.
- 3.6 Quality Control (QC) Results – This section contains the results of the QC procedures specified in the Final Point Source Test Plan including instrument calibration checks, canister sample collection procedures, and laboratory analytical checks.
- 3.7 Point Source Testing Conclusions – This section presents conclusions of the point source testing task.
- Appendix 3-A: Emissions summary for each point source site surveyed.
- Appendix 3-B: Two DVD discs containing the emissions calculation workbook, “MASTER - Well Char Emission Data 2011-07-13_FINAL” together with the data collected for each point source site.
- Appendix 3-C: One DVD containing the canister sample logbooks and the canister analytical results, the laboratory quality control results and the canister chain-of-custody documentation.

3.1 Introduction

The purpose of the point source emissions study was to characterize emissions from natural gas-related point sources located within the Fort Worth city limits. These sources are categorized in seven groups:

- Well Pads – Comprising the largest group of sites visited, natural gas well pads typically contained several active wells, produced water storage tanks, separators, and

- metering runs (piping). Approximately one-third (123) of the well pads also had lift compressors used to increase a well's gas production rate. Emission sources typically related with well pads include equipment leaks, produced water and condensate storage and loading, and lift compressors. The amount of condensate production and related emissions are usually dependant on whether the produced gas is wet or dry gas.
- **Compressor Stations** – Compressor stations contain one or more large (generally 250 horsepower (hp) or greater) line compressors which provide the necessary pressure to move the natural gas through many miles of transmission lines. The most significant emissions from compressor stations are usually from combustion at the compressor engines or turbines. Other emissions sources may include equipment leaks, storage tanks, glycol dehydrators, flares, and condensate and/or wastewater loading. None of the compressor stations visited included turbines.
 - **Processing Facilities** – Processing facilities generally remove impurities from the natural gas, such as carbon dioxide, water, and hydrogen sulfide. These facilities may also be designed to remove ethane, propane, and butane fractions from the natural gas for downstream marketing. Processing facilities are usually the largest emitting natural gas-related point sources including multiple emission sources such as, but not limited to equipment leaks, storage tanks, separator vents, glycol dehydrators, flares, condensate and wastewater loading, compressors, amine treatment and sulfur recovery units. The Processing Plant visited included most of these sources except for sulfur recovery units.
 - **Saltwater Treatment Facility** – The single saltwater treatment facility permitted for operation within the City's boundaries uses underground injection to dispose of well production liquids such as oilfield brine, drilling mud, fracture materials, and well treatment fluids. Emission sources typically related with salt water treatment facilities include equipment leaks, storage tanks, and generators.
 - **Drilling Operation** – Drilling of a new well is typically a two to three week process from start to finish and involves several large diesel-fueled generators. Other emission sources related to drilling operations may include equipment leaks and waste storage.
 - **Fracking Operation** – Fracking is the high pressure injection of water mixed with sand and a variety of chemical additives into the well to fracture the shale and stimulate natural gas production from the well. Fracking operations can last for several weeks and involve many large diesel-fueled generators. Other emission sources related to fracking operations may include equipment leaks and waste storage.
 - **Flowback** – Flowback is a well completion activity that occurs following the conclusion of a fracking operation. Flowback thus entails the removal of fracking fluids from the well in preparation either for a subsequent phase of treatment or for cleanup and returning the well to production. Similar to fracking operations, other related emission sources may include equipment leaks and waste storage.

The point source teams surveyed a total of 388 sites (including repeat visits at two sites). The sites are identified by owner and type in Table 3.1-1. Figure 3.1-1 locates each site on an overlay map of Fort Worth. Figure 3.1-2 indicates which well pads were considered to be wet gas, and which were considered to be dry gas. For purposes of this study, a site was considered to be a wet gas site if it produced more than 1 barrel of condensate/day as indicated by the Texas Railroad Commission records.

Key Point: Sites Surveyed

This study included surveying a total of 388 sites comprised of well pads, compressor stations, processing facilities, a salt water treatment facility, drilling operations, fracking operations, and completion operations.

The point source emissions survey occurred in two phases. Phase I was completed in the fall of 2010 (August 30 – October 21, 2010). Phase II took place during the beginning months of 2011 (January 4 – February 16, 2011). There were no significant differences in methodology or scope between the two phases. Any slight differences between the methodologies are discussed below. During Phase I, 199 point source sites were surveyed and are identified using Point Source ID's PS-001 through PS-201. An additional 189 sites were completed in Phase II and are identified as Point Source ID's 6 through 487.

Quality Control results indicate that the field and the laboratory equipment were in a state of control during the point source survey and that project quality control checks were followed. Site-by-site emission summaries are provided in Appendix 3-A of this report. Appendix 3-B provides the field data and emission calculation workbook on two DVD discs. Appendix 3-C contains the canister analytical data on one DVD disc.

3.2 Point Source Emissions Survey Sampling Equipment

The point source surveys were carried out by two teams of two persons each. In Phase I each team was staffed by a Sage employee and an employee from Hicks & Co. Environmental (Hicks). This changed in Phase II to one team of two Sage employees while the other team remained a Sage and a Hicks employee. The point source teams were equipped with the following test equipment:

- FLIR™ Infrared (IR) Camera.
- Thermo Environmental™ Toxic Vapor Analyzer.
- Bacharach™ Hi Flow Sampler.
- Summa Passivated Stainless Steel Canisters from TestAmerica™.
- Miscellaneous Support Equipment (Global Positioning System (GPS) Finder, Laser Distance Finder, Weather meter, Digital Camera).

Table 3.1-1. Point Source Sites by Owner and Type

Owners	Well Pad	Compressor Station	Processing Facility	Saltwater Treatment Facility	Drilling Operation	Fracking Operation	Completion Operation (Flowback)	Total
Burnett Oil Production	2							2
Chesapeake Operating Inc.	84 ^a	2		1				87
Crosstex			1					1
Crow Creek Operating Inc	3							3
Devon Energy Production Co	105							105
Eagle Oil And Gas	1							1
Encana Oil & Gas (USA) Inc	18 ^b							18
Finley	2							2
Frost Brothers	2							2
Grand Operating Inc	1							1
Lakota Energy LTD	1							1
Newark Energy	1							1
Proven Resources	3							3
Quicksilver Resources	28	1				1	1	31
Range Production Co	16	3						19
Vargus Energy LTD	1							1
Williams Production	5							5
XTO Energy Inc	102	2			1			105
Grand Total	375	8	1	1	1	1	1	388

^a Includes repeat visits to the same site i.e., Site IDs: PS-192 and 294.

^b Includes repeat visits to the same site i.e., Site IDs: PS-086 and 260.

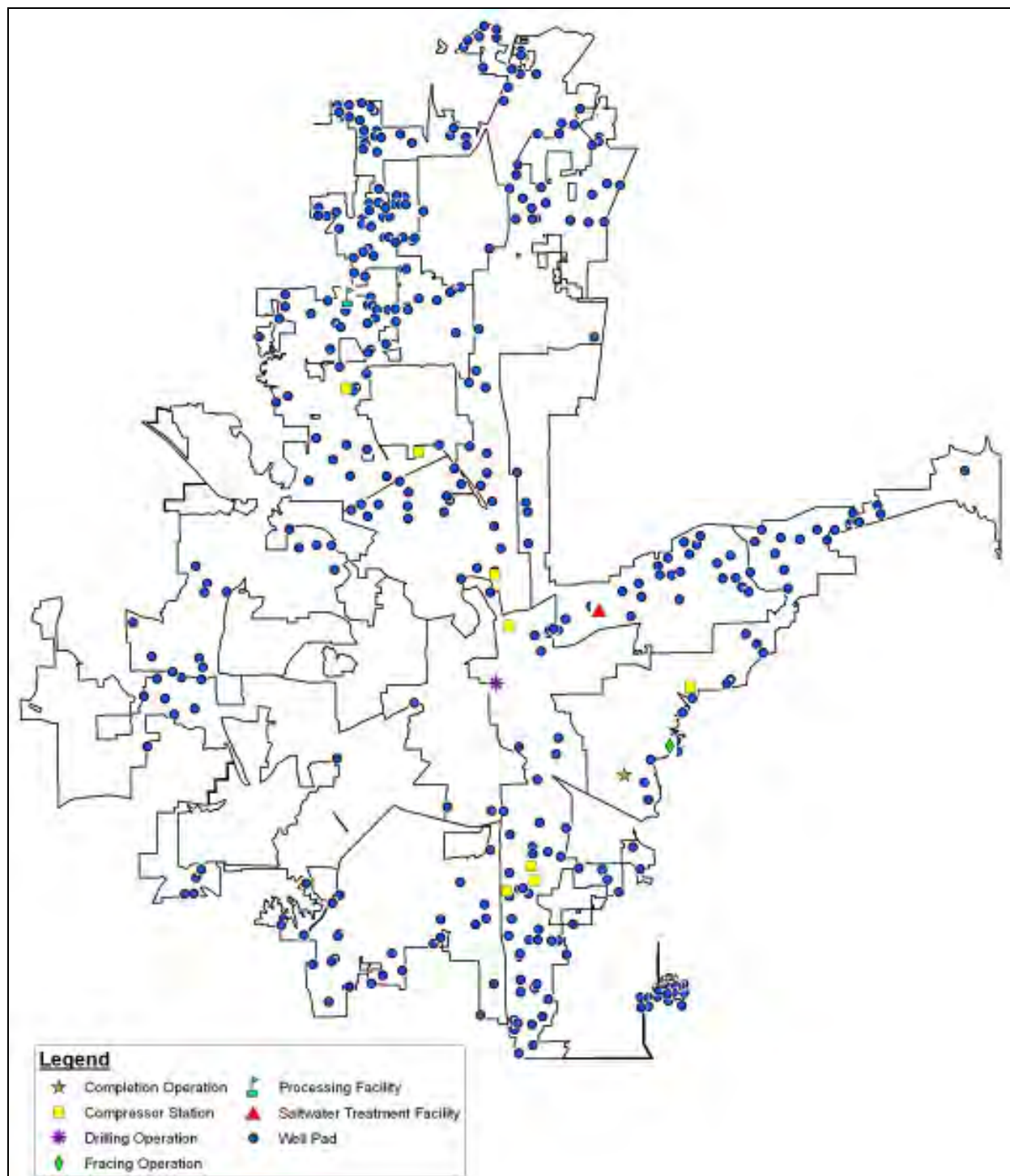


Figure 3.1-1. Point Source Survey Sites (August 2010 – February 2011)

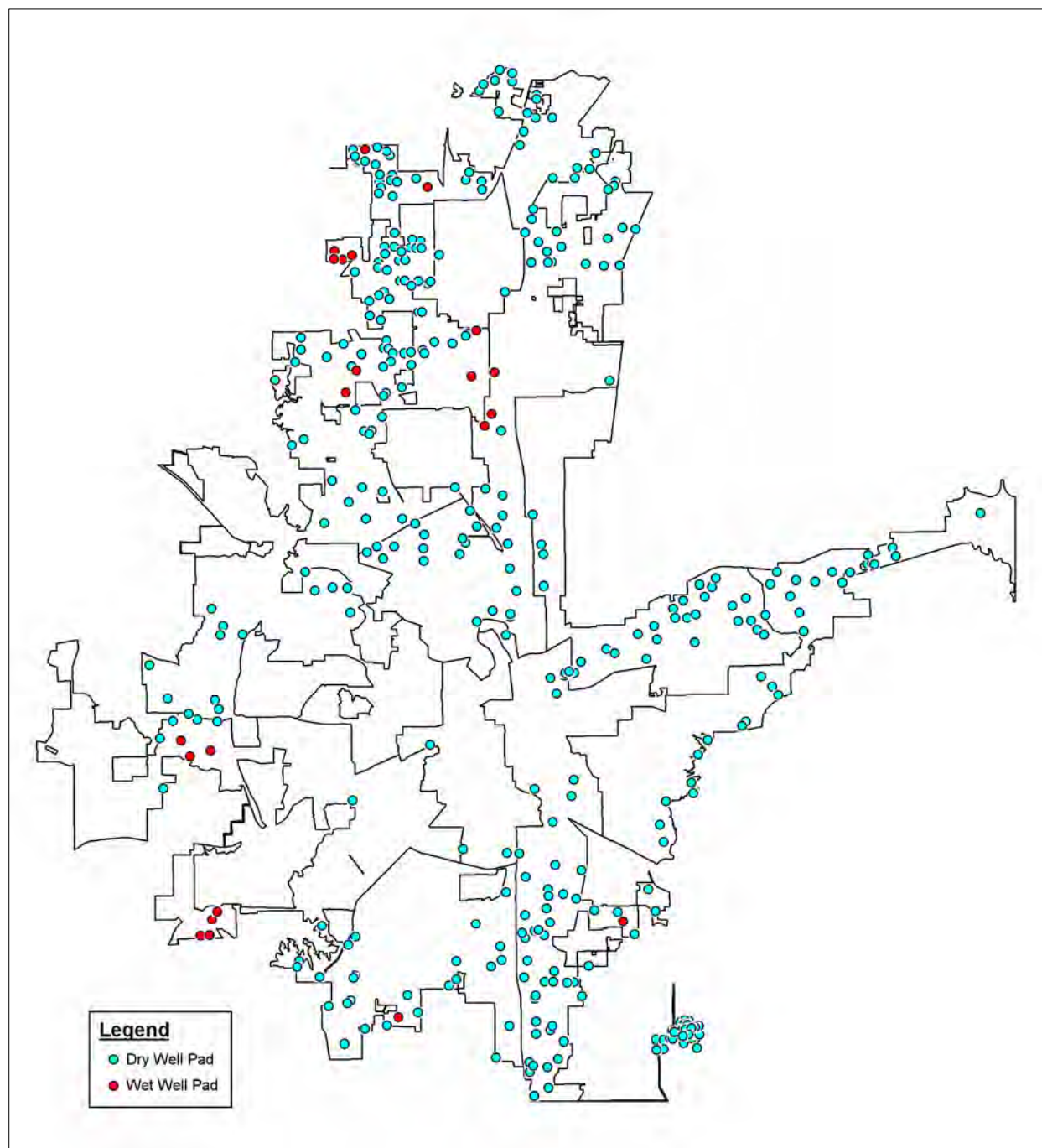


Figure 3.1-2. Wet Gas and Dry Gas Well Pads

3.2.1 The FLIR™ Infrared Camera

FLIR™ infrared cameras were used to survey all equipment in natural gas service at each point source site visited. The IR camera enables rapid detection of large emission sources (for instance, sources with concentrations > 10,000 parts per million by volume (ppmv)). Moreover, the infrared camera is well suited to detecting methane emissions, the largest constituent of

natural gas, as well as ethane, propane, and butane. Figure 3.2-1 illustrates the use of a FLIR™ infrared camera at a well site.



Figure 3.2-1. IR Camera Imaging at a Well Site

Two models of infrared camera were used on this project. One team used the GasFindIR™ camera equipped with a 50 mm lens and an external COWAN™ video recorder. The second team used the FLIR™ Model GF-320 infrared camera. While the two cameras share identical performance characteristics, the GF-320 has more user-friendly features (such as built-in video recorder and digital camera). All infrared camera imaging was performed by trained Level 1 or Level 2 Thermographers.

3.2.2 The Toxic Vapor Analyzer (TVA)

The TVA is a portable, battery-powered, intrinsically safe, hydrocarbon analyzer with a measurement range extending from 0.5 ppmv (parts per million by volume) to 50,000 ppmv hydrocarbon. This instrument was used to screen a random selection of site valves and connectors for leaks below the detection limit of the IR camera. It was also used to measure emissions detected with the camera, although in most cases these measurements resulted in a “flame-out” of the analyzer (that is, a reading greater than 50,000 ppmv). Figure 3.2-2 illustrates the use of a TVA at a well site.

Key Point: IR Camera and TVA Detection Limits

The Infrared camera is typically used to detect large emission sources at concentrations >10,000 ppmv whereas the TVA can detect emissions with concentrations as low as 0.5 ppmv.



Figure 3.2-2. Method 21 Screening with the TVA at a Well Site

Use of the TVA followed EPA Method 21 procedures (40 CFR 60 Appendix A), which prescribes how to screen various components for fugitive emissions. Each TVA was calibrated daily prior to use with methane-in-air calibration standards.

3.2.3 The Hi Flow Sampler

The Hi Flow Sampler is a portable, intrinsically safe instrument designed to measure the rate of gas leakage around various pipe fittings, valve packings and compressor seals found at natural gas facilities. Because of its high flow rate (8 to 10 standard cubic feet per minute (SCFM)) the Hi Flow Sampler is able to completely capture any gas emitting from a component. The rate of the gas leak is determined by accurately measuring the flow rate of the sampling stream and the natural gas concentration. Figure 3.2-3 illustrates the sampling of a tank vent with the Hi Flow sampler.



Figure 3.2-3. Sampling a Tank Vent with the Hi Flow Sampler

To make an emission measurement with the Hi Flow Sampler, an attachment is chosen that is suitable for capturing the entire leak. An assortment of attachments are available to enable testing of a wide variety of components. For instance, for thief hatches or tank vents, a large nylon bag attachment was used. A plunger-style attachment was used to enclose small valves. Flanges were enclosed with a plastic strap and secured with Velcro™. For equipment that could not be enclosed with the standard Hi Flow Sampler attachments, plastic wrapping was used. With one end of the attachment enclosing the emission source and the other end attached to the instrument's main sampling hose, the Sampler was switched on and sampling initiated using the menu options available through the unit's controller. An entire Hi Flow Sampler test run lasted approximately 3 to 5 minutes.

For the point source surveys the Hi Flow Sampler was operated in its Automatic 2-Stage Mode, performing a leak rate measurement first at a high flow rate setting for one minute, and then automatically switching to a lower flow rate for a second minute of additional sampling. The unit calculated the degree of comparison between two measurements and displayed the total sample flow rate in cubic feet per minute (CFM) and the leak as percent methane and as the percent of the sample flow rate (% CFM).

3.2.4 Summa Canisters

Evacuated, six-liter, canisters provided by TestAmerica's™ Austin, Texas laboratory, were used to collect gas samples from selected emission points for VOC and HAP analysis by Gas chromatograph/Mass spectrometer (GC/MS) and for methane analysis by gas chromatography with a thermal conductivity detector (TCD). Canisters were shipped to the field office in a pre-cleaned, evacuated condition. Completed canisters were returned within several days of sample collection, together with chain-of-custody documentation, to TestAmerica™ for analysis. Unused canisters were kept securely stored in the project field office. Figure 3.2-4 illustrates how a canister sample was collected from the exhaust port of the Hi Flow Sampler.



Figure 3.2-4. Collecting a Canister Sample from the Exhaust Port of the Hi Flow Sampler

3.2.5 Miscellaneous Equipment

In addition to the equipment described above the point source teams also employed:

- A GPS receiver to document a site's North and West coordinates.
- A Kestrel Weathermeter™ to measure wind speed, temperature, relative humidity, and barometric pressure during a site visit.
- A laser distance finder to measure heights of emission points.
- An Archer™ field computer to record site data.
- A digital camera for site and equipment photos.

3.3 Point Source Survey and Sampling Procedures

This section discusses pre-test equipment preparation, site survey procedures, and data retrieval/archiving activities. The point source survey and sampling procedures followed were consistent with the Point Source Test Plan previously submitted and approved by the City of Fort Worth. Any deviations from this plan are discussed in the following sections as applicable.

3.3.1 Pre-Test Equipment Preparation

Equipment was prepared for use each morning prior to the first site visit. Preparations included:

- The IR Camera Daily Demo.
- A calibration check of the Hi Flow Sampler.
- A multipoint calibration of the TVA.

IR Camera Daily Demo Quality Assurance Check

The IR Camera Daily Demo provides a validation of the camera's operation by releasing a known mass emission rate of gas (100% propane) and measuring the distance from which the release can be reliably viewed. This validation was performed first thing each morning with both cameras at two mass emission rates: a low emission rate of 10 grams/hour propane and a higher emission rate of 31 grams/hour propane. The distance from which each emission rate could be detected (i.e. sighting distance) was recorded, together with wind direction, wind speed, temperature, relative humidity, barometric pressure, and percent cloud cover information. The equipment used to perform the daily demo included a steel compressed gas cylinder of 100% propane gas, a single stage gas regulator, a calibrated rotameter, flow control valves and tubing to position the emission flow at eye-level. The results of the daily demos are provided in Section 3.6 of this report and further documented in the field log notes included in Appendix 3-B.

Calibration Check of the Hi Flow Samplers

The Hi Flow Sampler contains two sensors – a background sensor and a leak sensor. Both sensors were calibrated at the start of Phase I and at the start of Phase II using certified standards of 2.5% methane-in-air and 100% methane. On a daily basis, prior to testing, the background and leak sensors of each Sampler were calibration-checked with the 2.5% methane standard. If an error greater than 10% resulted, the instrument was re-calibrated. Each Monday, the background and leak sensors of both instruments were calibration-checked with both the 2.5% and the 100% methane standards. Again, errors above 10% required re-calibration of the instrument.

The results of the Hi Flow Sampler daily calibration checks are provided in Section 3.6 of this report and further documented in the field log notes included in Appendix 3-B.

Multipoint Calibration of the TVAs

A multipoint calibration of each TVA was performed daily prior to testing with the following gases:

- Zero gas (<0.1 ppmv total hydrocarbon).
- Low Level Span gas (nominally 500 ppmv methane-in-air).
- Mid Level Span gas (nominally 1,000 ppmv methane-in-air).
- High Level Span gas (nominally 10,000 ppmv methane-in-air).

Following the calibration, each TVA would be re-checked with the same gases. The instrument was considered to be in a state of control if its response to each gas was accurate to within +/- 10%. Failure to meet this criterion required recalibration, repair, or replacement of the instrument.

3.3.2 Final Preparations

Following the instrument performance checks, data from the previous day would be reviewed for completeness and accuracy, the City Chief Gas Inspector would be called with the addresses of the first sites to be visited, and the vans would be loaded with the instrumentation and canisters. There would be a brief group safety discussion, the field office would then be locked, and the each team would depart to the first of their assigned sites for the day.

KeyPoint: Random Site Selection

To reduce bias in the survey relative to owner, operator, location, or any other variable, sites were selected for surveying on a random basis.

Sites were selected for surveying on a random basis. During the day, City Gas Inspectors were only told of the next scheduled site upon departure. These procedures were followed to avoid the possibility of site owners learning of the survey schedule in advance.

3.3.3 Site Arrival

Upon arrival at the designated point source site, the survey team met with the City Gas Inspector who unlocked the site gate to allow entrance to the site. On no occasion did the team enter a site without the City Gas Inspector also being present. Customarily at this time, a picture was taken of the front gate signage as part of the site documentation (Figure 3.3-1 shows an example of front gate signage).



Figure 3.3-1. Front Gate Signage

Immediately after arrival, a brief safety screening of the site would be conducted with the TVA to avoid entering an area of potentially dangerous pollutant concentrations.

One objective of each point source site visit was to document important site parameters such as the number of wells, storage tanks, and compressors, the site's GPS coordinates, the site's Railroad Commission (RRC) postings, and site throughput. Much of this information would be collected on preformatted data forms at the start of the survey. The use of preformatted forms helped to ensure a consistent data collection effort between the two teams as well as between sites. Figure 3.3-2 illustrates the site characterization form on which much of this information was recorded. In the "SITE LAYOUT" section of the form a sketch illustrating the positions of all major pieces of equipment would be drawn. All forms completed during the site surveys are included in Appendix 3-B.

SITE CHARACTERIZATION FORM	
TEAM:	
SITE ID:	
OWNER:	
ADDRESS:	
DATE:	
ARRIVE:	
DEPART:	
RRC:	
THRUPUT (MCF):	
GPS: North	
GPS: West	
#WELLS	
#VALVES	
#CONNECTORS:	
#TANKS:	
#COMPRESSORS:	
OTHER EQUIP:	

SITE PHOTOS	
Picture ID	Description

COMPRESSORS						
ID#	Use (Lift/Line)	Type (NG-D-E)	Manufacturer	Model	HP	Duty Cycle (%)

SUMMARY:	
#M21 Valves:	
#M21 Connect.	
#M21 500 ppm	
# HiFlows	
#IRs	
# Canisters	

SITE LAYOUT:	

NOTES:	

Figure 3.3-2. Point Source Site Characterization Form

3.3.4 IR Camera Survey

The IR camera survey of a site began with the thermographer starting at one end of the site and working his way in logical fashion to the opposite end so that all equipment was surveyed. In a typical route, for instance, the thermographer would begin at the well pads, carefully surveying all of the valves and connectors associated with each well. From the well pads he would proceed to the compressor if one was present. Next, he might image the metering run and from there proceed to the piping and separators inside the tank battery. Finally he would finish the survey with a careful imaging of each storage tank, climbing up the stairs to the tank walkway in order to view each thief hatch and pressure relief valve (PRV) vent line. Depending on circumstances, such as the size and amount of equipment on the site and the number of

detected emission points, an IR camera site survey of a typical well pad might last from one to several hours.

When an emission was detected with the IR camera, a video recording of the IR imaging would be made, a photograph of the emission source would be taken and the following data documented:

- Date and time.
- Equipment description and size.
- Emission point height above ground (feet).
- GPS coordinates of emission point (Phase II only).
- Sighting distance (feet).
- TVA reading of emission (ppmv).
- Tank height and radius if tank emission (feet).
- Video file name.
- Maximum sighting distance (feet) – The maximum sighting distance is the distance from which the emission can be reliably detected with the IR camera and provides a measure of the emission's magnitude (i.e. large emissions can be detected from further away).
- Weather conditions (Wind Direction, Wind Speed, Temperature, Relative Humidity, Barometric Pressure, and Cloud Cover).

As standard practice, the thermographer would image equipment from different angles. This is necessary since environmental conditions such as sunlight, wind, and background (i.e. air, piping, concrete or heat profiles) can cause an emission stream to be difficult to see from one angle, but easily detected from another.

With the GasFindIR™ camera integration settings would be switched to enable viewing of very hot surfaces (typically found at compressors), manual mode would be used on occasion to verify the absence or presence of a subtle emission, and “nuking” would be employed as required to eliminate optical background noise. Nuking adjusts the GasFindIR's background so that a more uniform pixel response is obtained.

With the GF-320 camera the thermographer would frequently shift to High Sensitivity mode to confirm or detect a more subtle emission that was hard to see. All field data forms, digital photographs and videos are provided in electronic form in Appendix 3-B.

3.3.5 Method 21 Site Survey with the Toxic Vapor Analyzer

While one team member conducted the IR camera site survey, the second member calculated the total number of site valves and connectors. This was done by first determining the valve count and then applying a multiplying factor to arrive at the number of connectors. For this

project, a connector multiplier of 7 was conservatively used, based upon detailed connector counts performed at the beginning of both Phase I and Phase II. Thus if it was determined that a site contained 245 valves, then a connector count of 1,715 (7×245) was assumed. The 7:1 connector to valve ratio held true for all equipment except at compressor skids where a higher ratio was often noted. Consequently the number of connectors at compressor skids was estimated separately by multiplying the number of compressor valves by factors ranging from 10 to 15, depending on the size and complexity of the compressor.

These component counts were necessary since one objective of the point source testing was to estimate low level emissions (i.e. emissions below the detection limits of the IR camera) from fugitive equipment leaks. This objective was accomplished by screening at least ten percent of the valve and connector population at each point source site with the TVA. Thus while the IR camera survey was in progress, Method 21 screening of the site's valves and connectors was performed with the TVA on one of every ten valves and one of every ten connectors until ten percent of the total valve and connector counts was reached. This procedure ensured that the required number of components was screened and that the screening population was evenly distributed across all areas of the site. This screening was conducted independent of the IR camera survey. Once it was completed, the TVA was then used to screen any emission points identified by the IR camera.

Key Point: Method 21 Screening

To estimate low level emissions from fugitive equipment leaks, at least 10% of the valve and connector population at each site surveyed was screened.

Following Method 21 procedures, valves were screened at their three primary leak areas: the stem, the packing, and the bonnet flange. Method 21 screening entails placing the TVA's probe at the various leak interfaces and sampling the complete circumference. Flanges were screened by placing the TVA probe at the edge of the flange-gasket interface. Connectors were screened by sampling the circumference of the threaded sections. All other components were monitored through a peripheral traverse of the seal interface. Whenever an elevated reading was obtained the sample probe was left at this elevated point for at least twice the instrument's response time (i.e. at least for 8 seconds) to ensure that the maximum concentration was measured.

When an emission at or above 500 ppmv was detected with the TVA the following data would be recorded:

- Date and time.
- Screening concentration (ppmv).
- Equipment Description.
- Equipment Location (GPS coordinates in Phase II only).

3.3.6 Hi Flow Sampler Emissions Testing

The Hi Flow Sampler, as discussed previously, provides a quick and effective means of quantifying emissions by sampling at a high enough flow rate to capture all the emissions escaping from a component. By accurately measuring the flow rate of the sample stream and the natural gas concentration within the stream, the instrument is able to determine the gas leak rate expressed both as percent methane and percent CFM. When this data is combined with canister analytical data, mass emission rates for individual compounds can be calculated as explained in Section 3.4.

Hi Flow Sampler testing was conducted at all emission points identified with the IR Camera (high level emissions) as well as at each emission point identified through Method 21 screening with a concentration ≥ 500 ppmv (low level emissions). A number of low level emissions in Phase I were below the detection capability of the Hi Flow Sampler. Emissions from these points have had to be subsequently estimated. In Phase II this was remedied by sampling the exhaust stream of the Hi Flow Sampler with the TVA and using the resulting TVA concentration to calculate the low level emission rate.

The following data was documented for each Hi Flow Sampler test:

- Date and time.
- The percent difference in leak rate between the sample flow rates.
- Total sample flow (CFM).
- Background concentration (%).
- Leak rate as % methane (% CH₄).
- Leak rate as % of total sample flow (% CFM).

3.3.7 Canister Sampling

As documented in the Point Source Test Plan, it was originally intended that a canister sample be collected at each emission point identified by the IR camera. However, as Phase I testing commenced, it became apparent that the sampling teams were observing an unexpectedly high frequency of camera-detected emission points. Therefore,

an alternative canister sampling strategy was needed; neither the project budget nor laboratory resources would be able to keep up with the canister demand otherwise. A revised canister sampling plan was developed and subsequently approved by the City of Fort Worth. The revised canister sampling plan was based upon three criteria.

Key Point: Canister Sampling

164 canister samples were collected throughout Fort Worth during the study. Data obtained from the 164 canister samples were used to develop surrogate canister emission profiles and correlation equations to characterize emissions from those points not directly sampled.

A canister sample would be collected from an emission point only if:

1. The % CFM reading obtained with the Hi Flow Sampler from that point exceeded the daily rolling average % CFM for all Hi Flow Sampler tests conducted thus far. In other words, the emission rate had to equal or exceed the average emission rate. The average emission rate was originally expressed as the rolling average of the third quartile % CFM; this was later changed to the rolling average % CFM.
2. Less than three canister samples have been collected from a similar component at other sites.
3. Less than three canister samples had been collected in the general geographical region. Geographical regions will be defined as the north, east, south, and west quadrants of the City of Fort Worth as well as any particular region in which the characteristics of the natural gas are substantially different from other regions (for instance, regions with wet gas and regions with dry gas).

If all of these conditions were not met, a canister sample was not collected. This approach succeeded in reducing the canister demand to a manageable level and was followed through the remainder of Phase I and through all of Phase II (a total of 164 canister samples were collected, not including 8 duplicate canister samples). Data obtained from these 164 canister samples were then used to develop surrogate canister emission profiles and correlation equations to characterize points for which no canister sample was taken.

Figure 3.3-3 provides a map of Fort Worth indicating the locations where canister samples were collected, as well as those locations where no samples were taken. As indicated in the map, the locations where canister samples were collected provide a well distributed characterization of canister samples. In other words, there were no large geographic locations in which there were no canister samples taken.

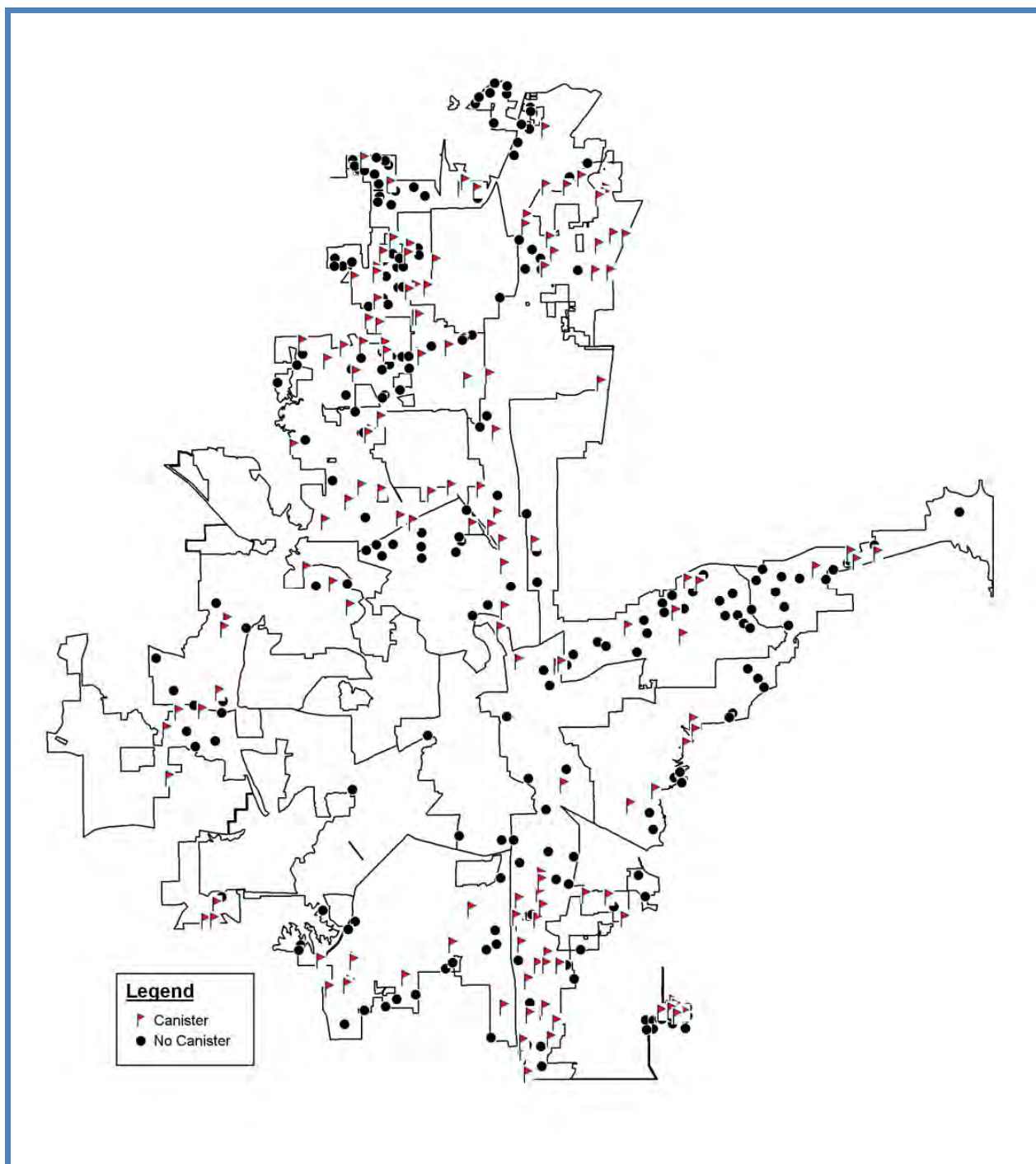


Figure 3.3-3. Canister Sample Locations

Whenever a canister sample was to be collected, the collection process followed specific protocols. A canister sampling manifold (Figure 3.3-4) consisting of a flow control valve and vacuum gauge was connected to the canister inlet port, and the canister's initial vacuum was checked. If less than 25-inches Hg vacuum was measured the canister was not used for sampling and was returned to the laboratory (this occurred only once).

To collect a sample, the canister's sample probe was directed into the exhaust port of the Hi Flow Sampler. Since it was possible, if the canister was opened very quickly, for the canister inlet flow to exceed the exhaust flow of the Hi Flow and thereby dilute the sample with ambient air, the sampling flow was carefully controlled. This was accomplished by adjusting the sample valve located upstream of the vacuum gauge (Figure 3.3-4) to ensure a slow but steady decrease in the canister vacuum. In practice, canister fill times were never less than 20 seconds and more typically, were between 30 seconds and 1 minute, far longer than the less than 2 second fill rate required to overcome the Hi Flow's exhaust rate.

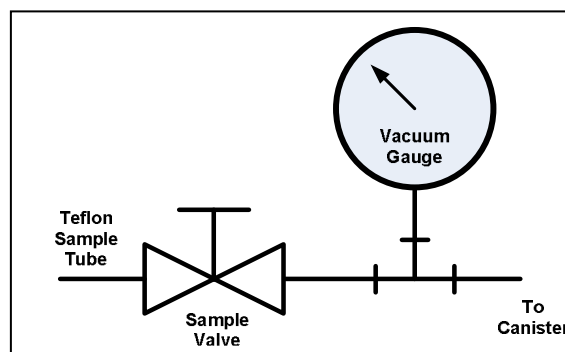


Figure 3.3-4. Canister Sampling Manifold

A canister was never filled completely but rather enough sample was collected to bring the canister vacuum up between 10 to 5 inches Hg. Following the collection of a canister sample the following data was documented both in a canister collection logbook and in the site's data form:

- Sample ID Number.
- Site Address.
- Date and Time.
- Initial Vacuum (inches Hg).

Similar information was also recorded on the canister's tag. Copies of the canister collection logbook entries are provided in Appendix 3-C.

3.3.8 Completion of the Site Survey

Following completion of the IR camera survey, the Method 21 screening, the Hi Flow Sampler testing of low level and high level emission points, and the canister sampling, the major equipment-containing areas of the site were documented both in photographs and with a site layout sketch. Figures 3.3-5, 3.3-6, and 3.3-7 provide typical examples of site photographs. Figure 3.3-8 illustrates a completed site layout sketch. Copies of all field data including site photos and site videos are provided in Appendix 3-B.



Figure 3.3-5. Site Documentation – Wells



Figure 3.3-6. Site Documentation – Tanks and Separators



Figure 3.3-7. Site Documentation – Lift Compressor

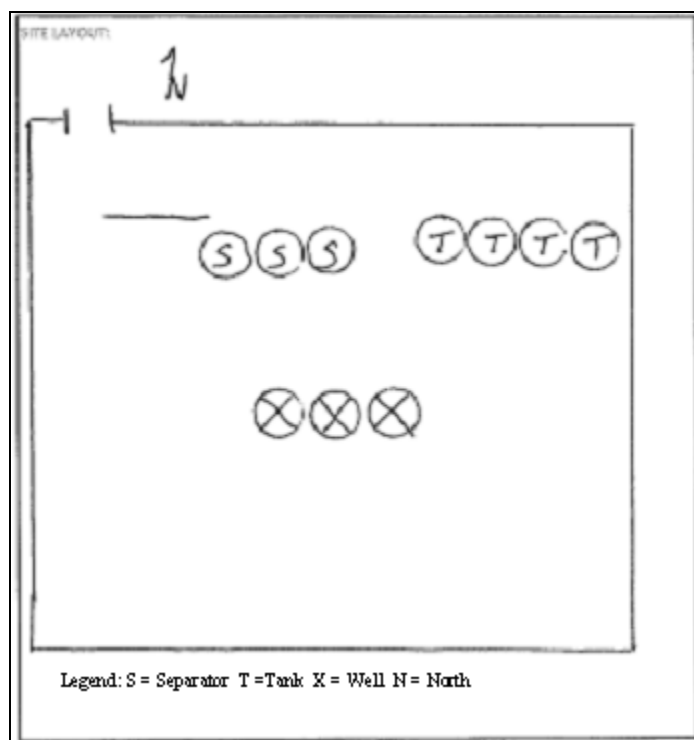


Figure 3.3-8. Example Site Sketch

Following this, the point source team prepared to depart from the site. The site data forms were checked for completeness and accuracy, any temporary flagging was removed the site's equipment, all well and tank battery gates were closed and secured, and the departure time was documented. The gas inspector was then told the address of the next site to visit, and the facility's main gate was locked behind the departing vehicles.

At the end of the day both teams returned to the field office where the equipment was off loaded from the project vans. Any canister samples taken that day were securely stored. The collected field data for that day was downloaded to a computer, printed out, and backed up.

Data archiving consisted of setting up separate computer site folders for the site's visited that day. Each folder was populated with the completed data forms, the site IR videos, and the site photos. Each team stored their data on the team computer and backed it up on dedicated hard drives. In addition, hardcopy printouts of the completed data forms were kept in large loose-leaf binders organized in chronological order. While one team member handled the data archiving, the other team member unloaded the van and prepared for the next work day. IR Camera, Hi Flow Sampler, TVA, digital camera and Archer data logger batteries were set up for overnight charging and facility field sketches were copied onto the printed out data forms. The completed data forms were quality control reviewed on a regular basis, either at the end of the day, the first thing the next day, or on the following weekend.

3.4 Emissions Calculation Procedures

This section describes the emissions calculation procedures used to derive a total emissions profile for each point source site. It is important to understand that for this study, not all of the site's emissions were calculated and/or characterized. For purposes of this study, in most cases, the emissions were calculated from only those sources in which emissions were detected and/or could be measured following the procedures described in the previous section. Hence, emissions were only estimated from piping and instrumentation equipment leaks, storage tanks, and compressors, which contribute the majority of emissions from natural gas-related facilities. Other sources of emissions, including but not limited to, storage tank breathing and standing losses, glycol dehydrator reboiler vents, wastewater and/or condensate loading, and flaring were not calculated. Non-routine emissions such as those generated during upsets or from maintenance, startup, and shutdown activities were also not measured or calculated as part of this study unless they were observed at the time of the site visit.

Annual emission estimates for each site were derived based on data obtained during the site visit and by assuming that conditions during the visit were representative of site conditions throughout the year. While it is important to note that emissions at any individual site can fluctuate depending on day-to-day operating and equipment conditions, the variation in emissions over the entire population were captured as a whole and are encompassed in this study as a result of breadth and depth of the point source testing and the use of surrogate emission profiles.

3.4.1 Well Pad, Compressor Station, Gas Plant, and Salt Water Disposal Facility Emissions

Total speciated emissions were calculated for each well pad, compressor station, gas plant and salt water disposal facility visited by the point source teams. These calculations fall into two categories: 1) Direct and 2) Indirect. Direct emission calculations were based upon the analytical results of the canister samples. Indirect emission measurements were derived from

several sources including the emission results from the canister sampling, correlation equations, calculated surrogate emission rates, EPA emission factors, and engine emission data for both natural gas and diesel powered engines. Each site's total emissions were calculated as a combination of direct and indirect emissions results. Figure 3.4-1 illustrates the overall approach followed in calculating total site emissions.

3.4.2 Direct Emission Calculations

Direct calculation of speciated emissions from a canister result was accomplished in 3 steps:

- Step 1: Convert the ppmv canister result to mg/m³ using Equation 5-1:

$$C = \frac{ppmv * MW}{24.45}$$

Where:

- C = Concentration in mg/m³
- ppmv = Parts per million by volume
- MW = Molecular Weight of analyte in gram/mols
- 24.45 = Molar Volume @ 25°C and 1 atmosphere in L/mols.

- Step 2: Convert the actual Hi Flow Sampler gas flow to standard gas flow using Equation 5-2:

$$CFM_{std} = (CFM_{act}) \left(\frac{T_{std}}{T_{act}} \right) \left(\frac{P_{act}}{P_{std}} \right)$$

Where:

- CFM_{std} = Flow rate corrected for standard conditions (ft³/min)
- CFM_{act} = Flow rate at actual conditions (ft³/min)
- T_{std} = Absolute gas temperature at standard conditions (°R)
- T_{act} = Absolute gas temperature at actual conditions (°R)
- P_a = Absolute gas pressure at actual conditions (psia)
- P_{std} = Absolute gas pressure at standard conditions (psia).

- Step 3: Calculate the emission rate using Equation 5-3:

$$ER = C * CFM_{std} * CF * 8760$$

Where:

- ER = Emission Rate (lb/yr)
- C = Analyte Concentration (mg/m³)
- CFM_{std} = Flow rate (ft³/min) corrected to standard conditions
- CF = Units Conversion Factor = 3.75E-06 (1 m³/35.32147 ft³) x 60 minutes/hour x (1 pound/453592.37 mg)
- 8760 = Hours per year

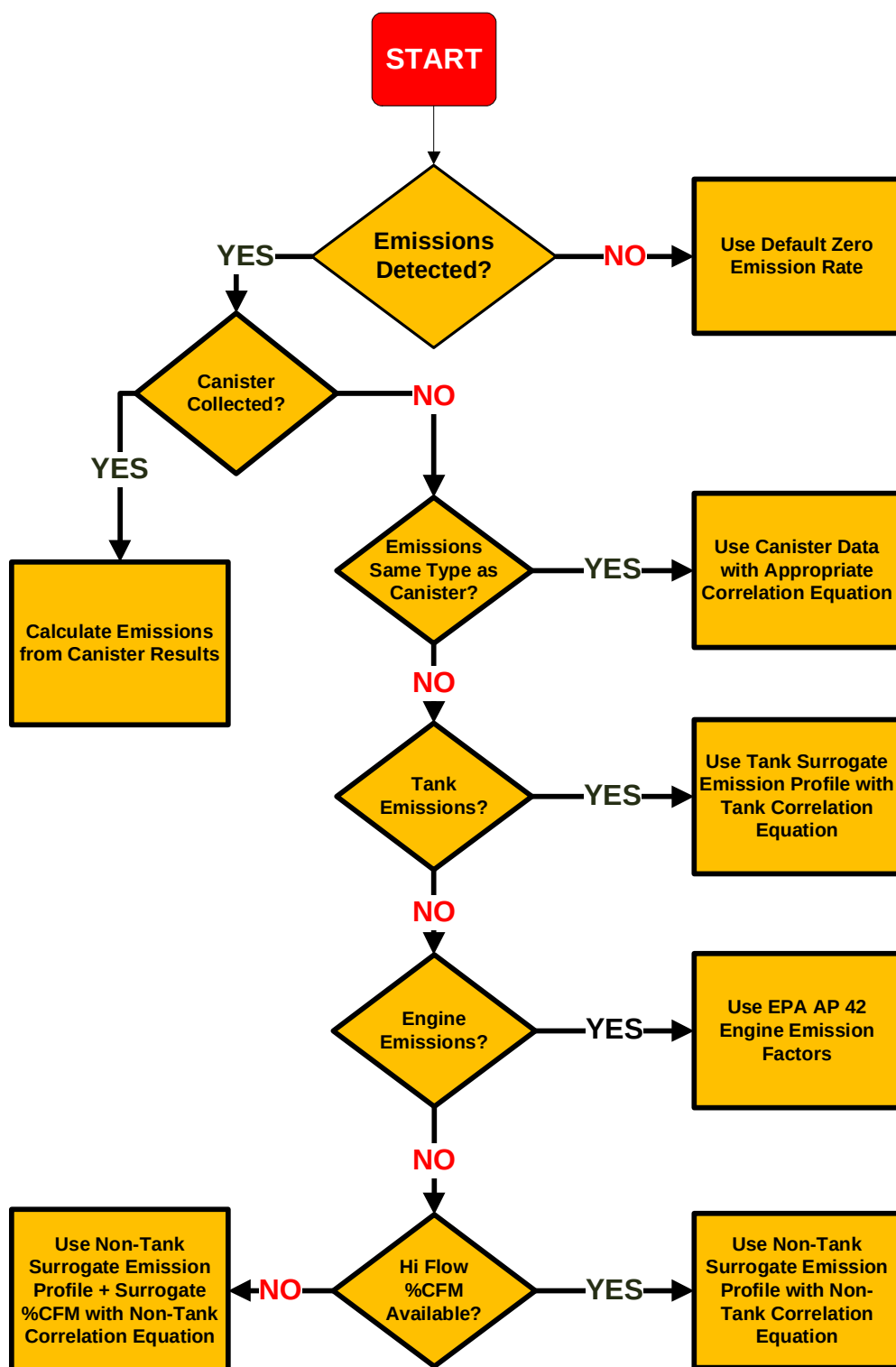


Figure 3.4-1. Emissions Calculation Flowchart

3.4.3 Indirect Emission Calculations -- Correlation Equation Development

The results of the canister samples were used to estimate emissions from those emission points that did not have a canister sample through the use of correlation equations. Two correlation equations, one for tank emissions and one for non-tank emissions, were developed based upon guidance from Section 2 and Appendix B of EPA's 1995 *Protocol for Equipment Leak Emission Estimates*.⁷

The first step in the development of the tank and non-tank correlation equations was the calculation of the natural logarithm of each canister's mass emission of total organic compounds (TOC) (lbs/yr) and its corresponding % CFM value.

The second step performed a linear regression in log space with the TOC values as the dependent variable (Y) and the % CFM values as the independent variable (X). The resulting regression line took the following form:

KeyPoint: Normality Correction

To estimate emissions from those sources not directly sampled with a canister, a correlation equation was developed between the calculated TOC (lb/yr) and the corresponding measured % CFM from those sources that were sampled. Since the data used to develop the correlation was not normally distributed, it was necessary to normalize the data by taking the natural logarithm of the data. A scale bias correction factor was then used to convert back to the arithmetic space.

$$\text{Emission Rate} = \beta_0 + \beta_1(\% \text{ CFM})$$

Where:

Emission Rate = Natural log of the leak rate determined by the canister results;

% CFM_i = Natural log of the % CFM_i;

β_0 = Intercept of regression line, and

β_1 = Slope of regression line.

The Mean Square Error (MSE) was then calculated by:

$$\text{MSE} = \frac{1}{n-2} \sum_{i=1}^n r_i^2$$

Where:

$$r_i = Y_i - \beta_0 - \beta_1 x_i$$

In the final step, the slope and intercept and a scale bias correction factor (SBCF) were used to transform the regression equations from log space to arithmetic space resulting in the tank and non-tank correlation equations:

$$\text{Leak Rate} = \text{SBCF} \times e^{\beta_0} \times \% \text{ CFM}^{\beta_1}$$

Where:

Leak Rate = Emission rate of TOC's from the individual source (lb/yr)

SBCF = Scale Bias Correction Factor

β_0, β_1 = Regression constants, and

% CFM = Cubic feet per minute measured by the Hi Flow Sampler.

The SBCF corrects for the variability of the log space data. It was calculated by summing 15 significant numbers of the terms from the infinite series:

$$SBCF = 1 + \frac{(m-1) * T}{m} + \frac{(m-1)^3 * T^2}{m^2 * 2! * (m+1)} + \frac{(m-1)^5 * T^3}{m^3 * 3! * (m+1) * (m+3)} + \dots$$

Where:

$T = MSE/2$.

MSE = mean square error from the regression.

m = number of data pairs.

3.4.4 Applying Canister Results to Non-Canister Emission Points

Canister-derived emission profiles were used to characterize non-canister emission points if 1) the non canister emission point was from the same site as the canister sample and 2) if the emission source types were the same (i.e. tank or non-tank).

For instance, if non-canister emissions were detected from a tank source, and if a canister had been collected at that site from another tank source, then that canister's data would be used to characterize the non-canister emission point. If the reverse was true, if the emissions were from a non-tank component, then a surrogate non-tank canister profile was used.

The distinction between tank and non-tank emission sources was made due to the differences in emissions characteristics observed between these two emission types. Tank emissions develop from the volatilization of heavier hydrocarbons entrained in the liquids produced by the facility separators, whereas non-tank emissions (i.e., particularly fugitive equipment leaks) are generally lighter gas emissions. Consequently, the chemical profile of each is somewhat different. For example, Table 3.4-1 provides a comparison of the average TOC, VOC, and HAP emissions resulting from a tank and non-tank canister sample collected during the study.

Table 3.4-1. Comparison of Emissions Between Tank and Non-Tank Emission Sources

Source Type (Canister Site ID)	TOC (tons/yr)	VOC (tons/yr)	HAP (tons/yr)
Non-Tank (PS-126)	6.65	0.01	0.00
Tank (295)	18.18	0.21	0.19

As indicated by the above comparison, tank emissions commonly exceed fugitive gas emissions.

Pairing a canister sample with a non-canister emission point provides the latter with a chemical composition. To calculate its emission rate, the Hi Flow Sampler results were used as follows:

1. The % CFM for the sample was entered into the correlation equation developed for the emission type (tank or non-tank) to determine the TOC mass emission rate.
2. The constituent contribution for each compound was determined from the weight percentages of the canister sample result.

This was done for each constituent so that the resulting products represented the speciated emission profile for the non-canister component.

For example, in Table 3.4-2 a canister sample (#A002) was collected from a leaking ¼-inch tubing connector – a non-tank sample type. Two other non-tank emission sources were detected at this site – a tee union connector and a pneumatically actuated valve. Since canister samples were not collected from these two sources, their emission profiles were derived as follows:

1. The non-canister total organic compound emission rate was calculated by the non-tank correlation equation. For the tee union with a % CFM of 0.39 the TOC emission rate was 11,644.25 lb/yr calculated as:

$$LR = 2.3759 * e^{9.674501743} * 0.39^{1.250318323} = 11,644.25 \text{ lbs / year} .$$

Where:

LR = TOC Leak Rate.

2.3759 = SBCF

9.674502= non-tank correlation equation intercept.

1.250318 = non-tank correlation equation slope.

2. Similarly, for the pneumatic valve which had a % CFM of 0.05 the TOC emission rate was 892.71 lb/yr calculated as:

$$LR = 2.3443 * e^{9.674501743} * 0.05^{1.2502318323} = 892.71 \text{ lbs / year} .$$

3. The non-canister emissions were assumed to have the same composition as the canister sample since they are both from the same site and from non-tank sources.
4. The speciated emissions of the non-canister were generated by multiplying the canister's speciated results by product of the ratio of each canister compound's emission to the canister TOC emission and the correlation equation TOC emission. The Tee union's methane emission rate, for instance, was 11,643.77 lbs/yr calculated as:

$$\frac{13,993.20}{13,993.78} * 11,644.25 = 11,643.77 \text{ lbs/yr methane}.$$

Where:

13,993.20 = Canister CH₄ lbs/yr.

13,993.78 = Canister TOC lbs/yr.

11,644.25 = Correlation Equation TOC lbs/yr.

Table 3.4-2. Non-Canister Methane Emissions Calculation Example

Emission Pt.	HF % CFM	Canister ID	Methane (lbs/yr)	Methane (tons/yr)
¼-inch tubing	1.01	A002	13,993	6.99
Tee Union	0.39	--	11,644	5.82
Pneumatic Valve	0.05	--	893	0.45

3.4.5 Surrogate Canister Profiles

For emission points which could not be directly tied to a canister profile, either because a canister was not collected at the site or because the canister sample from the site was from a non-matching source (i.e. tank vs. non-tank), then a surrogate canister profile was used in the emissions calculations. Two canister surrogate emission profiles with the units of pounds/yr were developed: 1) a non-tank surrogate emission profile and 2) a tank surrogate emission profile (Table 3.4-3). The non-tank surrogate emission profile was used for components associated with valves, connectors, and other piping and instrumentation equipment located at well heads, metering runs, separator pads and compressor skids. The tank surrogate emission profile was used to characterize emissions primarily from tank thief hatches and tank relief vents.

Table 3.4-3. Surrogate Tank and Non-Tank Emission Profiles

Category	Type	TOC (pounds/yr)	Non-VOC (pounds/yr)	VOC (pounds/yr)	HAP (pounds/yr)
Wet/Dry Gas	Non-Tank	13,256	13,252	4.12	0.78
Wet/Dry Gas	Tank	27,786	27,768	17.20	4.12

An attempt was made to further distinguish between emissions from sites in wet gas service versus sites in dry gas service for both tank and non-tank sources, but the number of emission sources in wet gas service turned out to be too small to draw statistically reliable inferences. At wet gas sites, emissions were detected from only 3 tank component types and 6 non-tank component types. At least 30 data points are needed to form reliable statistical conclusions.

The two surrogate emission profiles were developed using standard statistical procedures referenced in EPA's 1995 *Protocol for Equipment Leak Emission Estimates*:

1. The canister data for each emission type was checked for normality using probability plots to evaluate the correlation between the data and a normal distribution.
2. Since, in both cases, the data turned out to be non-normal, a natural logarithmic transformation of both sets of canister data was performed.
3. The normality of the transformed data was again checked using probability plots and found to be sufficiently linear.
4. The surrogate compositions were determined as the anti-logarithmic mean of the transformed data.

For summary purposes, Table 3.4-2 indicates the surrogate emission profiles only for categories of compounds (i.e. TOC, VOC, etc.). It is important to note that each surrogate profile also contains the emission rates for all of the individual compounds found in the aggregate canister samples used to generate the surrogate emission profiles.

Once the use of a surrogate canister profile was applied to an emission point, the emission calculation was performed according to the procedures described above in Section 3.4.3.

In Phase I there were several instances in which a low level emission fell below the detection limit of the Hi Flow Sampler (this limitation was overcome in Phase II by measuring the hydrocarbon concentration of the Hi Flow Sampler's exhaust stream with the TVA). For these occasions a surrogate % CFM was derived as the anti-log mean value of the normalized % CFM readings recorded in Phase II with the TVA.

3.4.6 Calculation of Non-Sampled Low Level Emission Points

While all site piping and instrumentation equipment was surveyed with the IR camera for high level emissions, only ten percent of the components at a site were sampled for low level emissions using a TVA following Method 21 screening procedures. Two separate emission calculations were used to arrive at emission rate estimates for the ninety percent not screened with the TVA:

1. The percent of components found leaking in the Method 21 screening was applied to the total non-sampled population of valves and connectors at the site and the non-tank correlation equation was used to estimate their emissions.
2. The remaining components were assumed to be non-leaking and their emissions were calculated using the Synthetic Organic Chemical Manufacturing Industry (SOCMI) default zero values listed in EPA's 1995 *Protocol for Equipment Leak Emission Estimates* (Figure 3.4-2). Studies by EPA have demonstrated that non-leaking equipment actually have low level emissions. These emission values are termed "default zeros" and are routinely used across the petroleum industry in the calculation of emission inventories.

TABLE 2-12. DEFAULT-ZERO VALUES: PETROLEUM INDUSTRY

Equipment type/service	Default-zero emission rates ^{a,b} (kg/hr/source)
Valves/all	7.8E-06
Pump seals/all	2.4E-05
Others ^c /all	4.0E-06
Connectors/all	7.5E-06
Flanges/all	3.1E-07
Open-ended lines/all	2.0E-06

^aDefault zero emission rates were based on the combined 1993 refinery and marketing terminal data only (default zero data were not collected from oil and gas production facilities).

^bThese default zero emission rates are for total organic compounds (including non-VOC's such as methane and ethane).

^cThe "other" equipment type was developed from instruments, loading arms, pressure relief valves, stuffing boxes, vents, compressors, and dump lever arms. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Figure 3.4-2. Default-Zero Values

As an example, a site component count indicates a site contains 150 valves and 1,050 connectors. Method 21 screening is therefore performed on 15 of the valves and 105 connectors (i.e. 10%). Emissions at or above 500 ppmv are detected on 3 of the valves (20%) and 2 of the connectors (1.9%). The remaining 135 valves and 945 connectors that were not monitored are assumed to have the same leak percentages. Accordingly an additional 27 valves (20% of 135) and 18 connectors (1.9% of 945) would be assumed to be leaking at this site. The emission rates of these components would be determined as follows:

1. For valves, the valve minor emission % CFM would be multiplied by 27. For connectors a multiplier of 18 would be used.
2. The resulting % CFMs would be entered into the non-tank correlation equation to calculate a single TOC emission for the additional 27 valves and a single TOC emission for the additional 18 connectors presumed leaking.
3. The calculated weight percentages from the non-tank surrogate profile would be applied to derive speciated emissions for each result.

The remaining 108 valves (135-27) and 927 connectors (945-18) would have the valve and connector default zero emission rates applied to them. This would be done by converting the default zero kg/hr emission rates to % CFM as methane. The resulting value would be then entered into the non-tank correlation equation to calculate TOC emissions. Speciated results would be obtained using the calculated weight percentages from the non-tank surrogate profile.

3.4.7 Compressor Engine Emissions

A total of 186 natural gas compressor engines were encountered during the site surveys. Of these, 150 were located at 123 well pad sites, 12 were located at the gas processing facility, 1 was located at the salt water treatment facility, and 23 were located at the eight line compressor stations. The majority of the compressor engines located on well pads functioned as lift compressors.

Emissions from compressor engines were derived from field data collected during the site surveys, vendor specification sheets and published emission factors. In calculating emissions for compressor engines, a 100% compressor duty cycle was conservatively assumed (i.e. 24 hours/day/ for 365 days/year). In addition, it was conservatively assumed that these engines were uncontrolled. Multiple XTO facilities were noted as having catalyst controls on their engines, but as stack testing of the exhaust from compressor engines was not included in the scope of this study, the control efficiency of these engines is unknown.

Key Point: Compressor Engine Controls

Emissions from compressor engines were estimated using the best available data collected during the point source testing. Where data was limited, conservative assumptions were used including but not limited to, the use of uncontrolled emission factors where controls were known to be present but no control efficiency data was readily available.

3.4.8 Well Drilling and Fracking Engine Emissions

Criteria pollutant, VOC and HAP emissions from natural gas and diesel engines used in well drilling and fracking operations were conservatively estimated based upon vendor specifications and published emission factors. Engine emissions from well drilling assume 504 hours of continuous operation (3 weeks, 7 days/week, 24 hours/day). Engine emissions associated with a fracking operation are based upon 120 hours of non-continuous operation (3 weeks, 5 days/week, 8 hours/day).

3.4.9 Calculation of Method 21 TOC Screening Emission Factors

Method 21 screening results were used to calculate VOC emission factors for non-tank equipment in natural gas service so that emissions due to future build out can be predicted based upon Method 21 monitoring results. Emission factors were calculated for the following equipment /screening categories:

- Valves: 500 ppmv to 999 ppmv and 1,000 ppmv to 10,000 ppmv.
- Connectors: 500 ppmv to 999 ppmv and 1,000 ppmv to 10,000 ppmv

- Other (sump pumps, pneumatic valve controllers, regulators, flow meters, knock-out pots, vents, etc.): 500 ppmv to 999 ppmv and 1,000 ppmv to 10,000 ppmv.

The emission factors were derived in a five step procedure:

1. Step 1: Filter for Phase II data since this data contained a larger data set of Hi Flow Sampler emission measurements for low level emissions.
2. Step 2: Sequentially filter the result of Step 1 by component type (valve, connector or other).
3. Step 3: Sequentially filter the result of Step 2 by the desired range of screening values (500 – 999 ppmv or 1000 – 10,000 ppmv).
4. Step 4: Sum the individual TOC emissions for the filtered results to produce total TOC emissions (lbs/hr) for each.
5. Calculate the emission factor for the selected component type and screening value range as the median of the Step 5 results and convert from pounds per hour to kilograms per hour.

3.5 Point Source Emissions Results

A total of 388 point source emissions sites were surveyed, including two repeated sites, for natural gas emissions in the point source study. Of these, 375 well pads and 8 compressor stations were visited, which comprised approximately 75% of the population. This section provides the point source survey results as TOC, VOC, HAP and Criteria Pollutant emissions in tons/yr. TOC are the sum of non-VOCs and VOCs. VOCs are the sum of non-HAP VOCs and HAPs. Criteria pollutants are VOCs, particulate matter (PM), Oxides of Nitrogen (NO_x), Carbon Monoxide (CO), and sulfur dioxide (SO₂).

Table 3.5-1 lists the average and maximum emission rates by site type. Emissions are extrapolated over a one year period (i.e. tons per year) for different site types. The average and maximum values are the same for processing and saltwater treatment facilities because only one of each was surveyed.

Table 3.5-1. Average and Maximum Point Source Emission Rates by Site Type^a

Site Type	TOC (tons/yr)		VOC (tons/yr)		HAP (tons/yr)	
	Average	Max	Average	Max	Average	Max
Well Pad	16	445	0.07	8.6	0.02	2
Well Pad with Compressor(s)	68	4433	2	22	0.9	8.8
Compressor Station	99	276	17	43	10	25
Processing Facility	1,293	1,293	80	80	47	47
Saltwater Treatment Facility	1.5	1.5	0.65	0.65	0.4	0.4

^a For values reported as <0.01 see Appendix 3-A for actual emissions expressed in scientific notation.

Table 3.5-2 summarizes the average emission volumes for each site type as measured by the Hi Flow Sampler. Note that engine emission volumes are not included in this table.

Table 3.5-2. Average Point Source Emission Volumes by Site Type

Site Type	TOC (cubic feet/yr)
Well Pad	148,552
Well Pad with Compressor(s)	218,035
Compressor Station	188,236
Processing Facility	372,019
Saltwater Treatment Facility	526

Table 3.5-1 shows the contribution compressor engines make to total site-wide emissions. In addition to increasing TOC, VOC and HAP emissions, the exhaust from a compressor engine contains the criteria pollutants (PM, SO₂, CO and NO_x). By way of illustration, Figure 3.5-1 compares the average annual emissions from a well pad without a compressor to one with a compressor. Clearly, compressor engines are a significant contributor of emissions at natural gas-related facilities.

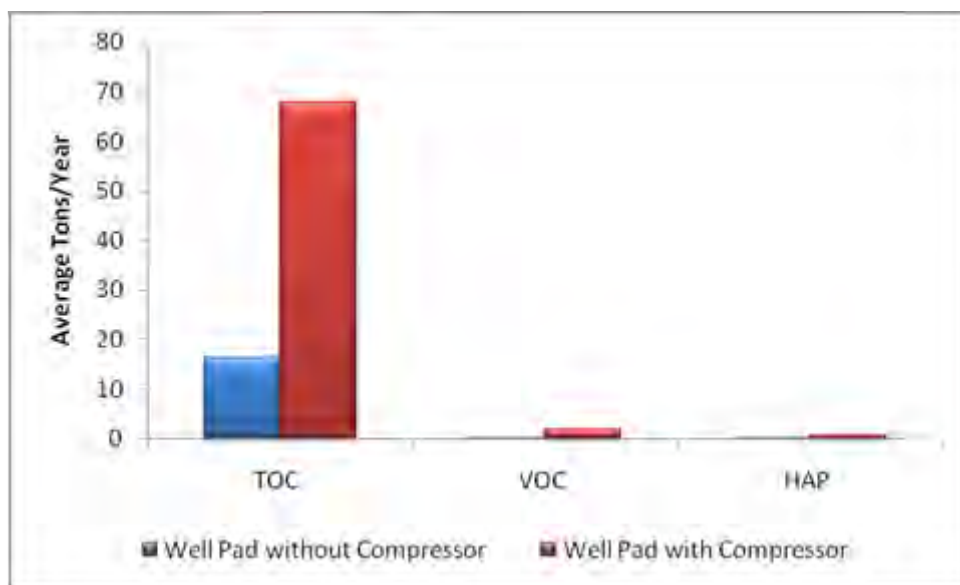


Figure 3.5-1. The Effect of Compressors on Site Emissions

Table 3.5-3 summarizes the emissions rates for all criteria pollutants and HAPs per each site surveyed during the point source testing. For each site, the summary provides the number of emission sources by type (e.g., compressor engines, storage tanks, fugitive leaks) and their contribution to total site-wide VOCs. Furthermore, the table provides for each site surveyed, the number of leaks detected by the IR camera and the number of leaks detected above 500 ppm using Method 21 screening.

Table 3.5-3. Point Source Emissions Summary by Site ^a

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
PS-001	16791 WOODSIDE DR	WELL PAD	2	89	384	2	0	6	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-002	2098 BRENNAN; F6	WELL PAD	3	347	2040	10	1	7	4	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-003	16616 FORD OAKS LN; F1	WELL PAD	1	65	320	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-004	2033 J CHESHEIR RD; F1	WELL PAD	1	73	286	1	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-005	SAM REYNOLDS; F1	WELL PAD	1	76	710	2	0	4	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-006	1101 HWY 114; F1	WELL PAD	1	59	590	2	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-007	1850 BLK HWY 114; F1	WELL PAD	1	22	220	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-008	2690 HWY 114 (BEECH) (C-PAD); F1	WELL PAD	3	214	2140	3	0	1	2	-0-	-0-	-0-	-0-	0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-009	2690 HWY 114 (BEECH) (B-PAD); F1	WELL PAD	2	198	1386	2	0	5	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-010	2598 HWY 114 (BEECH) (A-PAD); F1	WELL PAD	2	109	388	1	0	4	3	-0-	-0-	-0-	-0-	0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-011	15096 AMERICAN WAY (A-COMMERCE) (B-PAD); F1	WELL PAD	2	128	984	6	0	4	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-012	12601 KATY RD; G1	WELL PAD	1	207	1149	2	1	0	3	0.01	3.18	5.21	<0.01	0.17	0.17	<0.01	<0.01	0.10	0.07	<0.01
PS-013	CAYLOR RD; G3	WELL PAD	1	65	390	1	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-014	12497 OLD DENTON RD POWELL 1; G3	WELL PAD	1	8	48	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-015	12497 OLD DENTON RD POWELL 2; G3	WELL PAD	2	113	791	3	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-016	12698 OLD DENTON RD; G3	WELL PAD	1	9	56	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-017	12498 ALTA VISTA ; G3	WELL PAD	1	105	735	1	1	1	4	0.04	0.57	11.17	<0.01	0.58	0.58	<0.01	<0.01	0.34	0.23	<0.01
PS-018	3897 LITSEY RD; G1	WELL PAD	3	234	1190	6	1	4	0	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-019	15695 NORTH FWY (BEECH) (E-PAD); G3	WELL PAD	5	298	1888	5	0	3	4	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-020	2660 PETTY PLACE; G1	WELL PAD	1	77	548	2	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-021	16280 3 WILD DRIVE; G1	WELL PAD	3	172	1204	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-022	2898 HWY 114; G1	WELL PAD	2	87	609	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-023	2297 SILVER CREEK RD; C6	WELL PAD	1	53	371	2	0	1	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-024	2297 SILVER CREEK RD (PAD 2); C6	WELL PAD	2	82	574	3	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-025	3193 JIMISONS LN (XTO) (SURBER CA/CWS); J6	WELL PAD	3	209	1254	4	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-026	11494 MOSIER VALLEY RD (XTO) (REGAN); J6	WELL PAD	1	77	440	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-027	11468 MOSIER VALLEY RD (XTO) (KNAPP); J6	WELL PAD	1	84	500	1	0	0	3	-0-	-0-	-0-	-0-	0.01	<0.01	0.01	<0.01	<0.01	-0-	<0.01
PS-028	11693 MOSIER VALLEY RD (XTO) (EULESS A); J6	WELL PAD	4	273	1530	4	0	3	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-028.1	14193 JOHN DAY RD (H-PAD); E1	WELL PAD	2	96	672	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-029	14193 JOHN DAY RD (G-PAD); E1	WELL PAD	4	209	1449	4	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-030	14193 JOHN DAY RD (F-PAD); E1	WELL PAD	3	136	952	3	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-031	14193 JOHN DAY RD (D-PAD); E1	WELL PAD	1	48	336	1	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-032	11591 TRINITY BLVD (XTO) (EULESS C); J6	WELL PAD	1	78	468	1	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-033	11696 MOSIER VALLEY RD (XTO) (JW ARLINGTON); J6	WELL PAD	4	255	1300	4	0	2	3	-0-	-0-	-0-	-0-	0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-034	12196 TRINITY BLVD (XTO) (EULESS B); J6	WELL PAD	5	214	1284	5	0	0	2	-0-	-0-	-0-	-0-	0.01	<0.01	0.01	<0.01	<0.01	-0-	<0.01
PS-035	141931 JOHN DAY RD (C-PAD); E1	WELL PAD	1	50	350	1	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-036	14193 JOHN DAY RD (A-PAD); E1	WELL PAD	2	117	819	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-037	14193 JOHN DAY RD (E-PAD); E1	WELL PAD	2	105	735	2	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-038	14193 JOHN DAY RD (B-PAD); E1	WELL PAD	1	65	455	1	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-039	493 AVONDALE HASLET RD (DEVON) (GARNETT-LAPRELLE); E2	WELL PAD	2	194	1620	2	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-040	493 AVONDALE HASLET RD (XTO) (HUFFMAN); E2	WELL PAD	2	137	1218	3	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-041	1701 AVONDALE HASLET RD (DEVON) (MOSS) (A-PAD); E2	WELL PAD	2	140	840	1	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-042	1701 AVONDALE HASLET RD (DEVON) (MOSS) (B-PAD); E2	WELL PAD	2	150	1244	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-043	1502 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (F-PAD); E2	WELL PAD	2	131	917	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-044	1400 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (C-PAD); E2	WELL PAD	1	57	342	2	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-045	4594 HWY 360 SOUTH PAD; K5	WELL PAD	1	160	1120	3	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-046	10896 TRINITY BLVD; J6	WELL PAD	2	255	1785	3	0	1	4	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-047	1480 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (E-PAD); E2	WELL PAD	3	203	1421	3	0	0	4	-0-	-0-	-0-	-0-	0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-048	13800 SENDERA RANCH BLVD (DEVON) (MORRIS HARMONSON) (A-PAD); E2	WELL PAD	3	178	1176	3	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-049	694 AVONDALE HASLET (DEVON) (LBJ) (B-PAD); E2	WELL PAD	1	60	420	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-050	694 AVONDALE HASLET RD (XTO) (SONNY NANCE) (A-PAD); E2	WELL PAD	2	68	340	0	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-051	694 AVONDALE HASLET RD (XTO) (SONNY NANCE) (B-PAD); E2	WELL PAD	1	22	154	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-052	694 AVONDALE HASLET (DEVON) (LBJ) (K-PAD); E2	WELL PAD	2	127	889	2	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-053	694 AVONDALE HASLET RD (XTO) (SONNY NANCE) (C-PAD); E2	WELL PAD	1	86	516	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-054	694 AVONDALE HASLET (BOAZ) (N-PAD); E2	WELL PAD	3	196	1332	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
PS-055	12494 HWY 287 (DEVON) (PHASE 3) (A-PAD); E2	WELL PAD	1	63	441	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-056	290 BLUE MOUND RD (DEVON) (GARNETT-LAPRELLE) (B-PAD); E2	WELL PAD	2	137	822	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-057	4950 PAINT HORSE DR; G6	WELL PAD	6	291	2037	3	0	7	8	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-058	2796 PREMIER ST; G6	WELL PAD	1	197	1429	4	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-059	694 AVONDALE HASLET (DEVON) (LBJ) (A-PAD); E2	WELL PAD	1	62	434	1	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-060	694 AVONDALE HASLET (DEVON) (LBJ) (D-PAD); E2	WELL PAD	2	137	959	4	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-061	694 AVONDALE HASLET (DEVON) (LBJ) (E-PAD); E2	WELL PAD	1	69	414	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-062	1400 AVONDALE HASLET RD (DEVON) (MORRIS HARMONSON) (D-PAD); E2	WELL PAD	1	63	441	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-064	694 AVONDALE HASLET (DEVON) (LBJ) (F-PAD); E2	WELL PAD	2	120	840	4	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-065	694 AVONDALE HASLET (DEVON) (LBJ) (J-PAD); E2	WELL PAD	2	126	882	4	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-066	3399 E LONG AVE; G6	WELL PAD	5	472	5345	3	3	11	18	0.32	4.71	47.67	0.02	4.74	4.71	0.01	0.01	2.80	1.89	0.07

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
PS-067	694 AVONDALE HASLET (DEVON) (LBJ) (G-PAD); E2	WELL PAD	2	118	708	3	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-068	694 AVONDALE HASLET (DEVON) (LBJ) (H-PAD); E2	WELL PAD	1	62	372	1	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-069	694 AVONDALE HASLET (DEVON) (LBJ) (I-PAD); E2	WELL PAD	1	47	329	1	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-070	694 AVONDALE HASLET (DEVON) (LBJ) (M-PAD); E2	WELL PAD	3	200	1230	3	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-071	694 AVONDALE HASLET (DEVON) (LBJ) (L-PAD); E2	WELL PAD	1	62	434	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-072	2292 N TARRANT PKWY; F4	WELL PAD	4	438	3456	8	1	14	9	0.10	1.50	17.21	<0.01	1.39	1.38	0.01	<0.01	0.82	0.55	0.02
PS-073	693 AVONDALE HASLET (DEVON) (LBJ) (O-PAD); E2	WELL PAD	1	59	416	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-074	693 AVONDALE HASLET (DEVON) (LBJ) (N-PAD); E2	WELL PAD	1	65	390	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-075	693 AVONDALE HASLET (DEVON) (LBJ) (Q-PAD); E2	WELL PAD	2	126	882	4	0	2	1	-0-	-0-	-0-	-0-	3.57	<0.01	<0.01	3.57	0.72	-0-	<0.01
PS-076	693 AVONDALE HASLET (DEVON) (LBJ) (R-PAD); E2	WELL PAD	1	85	425	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-077	693 AVONDALE HASLET (DEVON) (LBJ) (S-PAD); E2	WELL PAD	2	147	735	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-078	1300 BLUFF SPRINGS RD (DEVON) (BOAZ) (B-PAD); E2	WELL PAD	1	54	324	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-079	1301 BLUFF SPRINGS RD (DEVON) (BOAZ) (C-PAD); E2	WELL PAD	1	60	360	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-080	1101 DURANGO SPRINGS DR (DEVON) (BOAZ) (A-PAD); E2	WELL PAD	1	61	376	1	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-081	1417 WHISPER WILLOWS (DEVON) (BOAZ) (D-PAD); E2	WELL PAD	1	50	315	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-082	8191 HORSEMAN RD; F4	WELL PAD	4	508	3646	6	1	8	3	0.15	2.00	6.38	<0.01	2.18	2.18	<0.01	<0.01	1.29	0.87	0.03
PS-083	9191 BLUE MOUND RD; F4	WELL PAD	1	152	1064	3	1	4	4	0.04	0.57	11.17	<0.01	0.59	0.58	<0.01	<0.01	0.35	0.23	<0.01
PS-084	7598 BLUE MOUND RD; F4	WELL PAD	1	109	763	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-085	2591 BASSWOOD BLVD; F4	WELL PAD	4	368	2100	5	1	4	5	0.10	1.57	5.02	<0.01	1.38	1.38	<0.01	<0.01	0.82	0.55	0.02
PS-086	11398 WEST FWY; B8	WELL PAD	3	217	1519	6	0	4	8	-0-	-0-	-0-	-0-	8.65	<0.01	8.65	<0.01	1.99	-0-	0.02
PS-087	4496 LOST CREEK BLVD; B8	WELL PAD	1	83	581	4	0	4	2	-0-	-0-	-0-	-0-	0.20	<0.01	0.20	<0.01	0.02	-0-	<0.01
PS-088	10293 OLD WEATHERFORD RD; C7	WELL PAD	2	130	910	4	0	2	4	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-090	14193 JOHN DAY RD (DEVON) (I-POOL PAD); E2	WELL PAD	2	101	707	2	0	3	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-091	14193 JOHN DAY RD (DEVON) (L-POOL PAD); E2	WELL PAD	1	62	372	1	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-092	14193 JOHN DAY RD (J-POOL PAD); E2	WELL PAD	1	68	476	1	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-093	14193 JOHN DAY RD (K-BLAKLEY PAD); E2	WELL PAD	4	198	1336	3	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-094	14193 JOHN DAY RD (M-BLAKLEY PAD); E2	WELL PAD	2	122	732	2	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-095	14193 JOHN DAY RD (N-BLAKLEY PAD); E2	WELL PAD	5	216	1512	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-096	14193 JOHN DAY RD (W-BLAKLEY PAD); E2	WELL PAD	4	283	1698	4	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-097	14193 JOHN DAY RD (O-POOL PAD); E2	WELL PAD	2	134	1164	2	0	1	9	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-098	14193 JOHN DAY RD (P-BLAKLEY PAD); E2	WELL PAD	5	225	1870	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-099	14293 SNAFFLE BIT TRL (Q-BLAKLEY PAD); E2	WELL PAD	4	258	2020	4	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-100	14193 JOHN DAY RD (U-BLAKLEY PAD); E2	WELL PAD	7	480	4016	7	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-101	14193 JOHN DAY RD (V-BLAKLEY PAD); E2	WELL PAD	5	131	1870	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-102	9767 VERNA TRAIL N; C7	WELL PAD	4	288	1816	4	0	5	4	-0-	-0-	-0-	-0-	0.53	<0.01	0.53	<0.01	0.07	-0-	0.02
PS-103	1299 W LOOP 820; C7	WELL PAD	1	65	455	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-104	9798 WESTPOINT DR; C7	WELL PAD	2	203	1550	2	1	0	8	0.07	1.04	2.91	<0.01	1.01	1.01	<0.01	<0.01	0.60	0.40	0.01
PS-105	9596 OLD WEATHERFORD; C7	WELL PAD	1	103	721	2	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-106	10590 OLD WEATHERFORD; B7	WELL PAD	2	142	994	4	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-107	5291 EVERMAN KENNEDALE BURLESON RD (CFW SOUTH); H10	WELL PAD	4	286	2002	4	1	0	3	0.07	0.98	32.48	<0.01	1.22	0.99	0.23	<0.01	0.64	0.40	0.03
PS-108	7196 WICHITA (GARRETT); G9	WELL PAD	2	105	805	2	0	0	1	-0-	-0-	-0-	-0-	0.02	<0.01	<0.01	0.02	<0.01	-0-	<0.01
PS-109	5691 CA ROBERSON BLVD (FWISD); G9	WELL PAD	8	547	3329	10	2	3	1	0.09	1.40	37.69	<0.01	1.40	1.36	<0.01	0.04	0.81	0.55	0.02
PS-110	2400 BLK CAMPUS ST (SMP); G9	WELL PAD	1	68	476	2	1	2	1	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-111	11495 WHITE SETTLEMENT RD (B-PAD); B7	WELL PAD	3	224	1568	4	0	3	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-112	10595 WEST CLEBURNE RD; E11	WELL PAD	6	549	4480	8	1	9	8	0.05	0.70	18.85	<0.01	0.69	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-113	10495 W CLEBURNE; E11	WELL PAD	3	236	2744	3	2	5	7	0.09	1.40	37.69	<0.01	1.38	1.36	<0.01	0.01	0.81	0.55	0.02
PS-114	6599 OAK GROVE RD (CARTER TRUST); G9	WELL PAD	3	316	2212	3	2	6	10	0.82	13.33	69.56	0.05	11.99	11.93	0.02	0.03	7.10	4.79	0.17
PS-115	10296 OLD CLEBURNE CROWLEY RD; E11	WELL PAD	1	146	1399	2	1	5	7	0.05	0.70	18.85	<0.01	0.69	0.68	<0.01	<0.01	0.41	0.27	0.01
PS-116	10699 OLD GRANDBURY RD; D11	WELL PAD	6	632	5022	8	1	9	12	0.05	0.70	18.85	<0.01	0.69	0.68	<0.01	<0.01	0.41	0.27	<0.01
PS-117	3595 ANGLE RD	WELL PAD	7	31	207	6	1	0	4	0.05	0.70	18.85	<0.01	0.70	0.68	<0.01	0.02	0.41	0.27	0.01
PS-118	590 NW LOOP 820; KS	COMPRESSOR STATION	0	1414	9888	3	6	2	7	0.02	51.42	269.95	0.18	42.69	42.59	<0.01	0.11	25.31	17.08	0.60
PS-119	6900 E ROSEDALE; I8; KS	COMPRESSOR STATION	0	985	6895	8	7	5	9	0.02	45.77	240.30	0.16	37.80	37.79	<0.01	0.01	22.46	15.16	0.53
PS-120	2298 E 4TH ST; F7; KS	COMPRESSOR STATION	0	325	2548	1	1	2	11	0.05	0.70	18.85	<0.01	0.72	0.68	<0.01	0.03	0.41	0.27	0.01
PS-121	7091 OAK GROVE; G10; KS	COMPRESSOR STATION	0	208	1456	0	1	0	3	<0.01	5.07	11.76	0.02	4.88	4.87	<0.01	<0.01	2.90	1.95	0.07

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-122	7091 OAK GROVE; G10	WELL PAD	4	208	1456	4	0	3	5	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-123	7695 OAK GROVE; G10	WELL PAD	5	204	1408	6	0	5	6	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-124	7695 OAK GROVE; G10; KS	COMPRESSOR STATION	5	242	1694	6	2	1	5	<0.01	10.14	23.52	0.04	9.76	9.75	<0.01	0.01	5.79	3.91	0.14
PS-125	7997 SOUTH FWY; G10; KS	COMPRESSOR STATION	2	357	4020	4	1	7	13	0.41	6.66	34.78	0.03	6.42	5.97	<0.01	0.45	3.56	2.39	0.09
PS-126	7997 SOUTH FWY; G10	WELL PAD	2	128	896	4	0	1	4	-0-	-0-	-0-	-0-	0.02	<0.01	0.01	<0.01	<0.01	-0-	<0.01
PS-127	5296 BAILEY BOSWELL; E4; KS	COMPRESSOR STATION	0	414	2898	4	3	6	11	1.61	24.33	545.08	0.10	23.70	23.56	0.11	0.04	14.02	9.45	0.34
PS-128	580 E ROSEDALE	DRILLING OPERATION	0	0	0	0	0	0	0	0.37	11.74	6.42	4.51	0.04	0.04	<0.01	<0.01	0.01	<0.01	<0.01
PS-129	10091 OLD GRANBURY RD; D11	WELL PAD	3	212	1913	4	1	2	9	0.05	0.70	18.85	<0.01	0.92	0.68	0.21	0.03	0.42	0.27	0.02
PS-130	6597 OAK GROVE (CARTER ALCON); G9	WELL PAD	5	517	3619	5	0	1	7	-0-	-0-	-0-	-0-	0.29	<0.01	0.25	0.04	0.06	-0-	0.03
PS-131	6799 OAK GROVE (CARTER TRUST); G9	WELL PAD	3	244	2458	3	1	1	3	0.07	0.98	32.48	<0.01	0.99	0.99	<0.01	<0.01	0.59	0.40	0.01
PS-132	2795 QUAIL RD (EXELON); H8	WELL PAD	4	338	2296	4	0	3	3	-0-	-0-	-0-	-0-	0.02	<0.01	<0.01	0.02	<0.01	-0-	<0.01
PS-133	6099 WILBARGER (OLCOTT SOUTH); H8	WELL PAD	8	613	4291	6	0	6	5	-0-	-0-	-0-	-0-	0.27	<0.01	0.27	<0.01	0.07	-0-	0.02
PS-134	5199 VILLAGE CREEK RD; H9	COMPLETION OPERATION	4	0	0	0	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-135	6293 HATCHERY RD; D6	WELL PAD	5	279	1953	5	1	1	17	0.05	0.70	18.85	<0.01	1.42	0.68	0.04	0.70	0.44	0.27	0.02
PS-136	6497 SHADY OAKS MANOR RD; D6	WELL PAD	3	232	2027	3	1	3	12	0.05	0.70	23.20	<0.01	1.06	0.71	0.05	0.31	0.45	0.28	0.02
PS-137	6791 NW LOOP 820; D6	WELL PAD	3	161	1127	3	0	1	6	-0-	-0-	-0-	-0-	0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
PS-138	4993 FREEMAN DR (KATES); H9	WELL PAD	1	84	588	1	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-139	7797 E LANCASTER AVE (GREEN OAKS); I8	WELL PAD	6	603	4219	6	2	6	6	0.09	1.40	37.69	<0.01	1.37	1.36	<0.01	0.01	0.81	0.55	0.02
PS-140	6896 NW LOOP 820; D6	WELL PAD	4	227	1589	4	0	2	5	-0-	-0-	-0-	-0-	0.05	<0.01	0.01	0.04	<0.01	-0-	<0.01
PS-141	2693 ROBERTS CUT-OFF RD; D6	WELL PAD	2	123	861	2	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-142	3291 NW LOOP 820; E6	WELL PAD	2	158	1706	2	1	0	11	0.05	0.70	23.20	<0.01	0.76	0.71	0.04	0.01	0.43	0.28	0.01
PS-143	3091 NW LOOP 820; E6	WELL PAD	3	116	813	3	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-144	2399 DOTTIE LYNN (SOWELL N); I7	WELL PAD	4	419	2933	4	2	9	5	0.11	1.74	21.75	<0.01	1.70	1.69	<0.01	0.01	1.01	0.68	0.02
PS-145	6093 WILBARGER (OLCOTT NORTH); H8	WELL PAD	12	366	2562	0	0	7	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-146	5693 E LOOP 820 S (DUKE); H9	WELL PAD	2	199	1393	2	0	4	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-147	5195 E LOOP 820 S (820 MARTIN); H9	WELL PAD	8	536	3752	4	1	9	8	0.05	0.70	18.85	<0.01	0.83	0.68	0.14	0.02	0.44	0.27	0.02
PS-148	3093 NW LOOP 820; E6	WELL PAD	2	202	1817	2	1	2	13	0.07	0.98	32.48	<0.01	1.14	0.99	0.12	0.03	0.62	0.40	0.02
PS-149	7500 RANDOL MILL RD (BLAKEMAN); I7	WELL PAD	1	129	903	1	1	0	2	0.07	0.98	32.48	<0.01	1.01	0.99	0.02	<0.01	0.59	0.40	0.02
PS-150	7891 RANDOL MILL RD (MORRIS); I7	WELL PAD	1	121	847	1	1	1	0	0.05	0.70	23.20	<0.01	0.71	0.71	<0.01	<0.01	0.42	0.28	<0.01
PS-151	8096 RANDOL MILL RD (DOREX); I7	WELL PAD	1	121	847	2	1	0	2	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-152	8390 RANDOL MILL RD (BUZZYS); I7	WELL PAD	2	143	1001	2	1	1	4	0.01	3.18	5.21	<0.01	0.18	0.17	<0.01	<0.01	0.10	0.07	<0.01
PS-153	2298 PRECINCT LINE (DUCK LAKE) (D-PAD); I7	WELL PAD	2	151	1057	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
PS-153.1	2298 PRECINCT LINE (DUCK LAKE) (B-PAD); I6	WELL PAD	4	0	0	3	1	0	0	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-154	8091 BRENTWOOD STAIR RD (CLANECO); I7	WELL PAD	1	154	1078	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-155	3598 ANGLE AVE; E6	WELL PAD	2	108	756	1	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-156	2095 NW LOOP 820; E6	WELL PAD	4	234	1638	4	0	3	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-157	4592 ANGLE AVE (LS); E6	WELL PAD	4	198	1386	2	0	2	6	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-158	3491 LINCOLN AVE (A-PAD); E6	WELL PAD	2	107	749	2	0	1	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-159	10488 HICKS FIELD RD (CROSSTEX AMINE TREATMENT CENTER)	PROCESSING FACILITY	0	1800	12590	10	12	10	67	1.00	87.74	1038.90	0.34	79.93	79.58	<0.01	0.34	47.32	31.93	1.14
PS-160	7595 E LANCASTER AVE (BOSWELL); I8	WELL PAD	7	429	3007	0	0	4	6	-0-	-0-	-0-	-0-	0.02	<0.01	<0.01	0.02	<0.01	-0-	<0.01
PS-161	7397 RANDOL MILL RD (DUCKHEAD); I6	WELL PAD	3	256	2176	0	1	4	4	0.07	1.04	2.91	<0.01	1.01	1.01	<0.01	<0.01	0.60	0.40	0.01
PS-162	1999 PRECINCT RD (RIVERBEND); I6	WELL PAD	2	226	1869	6	1	1	2	0.05	0.70	18.85	<0.01	0.69	0.68	<0.01	<0.01	0.41	0.27	<0.01
PS-163	490 E RENDON CROWLEY RD (N SPINKS); G11	WELL PAD	3	212	1484	4	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-164	14091 STONE RD (S SPINKS); G11	WELL PAD	4	260	1820	4	2	5	6	0.09	1.40	37.69	<0.01	1.36	1.36	<0.01	<0.01	0.81	0.55	0.02
PS-165	7996 TRAMMEL DAVIS RD (DUCK LAKE) (A-PAD); I6	WELL PAD	6	356	2492	2	1	1	4	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-166	9799 TRAMMEL DAVIS RD (TXI A); I6	WELL PAD	1	140	973	2	1	0	3	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-167	3198 S NORWOOD DR (TXI); I6	WELL PAD	1	144	1008	2	1	1	5	0.05	0.70	18.85	<0.01	0.78	0.68	0.10	<0.01	0.43	0.27	0.02

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
PS-168	9992 TRINITY BLVD (BELL) (B-PAD); I6	WELL PAD	3	264	1848	6	1	2	3	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-169	10190 TRINITY BLVD (BELL) (A-PAD); I6	WELL PAD	3	264	1848	4	1	1	2	0.05	0.70	18.85	<0.01	0.68	0.68	<0.01	<0.01	0.40	0.27	<0.01
PS-170	4697 ENON RD (KARANGES); G10	WELL PAD	3	273	1911	3	1	0	6	0.07	0.98	32.48	<0.01	1.09	0.99	<0.01	0.09	0.61	0.40	0.02
PS-171	3892 LON STEVENSON RD (WALLS COLEMAN); G10	WELL PAD	4	433	3031	4	2	3	6	0.14	1.96	64.96	<0.01	2.02	1.98	0.04	<0.01	1.19	0.79	0.03
PS-172	8290 ANGLIN CR (MOORE); G10	WELL PAD	3	161	1127	3	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-173	2999 LANA LN (HOSLER); G10	WELL PAD	3	183	1281	5	0	3	1	-0-	-0-	-0-	-0-	0.03	<0.01	<0.01	0.03	<0.01	-0-	<0.01
PS-174	5591 E 1ST ST (CARTER STATE) (SALT WATER DISPOSAL SITE); G7	SALTWATER TREATMENT FACILITY	3	211	1477	8	1	3	0	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
PS-176	1375 OAK GROVE SHELBY RD (SHULTZ); G10	WELL PAD	1	54	378	1	0	2	2	-0-	-0-	-0-	-0-	0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-177	9499 SOUTH RACE ST (HARRISON); G10	WELL PAD	1	88	616	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-178	10198 FOREST HILL EVERMAN RD (MISSION) (A-PAD); G10	WELL PAD	2	183	1775	2	1	1	2	0.07	0.98	32.48	<0.01	1.01	0.99	0.02	<0.01	0.59	0.40	0.01
PS-179	3691 MOPAC (PEARSON); E8	WELL PAD	4	30	210	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-180	695 E NORTHSIDE DR (STOCKYARDS); F7	WELL PAD	3	70	490	4	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-181	3298 VAN HORN AVE (CRAIN); G7	WELL PAD	1	75	525	3	0	1	2	-0-	-0-	-0-	-0-	0.02	<0.01	0.02	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-182	691 BEACH ST (FROST); G7	WELL PAD	3	115	705	4	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-184	10590 CHAPIN RD (CHAPEL CREEK); E9	WELL PAD	1	144	2408	2	1	0	12	0.30	4.01	12.76	0.02	22.32	4.36	<0.01	17.95	4.09	1.75	0.16
PS-185	10199 OAK GROVE RD (BEAN) (A-PAD); G10	WELL PAD	3	143	1001	3	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-186	394 EVERMAN PKWY (MARITZ); F10	WELL PAD	4	207	1449	4	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-187	9198 FORUM WAY (UNION PACIFIC); F10	WELL PAD	3	166	1162	3	0	3	4	-0-	-0-	-0-	-0-	0.01	<0.01	0.01	<0.01	<0.01	-0-	<0.01
PS-188	1298 W RISINGER RD (HOLT HICKMAN); F10	WELL PAD	2	117	819	2	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-189	2990 BRASWELL DR (RP STEPHENS); F6	WELL PAD	1	83	797	1	1	0	0	0.01	3.18	5.21	<0.01	0.17	0.17	<0.01	<0.01	0.10	0.07	<0.01
PS-190	796 MEACHAM BLVD (PRIME RAIL); F6	WELL PAD	3	146	1022	3	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-191	3592 DEEN RD; F6	WELL PAD	3	173	1211	3	0	3	4	-0-	-0-	-0-	-0-	0.05	<0.01	0.04	<0.01	<0.01	-0-	<0.01
PS-192	2299 MERCADO DRIVE; F6	WELL PAD	10	616	4312	13	2	6	12	0.13	2.08	5.81	<0.01	2.20	2.01	0.15	0.03	1.26	0.81	0.06
PS-193	5900 WILLBARGER (FRACKING JOB)	FRACKING OPERATION	3	0	0	0	0	0	0	0.51	16.37	8.26	5.82	0.05	0.05	<0.01	<0.01	0.02	<0.01	<0.01
PS-194	10395 CAMP BOWIE W (JOHNSON HUBBELL); E9	WELL PAD	1	93	652	2	0	0	4	-0-	-0-	-0-	-0-	0.02	<0.01	0.02	<0.01	<0.01	-0-	<0.01
PS-195	3497 LONGVUE (HAVENER); E9	WELL PAD	2	134	938	4	0	2	9	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-196	792 DE COSTA (EASTSIDES); G7	WELL PAD	4	215	1405	3	2	0	8	0.16	4.83	16.69	0.02	4.98	4.85	0.09	0.03	2.94	1.95	0.09

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
PS-197	692 BEACH ST (FROST); G7	WELL PAD	1	228	1596	3	1	2	7	0.07	1.04	2.91	<0.01	1.10	1.01	0.09	0.01	0.63	0.40	0.03
PS-198	5699 RANDOL MILL RD (GOODMAN); H7	WELL PAD	3	260	1824	4	1	4	2	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
PS-199	7094 JACK NEWELL BLVD S (TRIMBLE); H7	WELL PAD	2	118	826	4	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-200	7092 ENTERPRISE AVE (PARROT) (B-PAD); H7	WELL PAD	2	41	294	0	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
PS-201	5895 MARINE CREEK PKWY (MARINE CREEK) (A-PAD); E5	WELL PAD	2	183	1645	3	1	2	6	-0-	-0-	-0-	-0-	1.11	0.99	0.11	0.01	0.60	0.40	0.02
6	HWY 114	WELL PAD	1	62	134	1	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
20	4190 LITSEY RD	WELL PAD	2	103	960	8	0	5	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
23	4192 LITSEY RD	WELL PAD	6	448	3584	0	1	2	6	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
24	3596 ELIZABETHTOWN CEMETERY RD	WELL PAD	6	434	2738	6	1	3	2	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
25	14797 ELIZABETHTOWN CEMETERY RD	WELL PAD	5	206	1650	4	1	4	6	0.05	0.70	1.96	<0.01	0.67	0.65	<0.01	0.01	0.39	0.26	<0.01
26	14798 ELIZABETHTOWN CEMETERY RD	WELL PAD	6	463	4270	6	1	3	9	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
27	4791 HENRIETTA CREEK RD	WELL PAD	1	99	996	2	1	3	4	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
28	4794 HENRIETTA CREEK RD	WELL PAD	1	76	768	2	1	3	5	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
29	14404 CHAPARRAL	WELL PAD	2	154	1482	4	1	2	3	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
32	13794 NORTH FWY	WELL PAD	8	506	3542	8	1	1	8	0.05	0.70	1.96	<0.01	0.67	0.65	0.01	<0.01	0.39	0.26	0.01
33	13593 NORTH FWY	WELL PAD	8	539	4672	6	2	6	8	0.09	1.40	3.92	<0.01	1.34	1.31	0.03	<0.01	0.78	0.52	0.02
35	2890 WESTPORT PKWY	WELL PAD	1	68	476	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
36	3397 ALLIANCE GATEWAY	WELL PAD	8	549	4747	1	1	4	15	0.07	1.04	2.91	<0.01	1.04	1.01	<0.01	0.03	0.60	0.40	0.02
37	5198 WESTPORT PKWY	WELL PAD	2	128	1256	4	1	0	1	0.07	0.98	2.76	<0.01	1.00	1.00	<0.01	<0.01	0.59	0.40	0.01
38	5290 WESTPORT PKWY	WELL PAD	1	74	662	2	1	2	4	0.03	0.48	12.87	<0.01	0.45	0.45	<0.01	<0.01	0.26	0.18	<0.01
39	13195 PARK VISTA BLVD	WELL PAD	3	166	1282	3	1	4	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
41	3398 ALLIANCE GATEWAY	WELL PAD	12	801	7041	1	1	4	25	0.05	0.70	1.96	<0.01	0.67	0.65	<0.01	<0.01	0.39	0.26	0.01
44	12695 OLD DENTON	WELL PAD	1	193	1331	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
50	11498 HARMON RD	WELL PAD	2	218	1526	3	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
55	5696 N TARRANT PKWY	WELL PAD	2	275	2181	3	1	2	3	0.05	0.70	1.96	<0.01	0.67	0.65	<0.01	0.01	0.39	0.26	0.01
57	1098 BLK EAST BONDS RANCH RD S SIDE	WELL PAD	2	164	1099	1	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
59	1392 BLK E BONDS RANCH RD S-SIDE	WELL PAD	1	24	175	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
62	1098 E BONDS RANCH RD	WELL PAD	1	6	42	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
63	1096 EAST BONDS RANCH RD	WELL PAD	1	59	413	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
98	13393 SENDERA RANCH BLVD	WELL PAD	2	102	816	2	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
110	12595 WILLOW SPRINGS	WELL PAD	1	60	420	1	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
111	12591 BLK WILLOW SPRINGS RD W-SIDE	WELL PAD	1	74	518	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
125	12690 WILLOW SPRINGS RD	WELL PAD	1	53	371	1	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
126	693 AVONDALE HASLET RD	WELL PAD	3	220	1540	3	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
130	290 BLUE MOUND RD WEST	WELL PAD	2	133	931	3	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
132	12294 NW HWY 287 CFW	WELL PAD	2	151	1057	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
134	12290 NW HWY 287	WELL PAD	2	75	525	1	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
136	998 BLUE MOUND RD WEST	WELL PAD	7	421	2947	3	0	6	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
138	1096 BLK W BLUE MOUND AT HWY-287 N-SIDE	WELL PAD	3	245	1855	3	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
139	1099 BLUE MOUND RD W	WELL PAD	2	160	1120	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
141	692 BLUE MOUND RD	WELL PAD	1	60	420	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
142	392 BLUE MOUND RD WEST	WELL PAD	3	191	1337	3	0	3	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
143	893 BLUE MOUND RD W	WELL PAD	2	167	1169	3	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
147	12890 BLK SAGINAW BLVD	WELL PAD	2	162	1079	3	1	2	0	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
147A	12700 BLK HWY 287 & 81 S-SIDE	WELL PAD	1	60	420	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
149	12700 SAGINAW RD	WELL PAD	1	38	266	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
150	12700 SAGINAW RD	WELL PAD	1	42	294	1	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
153	2492 BLUE MOUND RD W	WELL PAD	2	128	896	3	0	5	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
154	11996 WILLOW SPRINGS RD	WELL PAD	1	87	609	1	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
155	11693 WILLOW SPRINGS RD	WELL PAD	4	315	2205	4	0	1	4	-0-	-0-	-0-	-0-	0.02	<0.01	0.02	<0.01	<0.01	-0-	<0.01
156	11498 WILLOW SPRINGS RD	WELL PAD	3	217	1519	3	0	0	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
159	LPA BONDS RANCH RD	WELL PAD	4	314	2198	3	0	5	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
160	1892 W BONDS RANCH RD	WELL PAD	5	377	2639	4	0	1	7	-0-	-0-	-0-	-0-	0.26	<0.01	0.26	<0.01	0.06	-0-	0.02

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
161	10999 WILLOW SPRINGS RD	WELL PAD	4	330	2310	4	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
164	11300 BLK HWY 287 & 81	WELL PAD	4	309	2163	3	0	3	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
165	452 WEST BONDS RANCH RD	WELL PAD	5	328	2672	2	1	5	1	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
167	4099 W BONDS RANCH RD	WELL PAD	2	76	725	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
168	3091 W BONDS RANCH RD	WELL PAD	4	245	1715	4	0	2	5	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
171	11593 SAGINAW BLVD	WELL PAD	7	286	2288	4	0	3	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
172	4099 W BONDS RANCH RD	WELL PAD	4	264	3248	8	0	5	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
174	9698 BOAT CLUB ROAD	WELL PAD	1	70	490	1	1	1	2	0.02	3.74	6.13	<0.01	0.20	0.20	<0.01	<0.01	0.12	0.08	<0.01
176	11593 SAGINAW BLVD	WELL PAD	5	371	2597	3	1	2	2	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
178	11601 BLK SAGINAW BLVD	WELL PAD	5	374	2597	3	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
182	1898 W BONDS RANCH RD	WELL PAD	3	189	1323	1	0	3	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
187	10398 HICKS FIELD RD	WELL PAD	5	200	1400	5	0	2	2	-0-	-0-	-0-	-0-	0.02	<0.01	0.02	<0.01	<0.01	-0-	<0.01
188	10398 HICKS FIELD RD	WELL PAD	1	53	371	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
189	10398 HICKS FIELD RD	WELL PAD	2	119	833	2	0	0	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
191	10094 HICKS FIELD RD	WELL PAD	2	130	910	3	0	2	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
192	LPA WAGLEY ROBERTSON RD	WELL PAD	1	167	1170	4	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
193	10197 WAGLEY ROBERTSON RD	WELL PAD	3	66	462	0	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
194	LPA WAGLEY ROBERTSON RD	WELL PAD	1	92	930	1	1	0	5	0.05	0.79	21.19	<0.01	0.76	0.76	<0.01	<0.01	0.45	0.31	0.01
195	10094 HICKS FIELD RD	WELL PAD	1	55	385	2	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
196	10000 BLK HICKS FIELD RD	WELL PAD	1	52	364	2	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
197	10200 BLK WAGLEY ROBERTSON RD	WELL PAD	3	170	1190	3	0	3	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
198	10196 EVENING VIEW DR	WELL PAD	4	162	1134	1	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
199	293 W BONDS RANCH RD	WELL PAD	3	184	1288	2	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
201	10191 NW HIGHWAY 287	WELL PAD	2	124	868	1	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
207	8799 WAGLEY ROBERTSON RD	WELL PAD	1	101	716	2	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
208	7999 WAGLEY ROBERTSON RD	WELL PAD	1	78	555	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
209	9491 SAGINAW BLVD	WELL PAD	2	187	1790	2	1	4	4	0.01	3.58	5.87	<0.01	0.19	0.19	<0.01	<0.01	0.11	0.08	<0.01
213	10999 SAGINAW RD	WELL PAD	1	80	560	2	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
214	9500 BLK PARK DR	WELL PAD	1	173	1211	2	1	4	1	0.03	0.46	12.35	<0.01	0.43	0.43	<0.01	<0.01	0.26	0.17	<0.01
216	9098 PARK DR	WELL PAD	1	51	357	1	0	0	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
217	8793 OLD DECATUR RD	WELL PAD	4	247	2262	3	1	4	11	0.05	0.70	1.96	<0.01	0.68	0.65	0.01	0.01	0.39	0.26	0.01
222	5299 W BAILEY BOSWELL RD	WELL PAD	2	73	511	3	0	3	4	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
223	5293 W BAILEY BOSWELL RD	WELL PAD	3	134	938	3	0	1	5	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
225	5696 W J BOAZ RD	WELL PAD	2	69	490	2	0	1	2	-0-	-0-	-0-	-0-	0.18	<0.01	0.18	<0.01	<0.01	-0-	<0.01
227	6325 CROMWELL MARINE CREEK RD	WELL PAD	1	82	572	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
228	5693 CROMWELL MARINE CREEK RD	WELL PAD	1	108	920	2	1	0	4	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Connectors	No. Tanks	No. Compressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
230	5996 BOWMAN ROBERTS RD	WELL PAD	2	163	1615	2	1	3	4	0.07	0.98	2.74	<0.01	1.01	0.99	<0.01	0.02	0.59	0.40	0.01
234	5492 TEN MILE BRIDGE RD	WELL PAD	1	48	320	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
235	6493 TEN MILE BRIDGE RD	WELL PAD	1	71	491	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
238	798 INDUSTRIAL ROAD	WELL PAD	2	691	5185	4	2	4	10	0.53	15.71	219.33	0.06	14.24	14.12	0.11	<0.01	8.42	5.67	0.21
240	1392 CANELL SAMPSON RD	WELL PAD	2	298	2586	2	1	0	5	0.05	0.70	1.96	<0.01	0.67	0.65	0.02	<0.01	0.39	0.26	0.01
241	1895 NORTHEAST LOOP 820	WELL PAD	2	218	1676	2	1	2	1	0.07	0.99	2.77	<0.01	1.00	1.00	<0.01	<0.01	0.59	0.40	0.01
247	1290 SILVER CREEK RD	WELL PAD	4	478	4646	4	0	2	4	-0-	-0-	-0-	-0-	0.97	<0.01	0.97	<0.01	0.11	-0-	0.02
257	10999 OLD WEATHERFORD RD	WELL PAD	3	253	2863	4	2	5	16	0.07	1.06	11.58	<0.01	20.93	1.01	19.91	<0.01	4.93	0.41	0.11
258	9595 OLD WEATHERFORD RD	WELL PAD	3	145	1015	2	0	0	5	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
260	11398 WEST FWY	WELL PAD	3	217	1519	6	0	4	8	-0-	-0-	-0-	-0-	0.02	<0.01	0.01	<0.01	<0.01	-0-	<0.01
261	10499 CHAPIN RD	WELL PAD	2	147	1029	4	0	1	6	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
266	11392 TIGER TRL	WELL PAD	5	310	1740	10	1	7	6	0.05	0.70	1.96	<0.01	1.43	0.65	0.01	0.77	0.46	0.26	0.01
267	11392 TIGER TRL	WELL PAD	5	445	3115	20	1	6	26	0.14	1.98	24.21	<0.01	19.87	2.00	17.85	0.02	3.02	0.80	0.16
268	11395 TIGER TRL	WELL PAD	5	311	3732	0	1	1	7	0.14	1.98	24.21	<0.01	4.30	2.00	<0.01	2.30	1.34	0.80	0.04
269	11392 TIGER TRL	WELL PAD	8	657	4599	0	0	1	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
282	4490 OLD DECATUR RD	WELL PAD	6	378	2485	6	1	3	13	0.05	0.70	1.96	<0.01	0.70	0.65	0.03	0.02	0.40	0.26	0.01
284	998 RAILHEAD RD	WELL PAD	2	138	966	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
285	4890 BLUE MOUND RD	WELL PAD	1	84	588	1	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
287	4201 BLUE MOUND RD	WELL PAD	1	151	357	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
288	291 NE 38TH ST	WELL PAD	4	175	1225	5	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
289	4999 MARK IV PKWY	WELL PAD	2	233	1781	2	1	3	3	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
290	1990 GREAT SOUTHWEST PKWY	WELL PAD	2	152	1064	2	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
291	2591 DOWNING DR	WELL PAD	4	181	1267	4	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
294K	2299 MERCADO DR	COMPRESSOR STATION	0	436	3310	0	2	4	6	0.80	12.94	67.54	0.05	11.59	11.59	<0.01	<0.01	6.89	4.65	0.16
294	2299 MERCADO DR	WELL PAD	10	616	4312	13	2	5	22	0.13	2.08	5.81	<0.01	2.16	2.01	0.13	0.02	1.21	0.81	0.03
295	1099 NIXON ST	WELL PAD	9	1010	7262	11	1	2	7	0.40	6.47	33.77	0.02	6.02	5.79	0.21	0.01	3.63	2.32	0.13
302	2099 MARTIN LYDON AVE	WELL PAD	2	150	1376	4	1	0	4	0.05	0.70	1.96	<0.01	0.67	0.65	0.02	<0.01	0.39	0.26	0.01
303	5092 SOUTH FWY	WELL PAD	4	437	3649	5	1	0	1	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
308	5990 COLUMBUS TRAIL	WELL PAD	4	368	2576	4	1	4	0	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
309	6091 COLUMBUS TRAIL	WELL PAD	1	75	525	2	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
310	9290 GRANBURY RD	WELL PAD	4	257	1799	4	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
311	9292 GRANBURY RD	WELL PAD	2	173	1211	2	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
312	9198 GRANBURY RD	WELL PAD	2	192	1344	2	0	2	1	-0-	-0-	-0-	-0-	1.50	<0.01	1.50	<0.01	1.08	-0-	0.23
315	5701 W RISINGER RD	WELL PAD	1	184	1288	2	1	3	1	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
316	8699 BREWER BLVD	WELL PAD	9	743	5201	12	0	5	6	-0-	-0-	-0-	-0-	0.05	<0.01	<0.01	0.05	<0.01	-0-	<0.01
317	9991 STEWART FELTZ RD	WELL PAD	5	223	1631	6	0	2	7	-0-	-0-	-0-	-0-	0.02	<0.01	<0.01	0.02	<0.01	-0-	<0.01
318	5892 STEWART FELTZ RD	WELL PAD	8	516	4128	12	0	4	7	-0-	-0-	-0-	-0-	0.07	<0.01	<0.01	0.07	<0.01	-0-	<0.01
324	10193 OLD CROWLEY CLEBURNE RD	WELL PAD	3	300	2100	4	1	1	1	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
325	9599 WEST CLEBURNE	WELL PAD	1	67	469	1	0	0	1	-0-	-0-	-0-	-0-	0.02	<0.01	0.02	<0.01	<0.01	-0-	<0.01
327	2998 N CROWLEY CLEBURNE RD	WELL PAD	3	226	2193	4	1	3	4	0.07	1.04	2.91	<0.01	1.01	1.01	<0.01	<0.01	0.60	0.40	0.01
328	2592 NORTH CROWLEY CLEBURNE RD	WELL PAD	2	176	924	4	1	1	3	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
329	2195 CUNNINGHAM	WELL PAD	1	110	866	1	1	0	4	0.05	0.70	1.96	<0.01	0.67	0.65	0.02	<0.01	0.39	0.26	0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
332	9590 TECHNOLOGY RD	WELL PAD	2	95	665	2	0	2	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
335	7393 CROWLEY RD	WELL PAD	1	95	897	1	1	1	4	0.05	0.70	1.96	<0.01	0.69	0.65	0.03	<0.01	0.39	0.26	0.01
336	293 ALTAMESA BLVD	WELL PAD	4	416	2912	4	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
338	11790 SOUTH FWY	WELL PAD	3	733	5805	4	2	8	7	<0.01	17.85	93.74	0.06	14.86	14.74	0.11	0.01	8.83	5.91	0.24
339	599 W RENDON CROWLEY RD	WELL PAD	6	492	3444	7	0	10	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
341	13790 WILDCAT WAY SOUTH	WELL PAD	3	263	1641	4	0	3	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
342	296 PACE ALSBURY COURT	WELL PAD	1	80	560	1	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
344	12795 SOUTH FWY	WELL PAD	1	223	1561	4	0	1	3	-0-	-0-	-0-	-0-	0.01	<0.01	0.01	<0.01	<0.01	-0-	<0.01
346	13790 WILDCAT WAY SOUTH	WELL PAD	3	198	1386	4	0	4	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
348	12298 OAK GROVE ROAD SOUTH	WELL PAD	8	553	5301	10	3	5	15	0.12	1.86	16.27	<0.01	1.77	1.74	0.02	<0.01	1.04	0.70	0.03
349	1297 E RENDON CROWLEY	WELL PAD	5	272	1904	4	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
350	495 OLD HWY 1187	WELL PAD	5	410	2870	5	0	6	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
351	1099 E RENDON CROWLEY RD	WELL PAD	4	268	1966	4	1	2	8	0.05	0.70	1.96	<0.01	0.67	0.65	<0.01	<0.01	0.39	0.26	0.01
352	1099 E RENDON CROWLEY RD	WELL PAD	4	230	1610	5	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
353	11799 SOUTH FWY	WELL PAD	2	130	910	2	0	5	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
354	492 GARDEN ACRES DR	WELL PAD	3	432	4064	3	1	2	1	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
355	10598 OAK GROVE RD	WELL PAD	2	224	1568	4	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
356	9798 OLD BURLESON RD	WELL PAD	3	276	2308	4	1	4	3	0.07	1.04	2.91	<0.01	1.01	1.01	<0.01	<0.01	0.60	0.40	0.01
357	10199 OAK GROVE RD	WELL PAD	3	208	1728	3	1	1	6	0.05	0.70	1.96	<0.01	0.67	0.65	<0.01	0.01	0.39	0.26	<0.01
360	10596 FOREST HILL- EVERMAN RD	WELL PAD	4	288	2016	5	0	2	4	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formal dehyde	Benzene
362	10196 FOREST HILL EVERMAN RD	WELL PAD	2	84	588	2	0	2	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
368	8598 WILL ROGERS BLVD	WELL PAD	1	53	371	1	0	1	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
369	8490 OAK GROVE RD	WELL PAD	5	236	1652	5	0	2	11	-0-	-0-	-0-	-0-	0.04	<0.01	<0.01	0.04	<0.01	-0-	<0.01
371	7893 WILL ROGERS RD	WELL PAD	2	115	805	3	1	1	1	0.08	1.23	3.45	<0.01	1.13	1.13	<0.01	<0.01	0.67	0.45	0.02
373	1290 JOHN BURGESS DR	WELL PAD	4	84	588	0	0	0	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
374	6994 WILL ROGERS BLVD	WELL PAD	2	273	2295	2	1	4	15	0.08	1.23	3.45	<0.01	1.24	1.13	0.01	0.10	0.69	0.45	0.02
381	1191 INTERMODEL PKWY	WELL PAD	12	759	6072	12	0	8	19	-0-	-0-	-0-	-0-	0.13	<0.01	0.13	<0.01	0.03	-0-	0.01
382	6197 SOUTH FWY	WELL PAD	1	119	833	1	0	0	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
392	5091 SOUTH FREEWAY	WELL PAD	1	69	483	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
396	2295 E SEMINARY DR	WELL PAD	10	858	6144	10	1	8	10	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
397	1294 E BERRY ST	WELL PAD	2	588	4494	5	3	2	2	0.85	13.64	69.50	0.05	12.24	12.24	<0.01	<0.01	7.27	4.91	0.17
399	4296 MITCHELL BLVD	WELL PAD	5	374	2986	6	1	6	3	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
400	3997 MITCHELL BLVD	WELL PAD	6	379	2989	8	1	3	7	0.07	1.04	2.91	<0.01	1.01	1.01	<0.01	<0.01	0.60	0.40	0.01
403	1999 BOMAR AVE	WELL PAD	4	467	3395	4	1	0	0	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
405	892 BEACH ST	WELL PAD	5	362	3619	0	1	1	2	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
409	4298 EAST FIRST ST	WELL PAD	3	278	1946	4	0	0	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
411	5391 EAST FIRST ST	WELL PAD	9	1143	8136	9	1	3	6	0.07	1.04	2.91	<0.01	1.01	1.01	<0.01	<0.01	0.60	0.40	0.01
415	7092 ENTERPRISE AVE	WELL PAD	1	76	670	1	1	2	2	0.03	0.46	12.35	<0.01	0.44	0.43	<0.01	<0.01	0.26	0.17	<0.01
416	5290 BOCA RATON BLVD	WELL PAD	3	238	1666	4	0	3	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
419	7090 ENTERPRISE AVE	WELL PAD	9	389	4049	12	2	3	19	0.13	2.08	5.81	<0.01	2.02	2.01	<0.01	0.01	1.20	0.81	0.03
420	7094 JACK NEWELL BLVD S	WELL PAD	2	159	1750	4	1	3	3	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01

Table 3.5-3. Point Source Emissions Summary by Site (Continued)

Site ID	Address	Site Type	No. Wells	No. Valves	No. Conn-ectors	No. Tanks	No. Comp-ressors	No. M21 >500 ppm	No. IRs	PM (tons/yr)	NOx (tons/yr)	CO (tons/yr)	SO2 (tons/yr)	VOCs (tons/yr)				HAPS ^b (tons/yr)		
														VOC Total	Engine VOC	Tank VOC	Fugitive VOC	HAP Total	Formaldehyde	Benzene
421	2392 AUSTIN RD	WELL PAD	2	146	1581	2	1	5	6	0.05	0.70	1.96	<0.01	0.66	0.65	<0.01	<0.01	0.39	0.26	<0.01
422	7213 ATCO DR	WELL PAD	3	137	959	3	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
423	7603 TRINITY BLVD	WELL PAD	3	273	2730	4	0	1	4	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
424	7498 MOSIER VIEW CT	WELL PAD	4	434	4510	4	4	4	11	0.19	2.80	7.84	0.01	2.63	2.61	0.01	<0.01	1.55	1.05	0.04
426	692 BRIDGEWOOD DR	WELL PAD	5	735	5427	5	2	1	11	0.09	1.40	3.92	<0.01	1.31	1.31	<0.01	<0.01	0.78	0.52	0.02
427	7990 TRINITY BLVD	WELL PAD	6	144	1008	0	0	0	6	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
428	7990 TRINITY BLVD	WELL PAD	5	780	6015	12	3	6	10	0.18	2.78	7.77	0.01	2.67	2.67	<0.01	<0.01	1.58	1.07	0.04
429	8097 TRINITY BLVD	WELL PAD	1	143	1337	2	1	2	4	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
438	9290 KEMP ST	WELL PAD	3	301	2786	5	1	0	2	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
447	2598 GREENBELT RD	WELL PAD	2	200	1400	2	1	2	5	0.05	0.70	1.96	<0.01	0.65	0.65	<0.01	<0.01	0.39	0.26	<0.01
457	1992 EAST CHASE PKWY	WELL PAD	1	119	786	2	0	1	1	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
462	6796 ROSEDALE ST	WELL PAD	13	600	4200	0	0	5	6	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
468	1593 INTERMODEL PKWY	WELL PAD	12	743	5201	0	0	2	3	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
469	7098 ROBERTSON RD	WELL PAD	11	260	1820	3	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
470	7294 ROBERTSON RD	WELL PAD	2	167	1570	6	1	1	4	0.01	3.58	5.87	<0.01	0.21	0.19	<0.01	<0.01	0.12	0.08	<0.01
471	1597 INTERMODEL PKWY	WELL PAD	6	383	2481	0	0	0	7	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
472	1791 INTERMODEL PKWY	WELL PAD	7	482	3374	0	0	5	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
474	6593 DIRKS RD	WELL PAD	1	80	560	1	0	3	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
480	5096 N SYLVANIA AVE	WELL PAD	3	357	2499	3	0	1	0	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01
483	4898 MARINE CREEK PKWY	WELL PAD	1	70	1095	1	1	0	7	0.05	0.70	1.96	<0.01	0.67	0.65	<0.01	0.02	0.39	0.26	<0.01
485	4691 E LOOP 820 S	WELL PAD	9	447	3465	6	2	2	19	0.09	1.40	3.92	<0.01	1.36	1.31	0.01	0.04	0.79	0.52	0.02
487	3490 BRYANT IRVIN RD	WELL PAD	2	97	679	2	0	0	2	-0-	-0-	-0-	-0-	<0.01	<0.01	<0.01	<0.01	<0.01	-0-	<0.01

^a For values reported as <0.01, see Appendix 3-A for actual emissions expressed in scientific notation.
^b The HAP Total emissions listed include all HAP emissions that were measured and calculated as part of this study. For a complete list of estimated HAPs emissions, see Appendix 3-A.

Figure 3.5-2 shows the average TOC emissions for the three basic component categories found at the natural gas facilities which were surveyed by the point source team: Valves, Connectors, and Other. Valves include manual valves, automatic actuation valves, and pressure relief valves. Connectors include flanges, threaded unions, tees, plugs, caps and open-ended lines where the plug or cap was missing. The category “Other” consists of all remaining components such as tank thief hatches, pneumatic valve controllers, instrumentation, regulators, gauges, vents, etc.

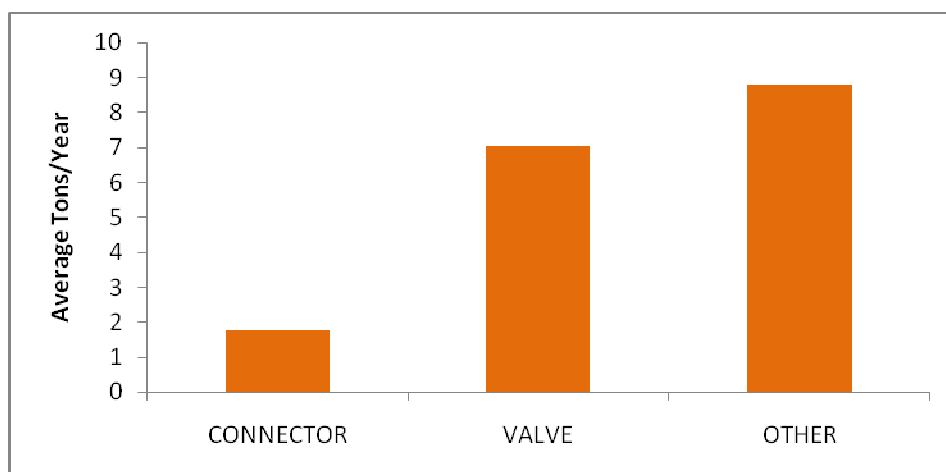


Figure 3.5-2. Average TOC Emissions by Component Category

As indicated in Figure 3.5-2, average TOC emissions from components in the “Other” category exceeded emissions from valves and connectors. Figure 3.5-3 identifies individual equipment types in the “Other” category with the highest average TOC emissions. Among these, tank thief hatches have the largest average TOC emission contribution, followed by miscellaneous equipment, tank vents, pneumatic valve controllers, and gas regulators. Miscellaneous equipment included a variety of emission sources such as holes and cracks in tank roofs, various types of instrumentation and meters, sumps, compressor shafts, orifice plates, sight glasses, and underground piping.

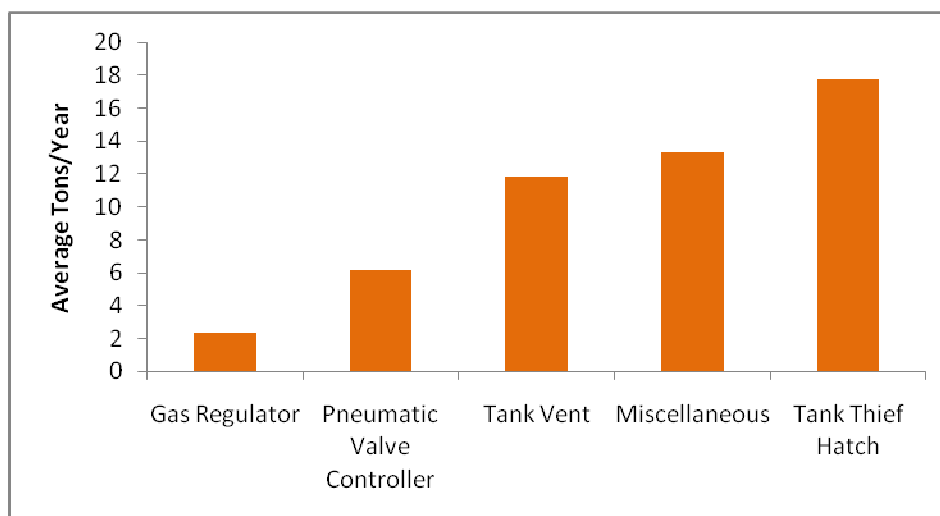


Figure 3.5-3. Average TOC Emissions in Category “Other”

Figure 3.5-4 summarizes the average annual TOC, VOC, HAP, and Criteria Pollutant emissions from compressor engines alone. Criteria pollutant emission data is based upon vendor-provided and published engine emission factors and pertains to those compressors encountered at well pad sites.

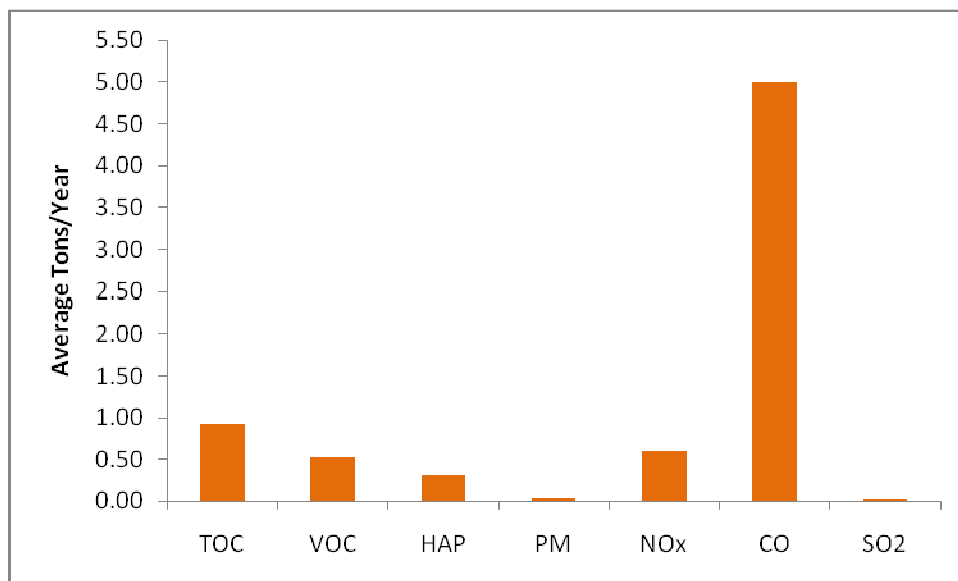


Figure 3.5-4. Average Annual Emissions from Well Pad Compressor Engines

Figure 3.5-5 compares VOC and HAP average annual emissions from Non-Tank and Tank sources.

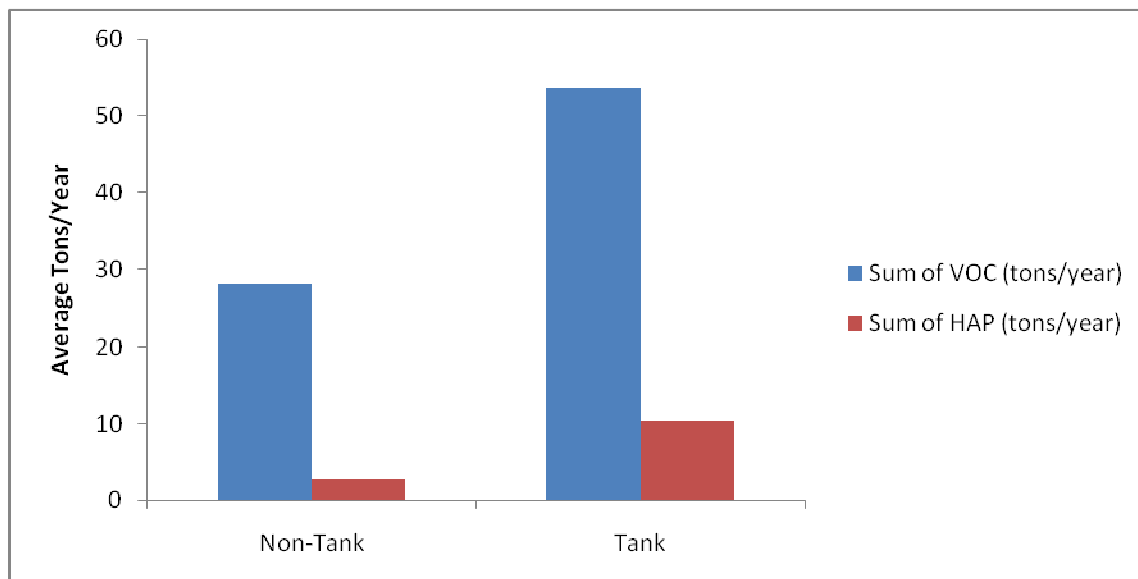


Figure 3.5-5. Non-Tank vs. Tank: Average VOC and HAP Emissions

Figures 3.5-6 and 3.5-7 compare TOC, VOC, and HAP average emissions from dry gas and wet gas sites. For purposes of this study, a site was considered to be a wet gas site if it produced more than 1 barrel of condensate/day as indicated by the Texas Railroad Commission.

Figure 3.5-6 indicates that average TOC emissions from wet gas well pad sites were higher than those from dry gas well pad sites. Also, indicated in Figure 3.5-7, wet gas well pad sites were found to have higher average VOC and HAP emissions.

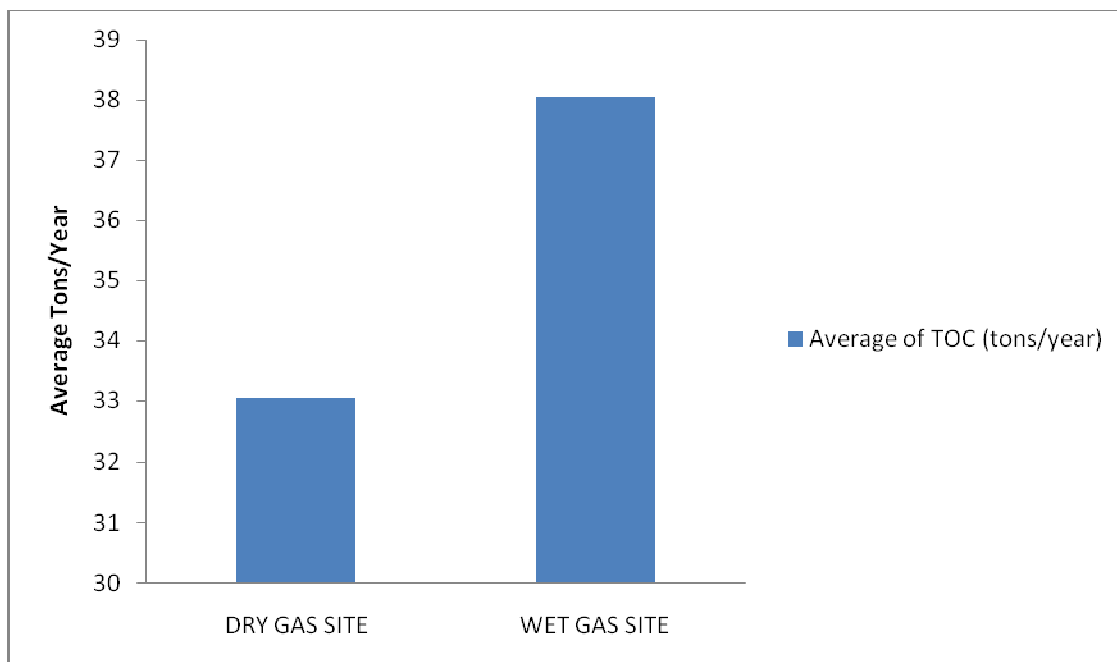


Figure 3.5-6. Average Wet Gas vs. Dry Gas TOC Emissions

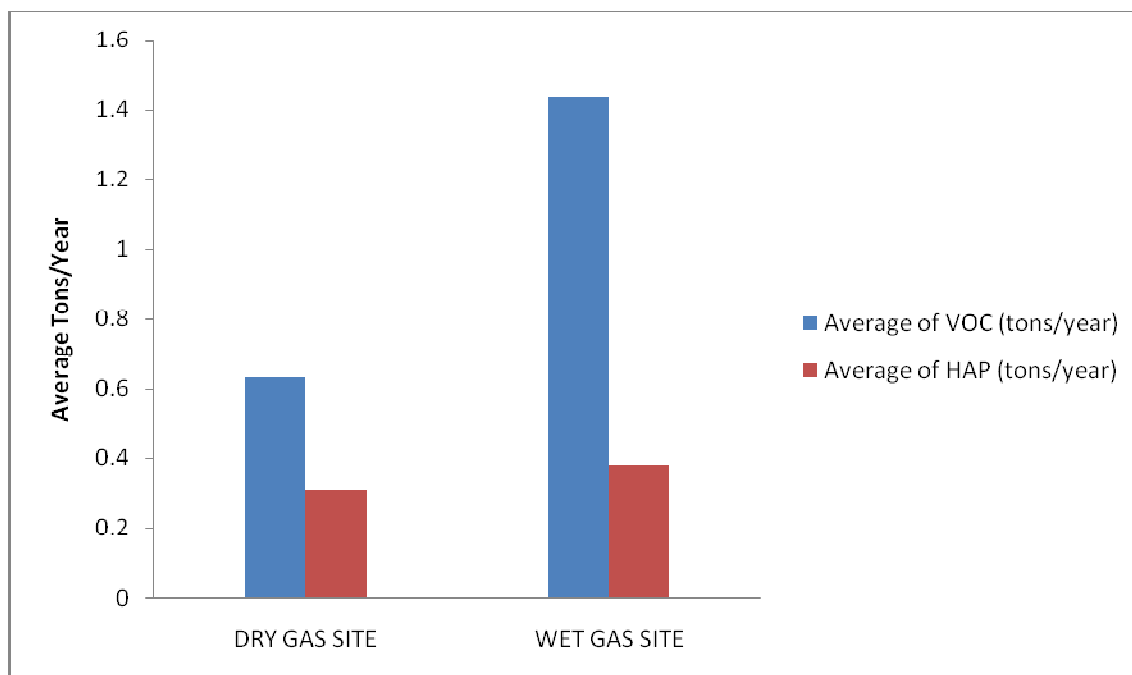


Figure 3.5-7. Average Wet Gas vs. Dry Gas VOC and HAP Emissions

At the City's request, the point source team re-visited two sites in Phase II that had been previously surveyed in Phase I. The Chesapeake site at 2299 Mercado Drive was surveyed on October 20, 2010 (Point Source ID PS -192) and again on February 15, 2011 (Point Source ID 294). The ENCANA site at 11398 West Freeway was surveyed in Phase I on September 21, 2010 (Point Source ID PS -086) and again, in Phase II on February 16, 2011 (Point Source ID 260). Table 3.5-4 summarizes the results of each survey.

Table 3.5-4. Summary of Repeat Surveys^a

Site/Date	Temp °F ^b	# IR Detects ^c	# M21 Detects ^d	TOC (tons/yr)	VOC (tons/yr)	HAP (tons/yr)
Chesapeake - 2299 Mercado Drive (Site IDs: PS-192 and 294)						
20-Oct-10	88	12	6	188	2.2	1.3
15-Feb-11	64	22	5	181	2.15	1.2
ENCANA - 11398 West Fwy (Site IDs: PS-086 and 260)^e						
21-Sep-10	87	8	4	25.7	8.7	1.9
16-Feb-11	65	8	4	35.7	<0.1	<0.1

^a For values reported as <0.01 see Appendix 3-A for actual emissions expressed in scientific notation.

^b Ambient site temperature in degrees Fahrenheit

^c Number of emission points detected with the IR camera

^d Number of emission points detected by Method 21 screening procedures.

^e During the first site visit, one canister sample was collected from a tank emission point and the results used to estimate the site's emissions accordingly. During the second site visit, no canister was collected. Therefore, consistent with the point source test plan, a surrogate emission rate was used to estimate the site's emissions during the second visit.

Detailed site-by-site emission results are provided in Appendix 3-A.

3.5.1 Well Activity Emissions

In addition to well pads, compressor stations, a natural gas processing facility and a salt water treatment facility, three types of exploration and stimulation activities were surveyed for emissions:

- Well Drilling.
- Fracking.
- Completion.

Figure 3.5-8 summarizes the hourly emissions from these operations. Since each lasts approximately three weeks or less, emissions are presented on a pounds/hour basis rather than annual basis.

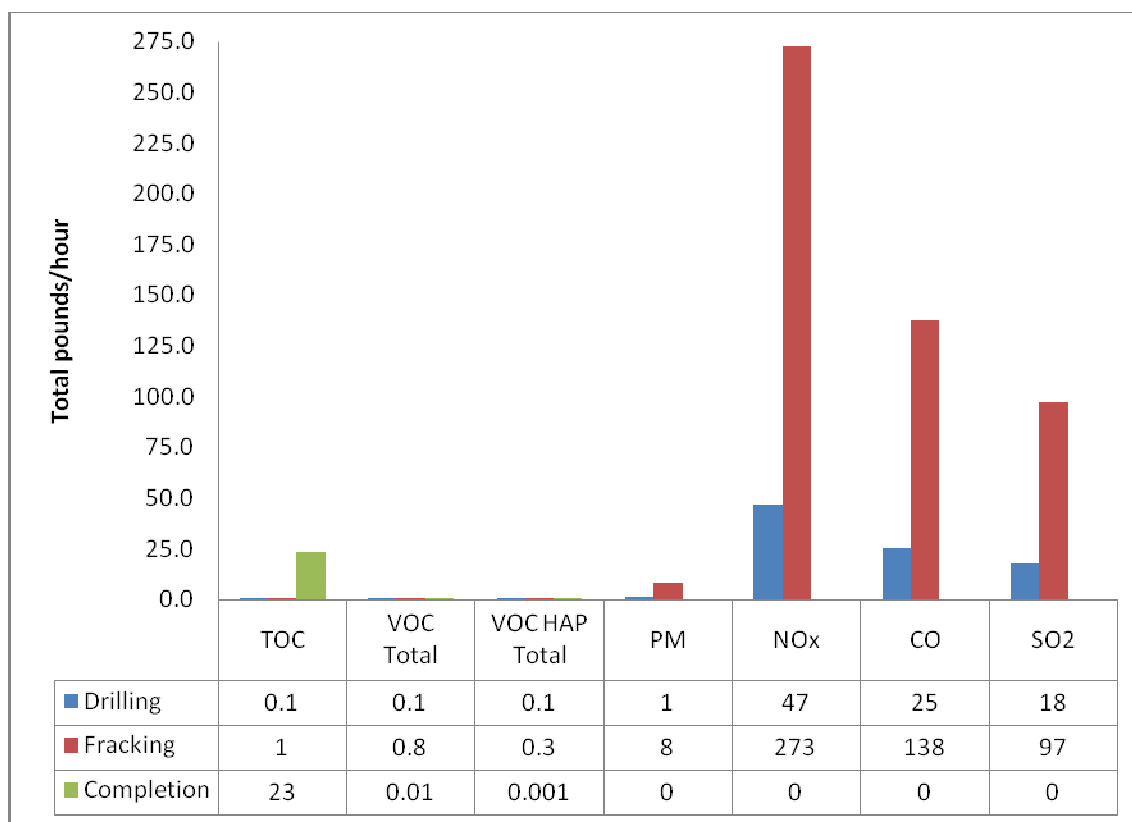


Figure 3.5-8. Well Activity Emissions (lbs/hr)

Well Drilling

A drilling site located at 580 East Rosedale and operated by XTO (Point Source ID PS-128) was surveyed on October 1, 2010. During the time of the site visit, the drilling operation was in process and operating under normal conditions. An IR camera scan was performed on all aspects of the drilling operation. No emissions from leaking components or drilling mud were detected by the camera during this survey. Estimated combustion emissions from the drilling rig engines are based on engine data obtained during the site survey. Detailed combustion emissions are provide in Appendix 3-A.

Fracking

A large fracking operation was surveyed on October 20, 2010 at 5900 Wilbarger (Point Source ID PS-193). During the time of the site visit, the fracking operation was in process and operating under normal conditions. The operation included the following equipment: 8 sand trucks, 11 diesel engine pump trucks, 8 mobile water trucks, 3 sand hoppers, 1 chemical injection flatbed trailer, and 1 chemical injection truck. Two complete IR camera scans were performed on all equipment. No emissions from leaking components or fluids handling were detected by the camera. Combustion emissions from the pump engines have been estimated and are based on engine data obtained during the site survey. Detailed combustion emissions are provide in Appendix 3-A.

Well Completion

A flowback operation was surveyed by the point source team on October 5, 2010 at 5199 Village Creek Road (Point Source ID PS-134). One emission point was detected with the IR camera and five low level emission points were identified with the TVA during Method 21 screening while the flowback operation was in progress. Detailed emissions are provide in Appendix 3-A.

3.5.2 Method 21 TOC Screening Emission Factors

Emission factors for the Method 21 screening ranges 500-999 ppmv and 1,000 to 10,000 ppmv were calculated for the equipment categories valves, connectors, and others according to the procedures explained in Section 3.4.2. Unfortunately, an insufficient number of valves and other equipment were found with emissions in the 500 – 999 ppmv category (two and four respectively) to derive reliable emission factors for this screening range. The remaining categories however were sufficiently populated to enable the derivation of the emission factors provided in Table 3.5-5 below.

Table 3.5-5. TOC Screening Emission Factors

Concentration Range	Valves	Connectors	Other
500 – 999 ppmv	—	2.17E-04 kg/hr 4.78E-04 lbs/hr	—
1000 – 10,000 ppmv	1.10E-03 kg/hr 2.43E-03 lbs/hr	4.70 E-04 kg/hr 1.04E-03 lbs/hr	1.60E-02 kg/hr 3.52E-02 lbs/hr

3.6 Quality Control Results

Point Source project Quality Assurance/Quality Control (QA\QC) was ensured through both field and analytical quality control procedures. Field QC procedures included:

- IR Camera Daily Demo.
- Hi Flow Sampler Daily Calibration Verification.
- TVA Daily Calibration and Drift Checks.
- Regular review of completed field data forms.
- Canister sampling protocols.
- Duplicate canister sample collection.

Analytical QC procedures included:

- Method Blanks.
- Surrogate Recoveries.
- Laboratory Control Samples and Control Sample Duplicates.
- Continuing Calibration Verification.

The results of the field QC checks are provided in the tables following. The results of the analytical QC are provided with the TestAmerica™ laboratory reports in the Appendix 3-C.

3.6.1 IR Camera Daily Demo Results

Three IR cameras were used during this project. IR cameras “GasFindIR” and “GF-320” were used continuously throughout the project. IR camera “Dexter” was used only for one day as a temporary replacement. The sensitivity of each IR camera was evaluated daily prior to testing (i.e. Daily Demo). The Daily Demo was performed at two flow rates: ~10 grams/hour propane and ~30 grams/hour propane. The maximum distance from which the two flow rates could be observed with the cameras was recorded together with current weather data. The results of the IR camera daily demos are provided in Tables 3.6-1 through 3.6-5.

3.6.2 Hi Flow Sampler Calibration Verification

Three Hi Flow Samplers were used during the project. Hi Flow Samplers #QS1002 was used in both Phase I and II. Hi Flow Sampler #QS 1005 was used in Phase I and was replaced in Phase II with Hi Flow Sampler #QX 1007. Each Hi Flow Sampler was calibrated at the start of Phase I and Phase II testing using certified gas cylinders of 2.5% and 99% methane. A calibration verification check of both background and sample sensors was performed daily prior to testing with the 2.5% methane standard. Once each week the calibration verification check of both sensors was performed with the 2.5% and the 99% methane gas standards with an acceptance criterion of +/- 10% agreement. The results of Hi Flow Sampler daily calibration verification checks are summarized in Tables 3.6-6 through 3.6-9.

**Table 3.6-1. IR Camera ID: GasFindIR Daily Demo
September – October, 2010**

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
9/1/10 9:26	27.00	100831_002	68.01	100831_003	N	6.5	84.5	73.4	99.4	35
9/2/10 10:15	24.16	100901_006	40.50	100901_007	S	1.5	76.7	89.1	98.7	95
9/3/10 7:39	27.72	100902_001	39.11	100902_002	W	5.5	72.1	61.0	99.9	100
9/7/10 7:25	50.10	100906_001	163.70	100906_002	CALM	CALM	84.2	72.0	99.6	100
9/8/10 8:33	53.25	100907_002	72.90	100907_001	CALM	CALM	80.0	82.8	99.2	0
9/9/10 8:20	28.32	100908_001	53.04	100908_002	N	2.6	91.3	86.5	99.17	100
9/10/10 8:30	39.04	100909_001	65.21	100909_002	SE	1.1	85.0	88.7	99.01	85
9/16/10 7:30	22.20	100915_001	36.90	100915_003	W	1.8	81.2	75.4	99.4	4
9/17/10 7:00	26.54	100916_001	31.16	100916_002	CALM	CALM	80.2	61.5	99.5	10
9/20/10 7:20	29.90	100919_001	39.65	100919_002	CALM	1.0	80.3	67.2	99.7	1
9/21/10 7:30	31.90	100920_001	52.24	100920_002	S	2.8	78.8	81.2	99.3	15
9/22/10 7:28	25.20	100921_002	42.92	100921_003	SE	2.3	75.7	83.8	99.5	0
9/23/10 7:20	27.10	100922_001	43.47	100922_002	E	3.4	78.0	81.1	99.4	97
9/24/10 7:25	32.68	100923_001	59.69	100923_002	SE	1.4	79.9	81.0	99.8	80
9/27/10 7:28	27.07	100926_001	38.12	100926_002	SW	1.5	57.5	65.8	99.8	0
9/28/10 7:26	26.61	100927_002	37.54	100927_003	SW	1.4	59.3	78.7	99.5	0
9/29/10 7:20	25.07	100928_001	35.94	100928_002	NW	4.0	63.8	71.0	99.1	0
9/30/10 7:45	30.92	100929_001	48.38	100929_002	CALM	CALM	64.3	72.1	99.5	0
9/31/10 7:45	26.70	100930_001	41.50	100930_002	CALM	CALM	64.3	71.9	101.2	0
10/4/10 7:44	14.60	101003_001	35.15	101003_002	CALM	CALM	61.4	68.1	100.7	5
10/5/10 7:45	16.50	101004_002	33.60	101004_003	CALM	CALM	51.6	69.4	100.7	0
10/6/10 7:50	15.90	101005_001	32.30	101005_002	CALM	CALM	59.2	67.5	100.7	0
10/7/10 7:37	26.53	101006_001	45.91	101006_001	CALM	CALM	57.8	72.5	100.4	0
10/8/10 7:45	22.73	101007_001	32.14	101007_002	CALM	CALM	58.9	66.9	100.1	0
10/11/10 7:36	27.54	101010_001	45.25	101010_002	CALM	CALM	72.1	70.8	99.2	100

Table 3.6-1. GasFindIR Daily Demo (Continued)

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
10/12/10 7:30	18.28	101011_001	36.51	101011_002	W	1.9	62.5	77.5	99.6	4
10/13/10 7:40	23.50	101012_001	35.28	101012_002	W	1.2	64.7	69.7	100.3	0
10/14/10 7:45	18.00	101013_001	29.80	101013_002	CALM	CALM	57.8	54.1	100.8	0
10/15/10 7:50	22.10	101014_001	33.80	101014_002	CALM	CALM	60.1	69.1	100.1	0
10/18/10 7:40	17.50	101017_001	27.45	101017_002	CALM	CALM	69.5	78.4	99.5	0
10/19/10 7:40	22.16	101018_001	35.21	101018_002	CALM	CALM	70.5	71.3	99.4	0
10/20/10 7:35	21.78	101019_001	30.03	101019_002	N	2.5	67.3	65.5	99.8	60
10/21/10 7:53	16.89	101020_001	31.38	101020_002	CALM	CALM	68.5	82.7	99.7	67

^a 10 grams/hour propane.^b 31.4 grams/hour propane.^c WD – Wind Direction^d WS – Wind Speed (mile/hour)^e TEMP – Temperature (°F)^f RH – Relative Humidity (%)^g BP – Barometric Pressure (kPa)

**Table 3.6-2. IR Camera ID: GF-320 Daily Demo
September – October, 2010**

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
9/7/10 8:30	38.83	0025	70.85	0026	CALM	CALM	84.2	72.0	99.6	100
9/8/10 8:30	53.25	0034	71.57	0033	CALM	CALM	80.0	82.8	99.21	0
9/9/10 8:08	9.00	0041	22.00	0042	S	2.3	80.0	90.3	99.9	100
9/10/10 7:45	18.50	0054	27.00	0055	SE	1.1	82.9	84.7	99.01	85
9/13/10 8:45	48.69	0058	77.18	0059	E	1.9	80.5	82.7	99.85	80
9/14/10 7:20	18.93	0069	228.36	0020	CALM	CALM	81.1	77.8	99.63	0
9/15/10 7:17	20.17	0079	25.30	0080	N	1.5	76.5	76.8	99.5	0
9/16/10 7:10	19.00	0086	23.00	0087	W	1.8	81.2	75.4	99.4	4
9/17/10 0:00	9.40	0109	18.80	0110	CALM	CALM	80.2	61.5	99.5	10
9/20/10 7:45	8.60	0121	23.50	0122	CALM	CALM	80.3	67.2	99.7	1
9/21/10 7:30	13.60	0135	31.30	0136	S	2.8	78.8	81.2	99.3	15
9/22/10 7:24	7.80	0151	24.70	0152	SE	2.3	75.7	83.8	99.5	1
9/23/10 7:40	6.50	0175	28.30	0176	E	3.4	78.0	81.1	99.4	97
9/24/10 7:28	16.80	0199	34.90	0200	SE	1.8	79.9	81.0	99.8	80
9/27/10 7:35	13.10	0221	21.30	0222	SW	1.5	57.5	65.8	99.8	0
9/28/10 7:26	14.60	0234	26.00	0235	SW	1.4	59.3	78.7	99.5	0
9/29/10 7:15	16.40	0247	23.30	0248	CALM	CALM	63.8	71.0	99.1	0
9/30/10 7:45	10.30	0268	24.50	0269	CALM	CALM	64.3	72.1	99.5	0
9/31/10 7:35	14.86	0299	20.70	0300	CALM	CALM	64.3	71.9	100	0

^a 10 grams/hour propane.^b 31.4 grams/hour propane.^c WD – Wind Direction^d WS – Wind Speed (mile/hour)^e TEMP – Temperature (°F)^f RH – Relative Humidity (%)^g BP – Barometric Pressure (kPa)

Table 3.6-2. GF-320 Daily Demo (Continued)

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
10/4/10 7:35	17.57	0313	30.80	0314	CALM	CALM	61.4	68.1	100.7	5
10/5/10 7:35	13.42	0325	24.80	0326	CALM	CALM	51.6	69.4	100.7	0
10/6/10 7:58	12.44	0345	21.00	0346	CALM	CALM	59.2	67.5	100.7	0
10/7/10 7:32	29.78	0368	36.25	0372	CALM	CALM	57.8	72.5	100.8	0
10/12/10 7:36	18.20	0423	24.20	0424	W	1.9	62.5	77.5	99.6	4
10/13/10 7:40	23.00	0436	31.00	0437	W	1.2	64.7	69.7	100.3	0
10/14/10 7:50	18.10	0460	26.60	0461	CALM	CALM	57.4	54.0	100.8	0
10/15/10 7:50	17.00	0504	25.80	0505	CALM	CALM	60.4	69.0	100.1	0
10/18/10 7:50	7.80	0506	14.60	0507	CALM	CALM	69.5	78.4	99.5	0
10/18/10 7:55	12.02	0511	19.17	0512	CALM	CALM	70.5	94.0	99.4	0
10/20/10 7:49	12.30	0529	24.60	0530	N	2.5	67.3	65.5	99.8	60
10/21/10 7:55	13.7	0549	23.9	0550	CALM	CALM	68.5	82.7	99.7	67

**Table 3.6-3. IR Camera ID: Dexter Daily Demo
September – October, 2010**

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
9/15/10 7:45	3.00	VID0016	4.00	VID0015	N	1.5	76.5	76.8	99.5	0

^a 10 grams/hour propane.

^b 31.4 grams/hour propane.

^c WD – Wind Direction

^d WS – Wind Speed (mile/hour)

^e TEMP – Temperature (°F)

^f RH – Relative Humidity (%)

^g BP – Barometric Pressure (kPa)

**Table 3.6-4. IR Camera ID: GasFindIR Daily Demo
January – February, 2011**

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
1/4/11 7:50	34.1	110103_001	84.7	110103_002	E	1.4	64.2	58.5	99.9	0
1/5/11 7:21	23.94	110104_001	54.6	110104_002	CALM	CALM	46.2	64.9	99.5	0
1/6/11 7:28	30.81	110105_001	51.46	110105_002	E	1.8	51.3	36.7	99.38	5
1/7/11 7:35	32.81	110106_001	57.17	110106_002	N	1	51.1	42.9	99.1	10
1/8/11 7:32	21.66	110107_001	38.87	110107_002	CALM	CALM	48.5	45.4	99.5	0
1/10/11 7:36	10.178	110109_001	31.96	110109_002	N	2.1	38.4	59.3	99.8	100
1/13/11 7:26	21.86	110112_001	52.41	110112_002	E	1.4	34.7	65.3	101.6	100
1/14/11 7:23	14.45	110113_001	30.49	110113_002	CALM	CALM	41.2	35.2	100.5	100
1/15/11 8:05	17.51	110114_001	50.4	110114_002	SE	3.2	38.2	69.2	100.4	100
1/18/11 7:20	8.38	110117_001	17.36	110117_002	2.7	W	44.9	78.1	99.1	100
1/19/11 7:30	12.74	110118_001	24.86	110118_002	CALM	CALM	38.9	45.6	99.7	5
1/20/11 7:31	14.36	110119_001	22.79	110119_002	N	4.8	38.6	72.3	99.8	100
1/21/11 7:27	16.9	110120_001	30.78	110120_002	CALM	CALM	33	39.5	100.1	50
1/22/11 7:08	18.2	110121_001	31.8	110121_002	CALM	CALM	39.1	50.0	99.7	0
1/24/11 7:23	21	110123_001	29.6	110123_002	CALM	CALM	36.3	55.7	99.9	0
1/25/11 7:18	11.4	110124_001	11.4	110124_002	NW	3.8	42.1	46.3	100.5	100
1/26/11 7:15	13.7	110125_001	30.7	110125_002	CALM	CALM	38.8	46.6	100.1	0
1/27/11 7:15	12.6	110126_001	20.1	110126_002	CALM	CALM	33.6	75.3	100.2	0
1/28/11 6:50	24.6	110127_001	47.5	110127_002	CALM	CALM	37.3	73.6	99.8	0

^a 10 grams/hour propane.^b 31.4 grams/hour propane.^c WD – Wind Direction^d WS – Wind Speed (mile/hour)^e TEMP – Temperature (°F)^f RH – Relative Humidity (%)^g BP – Barometric Pressure (kPa)

Table 3.6-4. GasFindIR Daily Demo (Continued)

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
1/31/11 7:25	39.7	110130_002	62.4	110130_003	NW	2.4	44.5	62.9	99.6	100
2/3/11 10:35	20.9	110202_001	44.1	110202_002	NW	5.2	20.5	50.1	101.5	100
2/5/11 11:15	41.3	110204_001	78.4	110204_002	W	2.4	51.5	38.7	99.1	0
2/6/11 8:14	26.5	110105_001	79.4	110205_002	CALM	CALM	44.1	61.1	98.9	10
2/7/11 8:41	8	110206_001	21.3	110206_002	W	7.1	40.1	62.8	100.6	0
2/8/11 7:28	20.8	110207_001	35	110207_002	E	4.2	37.3	57.4	100.1	0
2/10/11 10:05	30.1	110209_001	52.7	110209_002	N	4.1	26.1	38.1	101	0
2/11/11 7:10	11.6	110210_001	20.6	110210_002	CALM	CALM	30.6	64.8	100.6	0
2/14/11 7:17	51.3	110213_001	79.4	110213_002	CALM	CALM	49.4	76.8	100	30
2/15/11 7:25	60	110214_001	130.9	110214_002	SE	2.3	59.8	86.0	99.86	90
2/16/11 7:28	41.1	110215_001	109.9	110215_002	S	6.8	64.3	77.9	99.53	95

**Table 3.6-5. IR Camera ID: GF-320 Daily Demo
January – February, 2011**

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
1/4/11 8:15	17.4	827	53.4	828	E	1.4	64.2	58.5	99.9	0
1/5/11 7:31	11.1	840	17.04	841	W	5	46.2	64.9	99.5	0
1/6/11 7:48	16.41	859	37.63	860	E	1.8	51.3	36.7	99.38	5
1/7/11 7:13	15.7	879	37.58	880	N	1	51.1	42.9	99.1	10
1/8/11 7:17	10.21	916	15.52	917	N	3.0	48.5	45.4	99.5	0
1/10/11 7:46	9.14	934	20.35	935	N	2.1	38.4	59.3	99.8	100
1/11/11 7:35	7.08	963	21.51	964	NW	3.2	24.7	38.8	101.6	0
1/12/11 7:26	11.25	986	38.72	987	NW	2.7	29.1	37.9	102.1	95
1/13/11 7:17	21.24	1004	41.82	1005	E	1.4	44.7	65.3	101.6	100
1/14/11 7:13	12.22	1020	18.48	1021	CALM	CALM	41.2	35.2	100.5	100
1/15/11 7:15	13	1046	18.81	1047	SE	3.2	38.2	69.2	100.4	100
1/18/11 7:20	4.50	1062	15.24	1063	2.7	W	44.9	78.1	99.1	100
1/19/11 7:15	10.37	1081	25.86	1082	CALM	CALM	48.9	45.6	99.7	5
1/20/11 7:14	6.87	1113	15.1	1114	N	4.8	38.6	72.3	99.8	100
1/21/11 6:58	15.88	1123	28.45	1124	CALM	CALM	33	39.5	100.1	50
1/22/11 6:45	8.6	1132	17.8	1133	CALM	CALM	39.1	50.0	99.7	0
1/24/11 7:06	11.8	1141	18.9	1142	CALM	CALM	36.3	55.7	99.9	0
1/25/11 7:00	6.9	1157	10.5	1158	NW	3.8	42.1	46.3	100.5	100
1/26/11 7:03	10.7	1191	26.5	1192	CALM	CALM	38.8	46.6	100.1	0

^a 10 grams/hour propane.^b 31.4 grams/hour propane.^c WD – Wind Direction^d WS – Wind Speed (mile/hour)^e TEMP – Temperature (°F)^f RH – Relative Humidity (%)^g BP – Barometric Pressure (kPa)

Table 3.6-5. GF-320 Daily Demo (Continued)

Timestamp	Low Flow ^a		Hi Flow ^b		WD ^c (from)	WS ^d (mile/hr)	Temp ^e (°F)	RH ^f (%)	BP ^g (kPa)	Cloud (%)
	Sighting Distance (feet)	Video File	Sighting Distance (feet)	Video File						
1/27/11 7:07	8.8	1209	16	1210	CALM	CALM	33.6	75.3	100.2	0
1/28/11 6:50	11.1	1223	22.4	1224	W	4.0	37.3	73.6	99.8	0
1/31/11 7:15	22.9	1247	53.6	1248	NW	2.4	44.5	62.9	99.6	100
2/3/11 10:17	14.4	1270	50.7	1271	NW	5.2	20.5	50.1	101.5	100
2/5/11 11:05	16.5	1283	35.9	1284	W	2.4	51.5	38.7	99.1	0
2/6/11 8:24	16.5	1287	32.4	1288	CALM	CALM	44.1	61.1	98.9	10
2/7/11 8:30	5	1300	16.6	1301	W	7.1	40.1	62.8	100.6	0
2/8/11 7:15	12	1316	17.6	1317	E	4.2	37.3	57.4	100.1	0
2/10/11 9:57	10.5	1333	39.5	1334	N	4.1	26.1	38.1	101	0
2/11/11 7:00	12.7	1354	18.1	1355	CALM	CALM	30.6	64.8	100.6	0
2/14/11 7:05	15.1	1370	51.2	1371	CALM	CALM	49.4	76.8	100	30
2/15/11 7:08	10	1398	19.2	1399	SE	2.3	59.8	86.0	99.86	90
2/16/11 7:15	10.4	1413	19.3	1414	S	6.8	64.3	77.9	99.53	95

**Table 3.6-6. Hi Flow ID: QS1002 Verification
September – October 2010**

Timestamp	Input: 2.5% CH ₄		Input: 99% CH ₄	
	Background Sensor % Difference ^a	Leak Sensor % Difference ^b	Background Sensor % Difference	Leak Sensor % Difference
9/8/10 8:46	-0.8	0.4	-5.5	0.3
9/9/10 18:13	-1.2	-2.8	--	--
9/10/10 7:43	-0.8	-0.8	--	--
9/13/10 7:12	-1.2	-0.8	-2.8	-0.9
9/14/10 7:12	0.0	-0.8	--	--
9/15/10 7:15	-1.2	0.8	--	--
9/16/10 7:21	-1.2	-1.2	--	--
9/18/10 6:48	-2.0	0.4	--	--
9/20/10 7:34	5.6	0.8	--	--
9/21/10 7:28	-3.2	0.0	--	--
9/22/10 7:08	-2.8	0.4	--	--
9/23/10 7:17	-3.2	0.4	--	--
9/24/10 7:27	-0.8	-0.4	--	--
9/27/10 9:40	1.6	0.0	-0.1	-0.1
9/28/10 7:13	0.4	-0.4	--	--
9/29/10 7:12	-1.2	-0.8	--	--
9/30/10 7:55	-1.6	-0.4	--	--
10/1/10 7:33	0.0	-1.6	--	--
10/4/10 7:53	-0.4	-0.8	--	--
10/5/10 7:23	-0.8	-1.2	--	--
10/6/10 7:15	0.8	-3.2	--	--
10/7/10 7:14	0.4	-2.0	--	--
10/8/10 7:25	0.0	-3.2	--	--
10/11/10 7:15	-0.4	-4.8	--	--
10/12/10 7:22	-0.8	-4.4	--	--
10/13/10 7:26	-0.4	-3.6	--	--
10/14/10 7:21	-1.2	-3.2	--	--
10/15/10 7:26	-0.8	-2.4	--	--
10/18/10 7:23	-2.4	-3.6	--	--
10/19/10 7:19	-2.8	-3.6	--	--
10/20/10 7:25	-15.2	-4.8	--	--

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

**Table 3.6-7. Hi Flow ID: QS1005 Verification
September – October 2010**

Timestamp	Input: 2.5% CH ₄		Input: 99% CH ₄	
	Background Sensor % Difference ^a	Leak Sensor % Difference ^b	Background Sensor % Difference	Leak Sensor % Difference
9/8/10 8:27	-0.4	-0.8	-1.01	-3.84
9/9/10 6:51	1.2	0.4	--	--
9/10/10 7:31	8.0	-1.2	--	--
9/13/10 8:26	-7.6	0.4	--	--
9/14/10 7:45	-0.4	0.4	--	--
9/15/10 7:35	-4.8	1.2	--	--
9/16/10 7:15	-2.0	-2.0	--	--
9/17/10 6:32	0.0	1.2	--	--
9/20/10 7:40	1.2	-0.8	--	--
9/21/10 7:20	-2.0	-0.4	-1.11	-1.72
9/22/10 7:31	4.8	-1.2	--	--
9/23/10 7:14	1.6	-1.2	--	--
9/24/10 7:27	6.0	-0.4	--	--
10/4/10 8:12	-4.4	0.0	--	--
10/5/10 7:55	-2.0	-1.6	-1.92	1.11
10/6/10 7:10	-3.2	0.0	--	--
10/7/10 7:16	0.8	7.6	--	--
10/8/10 7:22	-0.4	10.4	--	--
10/11/10 7:13	-2.8	13.2	--	--
10/12/10 7:15	1.2	0.4	--	--
10/13/10 7:20	1.6	0.0	--	--
10/14/10 7:17	2.8	-1.6	--	--
10/15/10 7:30	2.4	3.2	--	--
10/18/10 7:40	1.2	3.2	--	--
10/19/10 7:23	2.8	4.8	--	--
10/20/10 7:30	3.2	4.0	--	--
10/21/10 7:34	2.8	5.2	--	--

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

Table 3.6-8. Hi Flow ID: QS1002 Verification
January – February, 2011

Timestamp	Input: 2.5% CH ₄		Input: 100% CH ₄	
	Background Sensor % Difference ^a	Leak Sensor % Difference ^b	Background Sensor % Difference	Leak Sensor % Difference
1/4/11 8:20	-1.2	2.0	--	--
1/5/11 7:26	-0.4	3.2	--	--
1/6/11 7:25	-0.4	3.6	--	--
1/7/11 7:41	-1.2	2.8	--	--
1/8/11 7:36	-0.8	3.2	--	--
1/10/11 7:50	-1.2	3.6	-1.9	0.0
1/11/11 7:30	0.4	4.0	--	--
1/12/11 7:36	0.4	4.0	--	--
1/13/11 7:26	-3.2	4.0	--	--
1/14/11 7:14	2.4	3.6	--	--
1/15/11 7:35	19.2	2.8	--	--
1/18/11 7:15	-30	0.8	-7.0	0.0
1/19/11 7:01	0	2.0	--	--
1/20/11 7:05	2.8	0.0	--	--
1/21/11 6:58	3.6	2.4	--	--
1/22/11 7:01	0.8	2.0	--	--
1/24/11 7:09	0	0.8	-2.2	0.0
1/25/11 6:51	25.2	2.0	-2.5	0.0
1/26/11 7:13	0	-0.8	0.0	0.0
1/27/11 6:45	-1.6	-0.8	--	--
1/28/11 6:40	-11.2	-0.8	--	--
1/31/11 7:40	0	1.2	0.0	-2.5
2/3/11 10:26	-8	-1.2	--	--
2/5/11 11:07	0	-1.6	--	--
2/6/11 8:07	0	-1.2	--	--
2/7/11 8:34	0	-1.2	-1.3	-0.1
2/8/11 7:05	0	-0.4	--	--
2/10/11 9:48	-0.4	0.8	--	--
2/11/11 7:04	-0.8	-1.2	--	--
2/14/11 6:55	0	-1.6	-0.7	-2.0
2/15/11 7:25	0	-0.4	--	--
2/16/11 7:06	0	-1.2	--	--

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

Table 3.6-9. Hi Flow ID: QX1007 Verification
January – February, 2011

Date/Time	Input: 2.5% CH ₄		Input: 100% CH ₄	
	Background Sensor % Difference ^a	Leak Sensor % Difference ^b	Background Sensor %	Leak Sensor % Difference
1/4/11 8:35	2.0	0.8	--	--
1/5/11 7:25	2.0	2.0	--	--
1/6/11 7:29	1.2	2.0	--	--
1/7/11 7:50	2.0	1.6	--	--
1/8/11 7:33	2.8	2.4	--	--
1/10/11 7:48	3.2	1.6	-0.5	-2.0
1/13/11 7:36	1.6	1.2	--	--
1/14/11 7:12	3.2	1.2	--	--
1/15/11 7:58	2.0	0.8	--	--
1/18/11 7:30	1.6	0.8	-2.0	0.0
1/19/11 6:55	2.8	0.4	--	--
1/20/11 6:59	2.4	0.4	--	--
1/21/11 6:50	4.0	1.6	--	--
1/22/11 6:58	3.2	1.6	--	--
1/24/11 6:58	2.8	0.0	0.0	0.0
1/25/11 6:35	4.0	0.8	-0.7	-3.5
1/26/11 6:55	3.2	0.4	--	--
1/27/11 6:40	2.8	0.8	--	--
1/28/11 6:35	2.0	0.0	--	--
1/31/11 7:45	2.8	-0.4	-4.0	-5.0
2/3/11 10:22	3.2	0.4	--	--
2/5/11 11:03	2.8	0.0	--	--
2/6/11 8:20	-0.4	-0.4	--	--
2/7/11 8:27	0.0	0.0	0.0	0.0
2/8/11 7:08	0.0	0.0	--	--
2/10/11 9:45	0.4	0.0	--	--
2/11/11 6:58	0.4	0.0	--	--
2/14/11 7:15	0.0	0.4	0.0	0.0
2/15/11 7:00	1.2	1.2	--	--
2/16/11 6:56	2.0	0.8	--	--

^a Background Sensor Percent Difference = ((Output-Input)/Input) x 100

^b Leak Sensor Percent Difference = ((Output-Input)/Input) x 100

3.6.3 TVA Calibration Procedures

Several TVAs were used during the point source field surveys. Each TVA was calibrated daily before testing with four certified gas standards:

- Zero Air (<0.1 total hydrocarbon content).
- Low Level Span (approximately 500 ppmv methane-in-air).
- Mid Level Span (approximately 2000 ppmv methane-in-air).
- High Level Span (approximately 10,000 ppmv methane-in-air).

Drift checks were performed during the test day using the Low Level calibration standard. Tables 3.6-10 through 3.6-15 summarize the calibration and drift check results for the project TVAs.

**Table 3.6-10. TVA Serial Number (S/N): 5362 Calibration and Drift Check Results
September – October 2010**

Timestamp	Zero (ppmv)	Low Span ^a % Difference ^b	Mid Span ^c % Difference	High Span ^d % Difference
8/30/10 10:00	-0.5	-1.22	-3.57	-9.83
9/1/10 8:05	0.4	-0.20	0.26	-0.23
9/1/10 14:50	--	-21.63	--	--
9/1/10 14:53	0.78	5.71	2.81	-0.59
9/1/10 17:25	--	25.10	--	--
9/2/10 9:03	0.61	4.90	2.24	4.06
9/2/10 17:33	--	13.27	--	--
9/3/10 9:10	0.2	0.61	0.36	-0.01
9/3/10 12:36	--	20.41	--	--
9/7/10 8:10	-0.98	-1.84	0.46	-0.46
9/8/10 8:02	-0.7	1.02	0.92	0.56
9/9/10 8:25	0.18	-3.88	-5.05	-7.20
9/9/10 16:28	--	5.31	--	--
9/10/10 8:02	-0.43	-0.20	-0.77	0.15
9/10/10 14:35	--	0.20	--	--
9/13/10 8:14	-0.37	0.20	0.10	-1.61
9/13/10 13:30	--	-0.41	--	--
9/14/10 7:13	-0.22	1.22	1.38	0.38
9/14/10 15:25	--	5.10	--	--
9/15/10 7:25	-0.17	-4.08	1.02	1.32
9/16/10 7:13	-0.27	0.41	0.66	0.03
9/17/10 7:35	-0.35	-3.06	-0.46	1.01
9/17/10 13:15	--	5.10	--	--

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-10. TVA S/N: 5362 (Continued)

Timestamp	Zero (ppmv)	Low Span ^a % Difference ^b	Mid Span ^c % Difference	High Span ^d % Difference
9/20/10 7:43	-0.75	0.61	0.56	0.20
9/20/10 16:04	--	3.06	--	--
9/21/10 7:49	-0.15	0.20	1.28	0.81
9/21/10 15:20	--	2.04	--	--
9/22/10 7:41	0.24	2.04	-2.81	3.45
9/22/10 16:15	--	0.82	--	--
9/23/10 7:34	-0.08	1.63	1.79	0.66
9/23/10 15:42	--	4.49	--	--
9/24/10 7:45	0.53	-2.24	-1.53	0.11
9/24/10 13:45	--	-6.73	--	--
9/27/10 7:50	0.32	0.41	0.92	2.43
9/28/10 7:53	0.07	0.82	0.56	1.42
9/29/10 7:51	0.17	0.20	0.20	-0.12
9/30/10 3:10	-0.27	3.67	1.58	0.15
9/30/10 17:15	--	-1.63	--	--
10/4/10 7:38	-0.15	1.63	0.77	0.95
10/4/10 15:57	--	-3.27	--	--
10/5/10 7:42	0.39	-2.45	1.68	0.58
10/5/10 16:48	--	8.57	--	--
10/6/10 7:35	1.62	-4.08	-1.53	-1.52
10/6/10 16:20	--	5.10	--	--
10/7/10 7:30	0.98	-4.49	2.55	-1.12
10/7/10 16:28	--	9.80	--	--
10/8/10 7:30	1.31	2.04	0.66	-0.10
10/8/10 12:42	--	1.22	--	--
10/11/10 7:32	1.24	-2.86	-1.84	-2.13
10/11/10 16:04	--	4.49	--	--
10/12/10 7:23	-0.39	3.47	3.62	0.16
10/12/10 16:41	--	13.27	--	--
10/13/10 7:21	1.07	0.00	-25.20	-1.12
10/14/10 7:35	-0.08	0.61	0.36	6.49
10/14/10 16:59	--	-2.45	--	--
10/15/10 7:36	-0.73	1.02	0.92	-0.19
10/15/10 12:24	--	-2.45	--	--
10/18/10 7:32	0.71	1.02	1.79	0.06
10/19/10 7:28	-0.25	1.63	1.17	1.42
10/19/10 15:29	--	-2.45	--	--
10/20/10 7:34	1.51	4.49	-3.06	5.48
10/20/10 17:00	--	10.61	--	--

**Table 3.6-11. TVA S/N: K10419 Calibration and Drift Check Results
September – October 2010**

Timestamp	Zero (ppmv)	Low Span^a % Difference^b	Mid Span^c % Difference	High Span^d % Difference
9/1/10 8:10	0.85	0.0	-0.3	-0.9
9/2/10 8:59	1.8	-0.6	-1.3	2.4
9/3/10 9:10	-0.46	1.8	1.1	1.4
9/3/10 12:36	--	-6.5	--	--
9/7/10 8:10	-0.63	-0.2	0.3	0.1
9/8/10 7:54	-0.26	0.8	-0.6	-0.2
9/9/10 7:34	1.9	0.6	0.2	0.3
9/10/10 8:10	1.13	1.0	1.0	0.4
9/13/10 7:23	0.47	-0.4	0.3	--
9/13/10 7:23	-1.33	-0.6	-0.3	1.0
9/14/10 7:25	-0.19	-1.0	1.2	0.2

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-11. TVA S/N: K10419 (Continued)

Timestamp	Zero (ppmv)	Low Span ^a % Difference ^b	Mid Span ^c % Difference	High Span ^d % Difference
9/15/10 6:42	0.82	1.0	-1.3	0.0
9/16/10 7:20	0.62	0.8	1.6	1.0
9/20/10 7:43	0.73	-1.6	-0.7	-2.8
9/21/10 7:14	0.13	-0.2	0.2	0.0
9/22/10 7:28	0.42	-0.6	-0.4	1.0
9/23/10 9:29	2.7	0.2	-0.2	1.0
9/24/10 7:35	7.6	3.9	2.3	2.0
9/27/10 7:52	0.8	0.2	1.0	1.0
9/28/10 7:50	0.2	1.0	0.1	1.0
9/29/10 7:39	0.93	-1.0	-1.4	-1.5
9/30/10 8:19	0.39	-3.9	-0.6	0.0
9/30/10 17:16	--	-0.6	--	--
10/1/10 8:07	-0.35	2.4	0.6	1.0
10/4/10 8:00	1.29	1.2	2.5	1.0
10/4/10 0:00	--	3.9	--	--
10/5/10 7:45	0.49	4.5	2.1	1.0
10/6/10 7:52	0.21	0.8	0.1	0.2
10/6/10 10:23	--	-8.8	--	--
10/7/10 7:26	0.01	-2.0	0.9	1.0
10/7/10 15:26	--	7.3	--	--
10/11/10 7:29	0.45	-3.7	-1.3	-0.6
10/12/10 7:42	1.8	3.9	2.4	1.0
10/13/10 7:45	-0.25	5.1	0.4	1.0
10/13/10 17:30	--	1.2	--	--
10/14/10 7:40	1.12	0.0	-0.4	0.4
10/14/10 17:05	--	5.1	--	--
10/15/10 7:25	0.2	1.0	0.6	2.0
10/15/10 12:20	--	0.4	--	--
10/18/10 7:30	0.35	6.1	3.6	1.0
10/18/10 17:30	--	-0.6	--	--
10/19/10 7:50	1.15	-0.8	-6.6	-5.5
10/19/10 16:05	--	9.4	--	--
10/20/10 7:40	1.35	-2.0	-0.6	-1.4
10/20/10 16:40	--	-3.7	--	--
10/21/10 8:05	1.45	0.8	1.5	-0.4
10/21/10 15:40	--	-0.6	--	--

^a Low Span = 490 ppm CH₄.^b % Difference = ((Output-Input)/Input) x 100^c Mid Span = 1960 ppm CH₄.^d High Span = 9860 ppm CH₄.

**Table 3.6-12. TVA S/N: 5362 Calibration and Drift Check Results
January – February 2011**

Timestamp	Zero (ppmv)	Low Span^a % Difference^b	Mid Span^c % Difference	High Span^d % Difference
1/5/11 7:48	2.21	-1.6	-0.1	-1.2
1/6/11 7:07	-0.97	1.8	1.2	0.6
1/6/11 16:38	--	-6.7	--	--
1/7/11 15:42	--	4.1	--	--
1/8/11 7:09	-0.42	1.8	0.7	0.5
1/8/11 14:41		-3.9	--	--
1/10/11 7:35	-0.29	-2.2	2.4	1.0
1/11/11 7:18	0.39	0.0	0.6	-0.5
1/11/11 16:27		-3.1	--	--
1/12/11 7:45	-1.07	0.0	0.2	0.1
1/12/11 13:36	--	-1.6	--	--
1/12/11 16:48	--	-1.2	--	--
1/13/11 7:30	0.19	0.6	-0.1	0.0
1/13/11 14:50	--	3.3	--	--
1/13/11 17:25	--	-6.5	--	--
1/14/11 7:07	0.22	-1.6	0.8	0.0
1/14/11 17:47	--	25.9	--	--
1/15/11 7:30	1.21	0.0	-0.4	0.3
1/15/11 15:22	--	6.5	--	--
1/18/11 7:07	0.19	0.4	0.5	0.5
1/18/11 17:41	--	-6.1	--	--
1/19/11 7:22	0.51	0.8	-0.1	0.4
1/19/11 14:13	--	5.1	--	--
1/19/11 17:22	--	8.4	--	--
1/20/11 7:45	0.72	-1.0	2.3	1.0
1/20/11 18:09	--	5.9	--	--
1/21/11 7:12	1.07	0.2	0.1	0.7
1/21/11 16:11	--	0.0	--	--
1/21/11 17:00	--	2.9	--	--
1/22/11 7:19	1.2	0.4	-1.0	-0.4
1/22/11 13:45	--	-0.4	--	--
1/22/11 15:23	--	-1.0	--	--
1/24/11 7:30	0	-0.6	-0.2	-0.4
1/24/11 17:27	--	5.7	--	--
1/25/2011 6:40	0.61	-2.4	-1.6	-1.2
1/26/2011 6:55	0.13	-1.4	-0.9	-1.0
1/26/11 14:26	0.55	-3.7	-5.9	-3.8
1/26/11 17:30	--	0.4	--	--

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-12. TVA S/N: 5362 (Continued)

Timestamp	Zero (ppmv)	Low Span ^a % Difference ^b	Mid Span ^c % Difference	High Span ^d % Difference
1/27/11 7:00	0.07	3.9	2.0	1.0
1/27/11 17:30	--	21.4	--	--
1/28/11 6:50	0.01	-0.4	-1.0	-0.3
1/28/11 18:10	--	-8.2	--	--
1/31/11 9:00	0.51	3.1	3.6	2.0
1/31/11 14:33	--	-3.1	--	--
1/31/11 17:22	--	2.4	--	--
2/3/11 10:45	0	0.4	0.1	0.1
2/3/11 17:52	--	3.7	--	--
2/5/11 11:33	0.56	1.2	1.0	-0.5
2/5/11 16:17	--	-2.4	--	--
2/6/11 8:26	0.55	0.0	-0.2	0.1
2/7/11 8:51	0	-4.1	0.2	0.0
2/7/11 15:36	--	1.2	--	--
2/7/11 17:05	--	-1.0	--	--
2/8/11 7:28	1.43	-0.2	0.4	0.7
2/8/11 16:45	--	3.3	--	--
2/10/11 11:12	0.59	0.4	2.0	0.0
2/10/11 16:45	--	5.7	--	--
2/11/11 7:25	0	0.8	0.8	-1.3
2/14/11 7:40	-1.71	-0.2	4.2	1.0
2/14/11 17:17	--	6.1	--	--
2/15/11 7:40	0.49	-0.6	-0.5	-1.1
2/15/11 16:55	--	-2.9	--	--
2/16/11 7:21	0.25	0.2	-0.1	0.8

**Table 3.6-13. TVA S/N: 0528413543 Calibration and Drift Check Results
January – February 2011**

Timestamp	Zero (ppmv)	Low Span^a % Difference^b	Mid Span^c % Difference	High Span^d % Difference
1/4/11 8:10	0.55	-0.4	1.0	0.5
1/4/11 14:17	--	-2.7	--	--
1/5/11 7:36	1.15	-0.4	-0.3	-0.1
1/5/11 13:33	0.8	1.0	0.2	-12.5
1/5/11 14:42	--	-0.4	--	--
1/6/11 7:14	1.35	0.0	0.2	-0.5
1/6/11 12:35	--	-4.1	--	--
1/6/11 13:06	--	-2.7	--	--
1/6/11 15:18	--	-4.3	--	--
1/6/11 16:32	--	-3.3	--	--
1/7/11 7:43	N/A	-2.4	2.8	8.1
1/7/11 11:53	--	-1.8	--	--
1/7/11 15:04	--	-4.7	--	--
1/8/11 7:25	-2.14	-1.6	-1.5	-0.2
1/10/11 7:28	-8.88	-0.4	-1.5	-0.5
1/10/11 12:52	--	4.5	--	--
1/10/11 15:30	--	10.2	--	--
1/13/11 7:21	2.7	0.2	-0.2	0.0
1/13/11 14:47	--	7.3	--	--
1/13/11 16:32	--	-6.1	--	--
1/14/11 7:17	-9	0.4	0.2	-0.1

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

**Table 3.6-14. TVA S/N: R6488 Calibration and Drift Check Results
January – February 2011**

Timestamp	Zero (ppmv)	Low Span^a % Difference^b	Mid Span^c % Difference	High Span^d % Difference
1/15/11 9:58	0	1.0	-1.5	1.0
1/15/11 17:20	--	-2.0	--	--
1/18/11 7:00	0.23	0.2	-1.5	-0.3
1/18/11 13:43	--	7.1	--	--
1/18/11 17:26	--	6.9	--	--
1/19/11 7:18	0.98	1.6	0.5	0.5
1/19/11 13:30	--	6.7	--	--
1/19/11 17:00	--	2.7	--	--
1/20/11 7:32	0.65	-3.3	0.3	0.5
1/20/11 13:50	--	7.1	--	--
1/21/11 7:05	0.89	-1.4	0.6	0.6
1/21/11 14:21	--	3.5	--	--
1/21/11 16:52	--	--	--	--
1/22/11 7:12	0.79	-2.2	-1.5	1.0
1/22/11 14:20	--	3.9	--	--
1/24/11 7:20	0	-0.4	-0.5	0.0
1/24/11 12:00	--	1.4	--	--
1/24/11 16:45	--	-17.1	--	--
1/25/11 7:00	0.01	-0.4	-0.4	-0.3
1/25/11 12:05	--	2.4	--	--
1/25/11 17:40	--	1.6	--	--
1/26/11 7:00	0.01	0.4	0.6	-0.6
1/26/11 11:45	--	1.2	--	--
1/26/11 14:55	--	1.8	--	--
1/27/11 6:50	0.03	0.2	-0.1	1.0
1/27/11 11:45	--	2.4	--	--
1/27/11 17:05	--	1.6	--	--
1/28/11 6:55	0.06	-1.6	-2.0	-0.7
1/28/11 11:45	--	2.4	--	--
1/28/11 16:20	--	1.8	--	--
1/31/11 7:39	0.5	-0.2	-2.0	-0.9
1/31/11 13:43	--	-5.3	-8.7	-7.5
1/31/11 17:55	--	-5.9	--	--
2/3/11 10:36	0	0.8	-2.0	0.0
2/3/11 15:16	--	-6.5	--	--

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

Table 3.6-14. TVA S/N: R6488 (Continued)

Timestamp	Zero (ppmv)	Low Span ^a % Difference ^b	Mid Span ^c % Difference	High Span ^d % Difference
2/5/11 11:25	1.03	-1.6	-1.1	0.3
2/5/11 14:56	--	-3.7	--	--
2/5/11 16:30	--	-6.5	--	--
2/6/11 8:20	0.12	2.4	-1.1	0.3
2/6/11 11:45	--	-0.8	--	--
2/7/11 8:39	0	0.0	0.4	0.7

**Table 3.6-15. TVA S/N: R1376 Calibration and Drift Check Results
January – February 2011**

Timestamp	Zero (ppmv)	Low Span^a % Difference^b	Mid Span^c % Difference	High Span^d % Difference
2/8/11 10:18	0.61	-0.8	-0.2	0.2
2/8/11 13:51	--	-1.4	--	--
2/8/11 16:47	--	-2.7	--	--
2/10/11 10:59	0.23	-0.6	-0.7	-0.1
2/10/11 14:05	--	-0.8	--	--
2/11/11 7:15	0	0.4	0.6	1.0
2/11/11 16:35	--	-3.9	--	--
2/11/11 16:35	--	3.7	--	--
2/14/11 7:43	0.12	0.6	1.5	0.0
2/14/11 16:52	--	3.1	--	--
2/15/11 7:32	0.93	-0.6	-0.8	0.1
2/15/11 15:07	--	8.2	--	--
2/16/11 7:15	0.5	-0.8	-0.3	0.2
2/16/11 13:00	--	1.0	--	--
2/16/11 17:03	--	-1.0	--	--

^a Low Span = 490 ppm CH₄.

^b % Difference = ((Output-Input)/Input) x 100

^c Mid Span = 1960 ppm CH₄.

^d High Span = 9860 ppm CH₄.

3.6.4 Field Data Review

Field data was reviewed each week in Phase I by the acting QA/QC Officer. In Phase II, this role was divided between the two field team leaders. Each team leader checked the other team's field data for completeness and accuracy on a daily basis. The team leaders also checked periodically for consistency in sampling procedures and data recording between the two teams.

3.6.5 Canister Sample Collection QC

A strict canister sampling protocol was followed to ensure quality sampling results:

1. All canisters were vacuum checked prior to sampling. Canisters with vacuums less than 25 inches Hg were rejected.
2. Residual vacuums of 2 to 10 inches Hg were left in canisters following sample collection.
3. Canister collection data was recorded on data forms as well as in canister logbooks (one per team).
4. Standard canister Chain-of-Custody procedures were observed.
5. Between use and prior to shipping, canisters were kept securely in the project field office.
6. Five percent of the canister samples were collected in duplicate to provide a measure of total sampling and analytical variability.

Eight duplicate canister samples were collected. Comparisons of the analytical results for each duplicate pair are provided in Table 3.6-16 as the relative percent differences (% RPD) between analytes. Since each canister sample was analyzed by EPA Method TO-15 for VOCs and by ASTM D1946 for methane, Table 3.6-16 includes the results for both analytical techniques. The average percent relative differences for the duplicate canisters range between 11 to 61 percent. This is considered an acceptable result for field samples.

Table 3.6-16. Duplicate Canister Results

Site ID:	PS-134
Site Address:	5199 Village Creek Rd
Owner/Operator:	Quicksilver Resources
Date:	10/5/2010
Time:	10:00-11:30
Canister Numbers:	103 and HL 0887

Compounds	Sample #A020	Sample #A021	RPD^a
Methane	255000	480000	61.2
Butane	16.1	32.9	68.6
Isopentane	2.30	2.51	8.7
Acetone	0.034	ND ^b	--
n-Pentane	1.53	1.08	34.5
Methylene chloride	0.0084	0.01120	28.6
Hexane	0.128	0.304	81.5
Benzene	1.87	3.01	46.7
Cyclohexane	1.10	1.32	18.2
Heptane	ND	0.0299	--
Toluene	0.852	1.93	77.5
n-Octane	ND	0.00876	--
Ethylbenzene	0.00531	0.0112	71.4
m-Xylene & p-Xylene	0.0466	0.0956	68.9
o-Xylene	0.0162	0.0316	64.4
Isopropylbenzene	0.00748	0.0134	56.7
n-Propylbenzene	0.0304	0.0574	61.5
4-Ethyltoluene	0.105	0.143	30.7
1,3,5-Trimethylbenzene	0.0599	0.12	66.8
1,2,4-Trimethylbenzene	0.145	0.381	89.7
n-Decane	ND	0.00681	--
sec-Butylbenzene	ND	0.00535	--
n-Undecane	ND	0.0187	--
n-Dodecane	0.128	1.49	168.4
Average RPD:			61.8
Maximum RPD:			168.4
Minimum RPD:			8.7

^a RPD = Relative Percent Difference = $100 * \text{Absolute Value}(X1-X2) / ((X1+X2)/2)$

^b ND = None Detected

Table 3.6-16. (Continued)

Site ID:	PS-171
Site Address:	3892 Lou Stevenson (Walls Coleman)
Owner/Operator:	Chesapeake Operating Inc.
Date:	10/14/2010
Time:	13:38-16:15
Canister Numbers:	5440 and RA 2402

Compounds	Sample #B034	Sample #B035	RPD
Methane	357000	334000	6.7
Chloromethane	0.00837	ND	--
Butane	8.18	7.86	4.0
Isopentane	0.486	0.494	1.6
Acetone	0.0196	0.0133	38.3
n-Pentane	0.490	0.539	9.5
Methylene chloride	0.01340	0.01450	7.9
Hexane	0.0165	0.0481	97.8
Benzene	0.188	0.370	65.2
Cyclohexane	0.183	0.249	30.6
Toluene	ND	0.0975	--
1,2,4-Trichlorobenzene	0.0199	ND	--
Naphthalene	0.0230	ND	--
n-Dodecane	0.0154	ND	--
1,2,3-Trichlorobenzene	0.0293	ND	--
Hexachlorobutadiene	0.00863	ND	--
Average RPD:			29.1
Maximum RPD:			97.8
Minimum RPD:			1.6

Table 3.6-16. (Continued)

Site ID:	176
Site Address:	11593 Saginaw Blvd
Owner/Operator:	Devon Energy Production Co
Date:	1/7/2011
Time:	11:55-14:45
Canister Numbers:	HL 0979 and 240

Compounds	Sample #A036	Sample #A037	RPD
Methane	65800	63800	3.1
Butane	1.20	1.14	5.1
Isopentane	0.0830	0.0833	0.4
n-Pentane	0.0525	0.0525	0.0
Methylene chloride	0.01260	0.01290	2.4
Benzene	0.117	0.115	1.7
Cyclohexane	0.0321	0.0255	22.9
Toluene	0.0906	0.0755	18.2
m-Xylene & p-Xylene	0.0289	0.0182	45.4
Average RPD:			11.0
Maximum RPD:			45.4
Minimum RPD:			0.0

Table 3.6-16. (Continued)

Site ID:	161
Site Address:	10999 Willow Springs Rd
Owner/Operator:	Devon Energy Production Co
Date:	1/15/2011
Time:	11:00-13:15
Canister Numbers:	RA 2247 and 221

Compounds	Sample #A042	Sample #A043	RPD
Methane	63800	35400	57.3
Butane	1.52	1.01	40.3
Isopentane	0.210	0.138	41.4
n-Pentane	0.103	0.0545	61.6
Methylene chloride	0.01080	0.0110	1.8
Hexane	0.0231	0.00570	120.8
Benzene	0.0803	0.0499	46.7
Cyclohexane	0.0250	0.0160	43.9
Toluene	0.0574	0.0299	63.0
m-Xylene & p-Xylene	0.0265	ND	--
1,2,4-Trimethylbenzene	0.00752	ND	--
Average RPD:			52.9
Maximum RPD:			120.8
Minimum RPD:			1.8

Table 3.6-16. (Continued)

Site ID:	153
Site Address:	2492 Blue Mound Rd W
Owner/Operator:	Devon Energy Production Co
Date:	1/19/2011
Time:	14:30-17:10
Canister Numbers:	203 and 5424

Compounds	Sample #A047	Sample #A048	RPD
Methane	118000	76200	43.1
Butane	2.28	1.57	36.9
Isopentane	0.139	0.0903	42.5
n-Pentane	0.0850	0.0533	45.8
Methylene chloride	0.010	0.01320	27.6
Benzene	0.189	0.144	27.0
Cyclohexane	0.0431	0.0295	37.5
Toluene	0.0475	0.0483	1.7
Average RPD:			32.8
Maximum RPD:			45.8
Minimum RPD:			1.7

Table 3.6-16. (Continued)

Site ID:	240
Site Address:	1392 Conell Sampson Rd
Owner/Operator:	XTO Energy Inc
Date:	1/27/2011
Time:	10:25-12:48
Canister Numbers:	KA 2315 and HL 0930

Compounds	Sample #A059	Sample #A060	RPD
Methane	21300	39400	59.6
Butane	1.01	1.99	65.3
Isopentane	0.0823	0.164	66.3
n-Pentane	0.0377	0.0648	52.9
Methylene chloride	0.01390	0.02050	38.4
Benzene	0.0820	0.143	54.2
Cyclohexane	0.0213	0.0362	51.8
Toluene	0.0440	0.0855	64.1
Average RPD:			56.6
Maximum RPD:			66.3
Minimum RPD:			38.4

Table 3.6-16. (Continued)

Site ID:	238
Site Address:	798 Industrial Rd
Owner/Operator:	XTO Energy Inc
Date:	1/31/2011
Time:	10:55-16:25
Canister Numbers:	279 and 217

Compounds	Sample #A065	Sample #A066	RPD
Methane	549000	528000	3.9
Butane	132	106	21.9
Isopentane	21.0	19.8	5.9
Acetone	0.0968	0.0898	7.5
n-Pentane	6.69	5.84	13.6
Methylene chloride	0.02310	0.01680	31.6
Hexane	2.90	2.65	9.0
Benzene	17.2	16.6	3.6
Cyclohexane	4.37	4.57	4.5
Heptane	0.269	0.259	3.8
Toluene	14.2	12.6	11.9
n-Octane	0.0285	0.0242	16.3
Ethylbenzene	0.139	0.126	9.8
m-Xylene & p-Xylene	3.67	3.04	18.8
o-Xylene	0.442	0.368	18.3
n-Nonane	0.0106	ND	--
Isopropylbenzene	0.0162	0.0129	22.7
n-Propylbenzene	0.0209	0.0176	17.1
4-Ethyltoluene	0.0312	0.0242	25.3
1,3,5-Trimethylbenzene	0.214	0.144	39.1
1,2,4-Trimethylbenzene	0.178	0.101	55.2
n-Decane	0.0126	0.00762	49.3
Naphthalene	0.0232	ND	--
1,2,3-Trichlorobenzene	0.0219	ND	--
Hexachlorobutadiene	0.00995	ND	--
Average RPD:			18.5
Maximum RPD:			55.2
Minimum RPD:			3.6

Table 3.6-16. (Continued)

Site ID:	426
Site Address:	692 Bridgewood Dr
Owner/Operator:	Chesapeake Operating Inc.
Date:	2/11/2011
Time:	9:50-12:25
Canister Numbers:	RA 2173 and RA 2150

Compounds	Sample #B095	Sample #B096	RPD
Methane	76600	93800	20.2
Butane	1.98	2.46	21.6
Isopentane	0.135	0.162	18.2
n-Pentane	0.0664	0.0694	4.4
Methylene chloride	0.01180	0.01200	1.7
Benzene	0.135	0.173	24.7
Cyclohexane	0.0177	0.0101	54.7
Toluene	0.0383	0.0522	30.7
Average RPD:			22.1
Maximum RPD:			54.7
Minimum RPD:			1.7

3.6.6 Analytical QC Results

To ensure high quality analytical results, TestAmerica™ performed several quality control checks during the analysis of each batch of canister samples received by them from the point source team. The most significant of these were: Method Blanks, Surrogate Recoveries, Laboratory Control Samples and Control Sample Duplicates, and Continuing Calibration Verification checks.

Method Blanks

Analytical method blanks were analyzed by TestAmerica™ either daily or after a certain number samples (i.e. after each batch of 20 samples). The method blank is treated like any other sample except that a clean material, free from any of the sample targets, is used. The results of the method blank indicate if any contaminants are present in the analytical system. The only compound that routinely appeared in the analytical method blanks associated with this project's canister samples was small amounts of methylene chloride, a common laboratory solvent. In calculating the canister emission factors the amount of methylene chloride detected in the method blank was subtracted from the reported methylene chloride result. Method blank results are provided for each canister sample result in the TestAmerica™ analytical reports provided in Appendix 3-C.

Surrogate Recoveries

A surrogate standard is a non-target analyte having a chemical structure similar to the target analytes that is added to a sample prior to extraction. Six surrogate standards were added to each point source canister sample prior to extraction and their percent recoveries were evaluated following analysis of the canister's contents. The surrogates monitor the efficiency of the extraction, the cleanup, and evaporation of the solvent if any has been used on the sample. Surrogate percent recoveries for each canister result together with acceptable recovery limits are provided with each of TestAmerica's™ analytical reports contained in Appendix 3-C.

Laboratory Control Samples and Control Sample Duplicates

The Laboratory Control Sample (LCS) is a clean matrix that is fortified with the target analytes and analyzed in the same manner as a batch of samples is analyzed. Since in this case the concentration of each analyte is known, the resulting values provide a measure of the accuracy of the system for each analyte. As a further measure of quality control, the LCS is analyzed in duplicate and the relative percent difference between the two results is calculated and evaluated against the laboratory's acceptance criteria. Both LCS and LCS duplicate results are provided towards the conclusion of each TestAmerica™ report.

Continuing Calibration Verification

Continuing Calibration Verification (CCV) checks are performed over specific time periods during sample analysis to confirm the instrument's calibration and performance. A CCV check was performed by TestAmerica™ with each batch of sample analyses. The results are evaluated as the percent recoveries of the known analyte concentrations making up the CCV spike. The results of each CCV check are reported under the heading "Calibration Check" in the TestAmerica™ documentation located in Appendix 3-C.

3.7 Point Source Testing Conclusions

Point source testing was conducted to determine how much air pollution is being released by natural gas exploration in Fort Worth, and if natural gas extraction and processing sites comply with environmental regulations. The point source testing program occurred in two phases, with Phase I occurring from August through October of 2010, and Phase II occurring in January and February of 2011. Under the point source testing program, field personnel determined the amount of air pollution released at individual well pads, compressor stations, and other natural gas processing facilities by visiting 388 sites, includes two repeat visits, and testing the equipment at each site for emissions using infrared cameras, toxic vapor analyzers (TVAs), Hi Flow Samplers, and evacuated canisters to collect emission samples for laboratory analysis.

TOC, VOC, and HAP emissions were calculated on an annual basis for each site as the sum of 1) direct canister sample results; 2) adjusted canister results using correlation equations; 3) tank and non-tank surrogate emission profiles; 4) engine emission data; and 5) default zero emission factors. Emissions associated with tank unloading, tank flashing, well snubbing, glycol

reboilers, flares or any type of maintenance/repair activities were not included in the calculated site emissions profiles.

Key findings from the point source testing program are as follows:

- A total of 2,126 emission points were identified in the four month field study: 192 of the emission points were Valves, 644 were Connectors and 1,290 were classified as Other Equipment. 1,330 emission points were detected with the IR camera (i.e. high level emissions) and 796 emission points were detected by Method 21 screening (i.e. low level emissions).
- At 96 sites, no emissions were detected by the IR camera. At 46 sites, no emissions were detected by either the IR camera or the TVA. Of these 46 sites, 38 had less than three wells and subsequently lower auxiliary equipment counts such as tanks, separators, valves, and connectors.
- Emissions from lift compressors have a significant impact on well pad emissions. Most lift compressors are mobile and are moved from site to site as needed. The addition of a lift compressor to a well pad site has the effect of raising TOC emissions four-fold while emitting an average 16 tons/yr of criteria pollutants.
- The largest source of fugitive emissions detected with the IR camera was leaking tank thief hatches. Emissions were detected at 252 tank thief hatches resulting in a combined TOC emission rate of 4,483 tons/yr. Some of these emissions were due to the operators simply leaving the hatches unsecured as shown in Figure 3.7-1 below. Many others, however, appeared to be due to lack of proper maintenance.



Figure 3.7-1. Thief Hatch Left Open

- Pneumatic Valve Controllers were the most frequent emission sources encountered at well pads and compressor stations. These controllers use pressurized natural gas to

actuate separator unloading valves. Under normal operation a pneumatic valve controller is designed to release a small amount of natural gas to the atmosphere during each unloading event. Due to contaminants in the natural gas stream, however, these controllers eventually fail (often within six months of installation) and begin leaking natural gas continually. The emissions from the 489 failed pneumatic valve controllers detected by the point source team result in a combined TOC emission rate of 3,003 tons per year.



Figure 3.7-2. Pneumatic Valve Controller on Separator

- Emissions from 175 storage tank vents were detected by the IR camera accounting for a combined total of 2,076 tons of TOC per year. In numerous instances several tanks would be manifolded to one vent controlled by a pressure relief valve. In these cases, vent emissions detected with the IR camera indicated a failure of the pressure relief valve.



Figure 3.7-3. Storage Tank Vent

- Emissions from 257 leaking natural gas pressure regulators accounted for a combined TOC total of 614 tons/yr.

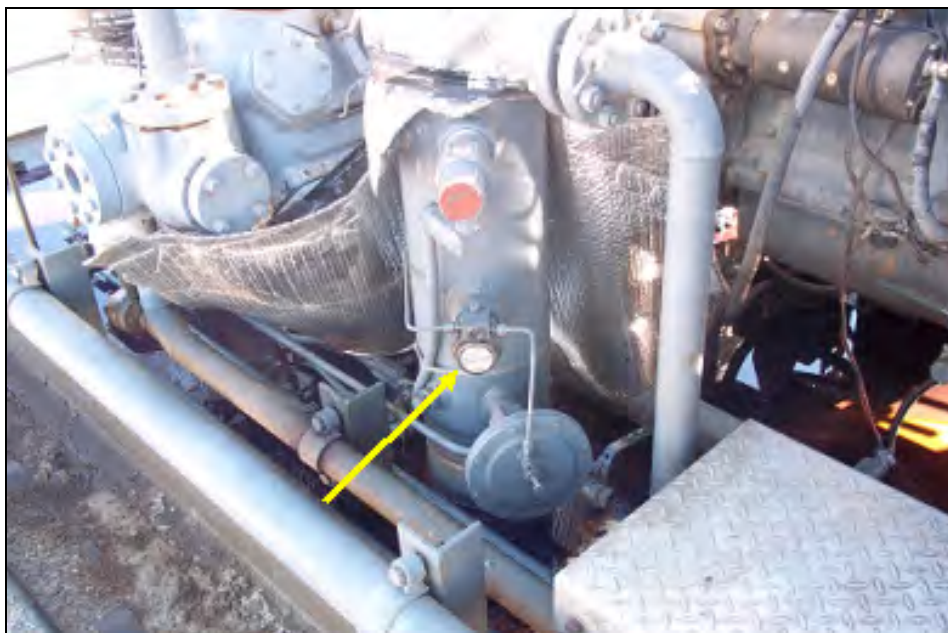


Figure 3.7-4. Natural Gas Pressure Regulator

- Fifty-five (55) instances of emissions from miscellaneous equipment were detected, accounting for a combined TOC emission rate of 731 tons/yr. Miscellaneous equipment includes pinholes, compressor shafts, sumps, knock-out pots, underground piping, glycol contactor controllers, pressure indicators, and quite frequently, holes or breaks in the tank roofs (Figure 3.7-5).



Figure 3.7-5. Hole in Tank Roof - Miscellaneous Emission Source

- No natural gas emissions associated with drilling and fracking activities were detected by the IR camera. Engine emissions associated with these activities were estimated based upon vendor data and published emission factors.
- Emissions were detected from a well completion activity with the IR camera. However, no measurements were taken using the TVA and Method 21 screening procedures and/or the highflow sampler due to safety considerations.
- Emissions were also detected at the Salt Water Treatment facility using the TVA. No emissions were detected using the IR camera. The emissions that were detected with the TVA resulted from minor fugitive emission components only. The Evaporative Unit was not able to be tested since it was out of service during the point source survey.
- Although there was little difference in average TOC emissions between dry and wet gas sites, average VOC and HAP emissions from wet gas sites proved to be considerably higher than dry gas sites as would be expected due to the additional storage and loading of condensate at wet gas sites.
- An Encana Oil & Gas Well Pad (Site ID PS-184) located at 10590 Chapin Road had the highest VOC emissions among well pads (22 tons/yr). This site had only a single well, with two tanks. However, it also had one large line compressor (Caterpillar G-399). Twelve (12) emission points were detected at this site with the IR camera: Four in the area of the separators, three on the tanks, and five at the compressor.



Final Report

**For Determining Bleed Rates for Pneumatic Devices in British
Columbia**

December 18, 2013

Executive Summary

Regulations in BC stipulate that all greenhouse gas (GHG) emissions from pneumatic instruments and pumps must be tracked for reporting and compliance purposes. In order to help industry quantify these emissions more efficiently and cost effectively, the BC Climate Action Secretariat (CAS), Ministry of Natural Gas Development and Canadian Association of Petroleum Producers (CAPP) engaged The Prasino Group (Prasino) to determine bleed rates for a suite of common pneumatic controllers and pumps. This survey is the first of its kind and was funded by the Science and Community Knowledge (SCEK) Fund.

Pneumatic controllers and pumps use pressurized fuel gas to perform operations such as pressure control, temperature control, liquid level controller and chemical injection. This fuel gas is subsequently released to the atmosphere after the operation is performed. The bleed rate of a pneumatic device is defined as the amount of fuel gas released to the atmosphere per hour. Figure 1 shows the breakdown of GHG emissions from the oil and gas sector in BC with a detailed breakdown of the sources of vented methane. The high bleed pneumatic controllers and pumps, which are the subject of this study, contribute 436,000 tCO₂e of the 1,723,000 tCO₂e from vented methane. The amount of contribution from pneumatic devices and pumps is expected to change as a result of this study.

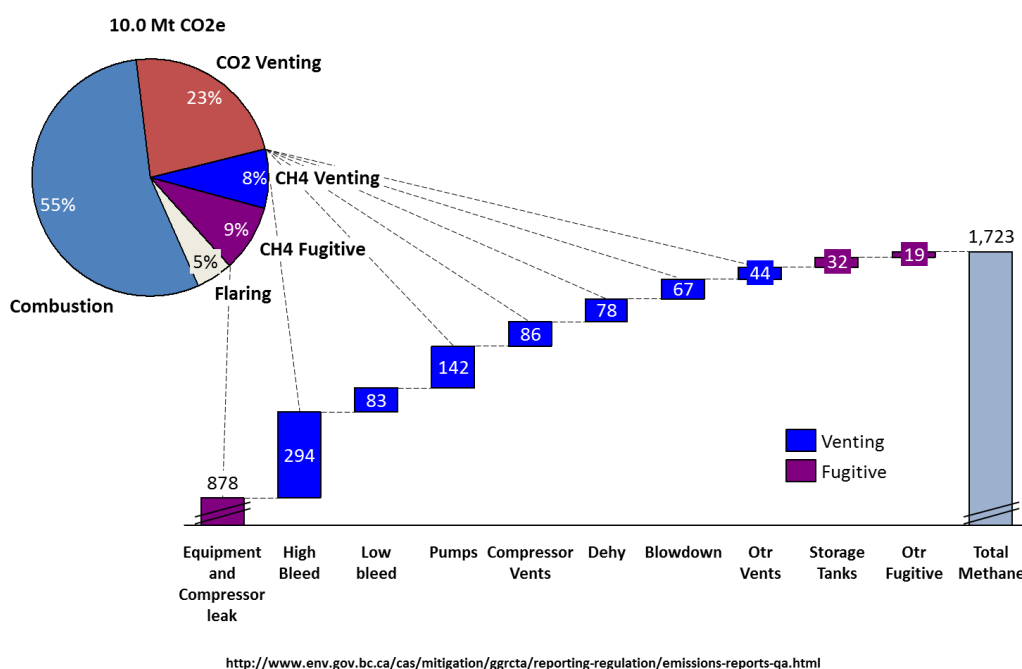


Figure 1: Detailed Breakdown of vented and fugitive methane sources in the BC oil and gas sector (source BC CAS 2013).

The purpose of the survey was to determine the average bleed rate of pneumatic controllers and pumps when operating under field conditions in BC. Bleed rates were sampled from pneumatic devices using a positive displacement bellows meter at upstream oil and gas facilities across a variety of producing fields in the Fort St. John, BC and surrounding, areas. Descriptive statistics, general linear models and regression analysis was performed on the data to investigate the bleed rates and draw robust, relevant conclusions.

All outcomes were achieved. The results of the analysis led to the development of three generic bleed rates and twenty specific bleed rates for common pneumatic controllers and pumps for BC's oil and gas industry. These bleed rates can be used in the development of emission factors for GHG reporting and potentially offset purposes.

Table 1: Summary of Findings

Pneumatic Device	Average Bleed Rate (m ³ /hr)	Coefficients ¹ (supply pressure, injection pressure, strokes per min)	Equivalent Device
Generic High Bleed Controller	0.2605	0.0012	-
Generic High Bleed Intermittent Controller	0.2476	0.0012	-
Pressure Controllers			
Fisher 4150	0.4209	0.0019	4150K, 4150R, 4160, CVS 4150
Fisher C1	0.0649	0.0003	-
Fisher 4660	0.0151	-	4660A
Level Controllers			
Fisher 2500	0.3967	0.0011	2500S, 2503, L3
Fisher 2680	0.2679	0.0014	2680A
Fisher 2900	0.1447	-	2900A, 2901, 2901A
Fisher L2	0.2641	0.0012	-
Murphy L1200	0.2619	0.0012	L1100, L1200N, L1200DVO
Norriseal 1001	0.1868	-	1001A, 1001XL
SOR 1530	0.0531	-	-
Positioners			
Fisher Fieldvue DVC6000	0.2649	0.0011	6030, 6020, 6010
Temperature Controllers			
Kimray HT-12	0.0351	-	-
Transducers			
Fairchild TXI7800	0.1543	0.0009	TXI7850
Fisher 546	0.3547	0.0017	546S
Fisher i2P-100	0.2157	0.0009	-
Pumps			
Generic Piston Pump	0.5917	0.00202, 0.000059, 0.0167	-
Generic Diaphragm Pump	1.0542	0.0005, 0.000027, 0.0091	-
Morgan HD312	1.1292	0.00418, 0.000034, 0.0073	HD312-3K, HD312-5K
Texsteam 5100	0.9670	0.0003, 0.000034, 0.0207	5100LP, 5100H
Williams P125	0.4098	0.00019, 0.000024, 0.0076	-
Williams P250	0.8022	0.00096, 0.000042, 0.0079	-
Williams P500	0.6969	0.00224, -0.000031, 0.0046	-

¹ Controllers that do not have a coefficient should use the mean bleed rate instead of the bleed rate equation.

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1. Introduction

This report outlines the methodology and analytical methods used to develop bleed rates for reporting GHG emissions from pneumatic controllers and pumps (collectively referred to as ‘devices’) in British Columbia (BC). The development of emissions factors may allow for an alternative method of monitoring and reporting GHGs from pneumatic devices, as per an agreement between the Canadian Association of Petroleum Producers (CAPP) and the B.C. Ministry of Environment’s Climate Action Secretariat (CAS). The Prasino Group (Prasino) has been engaged by the Science and Community Environmental Knowledge Fund (SCEK) in order to develop these bleed rates based on quantitative sampling of pneumatic devices in BC. This document is the final project report and builds off the subsequent three reports (Sampling Methodology, First Round Sampling Report and Final Sampling Report) that were submitted to SCEK. This document is meant to be a standalone report and describes:

- The sampling methodology used to obtain the field bleed rate samples;
- The characteristics of the samples;
- The statistical analysis performed on the field bleed rate samples as well as a discussion of the results; and
- The recommended bleed rates for each pneumatic device included in the survey.

2. Sampling Methodology

Pneumatic devices used in B.C.’s oil and gas sector fall into two categories:

1. Pneumatic chemical injection pumps (typically injecting methanol into a pipeline); and,
2. Pneumatic controllers, which regulate pressure, temperature, fluid level, or some other process variable.

There are dozens of manufacturers of the types of pneumatic devices listed above. Even though the device types perform similar functions, they have inherently different bleed rates. Due to constraints, it was necessary to narrow sampling to the most common or representative devices. A “Device Selection Approach” was used to narrow the sample and determine the most common devices in the field.

Figure 2 below outlines the steps that were followed to develop the initial list of devices for sampling. Further detail will be provided in the next section. The following section describes the process that was used for selecting which devices to include in the sampling regime.

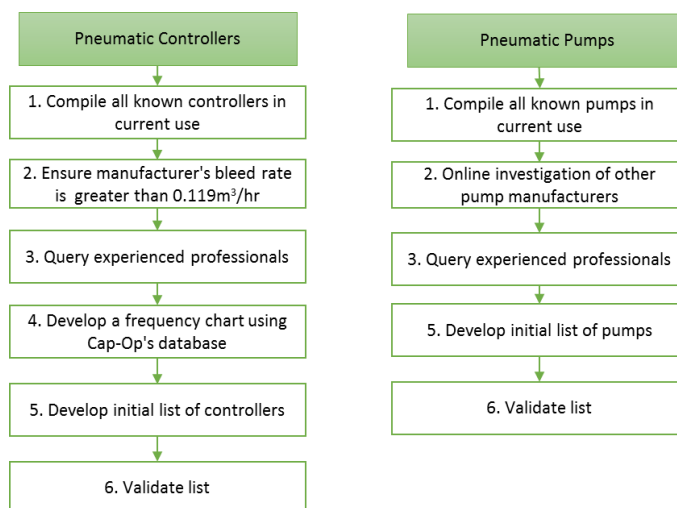


Figure 2: Device Selection Approach²

2.1 Pneumatic Controllers

In order to determine which pneumatic controllers to include in our sample, multiple steps were undertaken as illustrated in

Figure 2. Through this process, 15 controllers were identified as common. For the rare devices that are not within the scope of this project, a generic high-bleed rate has been developed for all high-bleed controllers. This ensures that any pneumatic controller can apply a bleed rate that is representative of field conditions.

Step 1: Compile All Known Controllers

Prasino initially developed a complete list of all known pneumatic low and high-bleed controllers that were anticipated to be used in the upstream oil and gas industry in BC. Using one or more of the sources listed below, the make, model, and manufacturers' stated bleed rate of each controller was determined:

- *Canadian Environmental Technology Advancement Corporation-West (CETAC): Efficient Use of Fuel Gas in Chemical Injection Pumps. Fuel Gas Best Management Practices.* The BMP lists manufacturer bleed rates of controllers in m³/hr of natural gas.
- *Pacific Carbon Trust (PCT): High-Bleed to Low-Bleed Conversion for Pneumatic Controllers. Meta-Protocol for Oil and Gas Emission Reductions Projects.* In the protocol, the bleed rates were stated in standard cubic feet per hour (scfh) of air, based on manufacturer stated specifications. The volume of air bled was converted to natural gas by multiplying by 1.3³. When a range of bleed rates was listed, the highest value was taken to be conservative.
- *Environmental Protection Agency: Gas STAR – Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry.* This document stated the bleed rates of high- and low-bleed controllers in scfh of air. These values were converted to m³/hr of natural gas.
- *Western Climate Initiative (WCI): Final Essential Requirements of Mandatory Reporting.* This report references the BMP, PCT Protocol and EPA Gas STAR for the pneumatic controller list and bleed rates. The manufacturer bleed rates in this document are in m³/hr.
- *Manufacturer websites* were referenced to determine the steady state air consumption for pneumatic controllers. The highest steady state air consumption was recorded. The bleed rates were stated in m³/hr and scfh.
- *Cap-Op Energy samples from the DEEPP database* were used to look at controllers and pumps that are already in the field and have been sampled previously by GreenPath Energy Ltd⁴.

Step 2: Equivalent Devices

Controllers may have different makes and models but serve the same function. Controllers are considered equivalent devices if they have interchangeable parts. A list of equivalent devices was compiled using information from device vendors and subject matter experts, and is presented in Appendix A (J. Anhalt, personal communication, July 2013; B. Van Vliet, personal communication, July 2013).

² "Cap-Op's Database" refers to Cap-Op Energy's Distributed Energy Efficiency Project Platform (DEEPP), which was queried for historical pneumatic controller information. Cap-Op Energy is a sub-contractor to Prasino.

³ The value 1.3 is based on the density and molar mass of air and natural gas in ideal gas conditions. This manner of conversion is an industry standard.

⁴ GreenPath Energy Ltd. is the contractor who was responsible for completing the field sampling protocol.

Step 3: Ensure Manufacturer Bleed Rates are Greater than 0.119 m³/hr

Manufacturer bleed rates were used to determine which controllers are considered high bleed and therefore relevant for sampling. However, these manufacturer bleed rates are based on manufacturer lab testing and may not reflect actual field conditions. The steady state bleed rates reported are static bleed rates of controllers that are not actuating and thus dynamic bleeding is not captured. Therefore, the manufacturer bleed rates may not accurately express the actual vented natural gas through these controllers because the steady state does not include dynamic bleeding. The relationship between the bleed rates of controllers that are running on dirty/wet natural gas compared to air is unknown. It is likely that controllers operating in the field bleed more than controllers tested in a laboratory using air.

The current definition whether a controller is a high or low bleed controller is based on the WCI Reporting Regulation definition: “high-bleed devices are defined as all natural gas powered devices which continuously bleed at a rate greater than 0.17 m³/hr.”

Many controllers have manufacturer bleed rates just below 0.17 m³/hr, and thus appear to be a low-bleed controller. Since manufacturers do not consider the dynamic bleed rate in their stated bleed rate, many low-bleed controllers in fact bleed more than 0.17 m³/hr on a regular basis. To ensure all relevant controllers that bleed more than 0.17 m³/hr (including static and dynamic bleeding) are included within the sample, the manufacturer bleed rates were compared to a limit of 0.119 m³/hr (CAS, 2013). In many cases, the manufacturer states a range of bleed rates that are dependent on other operating parameters of the controller (i.e. 1.4 scfh at 20 psi vs. 3 scfh at 30 psi). In this case, the highest bleed rate was recorded to ensure that all controllers with the potential to bleed higher than 0.17 m³/hr were included. Refer to Appendix A for highest manufacturer bleed rates. Controllers that have been excluded from sampling as a result of this step are represented at the bottom of the table in Appendix A.

Step 4: Query Subject Matter Experts

Subject matter experts were queried as per the request of CAS to determine if the list of pneumatic devices was inclusive and representative. Several low-bleed controllers below the limit of 0.119 m³/hr have been included based on these discussions to investigate if controllers that are labelled according to manufacturer specification actually perform as a low bleed device in the field. Four low-bleed controllers were included in the survey: Fisher C1, Fisher 4660, SOR 1530 and Kimray HT-12. The results of the query are represented in Appendix A.

Step 5: Determine the Frequency of Occurrence of Controllers

Using Cap-Op’s DEEPP database, the eligible list of all pneumatic controllers was filtered down to focus sampling on devices that are considered common. Cap-Op Energy has an extensive +2000 sample database from previous work on pneumatic devices from the upstream oil and gas industry in Alberta and BC. This database was used as a proxy for determining which controllers are common among producers in the Canadian oil and gas industry. The samples could not however be included in the survey because they were taken using the Bacharach High-Flow Sampler and this survey is using the Calscan vent gas bellows meter for reasons presented in Section 2.4.3. These eligible controllers were compared with the extensive field samples database from Cap-Op Energy’s DEEPP to examine the frequency of eligible controllers previously surveyed in the field. The results are depicted in Figure 3 below.

Step 6: Develop Initial List

The common list of pneumatic controllers used to guide first round sampling can be found in Appendix B. The results include:

- The top 10 controllers represent 89% of the surveyed controllers in the Cap-Op database.
- The top 15 controllers represent 97% of the surveyed controllers in the Cap-Op database.
- Rare devices are those that comprise the remaining 3% of the surveyed controllers in the Cap-Op database.

This initial list was used to guide first round of sampling because the selected devices were anticipated to be frequent enough to produce statistically valid emissions factors.

Step 7: Validate list

Upon completion of the first round of sampling the original list was compared with what was observed in the field to determine if the anticipated list of 15 devices was the most common. Based on survey data collected in the field, two devices were found to be common and added to the sample: Fairchild TXI7800; and Murphy L1200. Two devices were found to be rarer than initially thought and thus have been removed from the sample population: Fisher 2660 (no devices found in the field); and Dyna-Flo 4000 (two devices found in the field).

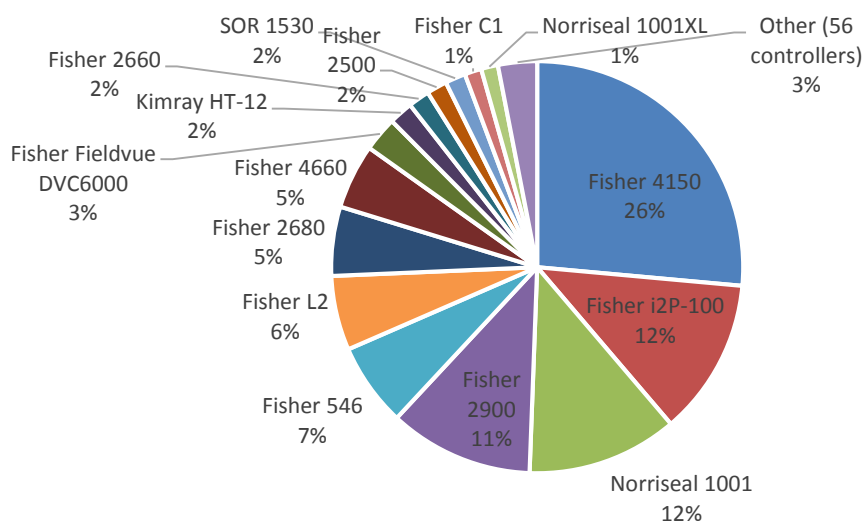


Figure 3: Frequency of pneumatic controllers found in the Cap-Op database

2.2 Pneumatic Pumps

The methodology used for determining the list of pneumatic pumps does not mirror the methodology used for pneumatic controllers because the Cap-Op database does not contain sufficient pump field samples to draw similar conclusions. The list of pneumatic pumps was compiled from the CAPP (2008), PCT (2011) and the Cap-Op DEEPP database. These sources were cross-referenced with manufacturer websites and subject matter experts to make a comprehensive initial list, presented in Appendix B. This initial list was used to guide first round of sampling; however, all pumps were sampled in the first round to determine which types were common among the producers sampled. Five common pumps were identified after the first round of sampling and were targeted during the second round of sampling: Textsteam 5100; Morgan HD 312; Williams P125; Williams P250; Williams P500.

2.3 Sampling Approach

The following section provides detail on how the field samples were collected as well as justification for which companies and geographic areas were selected for sampling.

The analysis and discussions in this report distinguish the 'sample set' or 'sample' from the 'population'. In general, this analysis operates under the assumptions that the true number and state of the population (i.e. all pneumatic devices in BC) is unknown. Determining whether the sample is representative of the population, and to what extent is a major

component of this report and helps to characterize the validity of the results. Statistical analyses and conclusions are contingent on the assumption of an unknown population.

2.3.1 Bleed Rate Metering

The metering requirements for this project are unique and as such there are few options for determining gas vent rates from devices in a cost effective manner.

The desired meter must have the following characteristics:

- Mobility – the meter will have to be mobile such that the sampling teams can apply the meter to pneumatic devices in-service at various facilities throughout BC. This requires a relatively simple installation and removal procedure, with a low weight and portability such that it can be moved by one or two people to within a few feet of an existing pneumatic device as it is installed on-site. Breaking, cutting or disassembling process pipes, flanges or joints is not acceptable, however vent tubing may be intercepted for measurement.
- Range – the meter must be designed to accommodate the measurement of flow rates between zero and approximately 1m³/h of gas at pressures ranging from atmospheric to a few feet of water column with minimal back pressure.
- Explosive Environment – All electronic devices intended for use within CSA classified zones require intrinsically safe electronic enclosures such that potentially arcing /sparking ignition sources are completely isolated from potentially explosive atmospheres that occur in oil and gas facilities. This is a minimum safety requirement for all sampling team and on-site personnel.

The desired meter should have the following characteristics:

- Time series data to distinguish static and dynamic operation on pneumatic devices.
- Minimal to no back pressure
- High precision, 2% or less uncertainty on reported values
- High accuracy, with correction for variable parameters such as gas composition, temperature, barometric pressure, humidity, etc.

Based on an extensive review of meters available in the industry, two options which were found to be best candidates included the Bacharach High Flow Sampler and the Calscan Hawk 9000 Vent Gas Meter. The Bacharach High Flow Sampler is designed to measure the rate of gas leakage around various processes in natural gas transmission, storage and compressor facilities. This is accomplished by sampling at a very large flow rate (8 to 10 scfh) to completely capture any gas leaking from the component. By accurately measuring the flow rate of the sampling stream and the natural gas concentration, it is possible to calculate the rate of gas leak.

Prasino elected to use the Hawk 9000 vent gas meter (supplied by Calscan Energy) to measure and digitally log flow vent gas over time (which will vary based on the device sampled). This allowed for both the static and dynamic bleed rates for pneumatic controllers, as well as the dump cycles for pneumatic pumps and level controllers, to be captured. A drawback of the Bacharach High Flow Sampler is that it captures a snapshot in time; rather than a time series measurement. The Bacharach High Flow Sampler can fail to capture the dynamic bleeding events. The Hawk 9000 meter uses a positive displacement diaphragm meter that detects flow rates down to zero, and can also effectively measure any type of vent gas (methane, air, or propane). In addition, the Hawk uses a precision pressure sensor, an external temperature probe and industry standard gas flow measurement algorithms to accurately measure the gas rates and correct for pressure and temperature differences. As a result, flow measurement accuracies within $\pm 2\%$ ⁵. A picture of the Calscan Hawk 9000 is presented in Figure 3 and an example output chart is provided in Figure 5 below.



Figure 4: Calscan Hawk 9000 Meter

⁵ The meter is calibrated from -40°C to +60°C and uses “Gas Rate Algorithm AGA7” and “Equation of State AGA8”.

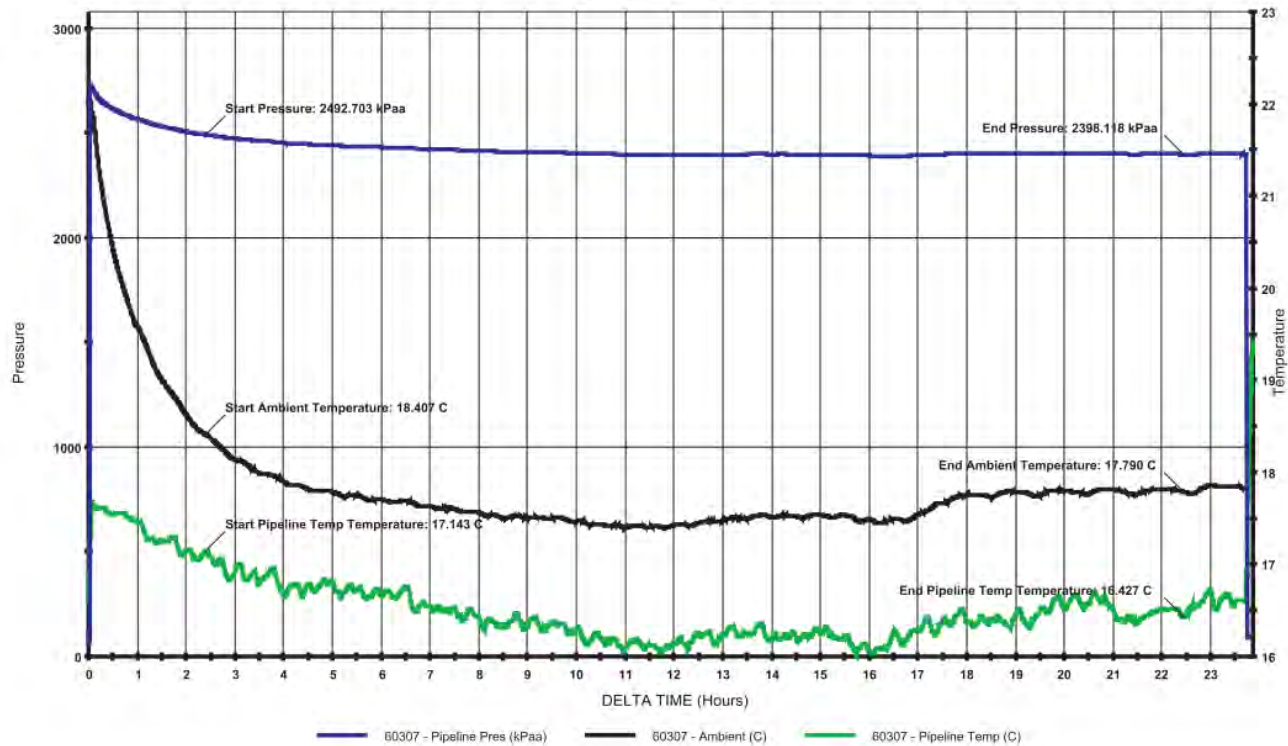


Figure 5: Example of Calscan Output Graph

2.3.2 Sample Size

The sampling program aimed to collect thirty samples of each device type identified as common according to Section 2.0 Sampling Methodology. Thirty was chosen as a minimum sample size in order to allow for statistical inferences to be drawn. When the sample size is sufficiently large (conventionally, 30 or larger), the standard error can be used to calculate a one-tail 95% confidence interval. As the sample population increases, the confidence interval should get smaller due to a decreased standard error (McClave and Sincich, 2003). In general, when calculating confidence interval, larger sample sizes and narrow confidence intervals must be balanced against the cost of additional sampling and the diminishing returns of incrementally smaller improvements to confidence intervals with each additional sample. Thirty samples for each common device type allows for the quantification of bleed rates with confidence intervals within a realistic budget and time frame.

2.3.3 Data Collection and Transfer

To manage the large amount of data that was collected during this sampling program, Cap-Op designed a software application (app) to be used in the field in order to increase data quality and tracking, and eliminate manual data recording. A field sampling guide was followed by the Greenpath sampling team and is provided in Appendix C.

All parameters were inputted into the app at the sampling location. Where appropriate, the app has dropdown menus to increase efficiency in compiling data. Numeric input fields have expected ranges of values and options for the units, so that if a value is entered outside of the range a message appears for the user to ensure the input is correct.

When the user has access to internet, the app will sync with Cap-Op Energy's DEEPP. The DEEPP will provide various functionalities for managing the data collected in the field including data storage and organizing the data into the desired output format of a download-able Excel files.

Controller

Cap-Op Controller ID# *: CS00004

Controller Type *: Select

Make *: Select

Model *: Select

Controller Serial #:

Supply Pressure *: Units

Controller Action *: Select

Condition of Controller *: Select

Gas Type *: Select

Quality of Gas *: N/A

Liquids Content : N/A

Sweet or Sour: N/A

Notes :

Take a Controller Photo

Perform Sample

Back to Site Overview

Cancel & Don't Save

Figure 6: Screen Shot of Cap-Op Energy's Data Collection App

2.3.4 Errors, Uncertainty and Biases

Errors, uncertainty and biases are part of every analysis and are discussed here for transparency and clarity. Overall, through critical review of the potential errors, uncertainties and biases inherent to this study, robust and reliable results can be attained.

An error is an unsupported result or conclusion that arose through improper application of methods, calculations, or data management. Every effort has been made to eliminate errors from the analysis and a system of checks has been employed to eliminate error from the analysis. Error can be eliminated from analysis, while bias and uncertainty cannot be.

Uncertainty, as it pertains to measurement of physical states or processes, describes the precision (or lack thereof) at which a characteristic or parameter can be defined. The precision associated with the measurement of bleed rates from a pneumatic device can be characterized through review of the techniques used to measure the parameters in question.

The meter chosen for this project (see Section 2.3.1) uses self-actuating, reciprocating bellows to discretely count fixed volumes of gas being vented from the device in five second intervals. The limitations associated with this type of measurement, and the uncertainties imposed, include:

- Volumes of gas vented lower than the fixed volume of one inflated bellow in a five second interval cannot be resolved. The uncertainty of any values of bleed rate reported by the meter under this value is large. This effect is typically characterized as the ‘turn-down ratio’ of a meter and every meter will have limits, turn-down or some range beyond which its reported values are unreliable. The Hawk 9000 meter has the range of flows that is appropriate for the intent of this study and thus mitigates this form of uncertainty to the extent possible.
- Pressures of vented gas lower than the back pressure imposed by the meter will significantly alter the value of gas being vented by the device. Back-pressure is a significant concern when measuring pneumatic control devices since the performance and bleed rate of the device may be inherently dependent on the back pressure of vented gas. This uncertainty impacts all ranges of gas flow, but in general will impose large uncertainty on high flows of gas since back pressure increases with flow. Devices which reported a zero bleed rate may actually have simply been ‘plugged’ by the internal actuating mechanisms of the meter. In general, it is impossible to measure the state of a system without disturbing the system, and this effect is unavoidable regardless of the type or extent of metering equipment chosen. It is anticipated that while the metering system chosen does impose a back pressure which may be more significant than other metering systems, the benefits of this metering system (time series bleed rate values and temperature pressure compensation) outweigh the detrimental effects of back pressure on the validity of results.
- Gas compositions vary from location to location and from moment to moment and the estimation of gas composition at each measurement point is a source of uncertainty. It is prohibitively expensive to have real-time gas composition parameters available to the measurement devices such that the uncertainty associated with gas composition could be further reduced. The estimations and assumptions made on gas composition for temperature and pressure correction of measured volumes is considered appropriate for the scope of this project.
- Digitization of data imposes uncertainty to values recorded during measurement through the limitation of significant digits (decimal places). The uncertainty imposed through the significant digits carried by data management systems in this project is considered to have contributed a negligible degree of uncertainty to the overall result.

In general, a statistic is biased if it is determined by an approach or method which systematically gives rise to differences between sample data and population data. Every effort was made in this sampling approach to avoid or minimize the effects of biases, nevertheless biases exist and are discussed below:

- Opportunistic Sampling Approach - The sampling approach used is a non-probability technique called opportunistic sampling, where sampling locations were chosen purposefully. The locations were chosen based on the following criteria:
 - The proximity to Fort St. John. Fort St. John is arguably a hub of oil and gas production within BC, with a majority of activity found within 500 km. In order to determine device bleed rates in an efficient and cost-effective manner, sampling was focused in this area. Sampling did not occur in the Fort Nelson region because many sites in Northern BC are winter access only or only accessible by helicopter.
 - The accessibility due to seasonality. Field locations with winter access only were excluded from the survey due to logistics and cost.
 - Producer identified device “hot spots”. Areas with a high concentration of devices were identified by cross-referencing producer’s inventories with the list of common devices.

- Sweet natural gas well-sites were preferred, followed by compressor stations and batteries, then sour gas well sites. Sweet sites were preferred over sour sites because they are typically run off compressed natural gas, whereas sour sites are typically run off propane or air. Well-sites were preferred over larger facilities because they typically house the common pneumatic controllers and pumps.

Opportunistic sampling has known limitations, including the sampling error⁶ which cannot be estimated, and that exclusion bias may arise from the non-random choice of sampling locations. However, random sampling was logistically impractical in this scenario and all efforts to minimize exclusion bias were made, by choosing sampling locations that were representative of a multitude of producers operating in BC, and production fields and sub-districts.

The effect of this exclusion bias is that the statistics describing the sample, may not accurately reflect the population statistics, and the extent to which this occurs cannot be determined. The likelihood and impact of this bias has been minimized by ensuring a sufficiently large sample size (the greater the sample size, the less selection biases will impact a result).

- Producer Influence – The sampling approach described above inherently allows for a set of biases which are the possibility for intentional and unintentional skewed sampling. Since permission was required from producers to access sites, and moreover, recommendations on which sites to visit were solicited from producers, it must be acknowledged that the producers may have unintentionally directed sampling to areas with more or less bleeding devices.
- Location – Pneumatic devices in the province of BC are limited to operation in the northern boreal shield or boreal plains climates at altitudes approximately centered around 690m above sea level. Oil and gas reserves are limited to those found in the western Canadian sedimentary basin and are not representative of global conditions. Biases arise from these geographic limitations and apply should the results of this study be implicated in jurisdictions outside of BC, however are irrelevant within the context of BC pneumatic device emissions.

⁶ *Sampling error* is an estimation of the difference between the true population mean and the sample mean, usually expressed in terms of standard error. Standard error cannot be reliably calculated using non-probability sampling techniques, although a mean, standard deviation, and confidence interval can be calculated with large (>30) sample numbers.

3. Sample Characteristics

In order to calculate a statistically significant bleed rate, with 95% confidence, a minimum of 30 samples was required per device. A total of 765 samples were taken across 28 producing fields in BC and 2 producing fields in Alberta.

Table 2. Number of Samples by Device Type

Device Type		Number of Samples
Pneumatic Controllers	Level Controller	254
	Positioner	43
	Pressure Controller	142
	Temperature Controller	41
	Transducer	101
Pneumatic Pumps	Chemical Injection	184

3.1 Pneumatic Controllers

Table 3 (below) summarises the number of samples by controller device. Devices in the “other” category were used to develop a generic emissions factor for pneumatic devices not specifically listed here.

Table 3. Pneumatic Controllers Sampled

Pneumatic Controllers	First Round Samples	Second Round Samples	Total
Pressure Controllers			
Fisher 4150	35	11	46
Fisher C1	27	3	30
Fisher 4660	29	1	30
Level Controllers			
Fisher L2	37	11	48
Murphy L1200	27	4	31
Norriseal 1001	47	10	57
SOR 1530	28	3	31
Fisher 2900	22	8	30
Fisher 2680	22	10	32
Fisher 2500	8	4	12
Positioner			
Fisher Fieldvue (DVC)	20	12	32
Temperature Controller			
Kimray HT-12	36	0	36
Transducer			
Fisher i2P-100	37	0	37
Fisher 546	27	3	30
Fairchild TXI7800	36	1	37
Other	53	7	64
Total	491	90	581

3.2 Pneumatic Pumps

The sampling results for pump devices are summarised in Table 4 (below).

Table 4. Pneumatic Pumps Sampled

Pneumatic Pumps	First Round Samples	Second Round Samples	Total
Morgan HD312	3	32	35
Texsteam 5100	47	0	47
Williams P125	50	0	50
Williams P250	28	0	28
Williams P500	12	0	12
Other	9	3	12
Total	149	35	184

3.3 Producers

To reduce sampling bias, a cross-section of oil and gas producing companies were included in the survey to ensure sampling was representative and spread across producers as well as producing fields. Figure 3 (below) shows the breakdown of sampling across the eight producers.

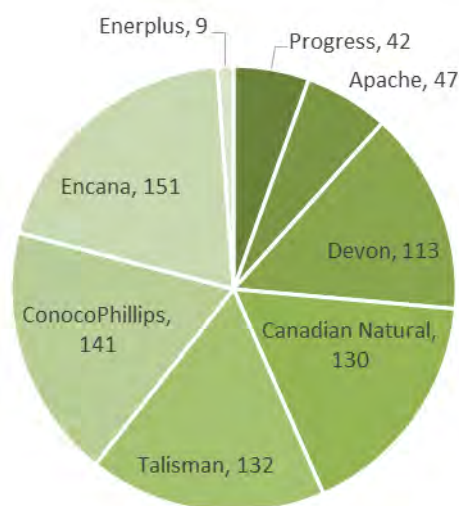


Figure 7: Breakdown of Samples by Producer

3.4 District and Sub-District

Table 5 outlines the number of samples per district as well as a breakdown of samples by producing field. Samples were collected from areas in northeastern BC; in the Fort St John, Brooks, Dawson Creek, Grand Prairie and Hanna districts (Figure 8). In total samples were taken from 30 different producing fields, with 756 samples coming from BC and 9 from Alberta.



Figure 8: Sampling Location

Table 5. Number of Samples by District and Sub-District

Producing Field	Number of Samples
Dawson Creek	254
Bissette	111
Brassey	7
Half Moon	7
Redwillow River	41
Sundown	25
Swan Lake	63
Fort St. John	394
Beaverdam	5
Blueberry	42
Buick Creek	29
Bullmoose	4
Bulrush	11
Burnt River	42
Cecil Lake	27
Eagle	36
Farrell	9
Farrell Creek West	43
Ladyfern	14
Monais	4
Muskrat	33
Nancy	26
North Cache	7

Producing Field	Number of Samples
North Pine	5
Owl	1
Septimus	16
Stoddart	29
Sukunka	11
Grand Prairie⁷	108
Hiding Creek	45
Noel	63
Hanna (AB)	7
Leo	7
Brooks (AB)	2
Verger	2
Total	765

4. Analysis

The analytical approach began by determining the mean sample bleed rate for each pneumatic controller and pump included in the survey. Table 6 below show the mean bleed rates, the 95% confidence interval (CI) and the standard deviation for the 20 common devices included in the survey. These bleeds rates are corrected for temperature, pressure and gas type.

Table 6: Results of Analysis by Device Model

Pneumatic Device	Number of Samples	Average Bleed Rate (m ³ /hr)	95% Confidence Interval (m ³ /hr)	Standard Deviation (m ³ /hr)
Pressure Controllers				
Fisher 4150	46	0.4209	0.5322	0.4593
Fisher C1	30	0.0649	0.0981	0.1106
Fisher 4660	30	0.0151	0.0329	0.0592
Level Controllers				
Fisher 2500	12	0.3967	0.5559	0.3353
Fisher 2680	32	0.2679	0.3782	0.3793
Fisher 2900	30	0.1447	0.2496	0.3490
Fisher L2	48	0.2641	0.3538	0.3779
Murphy L1200	31	0.2619	0.3618	0.3383
Norriseal 1001	57	0.1868	0.2670	0.3679
SOR 1530	31	0.0531	0.0841	0.1049
Positioners				
Fisher Fieldvue DVC6000	32	0.2649	0.3633	0.3386
Temperature Controllers				

⁷ Samples labelled Grand Prairie were taken from producing fields in BC.

Pneumatic Device	Number of Samples	Average Bleed Rate (m ³ /hr)	95% Confidence Interval (m ³ /hr)	Standard Deviation (m ³ /hr)
Kimray HT-12	36	0.0351	0.0621	0.0987
Transducers				
Fairchild TXI7800	37	0.1543	0.1877	0.1234
Fisher 546	30	0.3547	0.4279	0.2436
Fisher i2P-100	37	0.2157	0.2602	0.1646
Pumps				
Morgan HD312	35	1.1292	1.3592	0.8271
Texsteam 5100	47	0.9670	1.1467	0.7490
Williams P125	50	0.4098	0.5092	0.4272
Williams P250	28	0.8022	1.0156	0.6863
Williams P500	12	0.6969	0.9741	0.5836

4.1 Analysis for Determining a Generic Bleed Rate

The next step of the analysis was to determine if a generic bleed rate could be generated for high-bleed controllers and pumps. Devices that were determined to be high bleeding (i.e. bleed rate > 0.17 m³/hr) were grouped together in the analysis. If the calculated mean bleed rate was larger than the threshold, the device was included in the analysis, and if the calculated mean bleed rate was smaller than the threshold, the device was excluded from the analysis for determining a generic bleed rate. Certain controllers that are considered low-bleeding according to WCI or manufacturer specifications actually bled above the low bleed threshold and were therefore included in the analysis. Using Minitab, a statistical analysis software, a general linear model (GLM) was performed on the data to determine if there was a significant difference between the mean bleed rates of controllers and pumps. The results are presented in Table 7.

Table 7: Results of the Overview Analysis

Pneumatic Device	Number of Samples	Average Bleed Rate (m ³ /hr)	95% Confidence Interval (m ³ /hr)	Standard Deviation (m ³ /hr)	P-Value
High Bleed Controllers	406	0.2605	0.2880	0.3371	0.129
High Bleed Intermittent	195	0.2476	.2893	0.3537	0.738
Piston Pumps	96	0.5917	0.6926	0.6007	0.060
Diaphragm Pumps	85	1.0542	1.1948	0.7878	0.362

For high bleed controllers, a p-value > 0.05 was calculated, meaning that there was no significant differences between the mean bleed rates. The mean bleed rate is representative of the population and can therefore be applied to any high bleed controller model. For intermittent high bleed controller, a p-value > 0.05 was calculated, meaning that there was no significant differences between the mean bleed rates. The mean bleed rate is representative of the population and can therefore be applied to any intermittent high bleed controller model. For all pumps, a p-value < 0.05 was calculated, meaning that there is a significant difference between all pump models and a generic bleed rate may not be representative of the entire population. Due to the large variance in bleed rates across all pumps, the pumps were grouped into two categories: diaphragm pumps and piston pumps. A p-value > 0.05 was calculated for both types of pumps, meaning that the mean bleed rate is representative of the entire population.

Box plot distributions of all field samples are presented in Appendix D.

4.2 Bleed Rate Equations

The most accurate bleed rate would take into account quantitative variables. A regression analysis was performed to investigate which quantitative variables affected the bleed rate. A regression analysis showed that there was a positive correlation between certain pneumatic controller bleed rates and supply pressure. A regression analysis showed that there was a positive correlation between pneumatic pump bleed rates, supply pressure, injection pressure and strokes per minute.

Controller Bleed Rate Equation $Bleed Rate_j = m * SP_j$

Where:

m = the supply pressure coefficient (see Appendix E)
 SP_j = the supply pressure of controller j

Pump Bleed Rate Equation⁸ $Bleed Rate_j = (g * SP_j) + (n * DP_j) + (p * SPM_j)$

Where:

g = the supply pressure coefficient (see Appendix E)
 SP_j = the supply pressure of pump j, (kPa)
 n = the discharge pressure coefficient, (see Appendix E)
 DP_j = the discharge pressure of pump j, (kPa)
 p = the strokes per minute coefficient (see Appendix E)
 SPM_j = the strokes per minute of pump j

For producers who know the operating conditions of their devices, they should use the following bleed rate equations. It should be noted that this method will only provide a more accurate bleed rate compared to the average bleed rate shown in Table 7 and Table 8 if the producer is certain of the operating conditions. Adding complexity may increase the overall error in bleed rates if operating conditions are estimated. Figure 9 provides an overview of the approach used to analyze the data.

⁸ It should be noted that if the pump is operating at less than five strokes per minute, the emissions equation is not applicable and the mean bleed rate should be used.

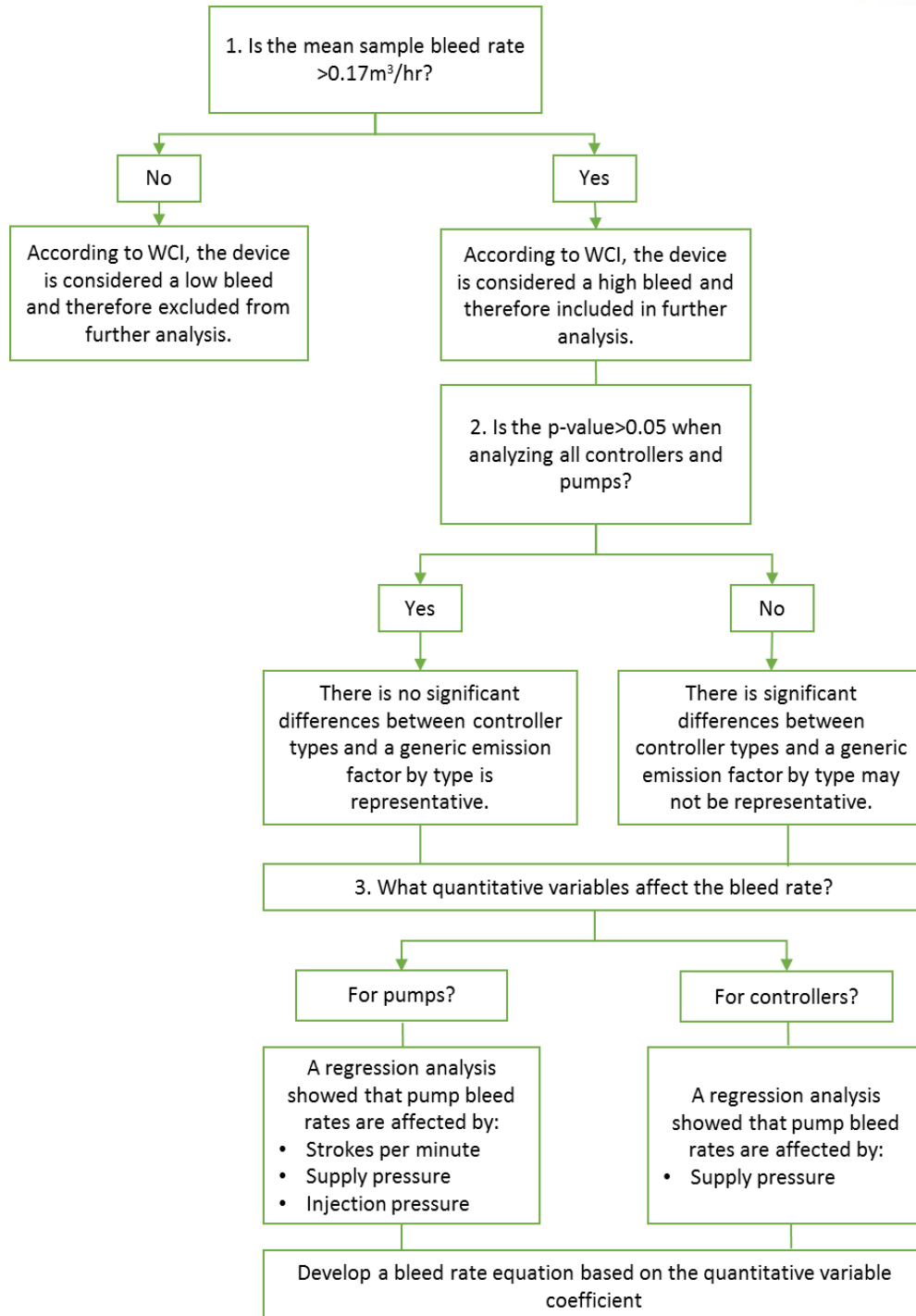


Figure 9: Diagram Illustrating the Quantitative Analysis

5. Comparison of Bleed Rates

Table 8 and Table 9 compare the average bleed rate to the manufacturer's specification as well as previously published bleed rates. A discussion on variability between the mean bleed rate and the manufacturer specification is provided in Section 6 below. A discussion on variability between the mean bleed rate and the EPA default is provided below. Overall, the average bleed rate for high bleed and intermittent controllers were lower than the EPA default; however, the average bleed rate for low bleed controllers and pumps were both higher than the EPA default. These findings align with a similar study that was performed in the United States by the University of Texas (Allen *et al.* 2013).

Table 8: Comparison of Pneumatic Controller Bleed Rates

Pneumatic Controllers	Average Bleed Rate (m ³ /hr)	Manufacturer Specification (m ³ /hr)	WCI (m ³ /hr)	CAPP (m ³ /hr)	EPA (m ³ /hr)
Pressure Controllers					
Fisher 4150	0.421	0.691	0.736	0.680-1.841	0.071-0.821
Fisher C1 ⁹	0.065	0.097	0.147	-	-
Fisher 4660	0.015	0.174	0.142	-	0.142
Level Controllers					
Fisher L2 ⁹	0.264	0.032	0.043	-	-
Fisher 2500	0.397	1.100	1.189	1.189	0.283-2.03
Fisher 2680 ⁹	0.268	0.040	0.028	<0.028	<0.028
Fisher 2900	0.145	0.453	0.651	0.510-3.60	-
Murphy L1200 ¹⁰	0.262	-	-	-	-
Norriseal 1001 ⁹	0.187	0.057	0.057	0.006	0.006
SOR 1530 ⁷	0.053	0.142	-	-	-
Positioners					
Fisher DVC6000	0.265	0.38	0.396	0.400-1.39	0.396
Temperature Controller					
Kimray HT-12 ⁹	0.035	0.000	-	-	-
Transducer					
Fairchild TXI7800	0.154	0.380	0.241	-	-
Fisher 546	0.355	0.648	0.850	0.423-1.700	0.595
Fisher i2P-100	0.216	0.180	0.283	-	-

⁹ Considered a low bleed controller according to manufacturer specification and WCI's definition <0.17m³/hr.

¹⁰ This pneumatic device was not on the initial list for pneumatics but was included due to prominence in the field.

Table 9. Comparison of pneumatic pump bleed rates.

Pneumatic Pumps	Mean Bleed Rate (m ³ /hr)	Max Air Consumption (Man Specification ¹¹ (m ³ /hr)	CAPP (m ³ /hr) ¹²	WCI (m ³ /hr) ¹³	EPA (m ³ /hr)
Morgan HD312	1.1292	1.35	0.236	0.3945	0.3767
Texsteam 5100	0.9670	2.31	0.236	0.3945	0.3767
Williams P125	0.4098	0.21	0.236	0.3945	0.3767
Williams P250	0.8022	1.33	0.236	0.3945	0.3767
Williams P500	0.6969	2.46	0.236	0.3945	0.3767

6. Discussion

6.1 Outliers

Outliers were not excluded from the sample population because the purpose of the survey was to capture real field conditions and generate a bleed rate that is representative of all field conditions. Certain controllers can have abnormally high bleed rates due to operations and maintenance; however, these bleed rates are representative of real world conditions and therefore were included in the analysis.

6.2 Throttling vs. Snap-Acting Controllers

Two types of controllers were sampled in the field, throttling and snap-acting controllers. Throttling controllers bleed continuously as they constantly throttle between static and dynamic states. Actuating or intermittent bleed devices perform snap-acting control and release gas only when they stroke a valve open or closed. The static bleed rate is steady-state gas consumption. When a controller performs an action, the pressurized gas is subsequently vented through the controller to the atmosphere, also known as the dynamic bleed rate.

The dynamic bleed rate can be much greater than the static bleed rate based on the operating conditions of the controller. The total bleed rate (static + dynamic) depends on the frequency the controller is performing an action. Snap-acting controllers typically have greater variability in dynamic and static action due to the intermittency of the actions. Snap-acting controllers are predominantly in their static, inactive state until an action is required, which results in a short burst of dynamic bleeding.

Figure 10 shows an example of how the bleed rate varies over time for a snap-acting controller. The difference between the static rate and the amplitude of the dynamic event is the dynamic bleed rate. The most important variable that dictates the bleed rate however is the frequency of the dynamic events, which is dependent on a number of variables (dry/wet gas, tank size, etc.) Level controllers are a prime example of a snap-acting controller because they only dynamically bleed when they are prompted by an event, typically to empty a liquids tank.

¹¹ The stated manufacturer max air consumption value assumes a supply pressure of 690 kPa (100 psi), which is a max supply pressure.

¹² <http://www.capp.ca/getdoc.aspx?DocId=86223&DT=NTV>

¹³ <http://www.theclimaterestory.org/downloads/2010/04/Final-OGP-Protocol.pdf>

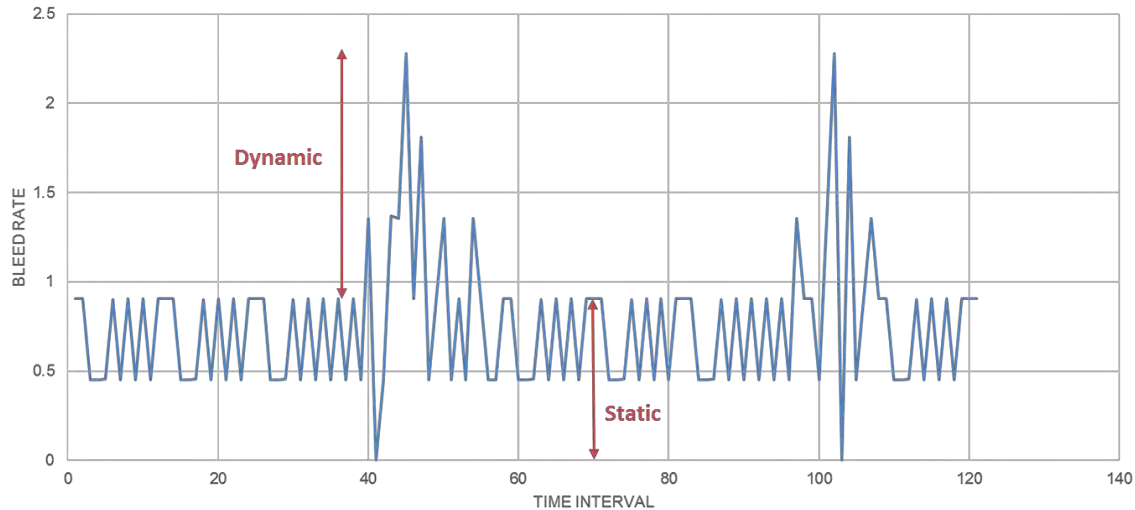


Figure 10: Graph Showing the Dynamic and Static Action

Since the sampling methodology limited the sample time to 30 minutes, there was variability in the amount of static and dynamic action that was captured from a given controller. This variability was due to the frequency of dynamic events. Depending on operating conditions, certain controllers did not perform an action within the 30 minute timeframe, so only the static bleed rate was captured. For example, if a level controller dumps on average every four hours, the sampling team may or may not have caught the dynamic bleed rate of the controller. This created variability in the amount of dynamic versus static bleeds that were captured by an individual sample; however, due to our large sample sets, this variability is representative of how controllers are performing under real operating condition.

This variance was mostly seen in level controllers because they are snap-acting and operate in an on or off type condition. The level controller samples showed a range of values depending on how many dynamic events occurred over a sampling period. This was an expected outcome because level controllers have primarily static bleed rates with variable dynamic events. Our analysis captured both static and dynamic events over the sampling time frame and are both accounted for when using the average as a representative bleed rate for the samples with skewed and bimodal distribution.

6.3 Manufacturer Specification

Differences are observed between the average bleed rate and the manufacturer specification. It should be noted that this variability was expected. The manufacturer specification measures the steady-state air consumption in a lab setting. The purpose of the survey is to determine the average bleed rate of pneumatic controllers and pumps when operating under real field conditions. The field bleed rates differed from manufacturer rates because they are operating under real world conditions with variability in dynamic and static action. For pumps, the field bleed rates are different than manufacturer rates because they are provided with a maximum air consumption using a maximum supply pressure.

6.4 Gas vs. Air vs. Propane

The majority of the field samples were taken at sweet well sites; however, as devices became harder to find, the sampling team targeted compressor stations and batteries as well as sour sites in order to reach the 30 sample threshold. A handful of air samples were obtained from larger facilities because typically, bigger facilities run compressed air instead of pressurized natural gas. A handful of propane samples were obtained from sour well sites because an alternative to process natural gas is required at sour sites, so pressurized propane is typically used. Air and propane samples were corrected using a density ratio in order to compare equivalent volumes of natural gas bled.

6.5 Calscan Vent Gas Meter

When determining which metering device to use during sampling, the Calscan bellows meter was chosen over the Bacharach High-Flow Sampler because it has greater accuracy and has the ability to capture the static and dynamic bleed rates (see Section 2.3.1 for a complete discussion on the differences). A drawback exists; however, that should be discussed and may explain some of the variability in the data. It is well-known that metering a device can affect the operation of the device when hooked up due to back pressure. It is possible that certain controllers didn't produce enough pressure when hooked up to overcome the back pressure, resulting in a zero reading.

6.6 Producer and Sub-District

A multitude of producers and sub districts within British Columbia were sampled; however, the purpose was not to determine differences between producers and sub-districts but determine generic BC wide bleed rates that reflect values from a variety of locations and producers. Since we have taken our samples from a variety of fields, the average bleed rate captures the variability between producers and sub-districts. The intent of the survey was not to determine whether producers and sub-districts were influencing variables; however, the methodology was designed to ensure that these variables were accounted.

6.7 Adding a Device Model to the Survey

If a producer wishes to develop an average bleed rate for a controller or pump that was outside the scope of this survey, they can follow the sampling methodology outlined in Section 2. A minimum of 30 bleed rates per device model must be achieved using a mass flow meter from a variety of producing fields and producers. Please reference the Project Methodology (July 29th 2013) report for the full protocol.

6.8 Mean vs. Median

Many of the snap acting level controllers had skewed or bi-modal distribution. Typically the median is used to represent the value for central tendency in non-normal distributions; however, the goal for this project was to develop an average where all the samples are weighted equally. The mean is recommended because it weights all samples equally; whereas the median would neglect samples on the tail of the distribution. The median would not accurately reflect the combined static and dynamic bleed rate; whereas the mean places equal weight on each sample. Using the median as a measure of central tendency would ignore the data that represents the dynamic action over the course of sampling. Thus, when calculating the most accurate bleed rate, the mean is more representative than the median because of static and dynamic actions.

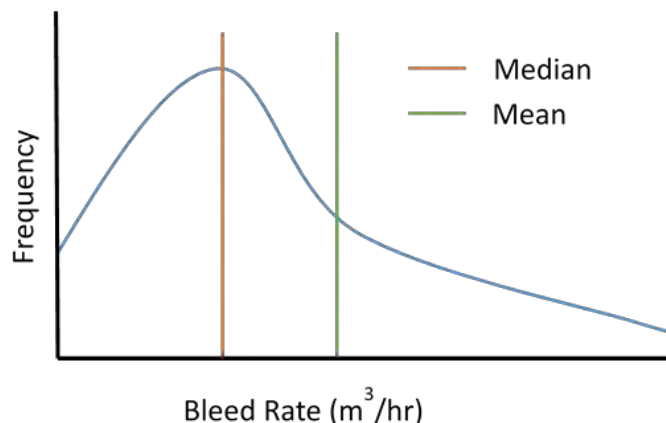


Figure 11: Non-Normal Distribution

6.9 General Linear Model

A general linear model is a statistical test that analyzes variance between sample populations. It was chosen to compare the samples because some populations showed a non-normal distribution and because the samples sizes differed. This statistical test incorporates different ANOVA tests and non-parametric tests to produce an accurate p-value. A general linear model is more robust when dealing with different normalities and variance in sample populations compared to a standard ANOVA and was therefore selected (Bolker *et al.* 2009).

6.10 Summer vs. Winter Sampling

The sampling was performed over the summer months of August and early September. The Calscan Hawk 9000 meter normalized all the samples for temperature and pressure differences in order to eliminate the different operating variables. A known constraint of our sampling methodology was that not all chemical injection pumps operate in the summer months. To eliminate this issue, the sampling team would turn the pump on and perform samples at three normal operating speeds (high, medium and low strokes per minute).

7. Applications of the Analysis

The mean bleed rates calculated in this survey are applicable for GHG reporting. A decision tree is provided in **Figure 12** and Figure 13 below to aid producers in determining which bleed rate to apply.

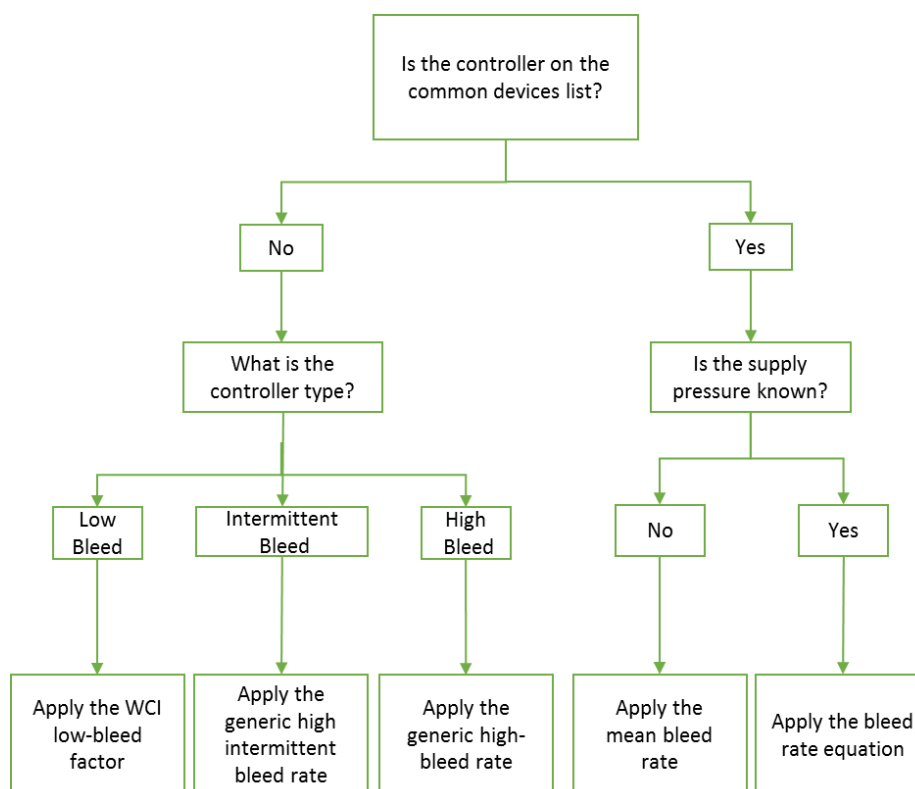


Figure 12: Controller Decision Tree

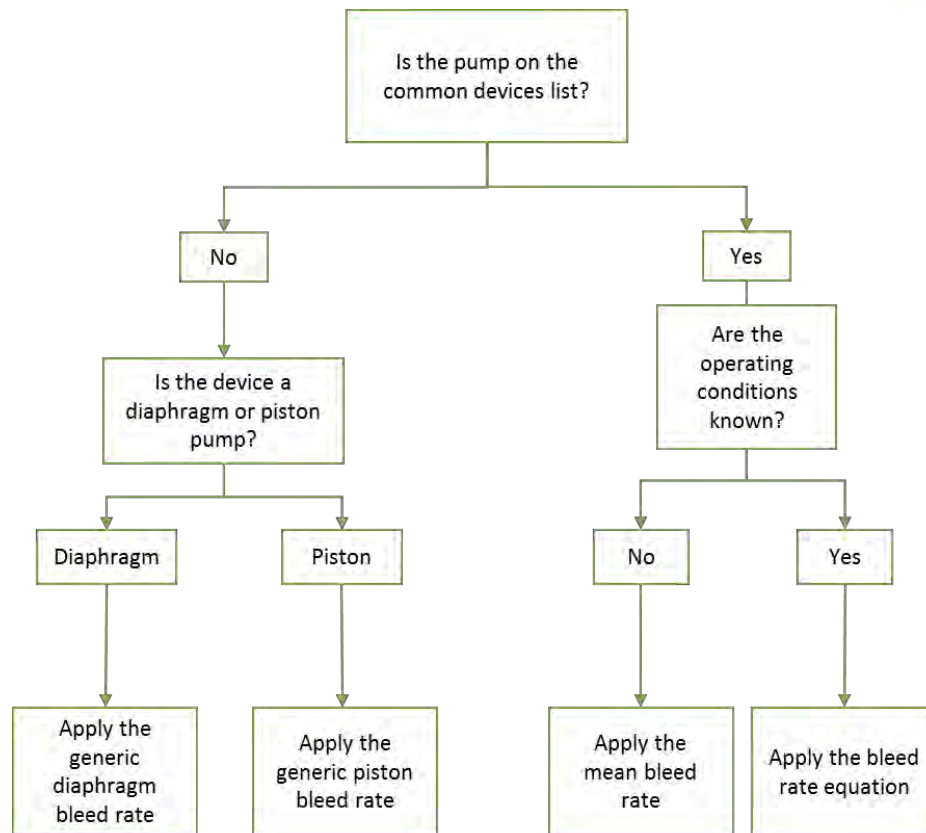


Figure 13: Pump Decision Tree

8. Observations

This study involved comprehensive analysis of pneumatic devices and a significant fieldwork program. This, combined with the fact that this study was one of the first of its kind, resulted in the research team observing several instances where the general body of scientific knowledge in this area could be advanced. These are outlined below:

1. Dynamic vs. static bleed rates: By nature, controller devices have a baseline bleed rate with dynamic events where more gas may be vented. In this study, the maximum sampling time was set at 30 minutes for each device, which added variability to the amount static and dynamic action captured in the sampling of snap-acting controllers (see section 6.2 for further discussion). The time interval between dynamic events may be longer than a 30 minute cycle. Future surveys investigating intermittent bleeding controllers, if undertaken, may consider capturing two complete dynamic cycles if reasonably practicable.
2. Categorisation of 'high', 'intermittent', and 'low bleed': The survey was focused around high-bleed pneumatic controllers. It was observed that for some high bleed devices the calculated mean bleed rate fell below the 0.17m³/hr WCI high bleed threshold and some tested low bleed controllers were higher. As an analysis of the observed differences were not within the scope of the project no further work to assess possible cause was undertaken, at this time. It is observed that future studies may consider all types of pneumatic controllers so that categorisation can be more fully tested and to ensure that field tested emission factors are available for all emitting pneumatic devices.

9. Conclusion

The purpose of the survey was to determine a representative average bleed rate for high bleed pneumatic controllers and pneumatic pumps when operating under field conditions. All outcomes were achieved. The results of the analysis led to the development of three generic bleed rates and twenty specific bleed rates for common pneumatic controllers and pumps for BC's oil and gas industry. These bleed rates can be used in the development of emission factors for GHG reporting and potentially offset purposes.

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Appendix A: Compilation of All Known Pneumatic Controllers

Description	Manufacturer	Model	Manufacturer Rate (m ³ /h NG)	Source	Equivalent Devices	Sample?	Justification
Pressure Controller	Ametek	Series 40	0.22	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Positioner	Becker	HPP-5	0.18	WCI		Yes	High-bleed
Pressure Controller	Bristol Babcock	Series 502 A/D	0.22	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Pressure Controller	Dyna-Flo	4000	0.89	WCI	Dyna-Flo 5000	Yes	High-bleed
Pressure Controller	Dyna-Flo	4000LB	0.13	Dyna-Flo		Yes	High-bleed
Transducer	Fairchild	TXI 7800	0.31	WCI		Yes	High-bleed
Transducer	Fisher	546	1.10	WCI	Fisher 546S Fisher 546	Yes	High-bleed
Transducer	Fisher	646	0.29	WCI		Yes	High-bleed
Transducer	Fisher	846	0.44	WCI/CAPP BMP/GAS Star	Fisher 846S	Yes	High-bleed
Level Controller	Fisher	2500	1.55	WCI		Yes	High-bleed
Level Controller	Fisher	2900	0.85	WCI/CAPP BMP/GAS Star	Fisher 2901 Fisher 2900A	Yes	High-bleed
Positioner	Fisher	3582	0.59	WCI		Yes	High-bleed
Positioner	Fisher	3590	1.10	WCI		Yes	High-bleed
Positioner	Fisher	3660	0.26	WCI		Yes	High-bleed
Positioner	Fisher	3661	0.38	WCI		Yes	High-bleed
Pressure Controller	Fisher	4100	1.83	WCI	Fisher 4101	Yes	High-bleed
Pressure Controller	Fisher	4150	0.96	WCI	Fisher 4150K Fisher 4160R CVS 4150	Yes	High-bleed

Description	Manufacturer	Model	Manufacturer Rate (m ³ /h NG)	Source	Equivalent Devices	Sample?	Justification
					Fisher 4150K Fisher 4160		
Temperature Controller	Fisher	4156			Fisher 4156 Fisher 4166	Yes	High-bleed
Pressure Controller	Fisher	4194	0.16	WCI		Yes	High-bleed
Pressure Controller	Fisher	4195	0.16	WCI		Yes	High-bleed
High-Low Pressure Pilot	Fisher	4660	0.18	Gas STAR	Fisher 4660A	Yes	High-bleed
Positioner	Fisher	Fieldvue DVC5000	0.37	WCI/CAPP BMP/GAS Star	FisherDVC5040 FisherDVC5030 FisherDVC5020 FisherDVC5010	Yes	High-bleed
Level Controller	Fisher	2900A			Fisher 2901A	Yes	High-bleed
Positioner	Fisher	3582i	0.76	WCI		Yes	High-bleed
Positioner	Fisher	3620J	0.98	WCI		Yes	High-bleed
Pressure Transmitter	Fisher	C1	0.19	WCI		Yes	High-bleed
Positioner	Fisher	Fieldvue DVC6000	0.52	WCI/CAPP BMP/GAS Star	FisherDVC6030 FisherDVC6020 FisherDVC6010	Yes	High-bleed
Transducer	Fisher	i2P-100	0.37	WCI	Fisher i2P-100, 4-20mA	Yes	High-bleed
Pressure Controller	Foxboro	43AP	0.66	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Level Controller	Invalco	AE-155	1.95	WCI		Yes	High-bleed

Description	Manufacturer	Model	Manufacturer Rate (m ³ /h NG)	Source	Equivalent Devices	Sample?	Justification
Level Controller	Invalco	CT Series	1.47	WCI/CAPP BMP/GAS Star	NATCO Flextube (CT Series)	Yes	High-bleed
Positioner	Invalco	Flextube (CT Series)	1.47	WCI	NATCO Flextube (CT Series)	Yes	High-bleed
Pressure Controller	ITT Barton	338	0.22	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Pressure Controller	ITT Barton	4195	0.13	Gas Star		Yes	High-bleed
Pressure Controller	ITT Barton	335P	0.22	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Level Controller	Kimray	Gen2	0.54	Manufacturer's website ¹⁴		Yes	High-bleed
Temperature Controller	Kimray	HT-12				Yes	High-bleed
Level Controller	Mallard	3201				Yes	High-bleed
Positioner	Masoneilan	4600B Series	0.88	WCI		Yes	High-bleed
Positioner	Masoneilan	4700B Series	0.88	WCI		Yes	High-bleed
Positioner	Masoneilan	7400 Series	1.36	WCI		Yes	High-bleed
Positioner	Moore Products	73N-B PtoP	1.33	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Positioner	Moore Products	750P	1.55	WCI/CAPP BMP/GAS Star		Yes	High-bleed
Transducer	Moore Products	IPX2				Yes	High-bleed

¹⁴ <http://mobile.kimray.com/downloads/instruction/GENIIBACKmount.pdf>

Description	Manufacturer	Model	Manufacturer Rate (m ³ /h NG)	Source	Equivalent Devices	Sample?	Justification
Pressure Controller	Natco	CT	1.55	WCI		Yes	High-bleed
Pressure Controller	Norriseal	4900				Yes	High-bleed
Level Controller	Norriseal	1005PI				Yes	High-bleed
Pressure Controller	Time Mate	2000				Yes	High-bleed
Level Controller	Wellmark	2001A	0.13	CAPP		Yes	High-bleed
Positioner	YTC	YT-2400				Yes	High-bleed
Level Controller	Fisher	2660	0.04	CAPP BMP	Fisher 2660A	Yes	PCT
Level Controller	Fisher	2680	0.04	CAPP BMP	Fisher 2680A	Yes	PCT
Level Controller	Fisher	L2	0.06	WCI		Yes	PCT
Level Controller	Norriseal	1001	0.07	WCI	1001A	No	PCT
Level Controller	Norriseal	1001XL	0.07	WCI		No	PCT
Positioner	Becker	ERP-2.0	0.00	WCI/CAPP BMP/GAS Star		No	Low-bleed
Controller	Becker	VRP-SB	0.00	Gas Star		No	Low-bleed
Pressure Controller	Bristol Babcock	358	0.07	Gas Star		No	Low-bleed
Pressure Controller	Bristol Babcock	359	0.07	Gas Star		No	Low-bleed
Pressure Controller	Bristol Babcock	5455 Model 624-III	0.09	WCI		No	Low-bleed

Description	Manufacturer	Model	Manufacturer Rate (m ³ /h NG)	Source	Equivalent Devices	Sample?	Justification
Pressure Controller	Bristol Babcock	Series 5453-Model 624 - II	0.11	Gas STAR		No	Low-bleed
Pressure Controller	Bristol Babcock	Series 5455 Model-624 10F	0.11	WCI/CAPP BMP/GAS Star		No	Low-bleed
Pressure Transmitter	Bristol Babcock	Series 5457-70F	0.11	Gas STAR		No	Low-bleed
Transducer	Bristol Babcock	Series 9110-00A	0.02	WCI/CAPP BMP/GAS Star		No	Low-bleed
Level Controller	Fisher	2100	0.04	WCI/CAPP BMP/GAS Star		No	Low-bleed
Positioner	Masoneilan	SVI Digital	0.04	CAPP		No	Low-bleed
Positioner	VRC	VP700G	0.04	WCI/CAPP BMP/GAS Star		No	Low-bleed

Appendix B: Initial List of Pneumatic Devices Included in the Sample

Pneumatic Controller List						
<i>This list was developed by analyzing the frequency each controller make/model appeared in Cap-Op's field sample database. These 15 controllers make up 97% of the database.</i>						
Description	Manufacturer	Model	Equivalents	Name	Count	Percentage
Pressure Controller	Fisher	4150	Fisher 4150K Fisher 4160R CVS 4150 Fisher 4150K Fisher 4160	Fisher 4150	380	26.44%
Transducer	Fisher	i2P-100	Fisher i2P-100, 4-20mA	Fisher i2P-100	177	12.32%
Level Controller	Norriseal	1001	1001A	Norriseal 1001	170	11.83%
Level Controller	Fisher	2900	Fisher 2901 Fisher 2900A Fisher 2901A	Fisher 2900	163	11.34%
Transducer	Fisher	546	Fisher 546S Fisher 546	Fisher 546	94	6.54%
Level Controller	Fisher	L2		Fisher L2	84	5.85%
Level Controller	Fisher	2680	Fisher 2680A	Fisher 2680	78	5.43%
High-Low Pressure Pilot	Fisher	4660	Fisher 4660A	Fisher 4660	73	5.08%
Positioner	Fisher	Fieldvue DVC6000	FisherDVC6030 FisherDVC6020 FisherDVC6010	Fisher Fieldvue DVC6000	39	2.71%
Temperature Controller	Kimray	HT-12		Kimray HT-12	27	1.88%
Level Controller	Fisher	2660	Fisher 2660A	Fisher 2660	24	1.67%
Level Controller	Fisher	2500	Fisher 2506	Fisher 2500	23	1.60%
Level Switch	SOR	1530		SOR 1530	23	1.60%
Pressure Transmitter	Fisher	C1		Fisher C1	19	1.32%
Level Controller	Norriseal	1001XL		Norriseal 1001XL	19	1.32%
Total						97%

Pneumatic Pump List

This is a comprehensive list of known pump models that exist in the field. The list was developed by surveying multiple sources (industry, manufacturers, etc.). First round sampling uncovered which pumps were common (see bolded below) in order to target were sampling.

Manufacturer	Model
Arrow	548
Arrow	5100
Bruin	5000
Bruin	BR113LP
Checkpoint	1250
COE	5100
CVS	5100
CVS	C-252
Flowmore	5100
Graco	716
Ingersoll Rand	-
Linc	84-T Series
Linc	282
Morgan	4500
Morgan	HD312
Plainsman	-
Texsteam	5100
Timberline	2500, 5000, 1560 Series
Western Chemical Pump	ACE Series
Wilden	5000
Williams	P125
Williams	P250
Williams	P500

Appendix C: Field Sampling Guide

The subsequent guidelines were taken from the full Sampling Methodology report and were followed by the GreenPath field sample team:

What to Sample On-Site

- Sample all pneumatic controllers (including their equivalents) from the list provided (found in Appendix B).
- Sample all pumps. If pumps are turned off and you have permission from the operator to turn it on, take separate samples of the pump at different operating speeds (high, medium and low strokes per minute). Limit different operating speeds to speeds that the pump would function under normal operating conditions.

Duration of Sampling

All samples need to:

- be taken for at least 30 min, or
- until 2 ft³ of gas has been collected

Sampling Device

- Attach the Calscan Hawk 9000 positive displacement bellows meter to the pneumatic device according to manufacturer specification.

Appendix D: Box Plot Distributions

A box plot distribution graph is a way to show the distribution of categorical samples. The black line represents the median value for a sample population. The grey box represents the first and third quartile or 50% of the data. The black lines show the range of observations. The median is represented by the horizontal line and the mean is the circle in the grey box.

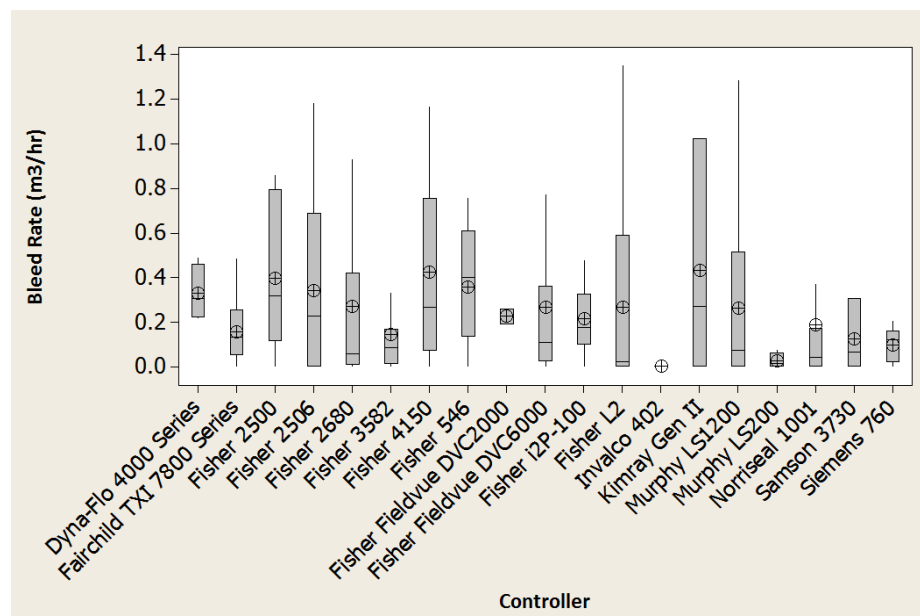


Figure 14: Box Plot Distribution for High-Bleed Controllers

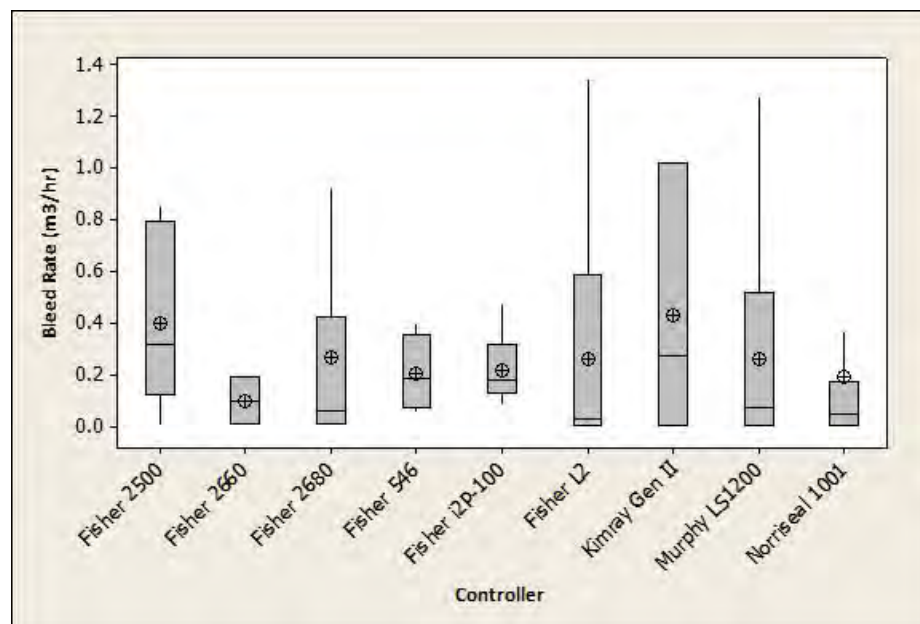


Figure 15: Box Plot Distribution for High Bleed Intermittent Controllers

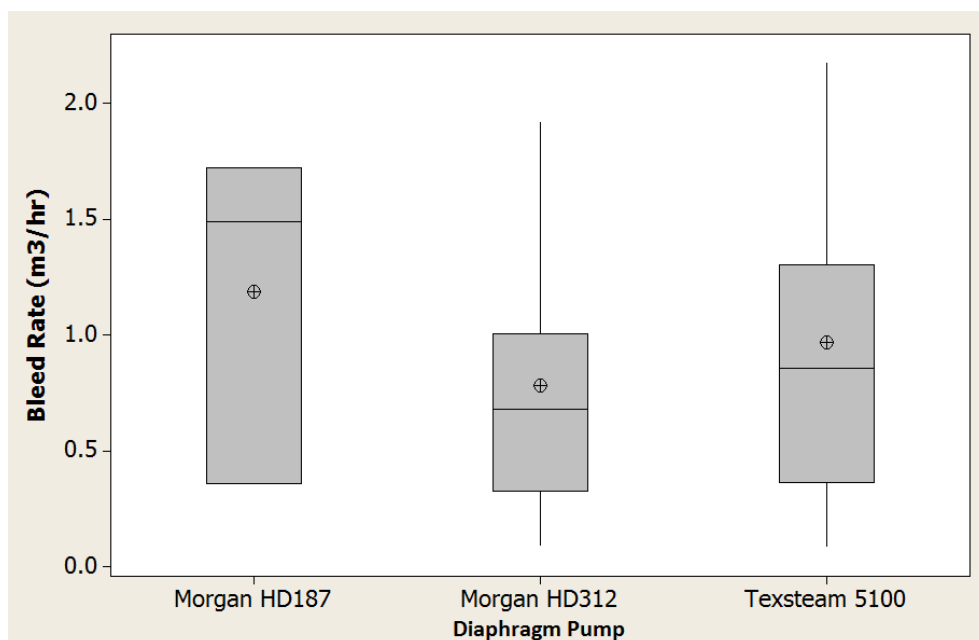


Figure 16: Box Plot Distribution for Diaphragm Pumps

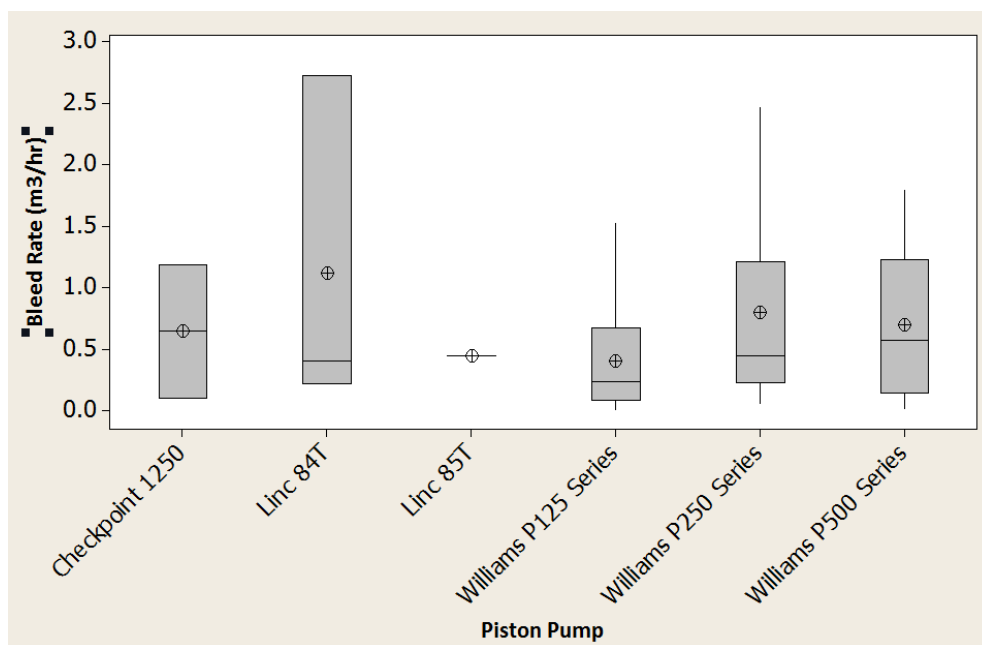


Figure 17: Box Plot Distribution for Piston Pumps

Appendix E: Bleed Rate Equation Coefficients

Pneumatic Controllers

A regression analysis showed that there was a positive correlation between certain pneumatic controller bleed rates and supply pressure.

Table 10: Controller Bleed Rate Equation Coefficients

Controller	Mean Bleed Rate (m ³ /hr)	Coefficient ¹⁵	R ²	Correlation ¹⁶
High Bleed Pneumatic Controllers	0.2605	0.0012	0.41	Positive
High Bleed Intermittent Controllers	0.2476	0.0012	0.35	Positive
Pressure Controller				
Fisher 4150	0.4209	0.0019	0.46	Positive
Fisher C1	0.0649	0.0003	0.25	Positive
Fisher 4660	0.0151	-	0.05	Weak
Level Controller				
Fisher 2500	0.3967	0.0011	0.73	Strong
Fisher 2680	0.2679	0.0014	0.39	Positive
Fisher 2900	0.1447	-	0.13	Weak
Fisher L2	0.2641	0.0012	0.33	Positive
Murphy L1200	0.2619	0.0012	0.38	Positive
Norriseal 1001	0.1868	-	0.23	Weak
SOR 1530	0.0531	-	0.21	Weak
Positioners				
Fisher DVC 6000	0.2649	0.0011	0.75	Strong
Temperature Controller				
Kimray HT-12	0.0351	-	0.06	Weak
Transducer				
Fairchild TXI7800	0.1543	0.0009	0.60	Positive
Fisher 546	0.3547	0.0017	0.77	Strong
Fisher i2P-100	0.2157	0.0009	0.65	Strong

¹⁵ Controllers showing a weak correlation to supply pressure do not have a representative bleed rate equation and should therefore use the mean bleed rate instead of the emission equation.

¹⁶ Strong correlation indicates $R^2 > 0.64$
 Positive correlation indicates $0.25 < R^2 < 0.64$
 Weak correlation indicates $R^2 < 0.25$

Pneumatic Pumps

A regression analysis showed that there was a positive correlation between pneumatic pump bleed rates, supply pressure, injection pressure and strokes per minute. The most accurate bleed rate would take into account these 3 operating variables when calculating the bleed rate for a pneumatic pump.

Table 11: Pump Bleed Rate Equation Coefficients

Pneumatic Pump	Mean Bleed Rate (m ³ /hr)	Supply Pressure Coefficient (g) ¹⁷	Injection Pressure Coefficient (n) ¹⁷	Strokes Per Minute Coefficient (p) ¹⁷	R ²	Correlation ¹⁸
Diaphragm	1.0542	0.00202	0.000059	0.0167	0.68	Strong
Piston	0.5917	0.00050	0.000027	0.0091	0.49	Positive
Morgan HD312	1.1292	0.00418	0.000034	0.0073	0.66	Strong
Texsteam 5100	0.9670	0.00030	0.000034	0.0207	0.74	Strong
Williams P125	0.4098	0.00019	0.000024	0.0076	0.53	Positive
Williams P250	0.8022	0.00096	0.000042	0.0079	0.53	Positive
Williams P500	0.6969	0.00224	-0.000031	0.0046	0.74	Strong

¹⁷ The coefficients are to be used in the pump bleed rate equation:
Bleed Rate = m * (Supply Pressure in kPa) + n * (Injection Pressure in kPa) + p * (Strokes per Min)

¹⁸ Strong correlation indicates R²>0.64
Positive correlation indicates 0.25<R²<0.64
Weak correlation indicates R²<0.25



Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras

CL report CL-13-27

This report was prepared by Carbon Limits AS.

Project title:	Marginal Abatement Cost Curve for reduction of methane emissions from US Oil Production and Natural Gas Systems
Client:	Clean Air Task Force (CATF)
Project leader:	Stephanie Saunier
Project members:	Torleif Haugland Anders Pederstad
Report name:	Quantifying cost-effectiveness of systematic Leak Detection and Repair Programs using Infrared cameras
Report number:	CL-13-27
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Special thanks to the two companies who provided the survey data used for this study - for their continuous support and precious information provided during the course of the study.



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Carbon Limits is a consulting company with long standing experience in climate change policies and emission reduction project identification and development. Our team works in close collaboration with industries, government, and public bodies to reduce greenhouse gas emissions, particularly in the oil and gas sector.

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EXECUTIVE SUMMARY

Overview

About 30% of the US anthropogenic methane emissions originate from the oil and natural gas sector. Emissions are partly *leaks* and partly engineered *vents*. Almost 30% of methane emissions from onshore oil and natural gas facilities are from leaks (1), which here means fugitive leaks past static seals on valves, connectors, regulators, or other components. This report presents results from an empirical analysis of real data on the costs and benefits of leak detection and repair (LDAR) programs at oil and natural gas facilities. These programs use infrared cameras to detect sources of gas emissions, which in addition to methane include volatile organic compounds (VOCs). Once emission rates are measured or estimated, repairs can be conducted, reducing emissions by 90% or more. The economic merits of a LDAR program depend on the amount and value of the gas otherwise leaked and the costs of the LDAR program, comprising both survey and repair costs.

The analysis presented is based on data from 4,293 surveys of oil and gas facilities in the USA and Canada. These surveys identified 58,421 components, which were either leaking or venting gas; leaks were detected from 39,505 components. A database was created with information on gas emission rates, repair costs, and repair lifetime for each emission source, in addition to average survey costs. This database allows calculation of the costs and benefits of LDAR programs with various designs, which is the main product of this work. In addition to repairs of leaks from static components, the economics and mitigation potential of addressing excess reciprocating compressor rod packing emissions are also examined in this study and the results are briefly presented in this report.

Main results

Costs and benefits of LDAR programs were analysed for three categories of facilities: (i) *gas processing plants*, (ii) *compressor stations* in gas transmission and gas gathering systems, and (iii) *well sites and well batteries*, including single well heads and multi-well batteries (up to 15 well heads).

There is considerable variability in leak rates across the facilities surveyed. Gas processing plants leak the most; well sites and well batteries leak more modestly, with about one third having no reported leaks and only 7% having leaks above 500 thousand standard cubic feet (Mcf) per year. Compressor stations leak more than well sites and well batteries, but less than gas plants.

Table 1: Distribution of facilities within each category by leak rate (in Mcf per facility and per year)

Category:	No leaks	≤99	100-499	500-1499	≥ 1500
(i) Gas processing plants	3%	17%	32%	25%	23%
(ii) Compressor stations	11%	30%	36%	15%	9%
(iii) Well sites & well batteries	36%	38%	18%	5%	2%

The vast majority of leaks are economic to repair once identified: even assuming a low value of gas (3 US dollars (USD) per Mcf), leaks amounting to more than 97% of total leak emissions are worth repairing. In addition, over 90% of the gas emissions are from leaks that can be repaired with a payback period of less than one year.

This means that once the survey has been performed, it is economic to repair almost every leak, even at low gas prices. This finding drives many of the results of this study.

The costs and benefits of LDAR programs were analysed from both an individual facility perspective, where the distribution of net present values (NPV) for facilities of each category is examined, and a public or corporate perspective, where the aggregate cost-effectiveness of conducting LDAR programs for a number of facilities (in a jurisdiction or owned by a single company) is considered. For these analyses, a **base case scenario** has been defined based on the following assumptions:

- (i) the value of recovered gas is 4 USD/Mcf;
- (ii) in addition to the *external* cost of hiring a firm to survey facilities for emissions, owners of those facilities pay for *internal* costs (e.g., administration, paperwork) equal to half of the external cost;
- (iii) facility owners fix all leaks that the survey identifies.

The base case presents results based on surveys as they were performed – with variable frequency. Alternative cases examined the cost-effectiveness of surveys at specific frequencies. Finally, changes in cost-effectiveness due to altering these and other assumptions, including the assumption that all leaks are fixed, were examined.

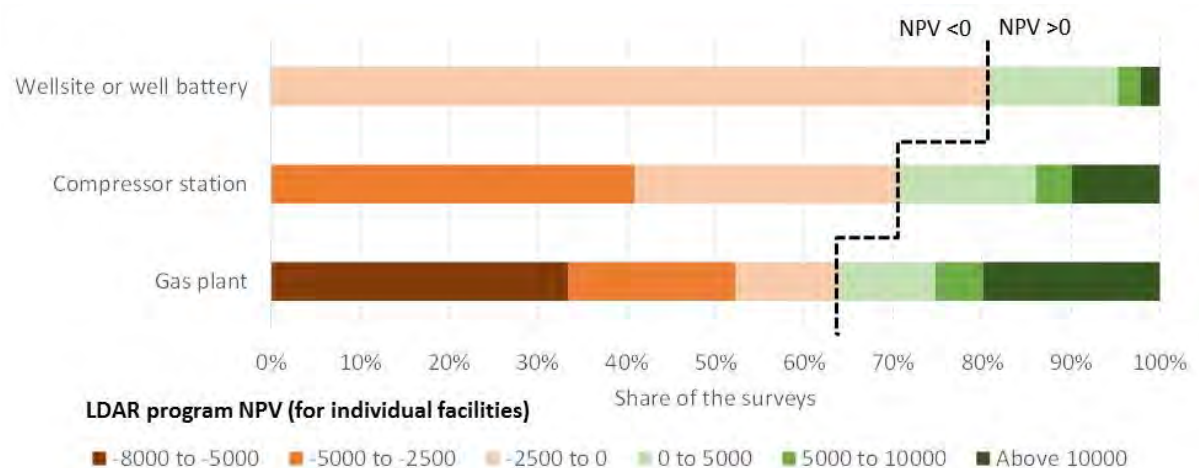
Economic assessments – Individual facilities

We first calculated the distribution of NPVs of LDAR programs conducted at individual facilities. We note that the detection surveys identified emissions from both leaks and vents. However, while this analysis considers the entire cost of surveys, it focuses on the potential benefits of leak repairs for static components. We also consider the benefits that can be realized through cost-effective reductions of excess emissions from reciprocal compressors. However, the potential benefits that can be realized through cost-effective reductions of other excess emissions identified by the surveys are not considered due to a lack of empirical information. As a result of this omission, this report underestimates the value of LDAR programs.

The NPV of a LDAR program is highly dependent on the number of identified emission sources and their leak rates. **Figure 1** shows the distribution of NPVs for individual facilities in the base case scenario. Overall, the majority of facilities have negative LDAR program NPV (net cost) with the well sites and batteries having the lowest percentage of facilities with positive NPV (net gain). This is because leak

rates for well sites and batteries are generally smaller than that for gas plants or compressor stations. However, even when implementing a LDAR program represents a net cost for an individual facility, the overall cost for the facility owner will always be relatively low. This is because surveys are relatively inexpensive, and any identified leaks are generally economic to repair. For example, for the well sites and batteries surveyed, the *lowest* NPV was -3,000 USD, while the *mean* NPV for the 340 well surveys having a positive NPV was +4,704 USD. For the 600 gas plants surveyed, the *lowest* NPV was -8,000 USD, while the *mean* NPV for the 221 gas plant surveys having a positive NPV was +34,412 USD.

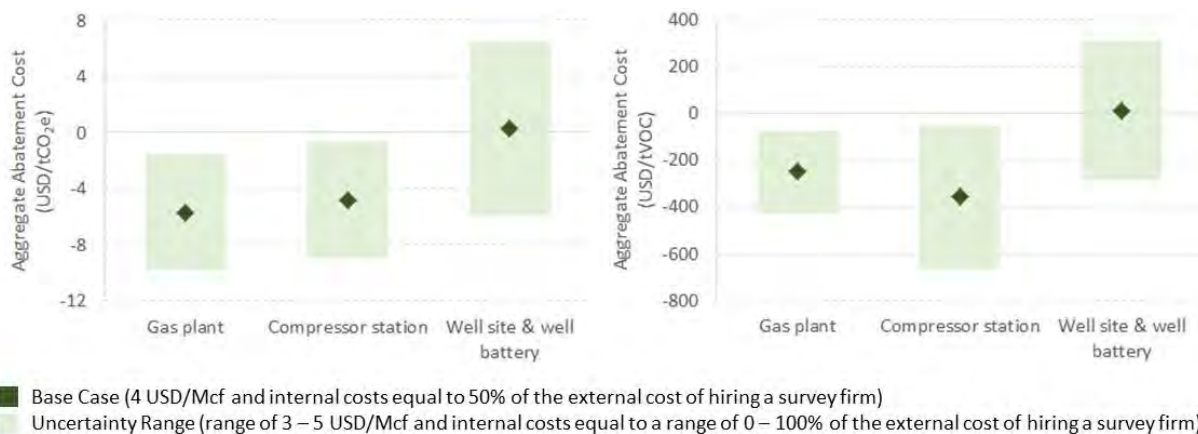
Figure 1: Distribution of Project NPV (base case assumptions) per survey for different types of facilities



Economic assessments – Aggregate cost effectiveness of LDAR programs

The aggregate economic result of conducting LDAR programs can be presented in terms of abatement cost per metric ton of CO₂e or VOC reduced by the program. A negative abatement cost means that the aggregate NPV is positive (net benefit for facility owners). LDAR programs in both gas plants and compressor stations have negative abatement costs, even with low gas prices. For well sites and batteries, the abatement cost is about zero USD/tCO₂e in the base case scenario and +6 USD/tCO₂e or +300 USD/tVOC in the most conservative scenario we considered (assuming a value of recovered gas of 3 USD/Mcf and that the *internal* cost of obtaining a survey is equal to 100% of the *external* cost of hiring the surveying firm). These abatement costs are low compared to many other GHG or VOC mitigation measures.

Figure 2: Aggregate VOC and CO₂e abatement cost for different types of facilities



In addition to the base case results, we have also evaluated whether requiring repair only of leaks that are economic to repair, or only of leaks with an emissions rate over a certain threshold, would reduce the abatement costs of systematic LDAR programs. As the vast majority of the identified leaks are economic to repair once the survey has been performed, it is most economic and environmentally effective to repair almost all the leaks. Adding an economic threshold to decide whether to undertake individual repairs only very marginally improves the economics of the overall LDAR program, by reducing the abatement cost by less than 15 USD/tVOC, while significantly reducing emissions abatement from the program.

The cost-effectiveness of surveying at different frequencies was also evaluated. **Figure 3** shows the effect of survey frequency on abatement cost. Increasing the survey frequency from annual to quarterly reduces the remaining emissions by 68%, as shown in **Figure 4**, but increases the abatement costs. The aggregate abatement costs for quarterly surveys, however, remain below 15 USD/tCO₂e and 800 USD/tVOC. Monthly surveys increase the maximum abatement cost to 55 USD/tCO₂e and 3,400 USD/tVOC. We note that the cost effectiveness of conducting frequent surveys depends on the facility type, maintenance, and size; the optimal frequency may best be determined by analyzing the results of past surveys. This study focused only on LDAR using IR cameras, which appears to be the dominant method at present and a significant improvement over previous detection methods. Alternative technologies in the future may reduce cost and improve effectiveness.

Figure 3: Aggregate abatement costs at various survey frequencies

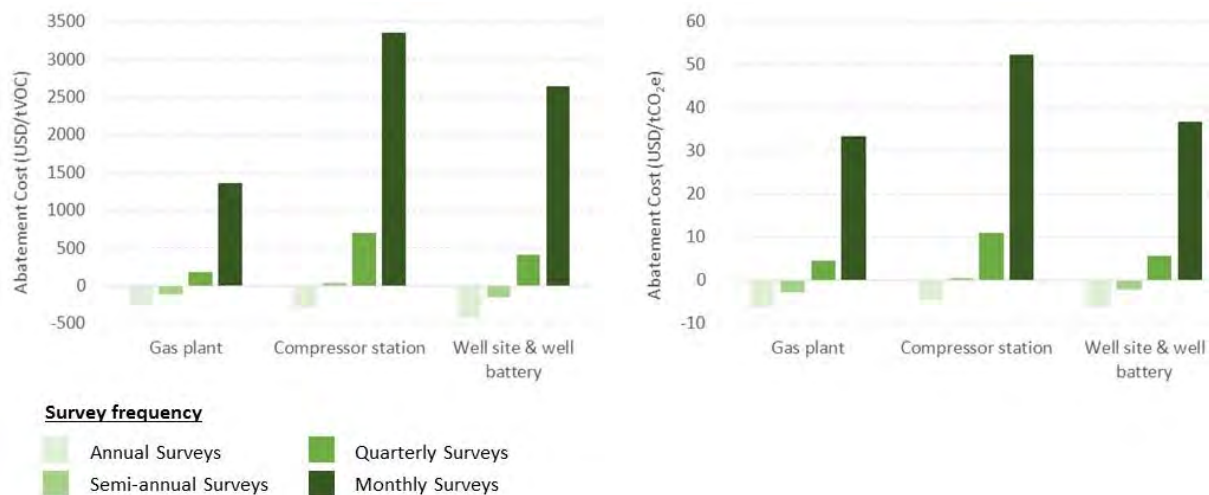
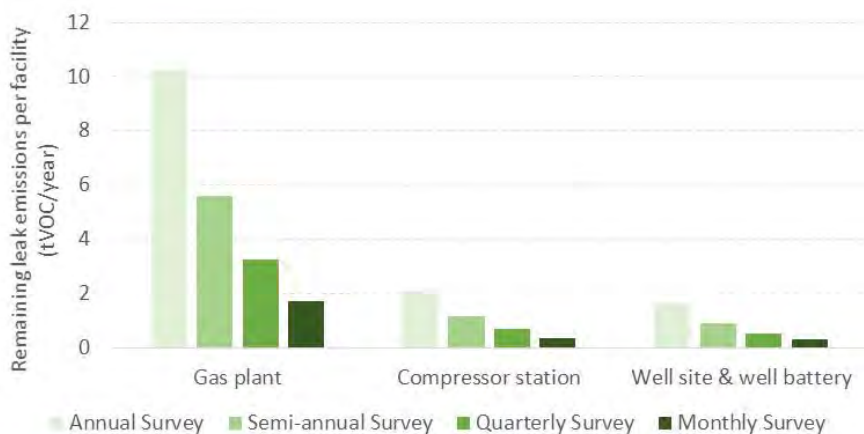


Figure 4: Remaining average leak emissions per facility for various survey frequencies



In general the analysis performed here is based on conservative assumptions, and will produce *overestimates* of the cost per ton of emissions abatement. Most importantly, the data used in this analysis is from facilities where LDAR programs have been in place for some time. Therefore, the observed emissions from leaks in this dataset are lower than the current level of leaks from a typical facility in the US, where, outside of new gas processing plants, LDAR programs are not generally required. Since the leaks (and therefore potential leak abatement) from the facilities in this database are *lower* than from the typical US facility, the cost per ton of emissions abatement is *higher* in this analysis than the real abatement cost in the US.

The economics of reducing excess emissions from reciprocating compressors by replacing rod packing rings were also examined. The rings can be cost-effectively replaced (i.e. NPV>0) for 13% of the

compressors at gas plants and 19% of the compressors at compressor stations. These compressors account for 70% and 73% of the total emissions from all compressor rod packing at gas plants and compressor stations, respectively. Including these cost-effective measures to reduce compressor emissions increases the overall mitigation potential of the LDAR survey program significantly compared to the base case, in which only static leak repairs were considered (+21% CO₂e and +14% VOC). Including abatement of excess emissions from rod packing does not significantly affect the overall cost-effectiveness of the LDAR programs for any facility type.

To conclude, this report provides empirical calculations of cost-effectiveness of leak detection and repair programs based on data from a very large number of facility inspections. It shows that leak detection and repair programs at oil and gas production and processing facilities using IR cameras can reduce emissions of methane and VOC at low cost.

1. INTRODUCTION

Methane is a potent greenhouse gas with a relatively short lifetime in the atmosphere. For this reason, measures to reduce emissions of methane can quickly lower its atmospheric concentration, yielding a relatively rapid climate response. In the United States, 30% of anthropogenic methane emissions are from oil and gas sector activities, and these represent about 3% of total US greenhouse gas emissions (2). There is increased attention given to methane emission reduction measures in general and to actions in the oil and gas sector in particular.

This report presents results from an empirical analysis of costs and benefits of emission reduction measures in the oil and gas sector. The analysis is based on data collected during surveys carried out by two private sector firms that provide gas emission detection and measurement services to the oil and gas industry. The data were made available to Carbon Limits in an anonymous form and checked for quality/consistency before being entered into a database. In total, data from 4,293 surveys were included in the database¹, covering all potential sources of emissions (both leaks and vents) and 58,421 sources with quantified emission rates. Some 90% of the surveys were performed in Canada, with the balance in the US. This report primarily focuses on **leaks** from static components, which comprise 39,505 of the individual emission sources in the database.

As part of the surveys, facilities were first screened using infrared (IR) cameras to locate hydrocarbon gas emissions. Identified emissions were then either measured (in general with a high-volume sampler²) or estimated³. An emission register, which includes estimations of the costs of repairs to reduce emissions, was then produced by the company conducting the survey and delivered to the facility owner.

The database contains information on the emitting component, the type of emission (i.e. leak or vent), the failure mode, the gas emissions rate, the type of gas emitted, the type of repair required, the repair costs, and the repair lifetime for each individual emission source detected in the surveys⁴. Facility specific information such as age, size, operating mode and the technology used are not available.

¹ Data from oil sands and oil bitumen emission sources were excluded from the database and the analysis.

² See definition on page 15 in

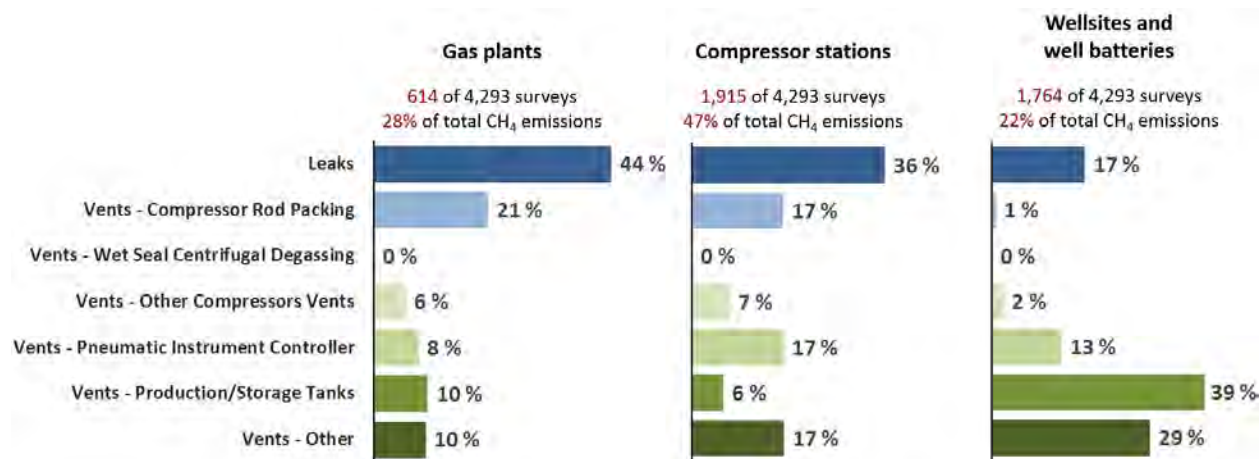
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³ In a number of cases, the facility owners do not need a precise volume measure; an estimate (evaluated visually using the IR camera based on the extensive experience of the operators) would be sufficient to make the decision to repair. In a few cases, the component leaking is also difficult to access for measurement. 51% of the leaks are estimated, representing 53% of the quantified leak emissions.

⁴ Repair lifetime in the database range from 1 to 5 years, with 30% of the repairs having a lifetime of 2 years or less and 97% of the repairs having a lifetime of 4 years or less.

While venting sources, such as tanks, instrument controllers, etc. constitute the majority of emissions at the surveyed facilities (see **Figure 5**), this report focuses primarily on leaks from static sources, such as connectors, valves, and regulators. We focus on emissions from leaks in this study due to the lack of empirical data on the cost-effectiveness of leak detection and repair (LDAR) programs using IR cameras as a means of reducing methane and VOC emissions from oil and natural gas facilities.

Figure 5: Distribution of emissions in the database by source and facility type



Almost 30% of methane emissions from the onshore oil and natural gas facilities are from leaks (1). In the database used for analysis, leaks account for 35% of total emissions. As shown in **Figure 5**, emissions from compressor rod packing represent about 14% of additional emissions, predominantly at gas plants and compressor stations. The potential value added to programs to detect and repair leaks by also identifying cost-effective opportunities for replacement of **compressor rod packing** is briefly discussed. However, due to limited data availability, we do not examine the economics of abatement of reducing emissions from venting sources such as tanks, pneumatic instrument controllers, dehydrators, or well completions in this reports.

2. ANALYTICAL APPROACH

2.1 Database coverage

Data from LDAR surveys of three main types of facilities were included in the database used for analysis, as shown in **Table 2**.

Table 2: Types of facilities and number of surveys⁵

Facility type:	No of surveys:	Description
Compressor station	1,915	This category includes mainly gathering and boosting compressors (upstream of processing plants) and compressor stations in the transmission and storage sector. Compressor stations in this category in general range from one ⁶ to three compressors and from 200 to 1,000 horsepower each. The majority of these compressor stations are more than five years old.
Gas plant	614	Gas plants in this category generally range from 10 MMcf/day to 500 MMcf/day. On average gas plants tends to be larger in USA than in Canada ⁷ . The vast majority of plants are more than five years old.
Well sites and well batteries	1,764	This category includes the following ⁸ : - Well sites are sites with only one well head - Well batteries include some equipment on site in addition to the well head (e.g. an oil/liquids storage tank, and/or separator, etc.). Multi-well batteries include in general five to fifteen well heads.

39,505 of the 58,421 individual emission sources in the database are classified as “leaks”, i.e. unintended emissions from connectors, valves, regulators, etc.⁹.

As seen in **Table 3**, while there is variability from site to site and between facility types, some trends in emissions are observed. Gas plants leak the most, whereas well sites and well batteries leak more

⁵ Information based on discussion with the data providers. However, this information is not documented in the database. As a result, it is generally not possible to quantify the distribution of facility sizes or sub-categories within the three categories of facility types, nor to analyse how leak rates or net program costs vary between sub-categories.

⁶ A large share of the compressor stations have only one compressor.

⁷ Natural Gas Annual Respondent Query System (EIA-757 Data through 2012) and presentation by BlueLine at EBRD/GGFR workshop on gas utilization in Moscow 19th June 2013 (for info see http://www.aebras.ru/en/member-notice-board/index.php?ELEMENT_ID=259927).

⁸ These three subcategories are used separately in the database, but due to inconsistent terminology and practices between the two data providers, the results may not be robust for sub-categories. Therefore, we present results for the category as a whole.

⁹ The database also includes 255 instances of improper venting from damaged pneumatic controllers and open thief hatches. Because these are inexpensive and simple to repair, in a manner similar to many leaks, they are included in the analysis of cost-effectiveness of LDAR, unlike other vented emissions recorded in the surveys. Due to the small number of these instances (less than 1% of leaks in the database), inclusion of these instances does not have a significant effect on the results of this work.

modestly, with about one-third having no detected leaks¹⁰ and only 7% having leaks above 500,000 cubic feet per year (Mcf/year). Compressor stations leak more than well sites and well batteries, but less than gas plants.

Table 3: Distribution of facilities within each category by leak rate (in Mcf per facility per year)

Category:	No leaks	≤99	100-499	500-1499	≥ 1500
Gas processing plants	3%	17%	32%	25%	23%
Compressor stations	11%	30%	36%	15%	9%
Well sites and well batteries	36%	38%	18%	5%	2%

It is important to highlight that the distributions presented in **Table 3** are *not* representative of distributions of current gas emissions in the US, where systematic leak detection and repair programs are less common. The database largely consists of identified leaks at Canadian facilities that have been subject to regular leak detection and repair for some time. At present, such systematic requirements are generally not in place for most natural gas facilities in the US, outside of gas processing plants built after 1984. As a result, current emissions from most US facilities are expected to be higher than the emissions typical in these surveys (see **Section 4.2**; US versus Canadian Facilities).

Using the information in the database, in addition to average survey costs for facility types provided by the two leak detection firms, we have calculated the costs and benefits of leak detection programs of various design. For many analyses, we present data on cost-effectiveness using an abatement cost defined as cost per metric ton of avoided pollution, where the avoided pollution is calculated from the observed leaks. However, leak emissions at the facilities in the database are lower than typical of US facilities, since the facilities in the database were subject to ongoing LDAR surveys. **Therefore, we consider the abatement costs presented in this report to be an overestimate of the real abatement cost for reducing emissions from US facilities, relative to the current (no-LDAR) baseline.**

2.2 Assumptions, base case scenario, and sensitivity analysis

A set of assumptions and realistic variations of key parameter values have been used in the analysis of cost-effectiveness of abatement options presented in this report, and are summarized below:

- **Gas price:** The value of recovered gas has been assumed to be similar for all emission sources, independent of the composition of the gas. Gas values from 3 to 5 USD/Mcf have been assessed in sensitivity analyses, with a base case scenario of 4 USD/Mcf.
- **Discount rate:** A 7% per year real term discount rate has been assumed.
- **Gas compositions and emission factors:** Based on the qualitative description of the type of gas emitted from each source, a gas composition was assumed for each emission source in the database and a CO₂e and a VOC emission factor have been calculated (see Appendix 3). Per US

¹⁰ This is very similar to the result from reference (7) where no leaks were detected at 34% of the well sites.

regulatory definitions, neither methane nor ethane are included in the calculations of VOC emissions.

- **Global warming potential (GWP)** of methane has been set at 25, for the purpose of calculating CO₂e tonnage.
- **Survey costs:** The total survey costs in the database are based on the current average market prices for purchasing such services¹¹ and an estimated mark-up to reflect the facility owner's internal cost. These internal costs include not only procurement costs to contract a service provider, but also staff time that may be required during the field survey. The total survey costs can vary between operators¹². The base case scenario assumes that this mark-up for internal costs is 50% of the cost of hiring the external survey providers (*i.e.*, the total survey cost to operators is equivalent to 150% of the cost of hiring an external service provider to survey the facility). Sensitivity analyses have been conducted for mark-ups of 0-100% of external survey costs (*i.e.*, total survey costs to operators varying from 100% – 200% of the market prices for hiring an external service provider).
- **Repair costs and lifetime:** The estimated repair costs and repair lifetime per leak are provided by the two data providers for the majority of components. For the remaining components, repair costs and lifetimes are estimated based on information provided by the survey companies on (a) the type of repair suggested for the component, or (b) the type, sub-type, and size of the leaking component. See Appendix 1 for minimum, maximum, average, and median repair costs for various component types.
- **Repair efficiency:** 95% repair efficiency has been assumed for leaks, 80% for other emissions due to improper conditions¹³.

In the base case, it is assumed that facility owners fix all leaks that the LDAR survey identifies. Variations in this assumption are examined in **Section 3.3.1**.

2.3 Methodology

The primary sources of information used for analysis, *i.e.* data from 4,293 LDAR surveys from two service providers, were subject to initial quality control prior to being compiled into a database. The manual coding done by the survey firms were checked (*e.g.* facility type, type of emissions, failure mode) and inconsistencies were rectified. Cost data provided for leak repairs were also carefully reviewed and changes made in cases of obvious errors.

The costs and benefits of implementing LDAR programs at oil and gas facilities have been assessed and used to determine the economic attractiveness of leak detection and repair programs at two levels:

¹¹ Service here includes gas emission detection and quantification survey and the delivery of a monitoring report to the operator. An average survey cost (see Appendix 1) has been assumed per type of facility category.

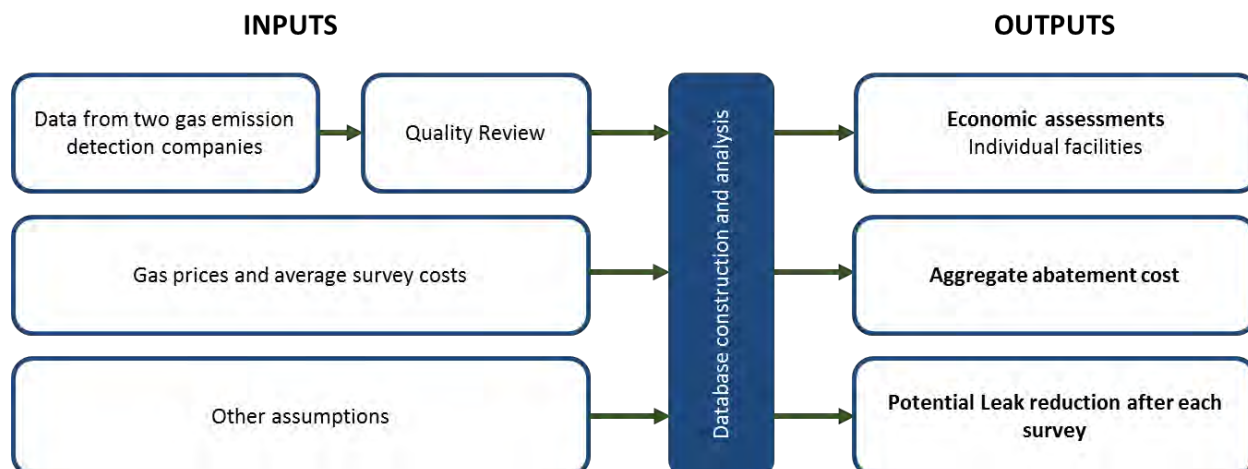
¹² Depending on the number and size of the facilities, distance between the facilities, internal organization, etc.

¹³ Estimates based on discussion with the two service providers who have provided data for this study.

- (i) The economic value of implementing LDAR programs at individual facilities.
- (ii) The cost-effectiveness of implementing LDAR programs at a group of facilities of a similar type (aggregate abatement costs).

Results of the analysis at these two levels are presented in **Section 3.1** and **Section 3.2** respectively. In addition, **Section 3.3** presents a comparison of different strategies for LDAR programs.

Figure 6: Overview of the methodology for assessment of cost-effectiveness of LDAR programs



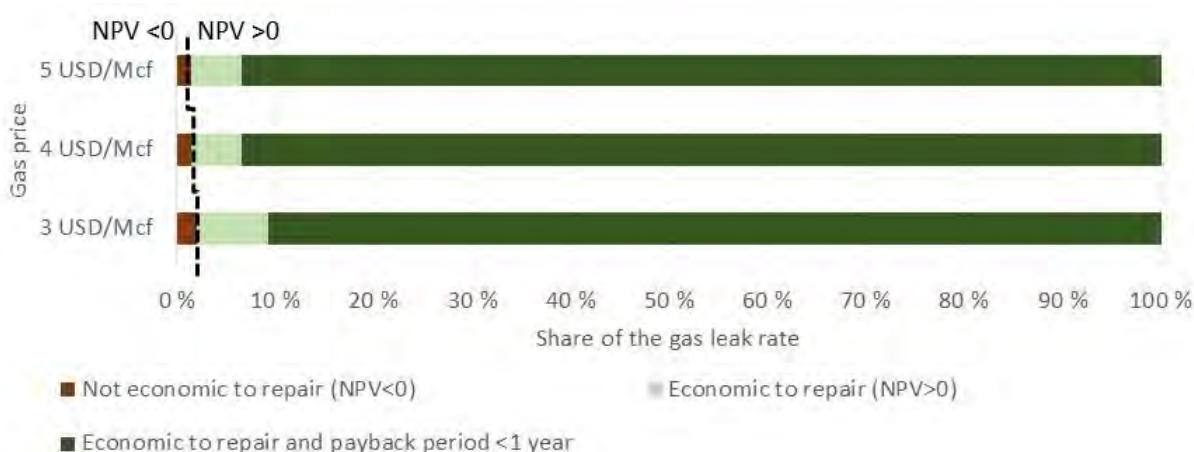
The assessment of the cost-effectiveness of implementing LDAR programs presented in **Sections 3.1** to **3.3** does not include potential benefits associated with cost-effective mitigation of venting emissions identified by the surveys. As LDAR programs could be expected to lead to identification and implementation of some of these cost-effective abatement measures targeted at vent sources, the overall value of LDAR programmes presented is conservatively estimated (the costs associated with quantifying the vent rate are included in the LDAR program costs, while potential benefits are excluded). **Section 3.4** presents the results of a sensitivity analysis where the net present value of implementing cost-effective replacements of reciprocating compressor packing rings has been taken into account when assessing the overall cost-effectiveness of the LDAR surveys.

3. LEAK DETECTION AND REPAIR (LDAR)

3.1 Economic assessment - Individual facilities

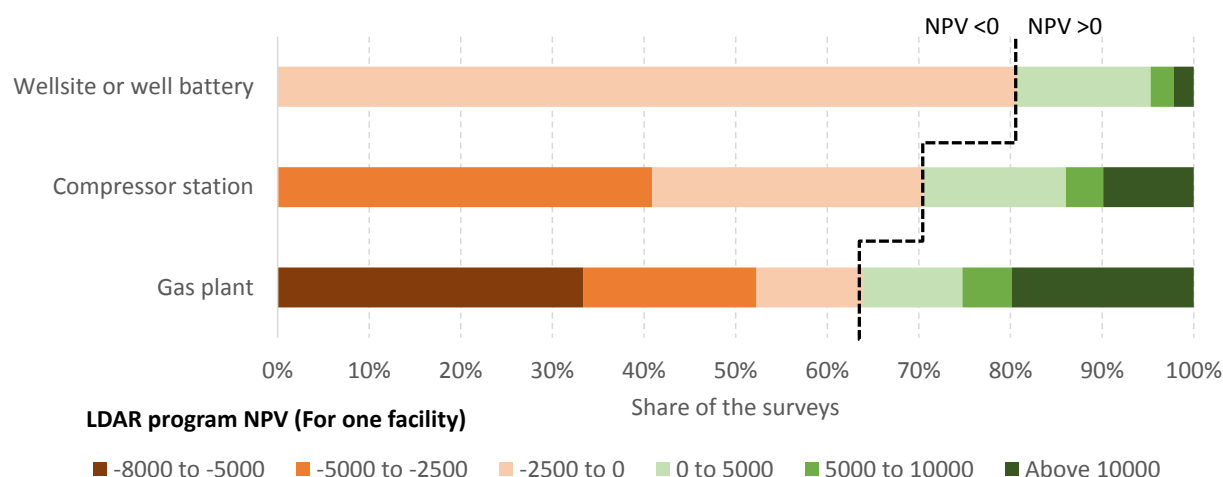
The net present values (NPVs) of repairing individual leaks identified in surveys have been calculated based on estimated repair costs and the value of gas conserved (for sale) by the repair. This analysis shows that the economic value of the conserved gas exceeds the repair cost in almost all cases. Once they are identified, the vast majority of the leaks, and the vast majority of emissions from leaks (more than 97% of the total leak rate), are economic to repair ($NPV > 0$), even when the value of gas is 3 USD/Mcf. In addition, over 90% of gas emissions are from leaks which can be repaired with a payback period of less than one year (see **Figure 7**). There is almost no difference in these results across the three categories of facilities.

Figure 7: Economic attractiveness of the individual repair for all types of facilities – only repair costs included.



We now consider the full program cost, including both the total survey cost and repair costs. Calculated NPVs of the LDAR program per facility survey, assuming all identified leaks are fixed independent of the size of the leak and the economics of repairing it, are more variable. The resultant distributions of facility level NPVs for each of the three categories of facilities are shown in **Figure 8**. For all three categories, the majority of facilities have negative NPVs (i.e. net costs), with the well sites & batteries having the lowest share of facilities with positive NPVs (i.e. net gains).

Figure 8 : Distribution of NPV per LDAR program for different types of facilities – survey and repair costs included.¹⁴



The low leak rates, which are typical for well sites & well batteries (see **Table 1**), explain the large share of negative NPVs found for this category. While the individual leaks are economic to repair, for many facilities the economic benefit from repairing the leaks is less than the total cost of the survey so the NPV of the LDAR program at those facilities is negative. However, the relatively low survey costs (600 to 1,800 USD per facility in total survey costs in the base case) limit the magnitude of net costs. For the well sites and batteries surveyed, the lowest NPV was -3,000 USD. The mean NPV for the 1,424 well surveys having a negative NPV (81%) was -1,167 USD, while the mean NPV for the 340 well surveys having a positive NPV was 4,704 USD. As a result, the average NPV at well facilities was -35 USD.

For compressor stations, about 30% of the surveys have positive NPV, and as many as 10% have NPVs exceeding 10,000 USD. For the 565 compressor station surveys having a positive NPV, the mean NPV was 17,182 USD. In contrast, none of the surveys have a NPV of less than -5,000 USD. The average survey NPV at compressor stations was 3,376 USD.

Gas plants typically have survey costs exceeding 5,000 USD¹⁵. Almost a third of the 600 gas plant surveys have a positive NPV, with about 120 gas plant surveys having a NPV above 10,000 USD. The mean NPV for the 221 gas plant surveys having a positive NPV was 34,412 USD. This category also has the lowest proportion of surveys with negative NPVs, and none with a negative NPV of less than -8,000 USD. The average survey NPV at gas plants was 9,403 USD.

The economic attractiveness assessed at the survey/facility level shows considerable variability, particularly for gas plant and compressor station surveys, but the net cost per facility survey, when there is a net cost, is always relatively low. However, it is important to consider that the NPVs illustrated in **Figure 8** are calculated per facility and most companies own several facilities. As a result, the aggregated

¹⁴ Under base case assumptions, including 50% mark-up for internal costs to administer surveys (total survey cost to operators is 150% of the cost of hiring an external service provider to survey the facility).

¹⁵ External costs only (mark-up for internal costs not included).

NPV for companies is likely to be higher than that of the median facility as displayed in Figure 4 and may be positive (see below).

3.2 Aggregate abatement cost

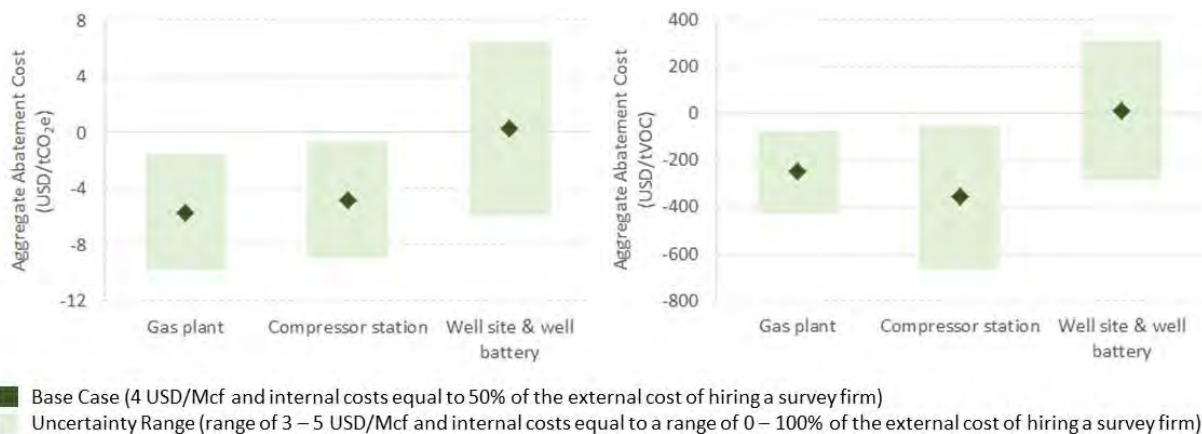
To evaluate the overall cost-efficiency of systematic implementation of regular LDAR programs for a group of facilities of a similar type (over a jurisdiction or over a large company), aggregate NPVs were estimated. Although the majority of the 4,293 facility surveys have negative NPVs when evaluated individually, the aggregated NPV for all facilities is positive, meaning that those facilities with surveys with negative NPVs (net cost) are outweighed by those having surveys with positive NPV (net gain). This is due to the asymmetry in NPV distributions for individual facility surveys (see **Figure 8**). The aggregate economic results of the LDAR programs can also be presented in terms of abatement costs (e.g. per metric ton of CO_{2e} or VOC emissions avoided), which is common when environmental policies are considered. The aggregate abatement costs have been calculated as:

$$\text{Aggregate Abatement Cost} = \frac{\text{Discounted sum of cash flows for all the facilities}}{\text{Discounted emission reductions for all the facilities}}$$

The discount rate applied is 7% in the base case both for cash flow elements and emission reductions. Other approaches, such as applying a lower (even zero) discount rate for future emission reductions, or amortizing costs of repair over its lifetime and then calculating annual net costs for emissions avoided in a given reference year, can also be used to evaluate and compare cost-efficiency of mitigation options. As shown in Section 4.2, the results are not very sensitive to variations in discount rate (due to limited repair lifetimes).

Figure 9 shows that gas processing plants and compressor stations have negative abatement costs (i.e. positive NPV) in the base case scenario. This conclusion also holds when assuming a lower gas price of 3 USD/Mcf and higher total survey costs (mark-up for internal costs up to 100% of the external cost of hiring an external service provider). With the base case assumptions, well sites & well batteries have abatement costs around zero, increasing to 6 USD/tCO_{2e} or 300 USD/tVOC applying the less favourable assumptions for gas price and total survey costs.

Figure 9: Aggregate VOC and CO₂e abatement cost for different types of facilities



3.3 Comparison of different approaches for LDAR programs

The results presented in the previous sections are based on the base case assumption that the operator would repair all the leaks that have been identified during a survey. In **Section 3.3.1**, we consider ways to potentially increase the value of routine LDAR by using economic or emissions thresholds to allow certain leaks not to be repaired. **Section 3.3.2** then examines costs and benefits of LDAR programs with different survey frequencies.

3.3.1 Impact of different repair strategies

Two alternative strategies to the base case strategy of repairing all identified leaks are analysed:

- **Strategy 2:** Perform a leak detection and quantification survey, and only repair the leaks which are economic to repair – i.e. those components that can be repaired with a net gain (NPV>0).
- **Strategy 3:** Perform a leak detection and quantification survey, and only repair leaking components with an emissions rate exceeding a certain threshold, e.g. 20 Mcf per year.

For each strategy, the potential leak reduction and aggregate abatement costs per metric ton of CO₂e and VOC are calculated for different types of facilities¹⁶. **Table 3** summarizes how the two alternative strategies compare to the base case strategy (i.e. “repair all leaks”) for two (sub-)categories of facilities; compressor stations and multi well batteries. Other types of facilities show similar patterns.

¹⁶ Only corrective maintenance program approaches are reviewed here. Preventive maintenance programs have not been evaluated as part of this project.

Table 4: Comparison of three hypothetical repair strategies for compressor stations and multi-well batteries (examples)¹⁷

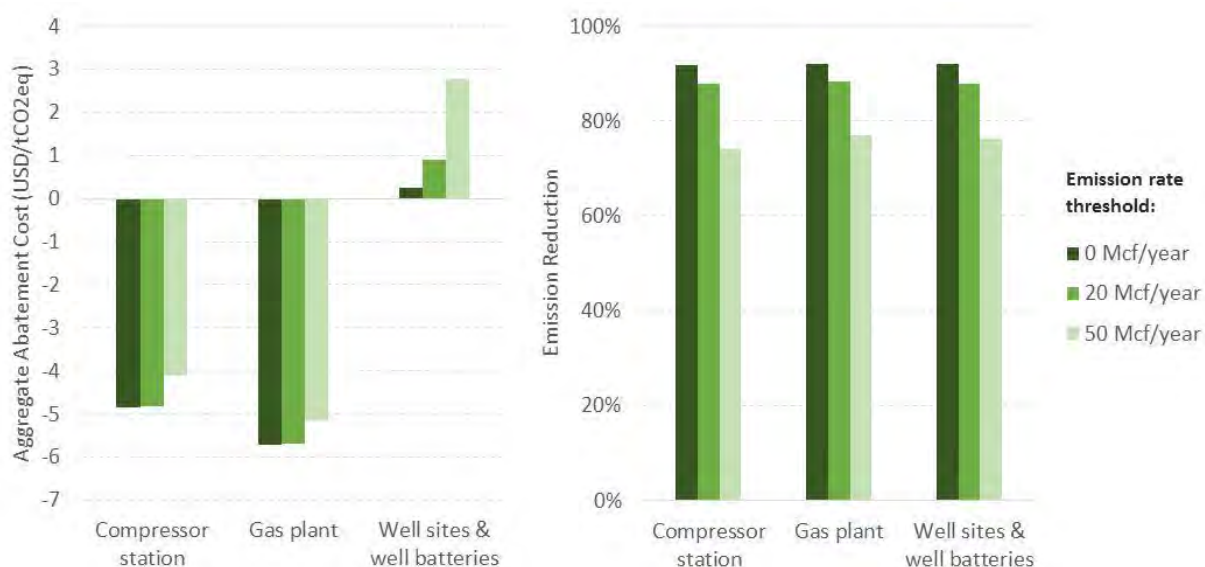
Compressor Station	Base Case (all identified leaks)	Strategy 2 (leaks with NPV>0)	Strategy 3 (leaks > 20 Mcf/yr)
Potential leak reduction after each survey	94.7%	93.0%	87.7%
Methane abatement cost (in USD/tCO _{2e})	-4.9	-5.0	-4.8
VOC abatement costs (in USD/tVOC)	-355	-368	-357
Average number of leaks to repair per facility	11.3	10.2	6.9
Multi well Battery	Base Case	Strategy 2	Strategy 3
Potential leak reduction after each survey	94.5%	92.6%	88.1%
Methane abatement cost (in USD/tCO _{2e})	1	0.8	1.7
VOC abatement cost (in USD/tVOC)	46	41	79
Average number of leaks to repair per facility	3.8	3.5	2.9

Comparing the alternative repair strategies and the “repair all leaks” base case shows:

- Strategy 2 results in lower aggregate abatement costs, since repairs that are uneconomic are not performed. However, the difference is minimal (<0.2 USD/tCO_{2e}). It is also important to consider that this strategy would be more complex to implement in practice. For each leak identified, at a minimum some evaluation (based on measurements or estimates of leak volume, etc.) would need to be carried out, and for those leaks not repaired, documentation of leak magnitude, repair cost, etc., might be required (and possibly verified). The additional administrative costs this entails are not accounted for in this analysis.
- Strategy 3 does not represent cost savings of any significance, and there are markedly less emission reductions. For multi well batteries, the aggregate abatement costs actually increase (this is due to the fact that small leaks can be economic to repair). As a result, abatement cost per ton *rises* as the threshold rises under Strategy 3. **Figure 6** explores further the emission reductions and aggregate abatement costs for different emissions rate thresholds for this strategy. The sensitivity analysis shows that, statistically, it is both more environmentally efficient and more economical to repair all the leaks detected.

¹⁷ The trend is similar for other types of facilities. The results of Strategy 3 depend on the volume threshold set (see Figure 11). Gas emission reductions are calculated for the year following the survey.

Figure 10: Strategy 3 - Sensitivity to the emissions rate threshold with base case assumptions¹⁸



To conclude, as the vast majority of leaks are economic to repair once the survey has been performed, it is most economic and environmentally effective to repair almost all the leaks. Adding an economic constraint on the repair program only marginally improves the economics of the overall program.¹⁹

3.3.2 Impact of the frequency of surveys

Increasing the frequency of surveys and subsequent repairs further reduces emissions, but will increase abatement costs. This section examines the effect of survey frequency.

The database used in this report includes surveys performed at a variety of facilities and in several jurisdictions in both Canada and the US. Some of the facilities are surveyed once every year or once every two years, while others are surveyed less frequently. It was possible to extract definitive information on the survey frequency for 12% of the total surveys in the database (i.e. 542 surveys)²⁰. Almost 80% of these repeated surveys were performed on a yearly basis and 17% were performed every two years. For the analysis of the impact of survey frequency presented below, only data for surveys with a known frequency of one year (427 surveys in the database) have been used.

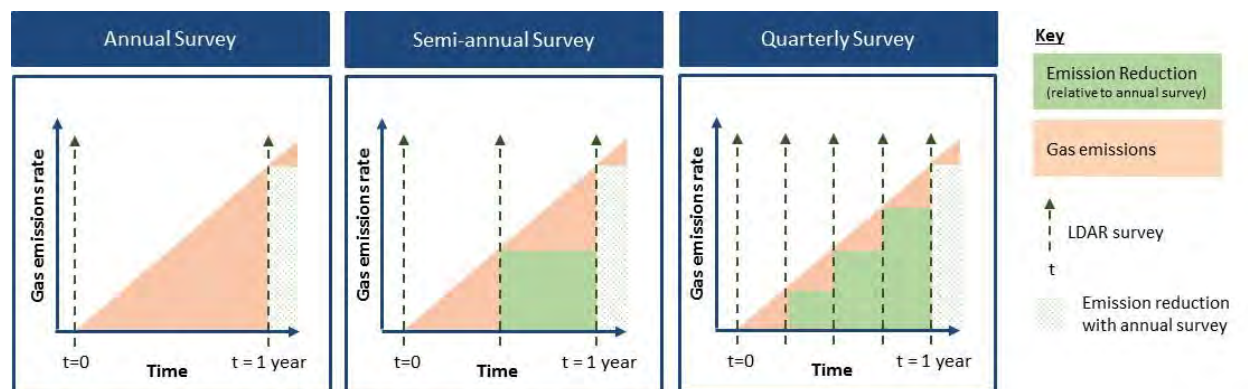
¹⁸ The abatement costs for VOC emission reductions (now shown) show the same trend as for CO₂e (illustrated in the figure).

¹⁹ The current study does not review the administrative cost of implementing and enforcing the regulation. However, we can highlight that Strategy 2 (and to some extent Strategy 3) are more complex to implement and to enforce than the base case strategy of repairing all identified leaks.

²⁰ While definitive frequency information is only available for 12% of the surveys, it is clear, based on interviews and reference (8), that the facilities in our database are typically surveyed every one or two years.

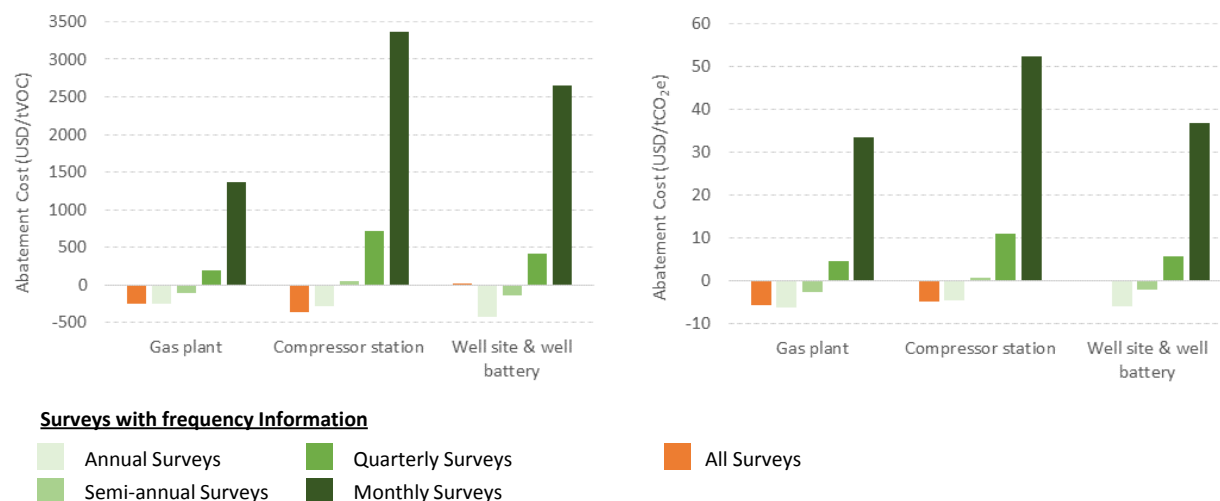
Increasing the frequency of the leak detection and repair survey will have a positive impact on the emission reductions that can be achieved, as the leaks are detected and can be repaired earlier (see Figure 11).

Figure 11: Schematic overview of emission reductions within a year depending on the frequency of the surveys



However, more frequent surveys increase program costs. **Figure 12** shows the increase in abatement costs for VOC and CO₂e as a function of increased survey frequency. However, even with these increased costs, in all the cases evaluated, the abatement costs remain below 55 USD/tCO₂e and 3,500 USD/tVOC.

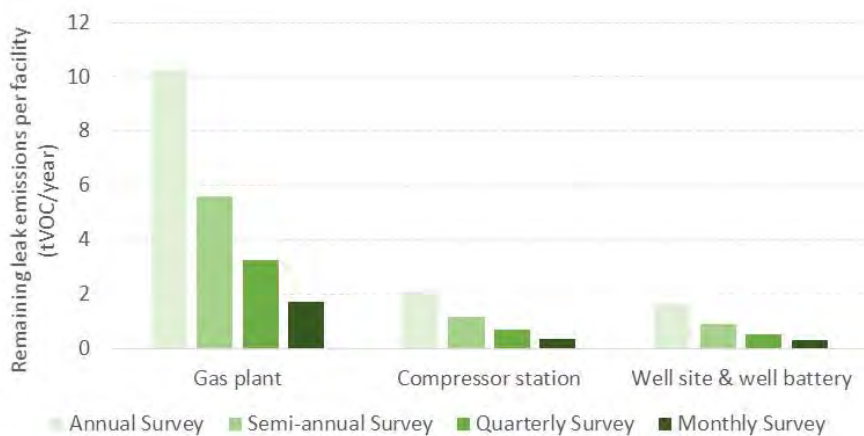
Figure 12: Aggregate abatement costs depending on the survey frequency²¹



²¹ Base case assumptions are applied, and repair lifetimes are maintained for all components. It is assumed that leaks arise over time - more frequent detection will lead to quicker repairs of identified leaks, but fewer leaks will be detected per survey. The repair cost for a component found to be leaking is independent of the survey frequency.

Figure 13 presents the remaining average VOC emissions per facility depending on the survey frequency.

Figure 13: Average remaining leak emissions per facility depending on the survey frequency²²



We note that the leak rates shown in **Figure 13** values are not, in general, representative of US facilities, where leak detection surveys are not generally routine.

To conclude, by increasing the survey frequency, remaining emissions are reduced, but abatement costs increase. Still, the abatement costs for quarterly surveys remain below 15 USD/tCO₂e and 800 USD/tVOC.

We note that the cost efficiency of conducting frequent surveys depends on the facility type, maintenance, and size, and therefore the optimal frequency may best be determined by analysis of the results of past surveys. This study focused only on LDAR using IR cameras, which appears to be the dominant method at present. Alternative technologies in the future may reduce cost and improve effectiveness.

²² It is important to highlight that we assumed that all the leaks are repaired quickly after the survey. This assumption is not realistic for leaks which cannot be repaired without shutdown of the facility or process unit (generally, repair of those leaks will be delayed until the next planned shutdown), or for repair of some other leaks, such as those that are difficult to access. As a result, emissions reduction overestimated, and abatement cost (per ton) is underestimated in regards to this aspect. The share of repairs which will be delayed is not available in the database.

3.4 Impact of including compressor rod packing replacements

This section assesses how the results of the analysis presented above are affected when the net present value of economic replacements²³ of compressor rod packing rings are included in the analysis.

As shown in **Figure 5**, compressor rod packing emissions represents 21.2% of total observed gas emissions for gas plants, 17.0% for compressor stations, and less than 1% for well sites and well batteries. There are various parameters that affect the packing vent rate, e.g.:

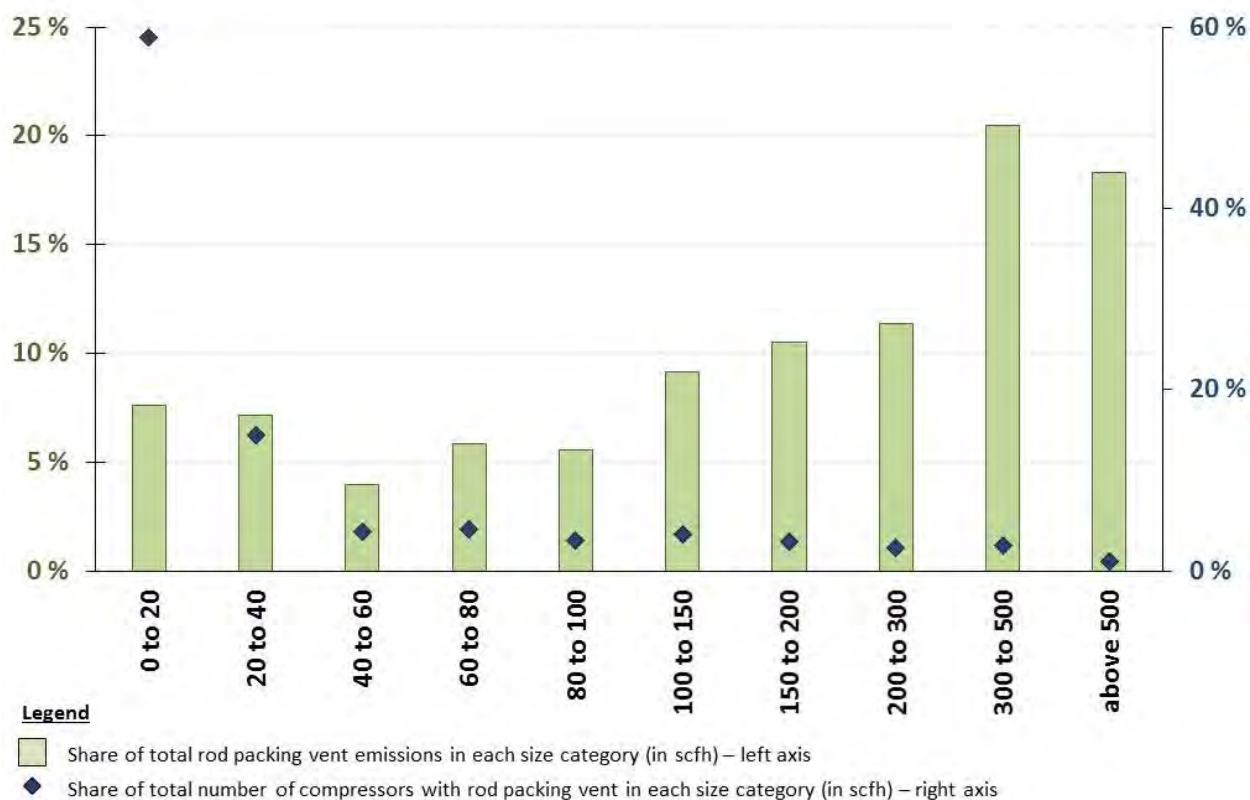
- The number of operating hours (packing rings become worn over time)
- The packing technology (various designs and materials with different initial performance and wear resistance are available)
- The deterioration of the piston rod (a worn or not properly aligned piston rod can affect the fit of rod packing against the shaft and increase leakage; piston rods can become worn because of friction, scratches, or when the compressor is operated intermittent or unused for a long period)

The emission database comprises 2,160 individual emission sources for compressor rod packing emissions, all with measured emission rates²⁴. The database used for this study does not contain sufficient context information to relate variations in rod packing emissions rates to variations in parameters that are expected to affect these rates. The mean rod packing emissions rate in the database is 56.7 scfh. **Figure 14** shows the distribution of measured rod packing vent rates in the database. A large portion of emissions originate from a relatively small fraction of compressors; 50% of gas emissions is from less than 7% of compressors emitting more than 200 scfh.

²³ Economic replacements are defined as those with a positive expected net present value (NPV>0).

²⁴ Emissions were measured using a hi-flow sampler, predominantly in Canada, during the period 2007-2013. 58% of total emissions of this nature are related to compressors in gas plants, 41% are related to compressors in compressor stations, while the remaining 1% are related to compressors in other types of facilities.

Figure 14: Distribution of measured rod packing vent rates per size category (in scfh)



In order to reduce excessive compressor packing emissions, it is necessary to replace the rod packing. It might also be necessary to re-align or replace the rod. Here we estimate the quantity of additional emissions reductions that could be achieved by using LDAR programs to identify compressors with excess emissions and replacing rod packing when economic to do so. We also estimate the effects of including rod packing replacements on the overall cost-effectiveness of LDAR programs. Because many of the parameters that affect the cost-effectiveness of rod-packing replacement are not available in our database, this estimate is less precise than our calculations of abatement costs, etc., for leaks from static components. We include this analysis to illustrate the additional benefits that may be realized by expanding LDAR programs to include other emissions sources at oil and gas facilities, beyond leaks from static components.

The following assumptions have been used to calculate the cost-effectiveness of replacing packing rings²⁵:

²⁵ Assumptions regarding the number of hours in pressurized mode and the average number of shafts per compressor in gas plants and in compressor stations are based on estimates provided in Table 6-2 in a TSD from EPA (9). Costs for equipment and installation are based on discussions with Ceko and John Crane and represent costs for rod packing replacement for larger compressors and are similar to those in (9).

- Economic lifetime of new packing rings: Three years
- Average number of cylinders per compressor: 2.5 for gas plants, 3.3 for compressor stations.
- Total purchase and installation cost for new rod packing: 1,800 USD per cylinder (*i.e.* total cost per compressor of 4,500 USD for gas plants, 5,940 for compressor stations).
- Annual hours in pressurization mode: for compressors in gas plants, 7,800; for compressor stations: 7,000.
- It is assumed that vent rates initially can be reduced to 11.5 scf/hr/cylinder after replacement of packing rings, and that the emission rate would grow over time in the same manner both if packing was not replaced and, if replaced, after replacement (from the lower, post-replacement value).

In addition, general (base case) assumptions presented in **Section 2.2** have been applied for the discount rate and the value of conserved gas. With these assumptions, packing rings can be replaced at zero or negative abatement cost when vent rates exceed ~85 scfh for gas plant compressors and ~120 scfh for compressors in compressor stations.

Including the potential emissions abatement from those compressors where rod packing can be replaced at zero or negative costs (*i.e.* 328 compressors with NPV>0 for packing replacement) increases the methane emissions mitigation in the first year after a survey achieved by the LDAR programs by 23% (**Table 5**). Over the lifetime of the mitigation measures (three years for new rod packing or lifetime of individual leak repairs), including rod packing increases LDAR program methane mitigation by 21% and VOC mitigation by 14%.

Table 5: Increase in mitigation potential and aggregate NPV from inclusion of economic Rod Packing Replacement (RPR) in LDAR programs

Facility type:	Average mitigation potential per facility (tons CO ₂ e, 1 st year)			Average NPV (USD per facility)		
	Base case (leaks only)	With RPR included in LDAR Program	Relative abatement increase from including RPR	Base case (leaks only)	With RPR included in LDAR Program	Relative NPV increase from including RPR
Gas plant	566	721	27%	9,403	12,394	32%
Compressor station	250	313	25%	3,376	4,616	37%
Wellsite and well battery	61	61	0%	-35	-35	0%
All facilities in database	217	267	23%	2,837	981	35%

It should be noted that little context information is available about the compressors in the emission database (*e.g.*, neither cylinder size nor the number of operating hours of the compressor since the last packing replacement are available). To be conservative we assumed replacement costs for all rod packing were representative of larger compressors. On the other hand, some operators would have

replaced rod packing within the three-year period after the survey (as part of fixed maintenance schedules, for example). As a result of the latter effect, our calculated NPVs for rod packing replacement may be too high.

While replacing rod packing when economic to do so would significantly increase emissions abatement from LDAR programs, it only has small effects on the overall abatement cost of an LDAR survey program ($< \pm 1$ USD/tCO₂e and $< \pm 65$ USD/tVOC compared to the base case presented in **Figure 9**).

To conclude, packing rings can be replaced at zero or negative abatement costs for 13% of the compressors at gas plants, and 19% of the compressors at compressor stations. These compressors account for 70% and 73% of the total emissions from reciprocal compressor rod packing vent volume at gas plants and compressor stations, respectively. While inclusion of these economic measures to reduce emissions from rod packing increases the mitigation potential significantly compared to the base case when only leaks from static components are considered (+21% for CO₂e and +14% for VOC), the overall cost-effectiveness of the LDAR programs is not significantly affected for any facility type.

4. Concluding remarks

4.1 Main findings

The analysis presented in this report provides new insight into leak detection and quantification survey costs and benefits, as it is based on data collected from over four thousand facility surveys and data on almost forty thousand leaks. This robust dataset allows calculation of the economic value of LDAR programs under a range of program designs and frequencies.

The evaluation of available survey data shows that most leaks, once identified, are economic to repair with a payback period less than one year. As a result, once the survey has been performed, it is economic to repair almost all the leaks.

Overall, LDAR programs at oil and gas production and processing facilities using IR cameras have low abatement costs on an aggregate basis. Program costs and emission reduction potentials are not very sensitive to program design, although aggregate abatement costs are sensitive to the survey frequency. However, abatement costs for quarterly surveys remain below 15 USD/tCO₂e and 800 USD/tVOC. For monthly surveys, abatement costs are below 55 USD/tCO₂e and 3,400 USD/tVOC.

The abatement costs reported here are calculated from the observed leaks at the surveyed facilities, where LDAR programs had been in place for some time. At US facilities, LDAR programs are not generally in place, and thus current leaks are expected to be larger than at the facilities in our database. Since emissions abatement from the current baseline due to LDAR programs would be higher at US facilities than the emissions abatement from *ongoing* LDAR documented in our database, the abatement costs presented here are an *overestimate* of the true emissions abatement cost from LDAR for most natural gas facilities in the US.

From a facility owner's perspective, implementing a routine LDAR program may represent a net cost (NPV < 0) for many facilities. However, even in those cases, the overall cost is always relatively low due to the low survey costs.

As described in the following section, the results presented here were calculated with conservative assumptions – with the exception of one assumption (prompt repair), all assumptions are set to overestimate abatement cost. Considering these assumptions and the overestimate of abatement cost described above in this section, we are confident that this analysis calculates a conservative estimate of the cost of mitigating methane and VOC emissions from oil and natural gas facilities.

4.2 How robust are the results?

Some sensitivity analyses were presented in **Section 3.1 to 3.3** with variations in survey costs and gas prices. However, there are other assumptions being made (see **Section 2.2**) that potentially impact the results. These assumptions are considered below, either quantitatively or qualitatively.

Discount rate: A discount rate of 7% (real terms) has been applied in all of the analyses presented in this Chapter. With an increase in the discount rate to 12%, aggregate abatement costs increase by less than 0.5 USD/tCO₂e or 30 USD/tVOC.

Measured versus estimated emissions: Leak rates are to some extent uncertain since a number of them were estimated and not measured. A sensitivity analysis was performed to evaluate if the inclusion of estimated leak rates impact the results of the analysis. Abatement costs were calculated for the subset of surveys for which more than 80% of total emissions was measured, as opposed to estimated. For all categories of facilities, the abatement costs calculated for this subset of surveys is very similar (within 1 USD/tCO₂e) to the results obtained using data from the entire database.

Value of recovered gas: The value of the recovered gas has been assumed to be similar for all emissions sources, independent of the composition of the gas. This is a conservative assumption when calculating the abatement costs of LDAR programs, as richer gas (propane, butane, etc.) leaks are detected in many cases, and the value of this gas would typically be higher.

GWP of methane: A GWP of 25 was used for methane (see **Section 2.2**), based upon the recommended 100-year GWP from IPCC's Fourth Assessment Report (10). The recently released Fifth Assessment Report recommends a 100-year GWP of 30 or 36 for methane from fossil sources, depending on the inclusion of certain climate feedbacks in the calculation²⁷. Using these more recent calculations of the GWP of methane would reduce the abatement costs per ton of CO₂e by 17 – 30%.

Survey costs: Operators may consider it economic to perform the survey internally instead of outsourcing the services, as was the case for the surveys analyzed in this work. In these cases, the total survey costs presented above might be on the high side.

Exclusion of benefits from reductions in venting: The exclusion of benefits from cost-effective repairs of venting sources identified in the surveys, while including the full cost of the survey identifying those vents in addition to leaks, underestimates the value of the LDAR programs and the emissions reductions resulting from such programs. As shown in **Figure 5**, most of the

²⁷ See Fifth Assessment Report, Working Group I Contribution, page 714.

Available at: http://www.climatechange2013.org/images/report/WG1AR5_Chapter08_FINAL.pdf.

identified emission sources at facilities are venting, so this effect may be significant. As illustrated in **Section 3.4**, the mitigation potential is significantly higher (+21% for CO₂e and +14% for VOC) when including economic (NPV>0) replacements of compressor rod packings in the analysis, while the overall cost-effectiveness of the LDAR programs is not significantly affected for any facility type.

No specific shutdown required: Repairs are assumed to be performed rapidly after surveys, during the normal (ongoing) operations of the facilities. Hence repair activities do not cause production losses, and no potential revenue losses are accounted for in the analysis. When the facility needs to be shut down to perform the repair, the repair is assumed to be postponed to the next planned maintenance. The potential delay in realizing emission reductions from repairs requiring shutdown, or other repairs which are not carried out rapidly (such as for components which are difficult to access), has not been accounted for in the analysis. The abatement costs per ton are underestimated, to some degree, since this approximation overestimates emissions abatement.

Gathering compressor stations versus transmission compressor stations: As described in **Section 2**, the database includes compressor stations in the production segment (e.g. gathering stations) and compression stations in the transmission segment. It was possible to extract definitive information on the location of the compressors for about half of the surveys of compressor stations. For these 1,032 surveys, the aggregate abatement cost for LDAR programs on compressor stations in the production segment is -1.7 USD/tCO₂e, while the aggregate abatement cost for LDAR programs in the transmission segment is -8.3 USD/tCO₂e in the base case scenario. For the latter category of compression stations, if the value of recovered gas is zero (i.e. no additional revenues from sale of gas), the abatement cost increase to 2.3 USD/tCO₂e.

US versus Canadian facilities:

The majority of the surveys included in the database have been performed in Canada, with about 500 surveys in the US. The key relevant similarities and differences between the two countries are:

- Results from analysis of data contained in the database: In general, the average leak emissions per facility is higher for the US facilities compared to the Canadian ones, which indicates that the abatement costs presented in this analysis are higher than they typically would be for the sample of US facilities. However, it is important to highlight that the surveys conducted in the US are not necessarily repeat surveys and thus may not be representative of *systematic repeat* LDAR programs examined in this report.

- Size of the facilities: Gas plants in the US are, on average, larger than Canadian ones²⁸. A large number of the gas plants in the database are very small plants and thus the abatement costs presented above for this facility type may be conservative.
- Other similarities: According to interviews with technology providers, the practices are very similar in the two countries, with similar designs, equipment, and suppliers. Maintenance practices vary significantly from site to site, but there is not necessarily a significant difference between the two countries, with the exception of different regulations, such as the requirements to perform regular LDAR in Alberta.²⁹

Finally it should be added that other analyses for US facilities generally show higher leak rates than presented in this analysis, see **Appendix 3**. For many analyses, we present data on cost-effectiveness using an abatement cost defined as cost per metric ton of avoided pollution, where the avoided pollution is calculated from the observed leaks. However, this review suggests that the results of the analysis performed in this study may be conservative when considering US facilities, since the facilities in the database were subject to ongoing LDAR surveys. Therefore, the abatement costs presented in this report are considered to be higher than the expected abatement cost for reducing emissions from US facilities where LDAR is not currently in place. Comparison with other studies as shown in **Appendix 3** should however be interpreted with great caution because of the great variation in statistical samples (this analysis having a far greater number of observations), type of facilities surveyed, and analytical approach.

The assumptions and considerations, with the exception of the assumption that all leaks can be repaired without waiting for shutdown, all tend to overestimate the cost of LDAR programs and/or underestimate of the mitigation potential associated with such programs. In summary, this indicates that our assessments of the value and cost-effectiveness of LDAR programs are in general conservative.

²⁸ Factor of about 3, calculated based on data from Natural Gas Annual Respondent Query System (EIA-757 Data through 2012) and a presentation by BlueLine at EBRD/GGFR workshop on gas utilization in Moscow 19th June 2013 (for info see http://www.aeprus.ru/en/member-notice-board/index.php?ELEMENT_ID=259927).

²⁹ See Alberta Energy Regulator Directive 060 at 8.7; <http://www.aer.ca/documents/directives/Directive060.pdf>

Appendix 1: LDAR costs

Table 6: Average cost of hiring an external service provider to conduct a survey, depending on the facility type (not including any internal administrative costs)

Facility type:	Cost of hiring an external service provider, USD:
Compressor station	2,300
Gas plant	5,000
Multi well batteries	1,200
Single well batteries	600
Well site	400

Table 7: Leak rate and repair costs depending on the component type (main component types only; rates are in cubic feet per minute (cfm))

	# in DB	Rate (cfm)			Repair Cost (USD)			
		Min	Average	Max	Min	Average	Median	Max
Valve	10,575	0.01	0.12	36	20	90	50	5,500
Connector/Connection	23,577	0.01	0.10	60	15	56	50	5,000
Regulator	1,081	0.01	0.12	5	20	189	125	1,000
Instrument Controller (Leak only)	1,106	0.01	0.14	5	20	129	50	2,000

Appendix 2: Leak rate per component type and per facility type

Table 8: Total average leak rate from facilities, only from specific component types (cfm)

	Compressor station	Gas plant	Well sites and well battery
Connector/Connection	0.58	1.69	0.11
Instrument Controller (Leak only)	0.04	0.05	0.03
Valve	0.41	0.77	0.04
Open Ended Line	0.10	0.11	0.02
Regulator	0.04	0.05	0.02

Appendix 3: Gas compositions

Based on the description of the type of gas emitted from each source, the following compositions were assumed for the leaks in the database, from which CO₂e and VOC emission factors have been calculated:

Table 9: Assumed gas compositions and emission factors for the main gas types used (these are used for > 99% of the gas leaks)

Type of gas (described in database)	Methane (Mol %)	EF _{CO₂e} (kgCO ₂ e/scf)	VOC (Mol %)	EF _{VOC} (kgVOC/scf)
Methane	100%	0.48	0.0%	0.0000
Custom gas	83%	0.40	6.8%	0.0047
Sweet gas	79%	0.38	7.5%	0.0045
Sour gas	71%	0.35	3.6%	0.0023
Propane	0%	0.00	100%	0.0813
Ethane	0%	0.00	0.0%	0.0000

Appendix 4: LDAR - Comparisons with past work

A number of other published studies evaluate either the emissions rates of different facilities or the economics of performing leak detection and repair programs. This section briefly reviews key similarities and differences in the approach and results of this study and other existing publications. However, while use of IR cameras in leak-detection has been discussed in previous work, the project team is not aware of a study that fully quantifies costs and benefits of screening facilities for leak emissions with IR cameras using extensive field data.

Emission rates

Table 10 presents a comparison of emissions rates from a number of published studies (results from some studies were analyzed by Carbon Limits to categorize emissions as leak and vent emissions).

Table 10: Comparison of the current study with previously published work (results presented in cfm)

		Wellsite & well batteries		Compressor stations		Gas plants	
		# of assessments	results	# of assessments	Results	# of assessments	Results
This study	Average leak	1,764	0.4	1,915	1.4	614	3.3
	Average vent		1.2		2.4		3.9
	Average emissions		2.1		3.8		7.3
Fort Worth Natural Gas air quality study (3) ³⁰	Average leak	375	NA	7	6.4	1	13.5
	Average vent		NA		4.3		45.2
	Average emissions		3.1		10.7		59.1
Natural gas star program, lessons learned 2006 (4) (5)	Min emissions	NA	NA	13	0.7	4	85.4
	Max emissions		NA		380.5		244.4
Clearstone 2006 (6)	Average leak ³¹	12	NA	7	NA	5	60.2
	Average vent ³²		NA		NA		65.2
	Average emissions ³³		0.8		12.2		155.1
University of Texas 2013 (7)	Average emissions	146	0.23 ³⁴	NA	NA	NA	NA

It is important to highlight that the studies compared in **Table 10** have been performed using very different approaches and methodologies, and with very different sample sizes. As a result, any comparison should be interpreted carefully.

Overall, the results for well sites are in the same order of magnitude for all the studies presenting measured gas rates. A few hypotheses may explain the differences observed in emissions rates from gas plants and to some extent from compressor stations:

- Sizes of facilities:
 - Gas plants in USA are, on average, about three times larger than Canadian ones. A large number of the gas plants in the database are very small plants, which would have an impact on the average emissions presented.

³⁰ Annex 3A

³¹ Includes: Pressure relief valves, regulators, block valves, connectors (unions, flanges, and plugs), and control valves

³² Includes: Crank case vent, compressor seals, open-ended lines, orifice meter, glycol dehydrators, pneumatic controllers, equipment blowdowns and purging activities, tank vents, combustion equipment

³³ For well sites and compressor stations, glycol dehydrators, pneumatic controllers, equipment blowdowns and purging activities, tank vents, flares, and combustion equipment are not included

³⁴ Estimate per well site based on the average number of wells per wellsite.

- Compressor stations in the database include a large share of compressors situated in the production segment (i.e. gathering/boosting compressors), which are generally smaller than the stations in the transmission sector.
- Some of the past studies have focused on very limited samples of facilities per survey. It is not clear what the selection criteria have been and how representative the sampling has been relative to the overall distribution of facilities.
- According to the data providers for this study, many gas plants in the database have been engineered to high standards, and many have a number of personnel on-site to identify and correct emission related problems before they are detected by third party companies.
- In a number of the other studies reviewed, the leak detection and repair programs were performed for the first time (pilot study or baseline survey), and a large number of leaks were detected. When leak detection surveys are repeated regularly, repeat year surveys (which constitute the majority of the data used for this study) may identify decreased leak rates.

Economic attractiveness of leak detection and repair

An earlier study confirmed that the vast majority of fugitive natural gas losses (96.6%) were cost-effective to repair (6). However, several reports ((5), (6), and (4)) find that in most of the evaluated individual facility cases, the full LDAR program – survey + repairs – is economic to implement. In this report, we find that LDAR programs at most *individual* facilities will have negative NPV, although the aggregated NPV is positive. This difference can be explained by the smaller overall emission rates identified at each facility in this study (see above).

This review of past work shows that the results of the analysis performed in this study may be conservative when considering US facilities.

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Experience

- 06/2014 - Current **Research and Analytics Senior Manager, Environmental Defense Fund (San Francisco, CA)**
Manage development of analytics and policy for EDF's state, federal and international oil and natural gas advocacy efforts, including regulatory advocacy, emissions inventory compilation, data and economic analytics, technical support for rulemaking and regulation, and policy analysis and development.
- 09/2012 – 06/2014 **Senior Project Engineer, Environmental Resources Management (Austin, TX & Walnut Creek, CA)**
Managed and worked on projects in the Air Quality and Performance & Assurance practice areas. Experience writing state and federal air permits, completing calculations for air emissions inventories, performing environmental site assessments, compiling Spill Prevention, Control and Countermeasure plans, and performing regulatory compliance reviews.
- 06/2011 - 08/2011 **Climate and Air Intern, Environmental Defense Fund (Washington, DC)**
Worked with Dr. Jason Funk and the international climate team to help construct and support climate policies worldwide. In particular, completed extensive research on the use of alternative fuels for aviation as well as an overall biofuels profile.
- 05/2008 - 08/2008 **Engineering Intern, Bechtel (Richland, WA)**
Worked as an intern on the nuclear waste vitrification project at the Department of Energy Hanford site in the Civil, Structural and Architectural department of Bechtel. Completed a variety of tasks pertaining to: concrete/steel structural design, radiation shielding design, steel embedment calculations, and drawing inspections.

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Study Abroad (Ankara, Turkey)

Studied abroad in Ankara during the summer of 2009. Took a course pertaining to the fundamentals of fuel cell engines, and a Turkish language course. Interacted routinely with Turkish engineering students to design fuel cell systems and evaluate cultural differences during time of study at the Middle Eastern Technical University in Ankara.

Engineers Without Borders (Limbe, Cameroon)

As a member of Engineers Without Borders and the Project Lead for the Cameroon Project, worked to implement a sanitary, reliable water supply for the Saker Baptist College in Limbe, Cameroon. Traveled to Limbe in January of 2008 for exploration, and again in January of 2009 for assessment. Work completed for the project includes: CADD designs for the existing and proposed tank and pipeline system, travel logistics, and intensive water testing.

Study Abroad (London, England)

Studied abroad in the summer of 2007 in London, England. Took a course in sustainable architecture and a course in energy. The architecture course included visits to many prominent architecture firms and engineering firms in London and the energy course explored the many facets of the energy market, as well as different energy sectors, such as: nuclear, coal, solar, biofuel, geothermal and wind.

Skills

Proficient in Microsoft Word, Power Point, and Excel

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Airborne Quantification of Methane Emissions over the Four Corners Region

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Supporting Information

ABSTRACT: Methane (CH₄) is a potent greenhouse gas and the primary component of natural gas. The San Juan Basin (SJB) is one of the largest coal-bed methane producing regions in North America and, including gas production from conventional and shale sources, contributed ~2% of U.S. natural gas production in 2015. In this work, we quantify the CH₄ flux from the SJB using continuous atmospheric sampling from aircraft collected during the TOP-DOWN2015 field campaign in April 2015. Using five independent days of measurements and the aircraft-based mass balance method, we calculate an average CH₄ flux of 0.54 ± 0.20 Tg yr⁻¹ (1σ), in close agreement with the previous space-based estimate made for 2003–2009. These results agree within error with the U.S. EPA gridded inventory for 2012. These flights combined with the previous satellite study suggest CH₄ emissions have not changed. While there have been significant declines in natural gas production between measurements, recent increases in oil production in the SJB may explain why emission of CH₄ has not declined. Airborne quantification of outcrops where seepage occurs are consistent with ground-based studies that indicate these geological sources are a small fraction of the basin total (0.02–0.12 Tg yr⁻¹) and cannot explain basinwide consistent emissions from 2003 to 2015.



1. INTRODUCTION

The San Juan Basin (SJB) in New Mexico and Colorado is a major natural gas production basin and the largest coal-bed methane producing region in North America as of 2015.^{1–3} An elevated CH₄ anomaly over the SJB was detected from space from 2003 to 2009. These observations were validated with ground-based measurements and, in combination with an atmospheric transport model, used to determine a CH₄ flux from the SJB of 0.59 Tg yr⁻¹ [0.50 – 0.67 2σ].⁴ At the time, this estimate exceeded inventory estimates for emissions from the region [EPA Greenhouse Gas Reporting Program (GHGRP) estimate for 2012 was 0.33 Tg yr⁻¹; we note this inventory estimate for 2012 has since changed, which is described below]. Since the 2003–2009 time period, gas production in the San Juan Basin declined to reach a level in 2015 that is 34% below average production from 2003 to 2009, while oil production has increased rapidly (~260%).⁵ Subsequent analyses with satellite data have estimated fluxes from the region consistent with the original study.^{6,7} The TOPDOWN2015 campaign in the SJB region was designed to follow up on the satellite finding, determine total CH₄ flux from the basin, assess the role of

geologic seepage, and better understand the distribution of contributing sources. Given the large change in production of oil and gas in this region, assessing how total emissions may have changed also provides key insights into response to changing production volumes and practices.

Airborne studies quantifying the total basinwide CH₄ flux from the SJB have not yet been published; however, the role of point sources contributing to the total flux has been investigated (understanding the distribution of contributing sources). During the TOPDOWN2015 campaign, Frankenberg et al.⁸ used aircraft-mounted infrared spectrometers to identify and quantify fluxes from individual point sources of CH₄ in the region. They found that the largest 10% of sources contributed disproportionately (49–66%) to the sum of observed CH₄ point source fluxes of 0.23 – 0.38 Tg yr⁻¹. This estimate includes only the identified large point sources sampled by the remote sensing aircraft but

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aids in understanding the origins of the total flux as well as apportionment of CH₄ to anthropogenic versus natural sources. The majority of sources observed by Frankenberg et al. were anthropogenic, largely related to gas and oil production sectors, as well as a coal mine venting shaft and geologic seepage.

In this work, we use airborne observations taken during the TOPDOWN2015 campaign to determine a quantified estimate of total CH₄ flux from the San Juan basin using the mass-balance methodology similarly to previous applications to other regions of oil and gas production.^{9–14} We also determine the CH₄ flux from several large point sources using in situ airborne measurements,¹⁵ including regions of geologic seepage. Finally, we compare our quantified emissions with estimates from inventories and discuss the implications of emissions observed in 2015 compared with previous findings for 2003–2009.

2. METHODS

2.1. Instrumentation and Aircraft. Airborne observations over the SJB of southern Colorado and northern New Mexico were collected onboard Twin Otter (NOAA) and Mooney (Scientific Aviation) aircraft during the TOPDOWN2015 field campaign in April 2015. Both aircraft were equipped with a cavity ring-down spectrometer (Picarro G2401-m; ~0.5–1 Hz sampling frequency) that quantified atmospheric CH₄ and H₂O mole fractions. Inflight calibrations were used to determine the reported CH₄ dry mole fraction on the WMO scale (X2004 scale maintained by NOAA GMD). Precision and accuracy of the measurement was 0.5 ppb. Further details regarding previous operation and validation of Picarro spectrometers on both airborne platforms can be found in Karion et al. (2013),¹⁶ Karion et al. (2015),⁹ and Peischl et al. (2016).¹⁷ Wind speed and direction, ambient temperature and pressure, relative humidity, and GPS location were measured on both aircraft as described in Karion et al. (2015).⁹ Additionally, a wind profiler (915-MHz boundary layer wind profiler)¹⁸ was deployed in the southwest region of the study area (Farmington, NM) that recorded wind speed and direction with altitude continuously during the study period.

Flights were designed to determine the total CH₄ flux from the SJB, as well as the flux from individual sources. The studied area is bounded approximately by 36.0° to 37.5° latitude and –108.5° to –107° longitude, which encompasses the majority of gas-producing wells in the region. This region also coincides with the location of the elevated CH₄ anomaly observed by Kort et al.⁴ derived from space-based SCIAMACHY retrievals from 2003 to 2009.

2.2. Basinwide Flux. The CH₄ enhancement downwind of the SJB study area was measured on 5 days when the wind speed and direction were stable for 5–7 h prior to the downwind flight transect (wind speed variance was on the order of 1–2 m s^{–1}, direction variance ranged from 20° to 60°). Wind speeds and directions were considered stable if wind back trajectories constructed using data from the wind profiler located in the southwest of the study area (Farmington, NM) indicated that the air intercepted by a downwind flight transect originated outside of the study area (section S1 and Figure S1, no data for April 7, 2015). Wind vectors for each hour were constructed using hourly vertical profiles of wind speed and direction measured by the NOAA wind profiler in Farmington, NM (Figure S2) in high-resolution mode (mode 1), which were averaged vertically from 250 magl to a PBL height that varied with time of day. The trajectories were run back in time from the time and location of a downwind transect (using the midpoint of the transect). These

combined constraints ensured that emissions contributing to the enhancement were from the current day rather than accumulation in the basin, either overnight or trapped by swirling winds and topography (cf. section S1). Multiple flights were conducted from April 7 to 30; measurements from five flights conducted between ~15:30 to 18:00 local time were determined to be suitable for mass balance analysis. This assessment and confirmation is of particular importance in the SJB where the topography of the region often leads to air pooling in the SJB overnight. Downwind flight transects were conducted within the well-mixed boundary layer (determined using aircraft vertical profile measurements; see below) at altitudes of ~630 to 1650 magl.

The molar flux is calculated using the mass balance method, which has been applied previously to calculation of regional fluxes,^{9,13,14,16,17} according to eq 1:

$$\text{flux}_{\text{CH}_4} = \nu \cos \theta \int_{-b}^b X_{\text{CH}_4} dx \int_{z_{\text{ground}}}^{z_1} n_{\text{air}} dz \quad (1)$$

where $-b$ to b is the width of the enhancement plume, X_{CH_4} the molar CH₄ enhancement above background mixing ratios, n_{air} the molar density of air, z_{ground} to z_1 the height of the planetary boundary layer (PBL), and $\nu \cos(\theta)$ the component of horizontal wind perpendicular to the flight path.

Methane background mole fractions are defined by taking the mean of the CH₄ mixing ratios at the edges of the enhancement plumes (Figure S3). The well-mixed boundary layer height (z_1) is calculated from vertical gradients in CH₄ and H₂O, which decrease sharply with increasing altitude as they transition from well-mixed layer to free tropospheric mixing ratios (further details provided in section S2 and Figure S4).¹⁷ We note that the mixing layer heights determined from the vertical profiles agree with the PBLs determined from the wind profiler (data not shown). Wind speeds and directions used for the flux calculation are derived from differential GPS measurements onboard the aircraft¹⁵ and averaged during the time a downwind transect was conducted. The average values determined from the aircraft-based wind measurements agree with the wind speeds and directions determined using the ground-based wind profiler data within error (Table S1). Uncertainties are calculated and propagated as is standard in the approach and described in Kort et al.¹⁴ and Peischl et al.¹⁷

2.3. Individual Source Flux. The CH₄ flux from 18 point sources, including gas processing plants (3), compressor stations (6), a reinjection facility, a power plant, a coal mine vent shaft, and a geological seep in the SJB, were investigated by circling individual sources with the Mooney aircraft, using the method of Conley et al.¹⁵ Point sources sampled by aircraft were chosen based on known large point sources in the EPA GHGRP, as well as randomly sampling sources when a large CH₄ signal was observed in flight. After a plume from a point source was detected, measurements were taken at multiple altitudes spaced approximately 50 m apart, starting as close to ground level as possible (typically a few hundred meters above ground level) and ending at an altitude where the plume was no longer observed.

This method enables quantification of emissions from defined point sources provided the source is persistently emitting during the time of aircraft circling, which typically takes ~20 min. Quantification of fluxes is possible with this approach, but the significant time needed to sample an individual site limits the number of point sources that can be assessed in this manner.

3. METHANE FLUX FROM THE SAN JUAN BASIN

Observations collected on 5 days during the larger TOP-DOWN2015 campaign in April 2015 are used to determine an average CH_4 flux from the San Juan Basin during the study period of $62 \pm 27 \text{ kg hr}^{-1}$ (1σ). Flight paths colored by CH_4 mixing ratio for the 5 days used in our analysis are shown in Figure 1. Extrapolating our 5 day average to a yearly flux, we find $0.54 \pm 0.20 \text{ Tg yr}^{-1}$ CH_4 are emitted. The range of observed fluxes ($0.31\text{--}0.84 \text{ Tg yr}^{-1}$; Table 1) underscores the importance of multiday realizations of emissions to determine a central estimate. One contributing reason for the range of observations is that each flight sampled slightly different source regions (e.g., some geological outcrops do extend beyond the boundaries, which may bias some estimates low). The observed flux from the SJB is of the same order of magnitude as other studied fossil fuel production basins, with CH_4 fluxes from the Bakken, Uintah, Barnett, Marcellus, Denver-Julesburg, Haynesville, and Eagle Ford basins ranging from 0.12 to 0.70 Tg yr^{-1} across all basins.^{9–11,16,17} Note that these estimates are based on measurements made in afternoon hours spanning at most a month, whereas the satellite-derived estimates are made from retrievals collected in all seasons over multiple years. We also calculated daily CH_4 fluxes using the wind speeds and directions measured by the wind profiler (Table S1) for four of the five flights (profiler data not available for April 7, 2015) to assess the influence of different wind estimates (i.e., aircraft winds averaged over a downwind transect compared to winds determined from profiler data). The 4 day mean CH_4 flux of 0.51 Tg yr^{-1} based on the profiler winds agrees within error with the mean CH_4 flux calculated using the aircraft-based wind data (0.54 ± 0.20).

4. BOTTOM-UP EMISSIONS ESTIMATES

We can investigate how this emission value compares with bottom-up inventories. The US EPA GHG gridded methane inventory for anthropogenic sources is recently available for the year 2012.¹⁹ Summing all sources for the San Juan basin totals 0.40 Tg yr^{-1} , where $>80\%$ of the emission is attributed to natural gas production and processing, with oil and coal representing most of the remaining emissions. Only $\sim 3\text{--}4\%$ of the total is from enteric fermentations and landfills. A very small seasonality exists in the inventory for this region, but if we consider only April, extrapolated to a yearly flux, 0.40 Tg yr^{-1} remains the estimate. This estimate includes all source categories in the basin with the exception of geologic seepage. In the Colorado portion of the basin, ongoing measurements of geologic seepage have been recorded, where large interannual variance is observed, with annual fluxes not showing a trend in recent years but fluctuating from 0.04 Tg yr^{-1} in 2007 to 0.02 Tg yr^{-1} in 2011 and 0.12 Tg yr^{-1} in 2015.²⁰ If we combine these bottom-up estimates, considering 0.40 Tg yr^{-1} from the EPA inventory, a range of $0.02\text{--}0.12$ for geologic seeps (representing the upper and lower bound from ground-based observations), we find an estimated bottom-up value ranging from 0.42 to 0.52 Tg yr^{-1} , though we note there are no robust uncertainties associated with these bottom-up estimates. Our top-down total basin estimated flux, an annual extrapolation based on 5 flight days, is within uncertainty of the bottom up estimates, and the bottom-up estimate is dominated by gas production and processing emissions.

5. POINT SOURCES

To further investigate the magnitude of emissions from individual point sources contributing to total CH_4 emissions in

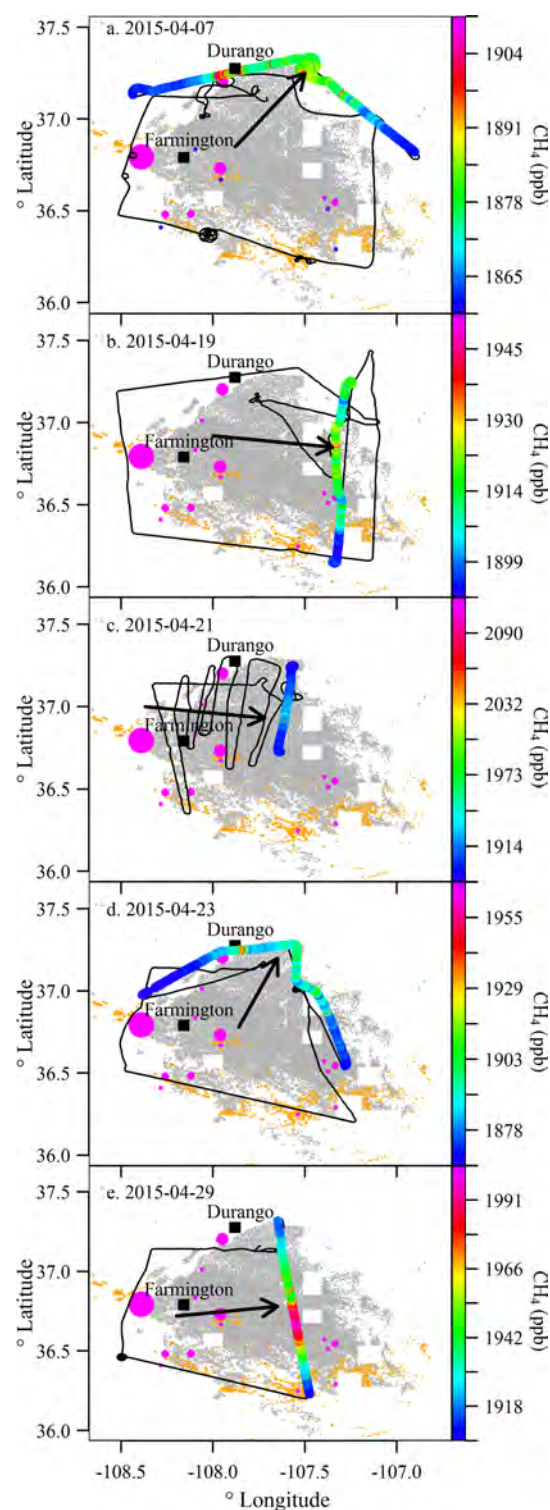


Figure 1. Mass balance flight transects. Color scale shows observed CH_4 mixing ratio along a downwind flight transect. Arrows show approximate wind direction. Also shown are gas wells (gray); oil wells (orange); point sources circled by the Mooney aircraft, scaled by relative measured CH_4 flux (magenta); and the locations of Durango, CO and Farmington, NM (black squares).

the basin, the Mooney aircraft circled oil, gas, coal, and geologic seeps at different altitudes while measuring atmospheric CH_4 mixing ratios as described in Conley et al.¹⁸ The largest point source observed by the Mooney was a coal mine vent shaft (also

Table 1. Summary of Inputs to eq 1 with 1σ Uncertainties and CH_4 Fluxes Calculated from Observations Onboard the Mooney Aircraft (Top Row) and the NOAA Twin Otter (Bottom Rows)^a

date	local hr (−6 UTC hr)	no. of transects	Θ (deg)	v (m s^{-1})	z_1 (magl)	$\text{flux}_{\text{CH}_4}$ (Tg yr^{-1})
Mooney						
4/07/2015	15.5	1	42 ± 10	10 ± 2	2138 ± 71	0.45 ± 0.15
Otter						
4/19/2015	16.2	1	93 ± 24	8.1 ± 2.6	2250 ± 124	0.57 ± 0.25
4/21/2015	16.2–17.2	4	95 ± 22	6.8 ± 1.9	2263 ± 106	0.31 ± 0.13
4/23/2015	15.8	1	45 ± 20	7.0 ± 1.8	2450 ± 257	0.55 ± 0.19
4/29/2015	17.0	1	83 ± 25	5.8 ± 1.6	2150 ± 347	0.84 ± 0.30
Campaign Mean:						0.54 ± 0.20^b

^aFlux values are daily means. Wind speeds and directions are determined using the mean values derived from aircraft data during each transect.

^bError on daily flux estimates are determined by summing the error of the components of eq 1 in quadrature; error on campaign flux mean is the 1σ of the mean.

observed by Frankenberg et al.,⁸ Table 2), which comprised 2.4% of total basin emissions (5 day average of $1446 \text{ kg hr}^{-1} \text{ CH}_4$).

Table 2. Examples of Some of the Largest CH_4 Point Sources Quantified by Aircraft Measurements (Top Rows) and Remote Infrared Sensing (Bottom Rows), as Well as the Sum of All Sources Observed but Not Listed^a

reported point source	$\text{flux}_{\text{CH}_4}$ (Tg yr^{-1})	% total basin $\text{flux}_{\text{CH}_4}$
this work (Mooney)		
one geological seep	0.0062	1.2
coal mine vent shaft	0.013	2.4
Σ observed sources ($n = 18$)	0.047	8.7
Frankenberg et al. ⁸ (2016)		
coal mine vent shaft	0.014	2.6
Σ observed sources ($n \geq 200$)	0.23–0.38	43–72

^aEstimates of the coal mine vent shaft from this work and Frankenberg et al.⁸ are expected to agree because data from the Mooney aircraft was used to validate the method of Frankenberg et al.

Additionally, the Mooney aircraft measured CH_4 geological seepage from a coal outcrop to investigate its magnitude; a large outcrop southwest of Durango was investigated on 2 separate days, and a flux of $709 \pm 325 \text{ kg hr}^{-1}$ was determined, which is $\sim 1\%$ of the total basinwide emission (Table 2). Thus, even the largest sources make up only a few percent of overall emissions, in contrast to the even more outsized role of large point sources reported in the Barnett Shale region.²¹ Although the sources measured by Frankenberg et al. follow a heavy-tail distribution,⁸ small emissions distributed across the field contribute substantively to the overall CH_4 flux.

6. TIME SERIES OF EMISSIONS AND GAS PRODUCTION

Kort et al. estimated no trend in CH_4 flux in the SJB during 2003–2009 (0.59 Tg yr^{-1} [0.50 – 0.67 ; 2σ]).⁴ The present study estimates an average CH_4 flux in 2015 of 0.54 Tg yr^{-1} [0.34 – 0.74 ; 1σ], which is consistent with the average for 2003–2009, even though gas production decreased in the SJB between the years 2003 to 2015. According to San Juan county gas production data, production in the region for 2015 decreased from the 2003–2009 average by 34% (time series of production shown in Figure 2). Different measurements and models are used in the studies of Kort et al. and our current study on emissions from the SJB, but if we consider the reported uncertainties as robust, using a t test for significance at a 95% confidence level, we find that we

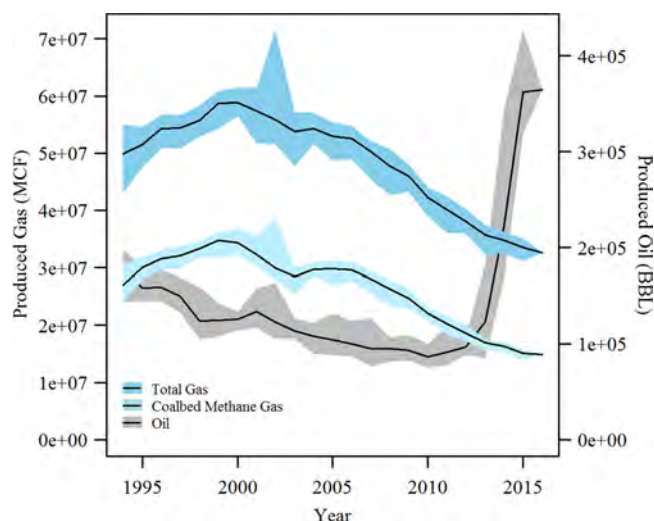


Figure 2. Gas and oil production in San Juan county from 1994 to 2016. Shading shows range of monthly reported values, and line shows the annual average. Production data from the New Mexico Energy, Minerals and Natural Resources Department, Oil Conservation Department.⁵

are able to statistically quantify if a decrease in emissions of 26% or more occurred between the earlier study of Kort et al. and 2015 (section S3). Thus, we would be able to detect a decrease in basinwide emissions if they were tightly correlated with gas production (which decreased by 34%) and there was no other major source of emissions. A common assumption is that the leak rate of natural gas scales with gas production,¹¹ though this has been shown to not be true on all scales, such as when considering individual gas production pads.²² Excluding other potential sources of CH_4 emissions our results indicate that in the SJB gas production is a poor predictor for total oil and gas CH_4 emissions over time (multiyear scales) as gas can be, and is, lost in ways not related to total gas production.

Considering other potential sources that might explain why emissions do not appear to have changed over the past decade, one hypothesis is that emissions from geological seepage have increased over time. However, the seepage determined from the Mooney aircraft measurement of one outcrop area where we were able to observe elevated methane signals indicated this source contributed $\sim 1\%$ to total CH_4 emission. Other outcrop areas we monitored (in CO and NM) did not present as discernible signals in the aircraft data. Given the magnitude from aircraft and ground-based sampling, and the lack of any large

increasing trend in ground-based sampling, geologic seepage cannot explain the persistent emissions in the basin over time.

A second hypothesis to explain the persistent emissions despite the decrease in natural gas production is the sharp increase from 2013 to 2015 (~260%) in oil production. Fossil fuel production regions with higher oil and liquids production are often associated with higher fugitive emissions. Lyon et al.²³ observed that oil-producing well-pads were more likely to be associated with observable CH₄ emissions than predominately gas-producing well-pads. It is possible then that in the San Juan basin as natural gas production decreased and methane emissions associated with those activities decreased, this fugitive loss was counterbalanced by increased oil production and fugitive emissions from these processes. To confirm or deny this hypothesis, more in depth analysis is needed, including fine-scale information on emissions associated with each process over time, but it does provide a possible explanation for the persistent emissions in the region in the face of declining natural gas production.

7. IMPLICATIONS

Combining the airborne results from 2015 with previous work reporting average emissions from 2003 to 2009,⁴ we find that the flux of CH₄ from the San Juan Basin has not changed in a statistically detectable manner for over a decade, despite a 34% decrease in gas production from the 2003–2009 average to 2015. Recent work with space-based observations has also suggested persistent and stable emissions for the Four Corners region over this time period.⁷ As geologic outcrops and other anthropogenic sources (ruminants and landfills) are not large enough sources nor do they exhibit the necessary trend to explain this phenomenon, the implication is that basinwide emissions of CH₄ do not scale with total basin gas production and that fugitive losses are not dominated by pathways that correlate with gas production volume. Further work should continue to investigate how changes (or lack thereof) in basinwide flux estimates over time are related to underlying factors, including type of fuel produced.

■ ASSOCIATED CONTENT

■ Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.6b06107.

Text describing selection of downwind flight transects for mass balance analysis and figures showing wind back-trajectories for four mass balance days; vertical profiles of wind speed, average wind speeds and directions, and CH₄ flux estimates using winds measured by the wind profiler; example of CH₄ enhancement plume; calculation of atmospheric mixing depths and vertical profiles of H₂O used to determine mixing depth height; *t* test for significant differences between satellite and airborne CH₄ flux estimates (PDF)

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Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers

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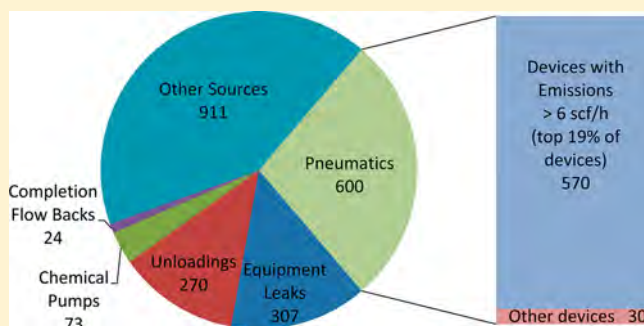
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Supporting Information

ABSTRACT: Emissions from 377 gas actuated (pneumatic) controllers were measured at natural gas production sites and a small number of oil production sites, throughout the United States. A small subset of the devices (19%), with whole gas emission rates in excess of 6 standard cubic feet per hour (scf/h), accounted for 95% of emissions. More than half of the controllers recorded emissions of 0.001 scf/h or less during 15 min of measurement. Pneumatic controllers in level control applications on separators and in compressor applications had higher emission rates than controllers in other types of applications. Regional differences in emissions were observed, with the lowest emissions measured in the Rocky Mountains and the highest emissions in the Gulf Coast. Average methane emissions per controller reported in this work are 17% higher than the average emissions per controller in the 2012 EPA greenhouse gas national emission inventory (2012 GHG NEI, released in 2014); the average of 2.7 controllers per well observed in this work is higher than the 1.0 controllers per well reported in the 2012 GHG NEI.



INTRODUCTION

Natural gas production in the United States is increasing; the U.S. Energy Information Administration projects that by 2040, total natural gas production in the United States will increase by 40%.¹ With increased production, natural gas is displacing other fuels,² and this fuel switching has implications for greenhouse gas emissions.

Natural gas may have a lower greenhouse gas footprint than other, more carbon intensive, fossil fuels (coal and petroleum), since the carbon dioxide emissions associated with natural gas combustion are less than those associated with the combustion of coal and petroleum. For example, for identical heat releases on combustion, natural gas generates less than half of the carbon dioxide emissions of a typical coal.³ The greenhouse gas benefits of natural gas relative to other fossil fuels may be eroded, however, by natural gas leaks in the supply chain. Methane, the principal component of natural gas, is a potent, but short-lived greenhouse gas. Because one kg of methane emissions is equivalent to between 28 and 120 kg of CO₂ emissions, depending on the time scale over which impacts are

assessed (100-year to immediate time horizons),^{4,5} methane emissions in the natural gas supply chain amounting to more than a few percent of natural gas use can change the greenhouse gas footprint of natural gas, relative to other fossil fuels.^{5–9} Thus, to characterize the greenhouse gas footprint of natural gas, it is important to determine the magnitude of methane emissions in the natural gas supply chain.¹⁰

Methane emissions in the natural gas supply chain have been estimated using two basic approaches, commonly referred to as top-down and bottom-up approaches. Top-down approaches for estimating methane emissions from the natural gas supply chain involve measuring ambient concentrations of methane near emission sources. These concentrations can be measured using fixed ground monitors,^{11,12} mobile and vehicle mounted ground monitors,^{13,14} aircraft based instruments^{15–17} or

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Table 1. Sample Population, Categorized by Controller Application and Region (AP= Appalachian; GC = Gulf Coast; MC = Mid-Continent; RM = Rocky Mountain)

region	separator	number of controllers sampled, categorized by application							total
		process heater	compressor	wellhead	plunger lift	dehydration system	flare	sales	
AP	14	13	0	24	1	0	0	0	52
GC	73	0	13	11	7	17	1	1	123
MC	48	11	7	0	11	0	0	0	77
RM	51	21	0	32	11	8	2	0	125
total	186	45	20	67	30	25	3	1	377

satellite instruments.¹⁸ Brandt et al.¹⁹ and Miller et al.²⁰ have summarized recent top-down estimates of methane emissions and conclude that top-down emission estimates are generally higher than current bottom-up inventories of methane emissions, and some of this difference may be due to methane emissions from the natural gas supply chain. However, these analyses do not reveal which of the many potential sources of methane emissions along the natural gas supply chain might be incorrectly estimated.

Complementing top-down measurements, bottom-up measurements of methane emissions are made directly at the emission sources. In this approach, emission measurements are made at a representative sample of sources; the measurements from the sample population are then extrapolated to larger regional or national populations. The advantage of “bottom-up” approaches is that they can gather much more detail about the emission sources, and therefore can identify which source categories, among many, are responsible for emissions. For example, Allen, et al.²¹ concluded that emissions from well completion flowbacks are overestimated, while emissions from pneumatic controllers may be underestimated, in current inventories of emissions. Both top-down and bottom-up approaches can contribute to an improved understanding of methane emissions from the natural gas supply chain. The work reported here uses bottom-up measurements to improve understanding of emissions from pneumatic controllers on natural gas production sites.

Pneumatic controllers use gas pressure to control the operation of mechanical devices, such as valves. The valves, in turn, control process conditions such as levels, temperatures, and pressures. When a pneumatic controller identifies the need to change liquid level, pressure, temperature or flow, it will open or close a control valve in order to return to a desired set point. The opening and closing of the valve can occur either through discrete (on/off) changes, or through changes that are proportional in magnitude to the deviation from the set point (throttling). Controllers can deliver this type of service (on/off and throttling) through either continuously venting or intermittent venting of gas. Thus, controllers can be grouped into four categories, depending on the type of service (on/off or throttling) and the type of venting (continuous or intermittent). In estimating emissions, the U.S. EPA uses the categories of low continuous bleed (<6 scf/h of gas vented), high continuous bleed (>6 standard cubic feet per hour (scf/h) of gas vented) and intermittent controllers.²² Finally, controllers can also be categorized based on equipment manufacturer, model number, and the type of application (e.g., separator level control) in which they are used. In this work, the primary categorization of controllers will be as either continuous vent or intermittent vent based on the pattern observed during measurement; data on applications, service

types, and EPA categorization for the controllers sampled in this work are provided in Supporting Information (SI).

The U.S. EPA²² reports 477 606 pneumatic controllers are in use at natural gas production sites in the United States. These controllers are estimated to emit 334 Gg/yr of methane (17.4 billion cubic feet (bcf) methane), for an average of 0.7 Mg device⁻¹ yr⁻¹ or 4.2 scf/h methane device⁻¹. These estimated emissions from pneumatic controllers have been based on relatively limited measurements;²³ recent field measurements have suggested that these emissions may be understated.

Allen et al.²¹ made measurements of emissions from 305 pneumatic controllers on well sites in the United States where the wells had been hydraulically fractured. Average emissions were 10.5 scf/h of methane, approximately double the average emission rate per device in the current EPA national emission inventory. Measurements of emissions from 581 pneumatic controllers, made in British Columbia and Alberta, averaged 9.2 scf/h of whole gas,²⁴ an emission rate similar to that reported by Allen et al.²¹ In both of these studies, emissions from controllers exhibited wide ranges. In both sets of measurements, a small subset of controllers accounted for most of the emissions.

While the measurements at hydraulically fractured gas wells in the United States²¹ and the measurements in British Columbia and Alberta²⁴ recorded emissions higher than the average emissions per device in the EPA national emission inventory, the sampled populations for these two sets of measurements were not necessarily broadly representative of U.S. national populations of pneumatic controllers. The measurements reported by Allen et al.²¹ were made exclusively in shale gas production regions, and at sites where the wells had been hydraulically fractured. Many of the sites were recently completed wells, which initially tend to have higher liquid production rates, and therefore may have more frequent actuation of certain types of pneumatic devices than the average for the entire population of gas wells in the United States, leading to potentially higher emissions. The Canadian measurements²⁴ were made exclusively in one production region and on devices with manufacturer specified emission rates in excess of 4.2 scf/h.

The goals of the work presented here were (i) to measure emissions from pneumatic controllers at a wider population of wells, geographically distributed across the United States, including conventional gas wells, shale gas wells and a limited number of oil wells, and (ii) to characterize the features of the controllers with high emissions, which previous work^{21,24} has found to be the major contributor to emissions.

■ MATERIALS AND METHODS

Sampled Population. A total of 377 pneumatic controllers were sampled at 65 sites (some with multiple wells) throughout the United States (an average of 5.8 pneumatic controllers per

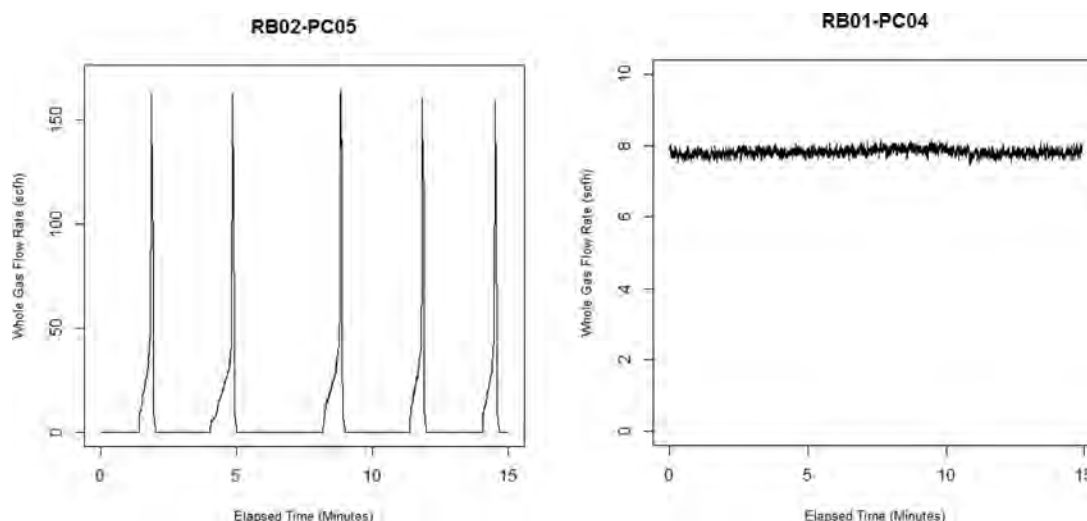


Figure 1. Representative time series for supply gas measurements for intermittent vent (left) and continuous vent (right) controllers; the intermittent vent controller (RB02-PC05) had a total of five actuations during the sampling period and an average emission rate, over the 15 min period of 7.9 scf/h; the continuous vent controller (RB01-PC04) had nearly constant emissions of 8.0 scf/h.

site, 2.7 controllers per well). Measurements were made primarily at natural gas production sites (351 of 377 controllers), and at a limited number of oil sites (26 controllers). Because the definitions of oil and gas wells vary, largely depending on gas to oil production ratios, the data will be treated as a single set. Sampling sites were selected from well sites owned by companies participating in the study using a process designed to yield a random sampling of participant sites (see SI, Section S1). For each well site that was visited, all controllers on the site were sampled using supply gas meters, unless operating conditions, safety issues or other factors prevented sampling. A total of 333 controllers had measurements made using the supply gas meters; 97 controllers could not be measured using the supply gas meter; of the 97 that were not sampled with the supply gas meter, 44 were sampled using exhaust gas measurements, leading to a total of 377 controllers in the sampled population. The applications that the controllers were used in (e.g., separator level control, compressor pressure control) are shown in Table 1. Details of the regions, device types, associated well types, operating methods and other characteristics of each of the 377 controllers sampled in this work are provided in SI, Section S4.

Emission Measurement Methods. Emissions from pneumatic controllers can be determined either by measuring the supply of gas entering the controller or by measuring the gas discharged from the controller. Both approaches were used in this work, and since there is no accumulation of gas in the controller, both measurement approaches should lead to equivalent measurements, if there are no leaks in the equipment downstream of the controller.

Measurements of the gas entering the controller were made by one of three Fox flow meters (model #FT2A); flow meters were inserted into the supply gas line for the controller. This supply gas measurement was the primary measurement method used in this work, and was used to measure emission rates on 333 of the 377 controllers in the sample population (the remainder were sampled by measuring gas emitted by the controller using a HiFlow Sampler described later in this section, see SI for comparisons between the supply gas and exhaust gas measurements). The flow meters reported flows at a sampling frequency of 10 Hz. Two of the Fox model #FT2A

instruments (labeled A and C in this study) had a range of operation of 0–300 scf/h, with a precision of $\pm 1\%$ of flow, and the third Fox model #FT2A (labeled B in this study) had a range of operation of 0–1200 scf/h, with a precision of $\pm 1\%$ of flow. The Fox model #FT2A instruments A and C were used whenever possible because of their greater absolute precision, however, if any instantaneous reading on the A or C Fox model #FT2A was greater than 300 scf/h, the measurement on the pneumatic device was repeated with the B meter to ensure that high leak rates were measured accurately. This happened only once during the measurement campaign, and for this single controller, the flow exceeded 300 scf/h only during a few seconds when the flow from an actuation was peaking (average whole gas flow rate over 15 min of sampling was 3.06 scf/h, a value lower than the average emissions per controller in the sampled population). A repeat test with the B instrument did not detect any actuations.

For each controller measurement using the supply gas flow meter, a site operator depressurized and disconnected the controller supply gas line; the flow meter was inserted and the system was reconnected, repressurized, and allowed to stabilize for several minutes before measurements began. Once the system had stabilized, measurements were made for approximately 15 min. Longer sampling times may have allowed a more complete measurement of emission rates from devices with relatively fewer controller actuations, but would have limited the number of controllers that could be sampled. Figure 1 shows representative 15 min emission time series for pneumatic controllers measured using the supply gas measurement.

All three Fox flow meters were calibrated by the instrument manufacturer and in laboratory testing, using methane. The instruments measure flow based on a thermal conductivity measurement. In this work, since gas composition information was available for each site where measurements were made, site specific correction factors were employed to estimate methane and whole gas emission rates. The method is described in SI Section S2. Results in this work are reported as both methane and whole gas emission rates, based on site specific gas composition data.

For some pneumatic controllers, it was not possible or safe to disrupt the supply gas to insert the supply gas flow meter, so exhaust gas measurements were used as the primary measurement on that subset of devices. Exhaust gas flow rate was measured using a Hi Flow instrument similar to that described by Allen et al.²¹ Briefly, the Hi Flow Sampler is a portable, intrinsically safe, battery-powered instrument that has been used for several decades in measuring emissions of methane in the natural gas supply chain.^{25–27} An emission source is enclosed, using attachments that come with the instrument; leak rate is measured by drawing air from the enclosure, through the sampler, at a high flow rate (up to 8–10 cfm) to capture all the gas emitted by the component, along with a certain amount of entrained surrounding air. By accurately measuring the flow rate of the sampled stream and the background corrected natural gas concentration within the sampled stream, the gas leak rate is calculated. Methane is measured, at concentrations less than approximately 5%, by a catalytic oxidizer unit coupled with a thermal conductivity detector. At methane concentrations greater than approximately 5%, concentrations are measured directly using a thermal conductivity detector. The instrument was calibrated using pure methane and a mixture containing 2.5% methane. The instrument reading based on the methane calibration was corrected for gas composition using site specific gas composition data and laboratory data, as described in SI Section S2. The commercial Hi Flow instrument is designed primarily to measure methane leaks that have a relatively steady flow and flow rates are not normally automatically recorded at high frequency. For this work, the instrument software was modified by the manufacturer to output data every 2–3 s. A 0.3–0.5 Hz reporting frequency was selected based on residence times expected in the leak enclosures at the maximum flow rate of the Hi Flow device (at a 10 cubic feet per minute sample flow, gas in a 1 ft³ sample enclosure has a residence time of 6 s). As with the in-line supply gas measurement, Hi Flow data were collected for approximately 15 min for each controller. A time series from the Hi Flow device, along with a parallel measurement made using a supply gas meter, is shown in Figure 2. The Hi Flow device, because it entrains ambient air in a long sample loop, dampens some of the peak rate. Therefore, the Hi Flow is not able to resolve high frequency actuations as well as the in-line supply measurement. For 24 controller measurements, both supply gas and Hi Flow measurements were made to compare the two measurement methods (for these controllers, the supply gas flow was treated as the primary measurement). The detailed results are provided in SI Section S3. To summarize, 11 of the 24 simultaneous measurements had emissions of less than 0.005 scfh (46%), as recorded by the in-line supply gas meter (the primary measurement device). For five devices which had an average emission rate greater than 6 scfh (measured by the supply gas meter) the supply gas meter to Hi Flow measurement ratio was between 0.7 and 1.1.

RESULTS AND DISCUSSION

Methane emissions from 377 controllers were measured in this work and details of each of the individual measurements are available in SI Section S4. A relatively small subset of devices accounts for a majority of the emissions. At the high end of the emission rate distribution, 20 percent of devices accounted for 96% of whole gas and methane emissions. The 19% of devices that had emissions in excess of 6 standard cubic feet whole gas

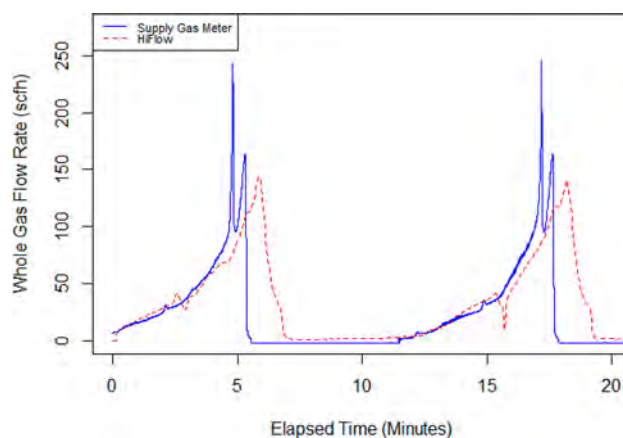


Figure 2. Comparison of supply gas meter (blue line) and Hi Flow measurements (red line) for device LB07-PC04, which was a water level control on a separator. The average emission rate measured by the supply gas meter was 27.0 scf/h as compared to 33.9 scf/h measured by the Hi Flow. Note that the time lag, longer period of emission detection, and the reduced maximum flow rate associated with the Hi Flow measurement is expected because of the dilution that occurs with ambient air in the exhaust enclosure and the flow through the instrument.

per hour (scf/h) accounted for 95% of all whole gas and methane emissions. At the low emission rate end of the distribution, more than half (51%) of the controllers had an emissions rate less than 0.001 scf/h over the 15 min sampling period; 62% had an emissions rate less than 0.01 scf/h over the 15 min sampling period.

The average emission rate for the 377 devices is 5.5 scf/h of whole gas (4.9 scf/h of methane), however, this average emission may be influenced by the estimated emission rates for devices that had no emissions over the 15 min sampling period. If the devices with no emissions detected over 15 min are assigned the lowest emission rate detected (0.001–0.01 scf/h), there is no change in the average emission rate. However, using this minimum detection limit approach may underestimate potential emissions for devices that had little to no detectable emissions over 15 min. Some of these devices may have relatively infrequent actuations that were not sampled. In principle, any device actuating less than four times per hour may not have been detected over a 15 min sampling period. To estimate the emissions from devices with no emissions detected over a 15 min sampling period, the average emission per actuation was calculated for controllers in each application. The average emissions per actuation were multiplied by an estimated frequency of actuation. For example, for separator level controllers, the average volume per actuation was estimated by averaging observed volumes per actuation for separator level controllers; the average frequency of actuation for devices, for which no actuations were observed, was estimated by extrapolating observed actuation frequency data for controllers in separator level control service. A variety of assumptions can be made in extrapolating actuation frequencies. Details of a variety of approaches are available in SI Section S5. Using a variety of approaches, the estimated average emissions associated with devices with no emissions recorded over a 15 min sampling increases the population average emissions by 2–11%. Because this increase is relatively small, for clarity, all of the data reported in this work are based on

Table 2. Whole Gas Emissions from Controllers (scf/h), Categorized by Region and Application^a

region	all devices	average whole gas emission rates from controllers (scf/h), categorized by the application								
		separator	process heater	compressor	wellhead	plunger lift	dehydration system	flare	sales	avg. w/o compressors
AP	1.7	0.3	1.3		2.8	0.0				1.7
GC	11.9	16.3		10.6	0.0	7.3	4.3	0.0	0.0	12.0
MC	5.8	4.9	0.0	20.2		6.5				4.4
RM	0.8	1.5	0.2		0.4	0.1	0.0	0.0		0.8
average	5.5	8.1	0.5	14.0	1.2	4.1	3.0	0.0	0.0	5.0

^aNumbers of devices sampled in each category are reported in Table 1.

actual measurements, not including additions to the emissions for devices with low (0.001–0.01 scf/h) observed emissions.

To estimate an uncertainty bound on the overall average, a bootstrapping process was used.²⁸ In the bootstrapping procedure, the original data set of 377 devices was recreated by making 377 random device selections, with replacement, from the data set. A total of 1000 of these resampled data sets were created and the mean value of the emissions for each resampled data set was determined. The 95% confidence interval for the average whole gas emission estimate of 5.5 scf/h is 4.0–7.2 scf/h, where the bounds represent the 2.5% and 97.5% percentiles of the means in the 1000 resampled data sets. Similarly, the 95% confidence interval for the average methane emissions estimate of 4.9 scf/h is 3.6–6.5 scf/h.

The measurements showed significant variations among regions, the controller application, and whether the device was continuous vent or intermittent vent. Table 2 summarizes the distribution of emission rates among controllers in various applications, and shows the regional distribution of controller emissions. Measurements made on pneumatics in service on compressors had average emission rates of 14.0 scf/h (12.4 scf/h methane), compared to an average whole gas emission rate of 5.5 scf/h (4.9 scf/h methane) for all devices. Devices in use for level control on separators averaged 8.1 scf whole gas/h (7.1 scf methane/h). Overall, 76% of devices measured with whole gas emission rates greater than 6 scf/h were in service on compressors or as level controllers on separators. Emission rates for continuous vent controllers (57 devices, average emissions of 24.1 scf/h whole gas, 21.8 scf/h methane) were higher than for intermittent vent devices (2.2 scf/h whole gas, 1.9 scf/h methane).

In addition to varying by application and controller type (continuous vent or intermittent vent), emissions also varied by region. Emissions were highest in the Gulf Coast and Mid-Continent regions and were lowest in the Rocky Mountain and Appalachian regions (see SI, Section S4, for geographical boundaries of regions). Controllers on compressors, with high average emissions, were only observed on sampling sites in the Gulf Coast and Mid-Continent regions, so some of the regional differences can be attributed to the presence of compressors. As shown in Table 2, however, if average emissions by region are recalculated without including controllers associated with compressors, the Gulf Coast and Mid-Continent regions still had average emissions greater than those observed in the Rocky Mountain and Appalachian regions.

Another factor that may account for regional differences in emission rates is frequency of actuation. For example, controllers on separators in the Gulf Coast could actuate more frequently due to higher liquid production rates, which could explain higher emission rates in that region. However, the frequencies of actuation for the devices in Gulf Coast were similar to those in most other regions, indicating a larger

emission per actuation for the devices in the Gulf Coast, rather than more frequent actuation. In contrast, the Appalachians showed a considerably higher frequency of actuations and a smaller emission rate, indicating a smaller emission per actuation for those devices (Table 3). Thus, regional differences

Table 3. Frequency of Actuations and Emissions from Intermittent Vent Controllers Where Actuations Were Observed, Categorized by Region

region	count of devices	frequency of actuations (#/min)	avg. emission rate (scf/h)
AP	8	2.42	4.85
GC	30	0.37	20.5
MC	17	0.93	5.05
RM	25	0.43	1.72
total	80	average: 0.73	average: 9.76

in pneumatic controller emission rates cannot be completely explained by frequency of actuation of controllers, or by controllers associated with compressors and separator level control (Table 2); much of the difference may be due to differences in controller type (continuous vent vs intermittent vent) among regions. Continuous vent devices, with average whole gas emissions of 24.1 scf/h, were 21% of the controllers in the Gulf Coast and Mid-Continent regions, but only 9% in the Appalachian and Rocky Mountain regions.

This data set of emissions from pneumatic devices has elements that are similar to and different from the previous data sets reported for the United States,²¹ and for British Columbia and Alberta.²⁴ The primary similarity is that all three data sets indicate that a small population of devices dominates total emissions. In this work, 19% of devices with emissions greater than 6 scf/h of whole gas account for 95% of the whole gas and methane emissions. In the previous measurements reported by Allen et al.,²¹ 20% of devices account for 80% of the whole gas emissions and 41% of devices with emissions greater than 6 scf/h of whole gas, account for 90% of the whole gas emissions (88% of the methane emissions). In the measurements for British Columbia and Alberta²⁴ (referred to here as the British Columbia data), which were restricted to pneumatic devices with manufacturer reported bleed rates greater than 4.2 scf/h, 44% of devices with emissions greater than 6 scf/h accounted for 91% of emissions. Both the British Columbia data and the measurements reported in this work had large numbers of devices for which no emissions were detected during the sampling period. For the British Columbia data (again, focused on devices with manufacturer reported bleed rates in excess of 4.2 cfh), 31% of measurements had no detectable emissions over a 30 min sampling period; in this work 62% of devices had emissions less than 0.01 scf/h over the 15 min sampling period.

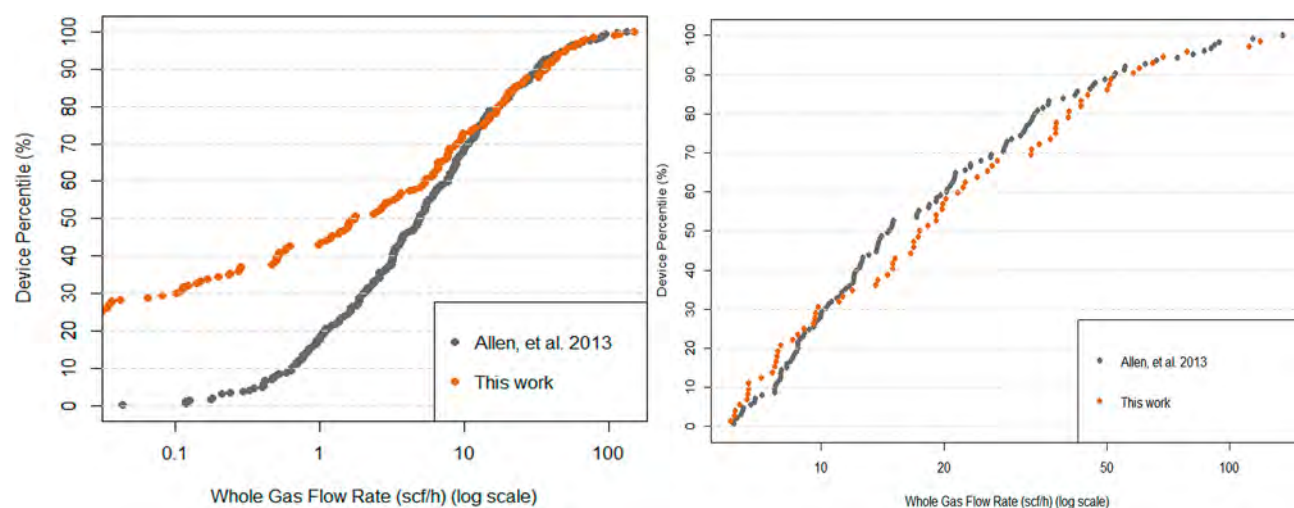


Figure 3. Distributions of emissions for subsets of controllers (38% of devices measured in this work) venting greater than 0.01 scf/h (left) and subsets of controllers venting greater than 6 scf/h of whole gas (right) as reported in this work (the 19% of devices that account for 95% of emissions) and Allen et al.²¹

The overall average emission rates reported in this work are lower than the previous data sets reported by Allen et al.²¹ for the United States, and for British Columbia and Alberta.²⁴ For the British Columbia data this can be attributed to the sampling design for that data set, which selected devices with manufacturer reported bleed rates in excess of 4.2 scf/h. These controller types tend to be found in particular applications. When the emissions from the British Columbia data set are compared to the emissions reported in this work, for devices in similar applications, the results are in reasonable agreement. For example, for the separator controllers that were the most frequent application observed in this work, the British Columbia data report an average emissions rate of approximately 7.8 scf/h (level control) while the average for this work was 8.1 scf/h (separator application).

The lower average emission rates reported in this work, compared to those reported by Allen et al.²¹ is primarily due to the number of controllers with no emissions detected over the sampling period. Figure 3 compares emission rates for controllers sampled in this work, with emissions rates reported by Allen et al.²¹ The results show reasonable agreement between the two studies for controllers with emissions above 6 scf/h. These controllers accounted for 95% of the emissions in this work and 90% of the emissions in the sample reported by Allen et al. (2013).

The primary reason for the differences in the average emission rates reported in this work and in Allen et al.²¹ is the higher percentage of low emission devices (<0.01 scf/h) observed in this work. This could be due to multiple factors. In this work, all controllers on-site were sampled, regardless of whether they would be reported through emission inventories. For example, emergency shut-down (ESD) controllers represented 12% of the sampled population in this work. These controllers do not have planned actuations, so they would not have been sampled in the work of Allen et al.,²¹ and they may or may not be included in controller counts in national emission inventories. In addition, in the work of Allen et al.²¹ about 40% of the inventoried controllers on sites were sampled; while these were intended to be selected randomly from inventoried controllers, there may have been an

unintentional bias toward devices that were observed, with an infrared camera, to have emissions.

Implications for National Emission Estimates. As shown in Table 4, if regional average emission rates determined

Table 4. National Emission Estimates, Based on Regional Device Counts for Pneumatic Controllers and Regional Average Emissions Measured in This Work

region	count of devices	avg. emission rate whole gas(scfh)	avg. emission rate methane (scfh)	regional emissions (Gg/yr)
AP	77 261	1.70	1.65	21.5
GC	53 436	11.80	10.61	95.4
MC ^a	222 684	5.80	4.87	182.5
RM ^b	124 225	0.75	0.67	14.0
total	477 606			313.4

^aMC totals include equipment counts for Mid-Continent and Southwest regions reported in the 2012 EPA GHG NEI. ^bRM totals include equipment counts for Rocky Mountain and West Coast regions reported in the 2012 EPA GHG NEI.

in this work are multiplied by regional controller counts reported in the 2012 EPA national greenhouse gas emission inventory (2012 GHG NEI, released in 2014), the national methane emission estimate for pneumatic controllers in natural gas service is 313 Gg/yr (within 10% of the 2012 GHG NEI estimate of 334 Gg). If the national average of the emission rates measured in this work (5.5 scf/h of whole gas, or 4.9 scf/h of methane) is multiplied by the total national equipment count in the 2012 GHG NEI (477 606 controllers) the national methane emission estimate is 394 Gg/yr, 17% higher than the 2012 GHG NEI estimate of 334 Gg. Adding an additional 2–11% to the estimated emission totals to account for potential emissions from controllers that had less than 0.01 scf/h of emissions over 15 min, would only slightly change these comparisons with the 2012 GHG NEI. This estimate may represent a lower bound on national emissions, however, since the average emissions per controller observed in this work includes some low- or nonemitting devices, such as ESD controllers, that may not be included in the count of national controllers. If the average emissions per controller from this

work were recalculated with ESD controllers excluded, the average emissions would increase by approximately 15% (see SI, Section S7).

The inclusion or exclusion of ESD controllers in national pneumatic controller counts is just one part of the uncertainty associated with the total count of controllers. The average number of controllers per well observed in this work (2.7 controllers per well) was higher than the average number of controllers per well (1.0 controllers per well) reported in the 2012 GHG NEI, potentially indicating an under-count of controllers in the GHG NEI. Some of the difference between the controllers per well observed in this work and the average pneumatic controllers per well in the GHG NEI is due to wells that use mechanical or other nonpneumatic controllers; as an example of how an alternative controller count could influence national emission estimates, if 75% of wells in the United States have an average of 2.7 pneumatic controllers per well (the remainder having nonpneumatic controllers), and if 75% of the controllers on well sites are inventoried as having emissions, the total count of pneumatic controllers would double the level in the current inventory, roughly doubling emissions to 600 Gg (see SI). It was beyond the scope of this work to develop new national pneumatic controller counts, but the data reported here indicate that this is a topic that merits attention.

Characteristics of High Emitting Devices. Because average emissions are strongly influenced by the highest emitting devices, the characteristics of the 40 controllers with highest emissions rates were examined in detail by experts in pneumatic device operation. These characterizations included the service type, region of use, device type, the numbers of actuations and other temporal features of the emission time series. Based on these analyses, many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer's design. For example, some devices not designed to bleed continuously had continuous emissions. This could be the result of a defect in the system, such as a crack or hole in the end-device's (control valve's) diaphragm actuator, or a defect in the controller itself, such as fouling or wear. No additional troubleshooting analysis was performed on these high emitters, so the actual root causes are not known with certainty. The results, however, do indicate that some of the high emissions were caused by repairable issues. Details are provided in the SI (Section S8).

■ ASSOCIATED CONTENT

■ Supporting Information

Additional material as described in the text. This material is available free of charge via the Internet at <http://pubs.acs.org/>.

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Notes

The authors declare the following competing financial interest(s): Lead author David Allen serves as chair of the Environmental Protection Agency's Science Advisory Board, and in this role is a paid Special Governmental Employee. He is also a journal editor for the American Chemical Society and has served as a consultant for multiple companies, including

Eastern Research Group, ExxonMobil, and Research Triangle Institute. He has worked on other research projects funded by a variety of governmental, nonprofit and private sector sources including the National Science Foundation, the Environmental Protection Agency, the Texas Commission on Environmental Quality, the American Petroleum Institute and an air monitoring and surveillance project that was ordered by the U.S. District Court for the Southern District of Texas. Adam Pacsi and Daniel Zavala-Araiza, who were graduate students at the University of Texas at the time the work in this paper was done, have accepted positions at Chevron Energy Technology Company and Environmental Defense Fund, respectively. John Seinfeld served as a consultant for Shell in 2012. A. Daniel Hill owns ExxonMobil, BP, and ConocoPhillips stock, serves on the Advisory Board for Sanchez Oil and Gas, for which he is compensated, and has been a consultant for Schlumberger and numerous oil and gas operating companies..

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San Juan and Permian Basin 2014 Oil and Gas Emission Inventory Inputs Final Report

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EXECUTIVE SUMMARY

This study provides emission inventory inputs necessary to develop criteria air pollutant (CAP) and greenhouse gas (GHG) emissions from oil and gas exploration, production, and midstream operations in the Greater San Juan Basin in Colorado and New Mexico and the portion of the Permian Basin in New Mexico. This analysis is being sponsored by the United States (US) Bureau of Land Management (BLM), New Mexico State Office, jointly with the Western Regional Air Partnership (WRAP). The results of this effort will be used in the next phase of the project to develop base year 2014 and future year emission inventories for the Greater San Juan and Permian basins to create the most accurate emission inventory that has been compiled to-date for each basin.

The primary sources of information used to develop oil and gas exploration and production well site emission inventory input factors were a survey outreach effort in the Greater San Juan Basin and a literature review in the Permian Basin. For midstream emission sources, detailed permit data was collected from the New Mexico Environment Department (NMED); Colorado Department of Public Health and Environment (CDPHE); and the US Environmental Protection Agency (EPA) Region 6, Region 8, and Region 9. Two survey forms were distributed to Greater San Juan basin operators to gather information on oil and gas exploration and production wellsite sources; the first form leveraged operators' Greenhouse Gas Reporting Protocol (GHGRP) Subpart W submissions to collect data from eight discrete source categories and the second form collected data on 12 additional source categories for which GHGRP data was insufficient to develop emission inventory inputs. Permian Basin wellsite input factors were developed based on data from other available studies and/or reporting because conducting a survey in the Permian Basin was not expected to yield adequate operator participation. The Permian Basin literature review focused on gathering data from two sources: the Texas Commission on Environmental Quality (TCEQ) oil and gas emission inventory and publically available GHGRP data.

The companies participating in the survey process for the Greater San Juan Basin represent approximately 53% of well ownership in the basin, 58% of gas production in the basin, and 53% of oil production in the basin. In order to increase operator representation for the development of accurate wellsite exploration and production input factors, Ramboll Environ compiled company specific GHGRP data for companies representing 13% of well ownership, 14% of gas production ownership, and 38% of oil production ownership that did not submit a survey. The combined operator representation from survey responses and the GHGRP data compilation is 65% of well ownership, 72% of gas production ownership, and 81% of oil production ownership. The percentage of oil and gas activity that was captured in the survey process and GHGRP data compilation allow for good representation of oil and gas operations in the basin.

Per stakeholder input, survey data was not collected for certain wellsite source categories because data was not expected to be available: amine units, truck loading at gas and natural gas liquid (NGL) processing plants and water disposal pits. This study does not consider fugitive emissions from oil and gas pipelines from well heads to the main compressor stations. Accurate

quantitative information on the length of pipeline in the basin was not available from sources queried as part of this effort.

In the next phase of this work, wellsite exploration and production emissions in the Greater San Juan and Permian basins will be estimated by combining the input factors developed from survey, literature review, and GHGRP data with county level 2014 oil and gas activity input factors. 2014 oil and gas activity, including spud count, well count and production by well type were obtained from a commercially available database of oil and gas data maintained by IHS Corporation (“the IHS database”).

The Greater San Juan Basin was defined consistent with the EPA GHGRP San Juan Basin definition, including the counties of Archuleta and La Plata in Colorado and Cibola, Los Alamos, McKinley, Rio Arriba, San Juan, Sandoval, and Valencia in New Mexico. In 2014, the Greater San Juan Basin consisted of close to 25,000 active oil and gas wells which produced over one billion cubic feet of natural gas per year. Greater San Juan Basin gas production accounts for about one-third of combined Colorado and New Mexico gas production and about 3% of national on-shore gas production. Notably, there were only 126 wells spudded in the Greater San Juan Basin in 2014. Historic Greater San Juan Basin spud counts have been much higher; for example, there were 976¹ spuds in the Greater San Juan Basin in 2006 (Bar-Ilan et al., 2009a; 2009c).

The portion of the Permian Basin in New Mexico was defined consistent with the EPA GHGRP Permian Basin definition, including the counties of Chaves, Eddy, Roosevelt, and Lea. In 2014, the portion of the Permian Basin in New Mexico consisted of over 28,000 active oil and gas wells which produced over 117 million barrels of oil. The portion of the Permian Basin in New Mexico accounted for approximately 95% of oil production in New Mexico and approximately 4% of national on-shore oil production in 2014. There were over 1,000 wells spudded in the Permian Basin in 2014.

The contents of the report by Chapter are summarized as follows:

- Chapter 1.0 is an introduction that describes the methodology and oil and gas activity inputs;
- Chapter 2.0 describes the development of 2014 midstream emission inventory inputs;
- Chapter 3.0 describes the development of Greater San Juan Basin 2014 wellsite exploration and production emission inventory inputs;
- Chapter 4.0 describes the development of Permian Basin 2014 wellsite exploration and production emission inventory inputs;
- Chapter 5.0: presents recommendations for the next phase of this work.

¹ 919 wells spudded in the South San Juan Basin in 2006 (Bar-Ilan et al., 2009a) and 57 wells spudded in the North San Juan Basin in 2006 (Bar-Ilan et al., 2009c) for a total of 976 wells spudded in the Greater San Juan Basin in 2006.

1.0 INTRODUCTION

The BLM is sponsoring the development of a regional oil and gas emission inventory for the Greater San Juan Basin (in New Mexico and Colorado) and the Permian Basin (in New Mexico) jointly with the WRAP. The Greater San Juan Basin inventory will be an update to the WRAP Phase III South San Juan and North San Juan baseline (2006) and future emission inventories (Bar-Ilan et al., 2009a; 2009b; 2009c) and forecast updates for the WestJump Air Quality Modeling Study (AQMS; Bar-Ilan et al., 2012) and the Intermountain West Data Warehouse (IWDW; Parikh et al., 2015). The Permian Basin inventory will be an update to the WestJump AQMS Permian Basin baseline (2008) inventory (Bar-Ilan et al., 2013).

Described in this report is the effort to develop a comprehensive set of inputs for developing criteria air pollutant and greenhouse gas emissions base year 2014 inventory for activities associated with oil and gas exploration, production, and midstream operations in the Greater San Juan and Permian basins.

1.1 Emission Inventory Input Data

The inventory inputs presented in this analysis are for the Greater San Juan Basin in Colorado and New Mexico and the portion of the Permian Basin in New Mexico².

The inventory inputs can be grouped into three categories: (1) midstream point source facilities that were permitted by the State of New Mexico, State of Colorado, or EPA (for tribal land) and (2) wellsite sources for which data was collected from surveys of major companies operating in the Greater San Juan Basin and gathered from existing studies in both the Permian basin, (3) oil and gas activity data obtained from IHS Enerdeq.

This document describes the methodologies by which the 2014 inventory inputs were developed for both the Greater San Juan and Permian basins. For midstream sources which were based on state and federal permitting databases, the source of emissions and any important assumptions for these emissions are described. For each wellsite source, the basis of the inputs for each source category is described.

Well count and production activity from a commercially available database of oil and gas data maintained by IHS Corporation ("the IHS database") have been compiled to develop emissions per unit of oil and gas activity wellsite source category inputs.

Additional data sources used to develop the inventory inputs include, GHGRP data³, Colorado Air Resources Management Modeling Study wellsite inputs (ENVIRON et al., 2015), the US EPA's

² The Texas Commission on Environmental Quality (TCEQ) has developed emission inventories for the portion of the Permian Basin in Texas.

³ <https://ghgdata.epa.gov/ghgp/main.do>

AP-42 emissions factor technical guidance (EPA, 1995), and the US EPA's MOVES emissions model (EPA, 2015).

1.2 Temporal and Geographical Scope

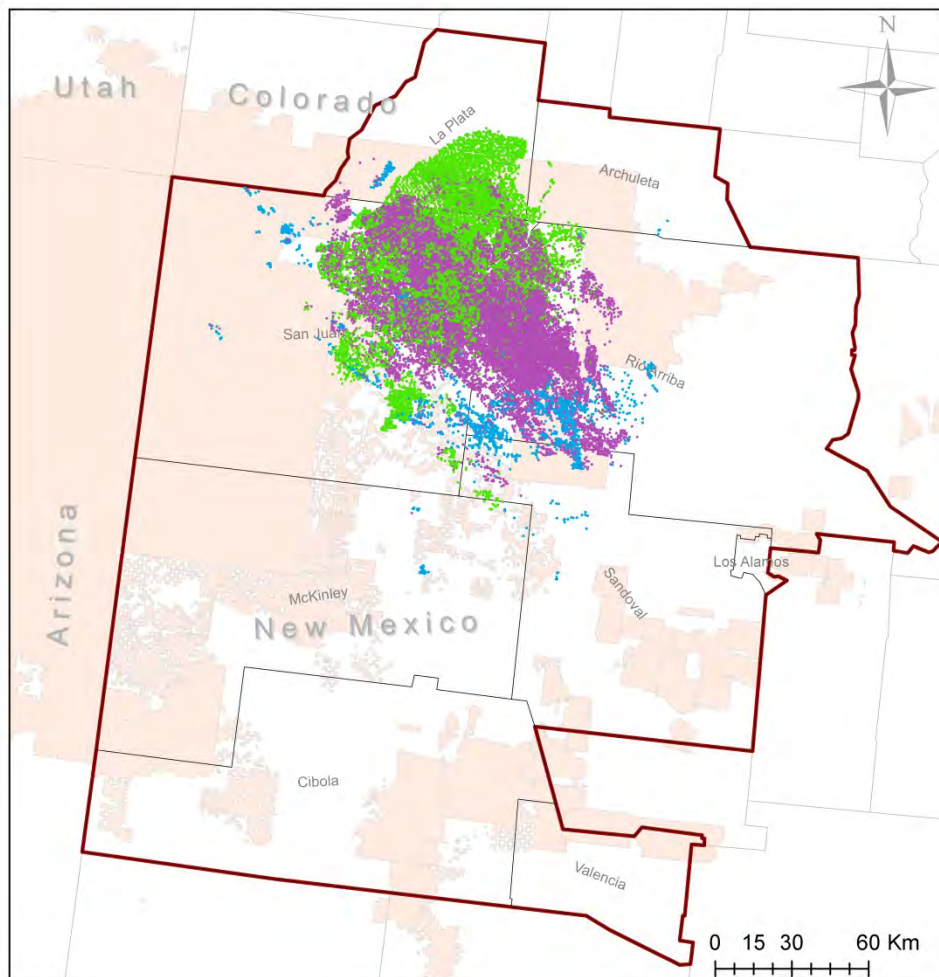
The inventory inputs were developed for base year 2014. All midstream facility data gathered from state and federal agencies and wellsite survey data requested from participating companies were for activities in the calendar year 2014. Similarly, all well count and production data obtained from the IHS database were for the calendar year 2014.

The geographic scope of the inventory inputs is the Greater San Juan Basin in north-western New Mexico and south-western Colorado and the portion of the Permian Basin in New Mexico. For the purposes of this study, the boundaries for the Greater San Juan Basin are based on the American Association of Petroleum Geologists⁴ (AAPG) San Juan Basin consistent with EPA GHGRP, including Archuleta and La Plata counties in Colorado and Cibola, Los Alamos, McKinley, Rio Arriba, San Juan, Sandoval, and Valencia counties in New Mexico. The Permian Basin in this study is limited to the portion of the Permian Basin in south-eastern New Mexico as defined by the AAPG⁴, including Chavez, Eddy, Lea, and Roosevelt counties. The geographic scope of the analysis also considers activities by mineral estate ownership: Federal, Bureau of Indian Affairs (BIA or tribal), and state/private fee land.

Figure 1-1 through Figure 1-4 show the boundaries of the Greater San Juan and Permian basins, with 2014 well locations extracted from the IHS database overlaid. Figure 1-1 presents wells by type and Figure 1-2 present wells by mineral designation for the Greater San Juan Basin. Figure 1-3 presents wells by type and Figure 1-4 present wells by mineral designation for the Permian Basin.

⁴ <http://ngmdb.usgs.gov/Geolex/stratres/provinces>

Greater San Juan Basin



Legend

-  Greater San Juan Basin (consistent with GHGRP Subpart W definition)
-  Tribal Lands

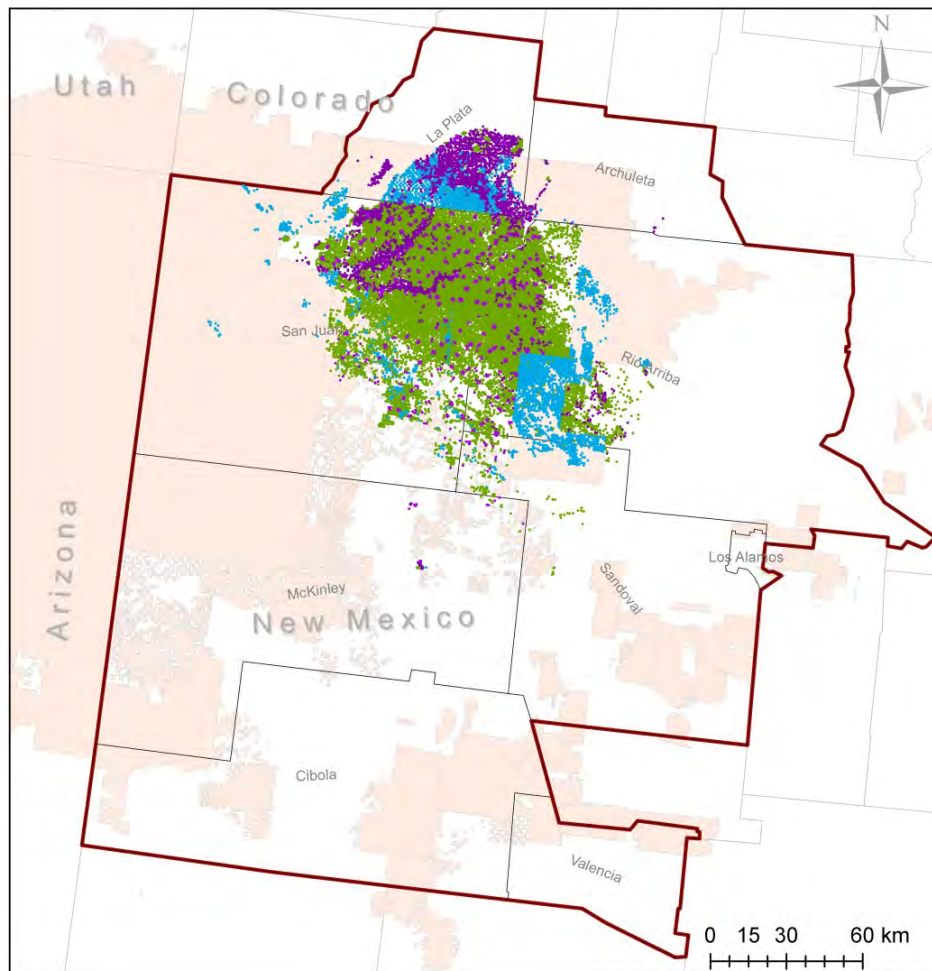
Well Type

-  Oil
-  CBM
-  Gas

Figure 1-1. Greater San Juan Basin boundaries overlaid with 2014 oil and gas well locations by well type.⁵

⁵ Includes data supplied by IHS Inc., its subsidiary and affiliated companies; Copyright (2011) all rights reserved.

Greater San Juan Basin



Legend

 Greater San Juan Basin (consistent with GHGRP Subpart W definition)

 Tribal Lands

Mineral Ownership (2014 Wells)

 Private/State

 Tribal

 Federal

Figure 1-2. Greater San Juan Basin boundaries overlaid with 2014 oil and gas well locations by mineral designation.⁵

Permian Basin

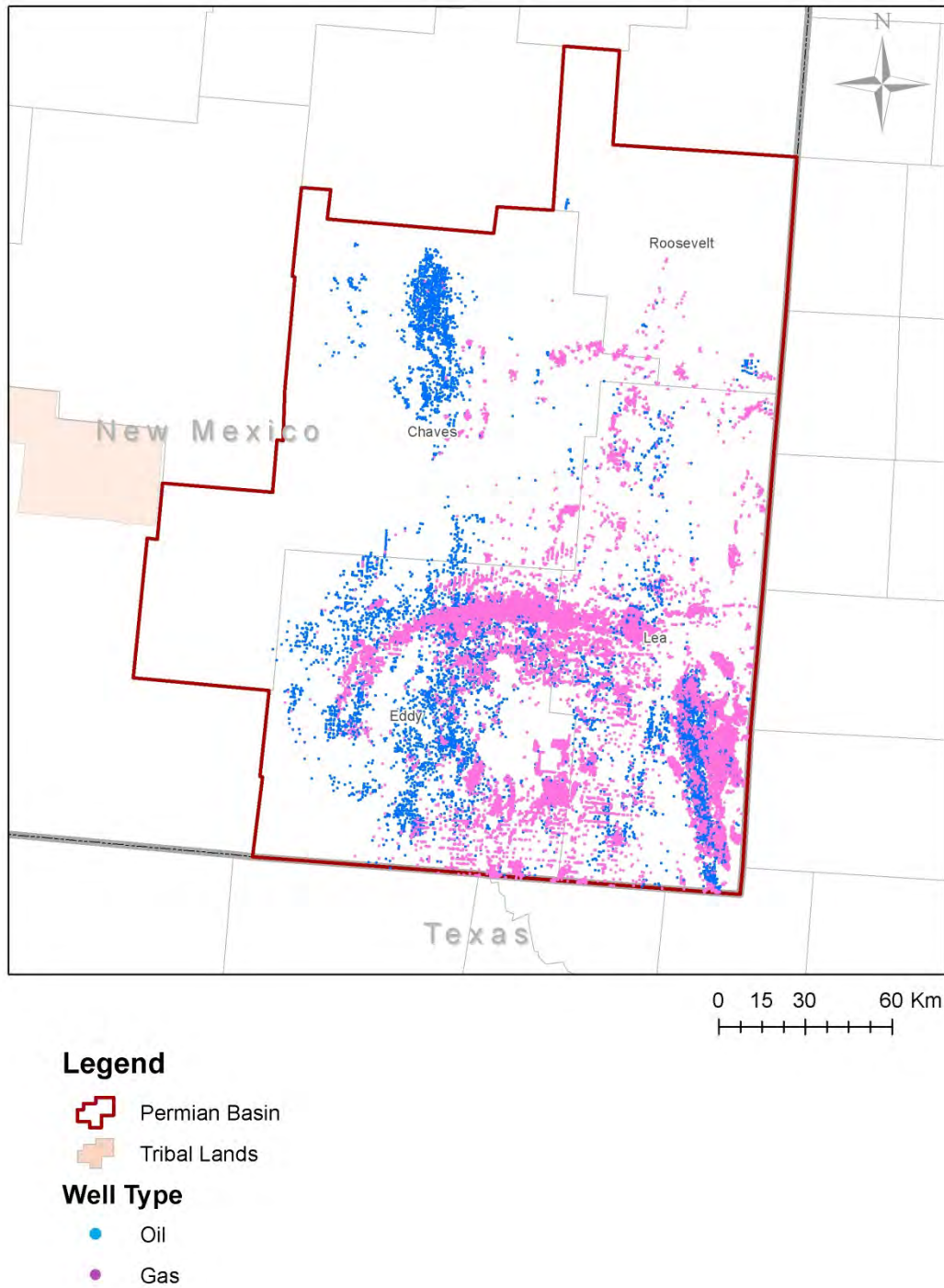


Figure 1-3. Permian Basin boundaries overlaid with 2014 oil and gas well locations by well type.⁵

Permian Basin

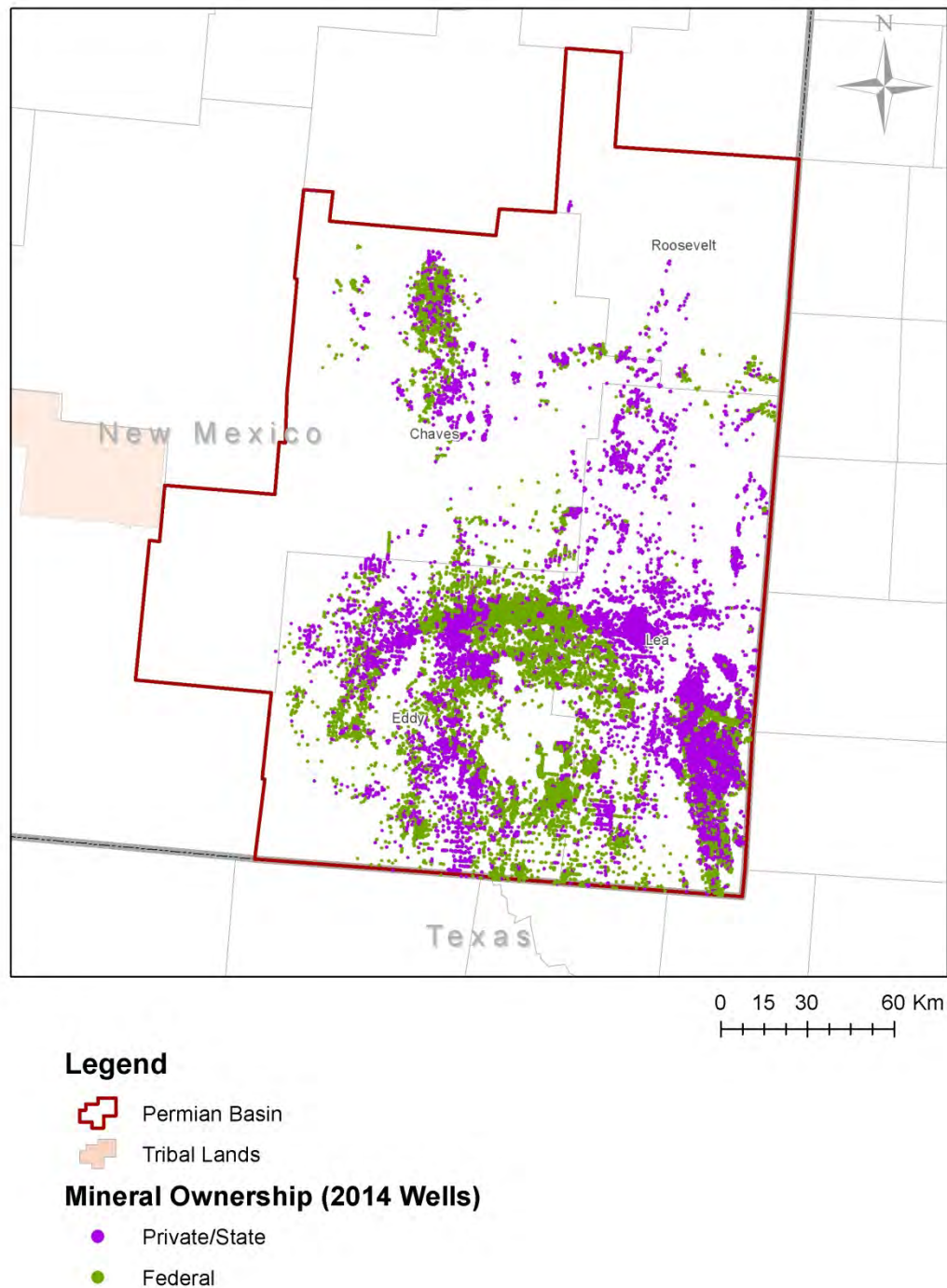


Figure 1-4. Permian Basin boundaries overlaid with 2014 oil and gas well locations by mineral designation.⁵

1.3 Well Count and Production Data

Oil and gas related activity data for the Greater San Juan and Permian basins were obtained from the IHS Enerdeq database queried via online interface. The IHS database uses data from each state's Oil and Gas Conservation Commission (OGCC or equivalent) as sources of information for oil and gas activity. This data is also available directly through database querying tools maintained by the respective agencies. It was determined that the IHS database is more accurate and complete than the state databases; the IHS database was also used to develop emission inventories in the WRAP Phase III, WestJump AQMS, and IWDW studies. Therefore, the IHS database was chosen as the basis for oil and gas activity statistics for this analysis. Two types of data were queried from the Enerdeq database: production data and well data. Production data includes information relevant to producing wells in the basin while well data includes information relevant to drilling activity ("spuds") and completions in the basin.

Production data were obtained for all counties in the Greater San Juan and Permian Basins in the form of IHS "298" format data files. The "298" well data contain information regarding historical oil and gas production. The "298" well data were processed with a PERL script to arrive at a database of by American Petroleum Institute (API)-number, well type (oil, gas, or coalbed methane; CBM), annual gas production, oil production, and water production with latitude and longitude information.

The API number in the IHS database consists of 14 digits as follows:

- Digits 1 to 2: state identifier
- Digits 3 to 5: county identifier
- Digits 6 to 10: borehole identifier
- Digits 11 to 12: sidetracks
- Digits 13 to 14: event sequence code (recompletions)

Based on the expectation that the first 10 digits, which include geographic and borehole identifiers, would predict unique sets of well head equipment, the unique wells were identified by the first 10 digits of the API number.

Well data were also obtained from the IHS Enerdeq database for the counties that make up the Greater San Juan and Permian Basins in the form of "297" well data. The "297" well data contain information regarding spuds and completions. The "297" well data were processed with a PERL script to arrive at a database of by-API-number, spud and completion dates with latitude and longitude information. Drilling events in 2014 were identified by indication that the spud occurred within 2014. If the well API number indicated the well was a recompletion, it was not counted as a drilling event, though if the API number indicated the well was a sidetrack, it was counted as a drilling event.

Oil and gas activity by well type and mineral designation are shown in Table 1-1 and Table 1-2 for the Greater San Juan Basin and in Table 1-3 and Table 1-4 for the Permian Basin.

Table 1-1. Greater San Juan Basin 2014 oil and gas activity by county (counties without oil and gas production are not shown).

County, State	Active Well Count			Liquid Hydrocarbon Production (Mbbbl/yr)		Gas Production (MMCF/yr)			Spuds
	Gas	Oil	CBM	Condensate	Oil	Natural Gas	Associated Gas	CBM	
Archuleta, CO	3	6	93	0	2	609	0	15,011	1
La Plata, CO	858	80	2,154	7	23	22,962	40	311,200	19
Colorado Subtotals	861	86	2,247	7	25	23,571	40	326,211	20
McKinley, NM	2	112	8	17	51	0	0	181	0
Rio Arriba, NM	6,746	729	1,057	638	871	190,228	8,926	84,916	24
Sandoval, NM	149	203	33	42	1,849	565	7,889	1,162	26
San Juan, NM	8,289	595	3,753	950	1,618	212,426	6,978	197,307	52
New Mexico Subtotals	15,186	1,639	4,851	1,647	4,389	403,219	23,793	283,566	102
Basin-wide Totals	16,047	1,725	7,098	1,653	4,413	426,789	23,833	609,777	122

Table 1-2. Greater San Juan Basin percent of 2014 oil and gas activity by mineral designation.

Mineral Designation	Active Well Count			Liquid Hydrocarbon Production		Gas Production			Spuds
	Gas	Oil	CBM	Oil	Condensate	Natural Gas	Associated Gas	CBM	
Private/State	18%	19%	34%	22%	14%	19%	18%	45%	25%
Tribal	15%	30%	13%	12%	12%	12%	16%	19%	14%
Federal	67%	51%	54%	66%	74%	69%	66%	36%	61%

Table 1-3. Permian Basin 2014 oil and gas activity by county (counties without oil and gas production are not shown).

County, State	Active Well Count		Liquid Hydrocarbon Production (Mbbl/yr)		Gas Production (MMCF/yr)		Spuds
	Gas	Oil	Condensate	Oil	Natural Gas	Associated Gas	
Chaves, NM	1,209	692	40	1,420	12,137	6,624	12
Eddy, NM	2,640	10,809	1,592	57,909	69,243	219,727	601
Lea, NM	2,073	10,961	996	55,079	35,560	160,000	471
Roosevelt, NM	35	149	16	205	1,065	1,508	5
Basin-wide Totals	5,957	22,611	2,644	114,613	118,006	387,858	1,089

Table 1-4. Permian San Juan Basin percent of 2014 oil and gas activity by mineral designation.

Mineral Designation ¹	Active Well Count		Liquid Hydrocarbon Production		Gas Production		Spuds
	Gas	Oil	Oil	Condensate	Natural Gas	Associated Gas	
Private/State	56%	54%	52%	48%	56%	49%	55%
Federal	44%	46%	48%	52%	44%	51%	45%

¹ The Permian Basin did not include any oil and gas activity from tribal mineral estate.

2.0 MIDSTREAM PERMIT DATA

Permitted sources in this analysis refer primarily to larger sources in use in midstream, gas gathering and gas treatment applications that are generally treated in inventories as point sources. This includes large gas processing plants, major compressor stations, and other smaller compressor stations, including the associated equipment at these stations. Permitted midstream sources were obtained from several data sources:

1. Title V major sources in use in midstream, gas gathering applications from NMED permit data;
2. Major and minor sources in use in midstream applications from CDPHE permit data;
3. Title V major sources on tribal land from US EPA Region 6;
4. Title V major sources on tribal land from US EPA Region 9;
5. Midstream point source emissions from the 2014 National Emission Inventory (v1).

Facilities in attainment areas such as the Greater San Juan and Permian basins are required to obtain a Title V operating permit (Part 70 or Part 71 permit) if emissions exceed 100 tons per year for any criteria pollutant or 10 tons per year for any hazardous air pollutant. Minor sources on tribal land are registered under the Indian Country Minor New Source Review Rule which requires registration of existing and new minor sources on tribal land. Minor sources are defined in attainment areas as those sources which do not meet major permitting thresholds with the potential to emit more than:

- 10 tons per year of carbon monoxide (CO), nitrogen oxides (NO_x), sulfur dioxide (SO₂), or particulate matter (PM), or
- Five tons per year of volatile organic compounds (VOCs), or
- Five tons per year of particulate matter less than 10 microns (PM₁₀), or
- Three tons per year of particulate matter less than 2.5 microns (PM_{2.5}), or
- 0.1 tons per year of lead, or
- One ton per year of fluorides, or
- Two tons per year of hydrogen sulfide (H₂S)

It should be noted that all midstream emissions for the Permian Basin were obtained solely from the NMED database since the scope of this project is limited to the New Mexico counties of the Permian Basin which include no tribal land. The Greater San Juan and Permian basin permitted sources will be used to supplement the emissions associated with wellsite sources which will be estimated based on the analysis presented in Section 3.0 and Section 4.0. Most permitted emissions are midstream facilities not included in the exploration and production (E&P) sector described in Section 3.0 and Section 4.0. Although NMED and CDPHE register production-site equipment, this study has relied on the survey or literature review data to estimate emission inputs from these sources rather than permit data for individual production sites because (1) a comprehensive, readily available database of NMED registered wellsite

facilities is not available and (2) CDPHE registered wellsite facilities are not expected to capture a substantial fraction of wellsite emissions because most activity in the Greater San Juan Basin in Colorado is on tribal lands.

2.1 Permit Data for Midstream Facilities from the New Mexico Environmental Department

Similar to the WRAP Phase III emissions inventories⁶, midstream companies were not participants in the survey process conducted in the Greater San Juan Basin. Because NMED permits midstream sources on non-tribal land in New Mexico, it was determined that the NMED permit database would be the most comprehensive source of data on midstream facilities such as gas plants, compressor stations and associated equipment on non-tribal land. Actual emissions data from applicable midstream Title V facilities are included in this report. For midstream sources with emissions that are not large enough to meet Title V thresholds, a request has been made for an extraction from the NMED's permit database, Tools for Environmental Management and Protection Organizations (TEMPO). It is anticipated that NMED staff will query the database using a specific combination of North American Industry Classification System (NAICS) codes pertaining to oil and gas source categories that will mitigate the retrieval of well-head compressors which was a concern in previous emission inventory efforts (Bar-Ilan et al., 2008; Bar-Ilan et al., 2012; Parikh et al. 2015). The inclusion of non-Title V midstream sources in the next phase of this study (emission inventory development) will enhance its quality relative to prior emission studies.

2.2 Permit Data for Midstream Facilities from the Colorado Department of Public Health and Environment

2014 permitted point sources data for oil and gas sources on non-tribal land in Colorado was obtained directly from Air Permit Emission Notices (APENs) collected by the CDPHE for the Greater San Juan Basin. The reporting threshold in Colorado for a point source is 2 tons per year (tpy) of any criteria pollutant in attainment areas such as the portion of the Greater San Juan Basin in Colorado, and because of this low permitting threshold the database of emissions for permitted sources in the APENs was considered a highly comprehensive source of data. Wellsite area sources were filtered out of the APENs database as wellsite inputs in the Greater San Juan basins will be determined from survey responses. APENs sources on tribal lands (as determined by the latitude/longitude coordinates for each source) were also excluded from the analysis to avoid double counting with tribal midstream emissions data. Since the oil and gas activity in the Greater San Juan Basin in Colorado is primarily on tribal lands, excluding wellsite APENs facilities is warranted.

⁶ <http://www.wrapair2.org/PhaseIII.aspx>

2.3 Permit Data for Midstream Facilities from EPA Region 8

In consultation with the Southern Ute Indian Tribe Environmental Programs Division, midstream permitted emissions data for tribal lands in EPA Region 8 were taken from the 2014 NEI v1⁷.

2.4 Permit Data for Midstream Facilities from EPA Region 6

Title V and the minor source permits for the Jicarilla Apache and Laguna Reservations were obtained from EPA Region 6 for the Greater San Juan Basin. The Region 6 minor source database contains wellsite and midstream source emissions. Based on the facility name, wellsite area sources were filtered out of the minor source permit data as wellsite inputs in this analysis will be determined from survey responses.

2.5 Permit Data for Midstream Facilities from EPA Region 9

The Navajo Nation Reservation minor source permits were obtained from EPA Region 9. Analysis of the minor source permit data indicated that all Navajo Nation Reservation minor source permits were located in Utah, thus they were excluded from this analysis. Emissions from Title V facilities on the Navajo Nation Reservation were obtained from the 2014 NEI v1.

2.6 Greater San Juan Permit Data Emissions Summary

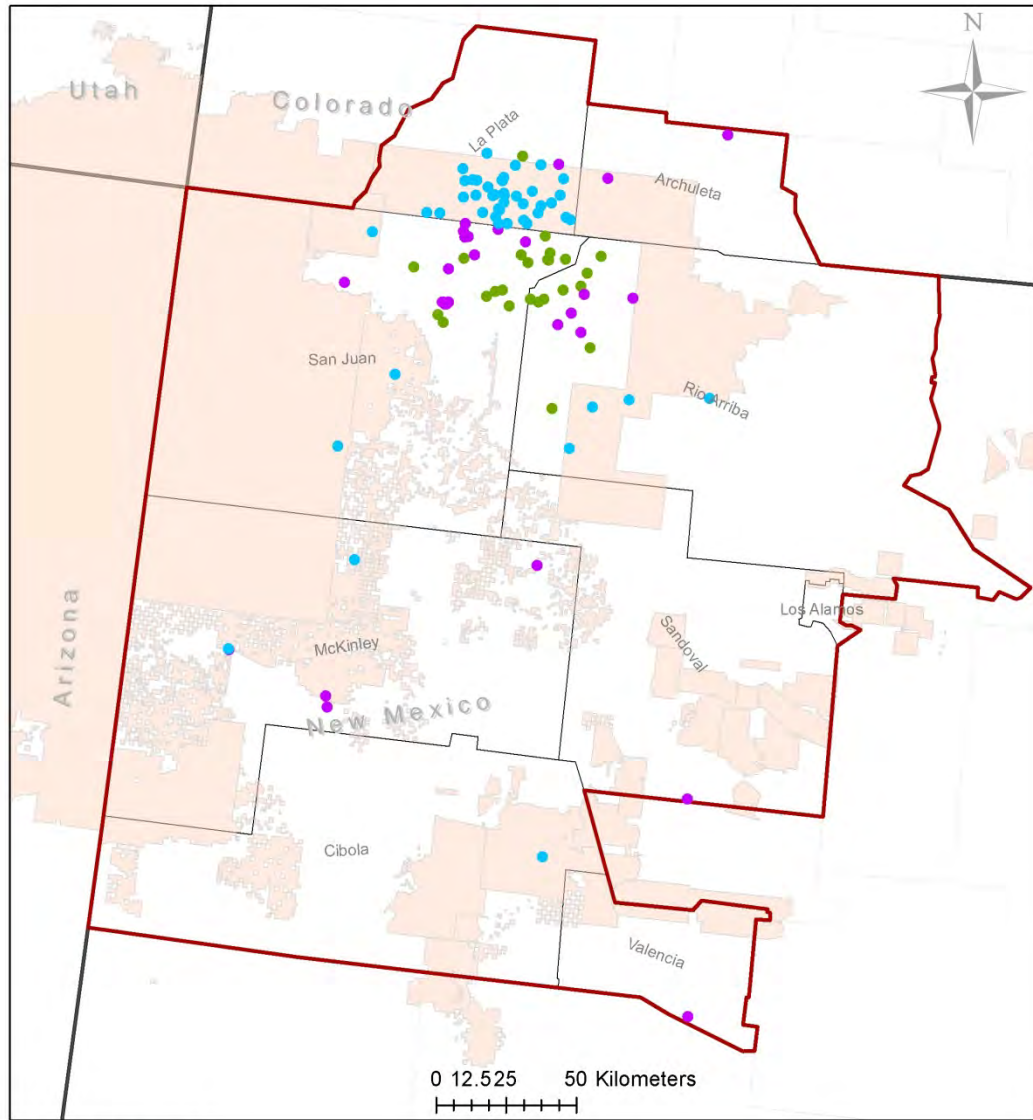
The Greater San Juan basin permitted emissions are summarized in Table 2-1. The majority of emissions are from the NMED permit source database. Figure 2-1 shows the facility locations by mineral designation; as described above tribal midstream facilities include both Title V/Part71 and minor sources (CDPHE also provided a small number of minor source midstream facilities) while BLM and private/state fee facilities provided by NMED only include Title V emissions because no minor facilities were able to be included from NMED's permit database. 40% of midstream NO_x emissions are from sources on tribal land, 32% from sources on private/state fee land and remaining from the sources on federal land. For VOC, 45% of emissions are from the sources on federal land and 29% and 26% of VOC emissions are from the sources on tribal and private/state fee land respectively.

Table 2-1. Summary of midstream permitted source emissions (tons/year) by data source for the Greater San Juan Basin.

Emission Data Source	Emissions (tons/yr)				
	NO _x	VOC	CO	PM ₁₀	SO ₂
NMED	7,651	3,000	5,114	270	186
CDPHE	89	26	88	2	0
EPA Region 6	618	377	257	4	0
EPA Region 8	3,368	1,698	2,094	81	52
EPA Region 9	9	8	7	0	0
Total	11,735	5,109	7,560	357	238

⁷ <https://www.epa.gov/air-emissions-inventories/2014-nei-data>

Greater San Juan Basin



Legend

- Greater San Juan Basin (consistent with GHGRP Subpart W definition)
- Tribal Lands

Ownership

- Federal
- Private/State
- Tribal

Figure 2-1. Greater San Juan Basin boundaries overlaid with 2014 midstream facility point source locations.

2.7 Permian Permit Data Emissions Summary

The Permian basin permitted emissions are summarized in Table 2-2. All permitted emissions are from the NMED permit source database. Figure 2-2 shows the facility locations by mineral designation. 89% of midstream NO_x emissions are from sources on private/state fee land and 11% from sources on BLM land. 73% of midstream VOC emissions are from sources on private/state fee land and 27% from sources on BLM land.

Table 2-2. Summary of midstream permitted source emissions (tons/year) for the Permian Basin.

Emission Data Source	Emissions (tons/yr)				
	NO _x	VOC	CO	PM ₁₀	SO ₂
NMED	10,578	2,678	5,230	224	6,681
Total	10,578	2,678	5,230	224	6,681

Permian Basin

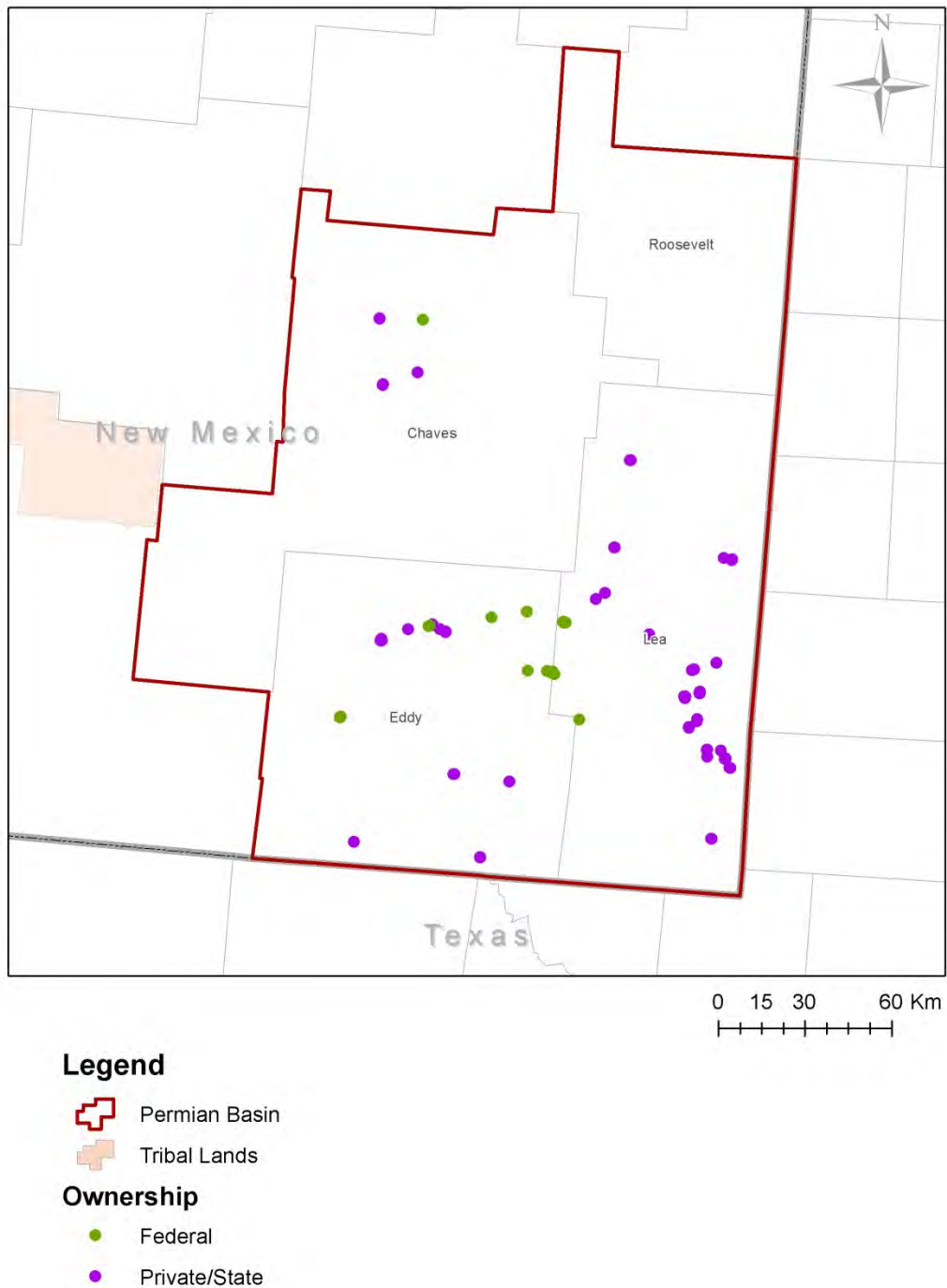


Figure 2-2. Permian Basin boundaries overlaid with 2014 midstream facility point source locations.

3.0 GREATER SAN JUAN BASIN WELLSITE INPUTS

Input factors to estimate emissions for the Greater San Juan Basin were derived primarily from operator surveys. Where gaps were identified for specific input parameters, they were filled with data collected for the Greater San Juan Basin from the EPA GHGRP data, the EPA 2011 NEI Oil and Gas Tool⁸, and the Colorado Air Resources Management Modeling Study (ENVIRON et al., 2015)

3.1 Operator Survey

Two surveys were developed to query wellsite emission inventory inputs from operators of the Greater San Juan Basin. A survey was developed to request Subpart W submittals from operators along with other supplemental Subpart W data needed to develop wellsite inputs for wellsite sources reported under Subpart W. Additionally, a second survey was developed to gather wellsite emission inventory inputs for: (1) sources for which Subpart W data is insufficient; (2) sources which are not included in Subpart W; and (3) supporting data (e.g. gas compositions and simulation model input/output). Table 3-1 below shows each oil and gas source category for which data was requested along with the associated survey from which data was gathered.

Table 3-1. Emission source categories by survey source.

Source Category	
Non-Subpart W Survey	Subpart W Survey
Drilling	Pneumatic Controllers
Fracing Engines	Pneumatic Pumps
Completion Venting	Dehydrators
Completion Engines	Casinghead Gas Venting/Flaring
Field Compressor Engines	Fugitive Components
Field Water Pump Engines	Liquid Unloading
Well Truck Loading	Condensate and Crude Oil Tanks
Artificial Lift Engines	Heaters
Workover Rigs	
Refracing Engines	
Miscellaneous Engines	
Water Tanks	

The companies participating in the survey process for the Greater San Juan Basin represented approximately 53% of well ownership, 58% of gas production, and 53% of oil production. In order to increase operator representation, Ramboll Environ compiled company specific GHGRP data and gap filled source categories for which GHGRP data were not available for companies representing 13% of well ownership, 14% of gas production ownership, and 38% of oil production ownership to bring operator representation up to 65% of well ownership, 72% of

⁸ ftp://ftp.epa.gov/EmisInventory/2011nei/doc/Tool_and_Report112614.zip

gas production ownership, and 81% of oil production ownership. The percentage of oil and gas activity that was captured in the survey process and based on company specific GHGRP data allow for good representation of oil and gas operations in the basin.

3.1.1 Gap Fill Data Sources

There are three data sources which were relied upon to create wellsite input factors to fill survey gaps (i.e. source categories for which operators were unable to provide survey data): (1) EPA GHGRP data and (2) Basin factors from the EPA Oil & Gas Emission Estimation Tool, and (3) Emission inventory input factors from ENVIRON et al. (2015) for source categories for which input factors were not available from the EPA Oil & Gas Emission Estimation Tool. GHGRP data gap filling was limited to two companies that did not complete a Subpart W survey. All of the wellsite input factors not able to be sourced from operator surveys or 2014 GHGRP data were filled with basin factors from the EPA Oil & Gas Emission Estimation Tool or ENVIRON et al. (2015).

3.1.1.1 GHGRP Wellsite Data

EPA makes GHGRP supporting data available on the Envirofacts⁹ and Facility Level Information on GreenHouse gases Tool (FLIGHT)¹⁰. The information available in the GHGRP supporting data depends on the reporting requirements for each source category; the reported data is not sufficient to derive a complete set of wellsite input factors for any source category. For example, pertinent information on compressor engines is limited to compressor engine counts and combustion GHG emissions whereas a criteria pollutant emission inventory requires information on engine type (rich or lean burn) and emission controls to estimate criteria pollutant emission rates. In general, available GHGRP data that is suggested for use to populate wellsite input factors is limited to event counts, equipment counts, and control prevalence. For parameters such as vented volumes, gas composition, engine horsepower, and engine emission rates, the EPA Oil and Gas Emission Estimation Tool estimates are used.

3.1.1.2 EPA Oil and Gas Tool Data

For its 2011 NEI, EPA used the Oil & Gas Emission Estimation Tool to estimate oil and gas area source emissions for counties in which state/local/tribal agencies did not provide their own estimates of area source oil and gas emissions. The Oil & Gas Emission Estimation Tool was used in the 2011 NEI to estimate emissions throughout the Greater San Juan Basin.

The Tool calculates a comprehensive county-level criteria pollutant area source emission inventory based on county-level wellsite input factors and oil and gas activity data. The wellsite input factors in the Tool for the Greater San Juan Basin are based on Western Regional Air Partnership (WRAP) Phase III study⁶ estimates that were provided to EPA by Ramboll Environ and WESTAR (Moore, 2013).

⁹ <http://www2.epa.gov/enviro/greenhouse-gas-overview>

¹⁰ <http://ghgdata.epa.gov/ghgp/main.do>

3.2 Input Factors

The Greater San Juan Basin input factors that were compiled from operator surveys, GHGRP data, EPA Oil and Gas Estimation Tool data, and ENVIRON et al. (2015) are shown in Appendix A. Survey data was aggregated together at the basin-wide level by well type to maintain the confidentiality of each company's data. Survey data was aggregated across all operators by the weighted average contribution of each company's data using the surrogate as the weighting factor. This methodology allows each company's survey data to impact the emissions from each source category in proportion to the company's ownership of the surrogate assigned to each category. The possibility of developing sub-basin level input factors was investigated; however, the survey data provided did not allow for protection of operator confidentiality for aggregate sub-basin level inputs.

For emissions from those source categories that relied on estimates of volume of gas vented or leaked, such as tank flashing, well blowdowns, completions, and fugitive emissions, gas composition analyses were requested from all participating companies for gas produced from oil wells (i.e. casinghead or associated gas), gas produced from gas wells (primary gas), gas produced from CBM wells (coalbed methane gas) and flash gas associated with oil, condensate, and water tanks. These composition analyses were averaged to derive representative basin-wide gas composition for oil wells by associated gas production, for gas wells by primary gas production, and for CBM wells by coalbed methane production. The average composition analyses are used to determine the average basin-wide VOC volume and mass fractions of the vented gas by type (see Table 3-2). Due to lack of survey data, oil, condensate, and water tank flash gas compositions were taken from (ENVIRON et al., 2015).

Table 3-2. Gas composition input factors by well type.

Gas Composition Parameter	Associated Gas	Natural Gas	CBM	Condensate and Crude Oil Tanks	Water Tanks
Gas Molecular Weight (g/mol)	20	20	16	not available	not available
VOC Fraction (molar)	3%	6%	1%	not available	not available
VOC/TOC (weight)	9%	16%	2%	not available	not available
VOC Molecular Weight (g/mol)	59	55	48	36	55
Percent VOC (weight)	7%	15%	2%	58%	5%
Percent CH ₄ (weight)	65%	64%	84%	9%	84%
Percent CO ₂ (weight)	12%	5%	5%	2%	1%

3.3 Uncertainty

It should be noted that the input factor estimates for wellsite sources rely on data that is not as rigorously documented as permitted sources. Much of the data provided for these sources is based upon estimates and extrapolation from survey responses and other supporting data as described above. However, the level of detail of the surveys and other supporting data (e.g. GHGRP) and the extent of participation in the survey effort allow for representative input

factors to be developed for wellsite sources that are an improvement over previous studies for which input factors were developed for the 2006 timeframe (Bar-Ilan et al., 2009a; 2009c).

Per stakeholder input, survey data was not collected for certain wellsite source categories because data was not expected to be available: amine units, truck loading at gas and NGL processing plants, and water disposal pits. Finally, input factors for potential fugitive emissions from oil and gas pipelines from well heads to the main compressor stations were not estimated. Insufficient data was available on the components of pipelines or the complete extent of pipelines in the basins.

4.0 PERMIAN BASIN WELLSITE INPUTS

Permian Basin wellsite input factors were developed based on data available from other studies and/or reporting because conducting a survey in the Permian Basin was not expected to yield adequate operator participation. The possibility of conducting a survey in the Permian Basin was explored through outreach to some Permian Basin operators with assistance from BLM staff, but the operator responses indicated that a survey was not likely to be successful.

A literature review was performed to gather data on Permian Basin wellsite emission sources. Review of available literature indicated that there are two recent and applicable sources: (1) the TCEQ oil and gas emission inventory; and (2) data available as part of EPA Subpart W reporting for wellsite sources for the Permian Basin. These two sources are the subject of the review presented in this chapter. There are two more studies, a 2012 Central States Air Resources Agencies (CENSARA) study (ENVIRON, 2012) and a 2008 Central Regional Air Planning Association (CENRAP) study (Bar-Ilan et al., 2008), that include data for the Permian Basin, however Permian Basin wellsite inputs collected for these studies are primarily from data collected in calendar year 2008 and this data has been incorporated into or updated in the TCEQ Permian Basin oil and gas inventory.

4.1 Subpart W Greenhouse Gas Reporting Program (GHGRP)

A review of the Subpart W reporting (40 CFR 98, Subpart W) data was performed¹¹. Owners or operators of facilities¹² that contain petroleum and natural gas systems and emit 25,000 metric tons or more of GHGs per year (expressed as carbon dioxide equivalents) are required to report GHG data to EPA. The Subpart W reporting is required for the following petroleum and natural gas industry segments:

1. Onshore petroleum and natural gas production
2. Offshore petroleum and natural gas production
3. Onshore natural gas processing plants
4. Onshore natural gas transmission compression
5. Underground natural gas storage
6. Liquefied natural gas (LNG) storage
7. Liquefied natural gas import and export equipment
8. Natural gas distribution

The purpose of the review of Subpart W data in this study is to develop representative wellsite emission inventory inputs, therefore, the literature review was performed on data available for the “Onshore petroleum and natural gas production” segment only. Table 4-1 identifies the source categories required to report under the Subpart W for this segment. The Subpart W data available on Envirofacts⁹ and Facility Level Information on GreenHouse gases Tool (FLIGHT)¹⁰

¹¹ <http://www.epa.gov/ghgreporting/reporters/subpart/w.html>

¹² <http://www2.epa.gov/sites/production/files/2015-08/documents/petroleumnaturalgassystems.pdf>

provides GHG emissions with limited equipment/process-level data which are required to develop representative input factors.

Table 4-1. Source categories required to report under the Subpart W for the onshore petroleum and natural gas production segment.

Source Type
Natural gas pneumatic device venting
Natural gas driven pneumatic pump venting
Acid gas removal vents
Dehydrator vents
Well venting for liquids unloading
Gas well venting during completions and workovers from hydraulic fracturing
Gas well venting during completions and workovers without hydraulic fracturing
Onshore production storage tanks
Well testing venting and flaring
Associated gas venting and flaring
Flare stack emissions
Centrifugal compressor venting
Reciprocating compressor venting
Population count and emissions factors
Enhanced Oil Recovery (EOR) injection pump blowdown
EOR hydrocarbon liquids dissolved CO ₂
Combustion emissions by following subpart W

The Subpart W GHGRP submissions for all facilities¹² within the Permian Basin boundary¹³, which includes counties in both western Texas and south-eastern New Mexico, were downloaded for calendar year 2014. 62 facilities submitted data for the Permian Basin, however, data from 17 facilities were not able to be used for this analysis for the following reasons:

- Seven facilities did not report their data due to undisclosed valid reasons.
- Four facilities have not met the EPA verification requirement.
- One facility's data was not accessible for download from the FLIGHT database.
- Five facilities did not have well count information available in their GHGRP submissions. Without well count, representative input factors were unable to be calculated.

For each facility, data were downloaded in ".txt" format and a macro was developed in MS EXCEL to efficiently compile data from each facility's file for analysis. It was concluded that there was publicly available data relevant to compiling basin-wide input factors for a limited number of source categories: pneumatic devices, pneumatic pumps, fugitives and wellhead compressor engines. Total equipment counts for each of these sources were compiled for 45

¹³ <http://www.ccdsupport.com/confluence/display/help/Subpart+W+Basin+and+County+Combinations>

facilities. These 45 facilities represent 107,217 wells in the Permian Basin. Table 4-2 summarizes input factors developed for pneumatic devices, pneumatic pumps, fugitives and compressor engines based on the 2014 Subpart W data. It should be noted that the GHGRP does not provide data by well type for these sources. Additional data beyond what is made publicly available by EPA from the reporting operators would be required to make use of Subpart W data for sources not listed in Table 4-2.

Table 4-2. Input factors developed using the GHGRP submissions for the Permian Basin.

Parameter		Value	Unit
Pneumatic Devices			
Devices counts for oil and gas wells	High Bleed	0.04	number of devices per well
	Intermittent	0.31	
	Low Bleed	0.24	
EPA default bleed rate	High Bleed	37.00	scf/hr
	Intermittent	13.50	
	Low Bleed	1.39	
Fugitives			
Fugitives counts for gas and oil wells	Onshore, gas service - connector	29.56	number of components per well
	Onshore, gas service - open-ended line	0.99	
	Onshore, gas service - pressure relief valve	0.43	
	Onshore, gas service - valve	9.15	
	Onshore, light crude service - connector	5.89	
	Onshore, light crude service - flange	9.72	
	Onshore, light crude service - other	0.79	
	Onshore, light crude service - valve	5.00	
Pneumatic Pumps			
Number of pumps per well		0.03	pumps/well
Vent rate for pumps		13.3	scf/hr/pump
Compressor Engines*			
Number of compressor engines		0.02	engines/well

* For the compressor engines, the GHGRP does not provide sufficient information to develop engine activity i.e. average horsepower, load factor, hours of operation, etc.

4.2 Texas Oil and Gas Emission Inventory

The TCEQ has developed a 2012 oil and gas emission inventory based primarily on ERG (2010), but with some significant updates to source categories such as compressor engines, storage tanks, heaters, pneumatic devices, completions, etc. (TCEQ, 2015) as well as a 2014 emission inventory that updates the 2012 emission inventory (TCEQ, 2016). Table 4-3 lists the reports that provide emission estimation methodologies for each source category and the associated oil and gas activity surrogate used to develop emissions.

The TCEQ reports provide detailed wellsite input factor data used in development of the Texas oil and gas inventory. The input factor data in the TCEQ reports are based on a variety of

sources including oil and gas operator data, CENRAP study data (Bar-Ilan, et al., 2008), EPA Oil and Gas Tool V.2.0¹⁴, EPA AP-42¹⁵ factors, manufacturing specifications, etc. The input factors used in the TCEQ inventory to estimate Permian Basin oil and gas wellsite emissions are summarized in Table 4-4.

Table 4-3. List of TCEQ reports reviewed for each wellsite source.

Wellsite Source	Associated Surrogate	Report
Artificial Lift Engines	Oil Well Counts	ERG (2010)
Well Blowdowns	Well Counts	
Dehydrators	Well Counts	
Oil and Condensate Loading	Oil Production and Condensate Production	
Fugitives	Well Counts	
Wellhead Compressor Engines	Gas Production	
Crude Oil Storage Tanks	Oil Production	
Pneumatic Pumps	Well Counts	
Fracturing	Spuds	
Completions	Spuds	
Produced Water	Water Production	ENVIRON (2010)
Drilling	Spuds	ERG (2011)
Condensate Tanks	Condensate Production	ERG (2012)
Heaters	Well Counts	ERG (2010, 2013)
Mud Degassing	Spuds	ERG (2014)
Pneumatic Device	Well Counts	TCEQ (2014)

Table 4-4. Input factors used in the TCEQ inventory for wellsite sources.

Parameter		Value	Unit
Artificial Lift Engines			
Fraction of oil wells with artificial lift engines		96.70%	%
Fraction of artificial lift engines that are electrically operated		70.00%	%
Average horsepower of the engine		20.55	hp
Average Fuel Consumption		0.21	mmbtu/hp-hr
Load factor		71.00%	%
Annual number of hours		4,380	hr/yr
Emission Factors	NOx	14.75	g/hp-hr
	VOC	0.14	
	CO	7.37	
	PM	0.05	
	SOx	<0.01	

¹⁴ EPA Oil and Gas Toll V2.0, November, 2014.

ftp://ftp.epa.gov/EmisInventory/2011nei/doc/Tool_and_Report112614.zip

¹⁵ EPA AP-42. Emission Factors & AP42, Compilation of Air Pollutant Emission Factors.

<http://www3.epa.gov/ttnchie1/ap42/>

Parameter				Value	Unit
Well Blowdown ¹⁶					
Volume of vented gas per blowdown				50.00	mcf/event/wellhead
Number of blowdowns per well				5.00	event/wellhead/yr
Number of blowdowns controlled by flares				0.00 ¹⁷	-
Dehydrators					
VOC Venting emission factors				1.63	lb/mmscf
Amount of produced gas flared				13.40	lbs flared/mmscf produced
Density of gas flared				46,952	lb/mmscf
Heat value of the gas flared				1,209	mmbtu/mmscf
Flaring Emission Factors		NOx		0.07	lb/mmbtu
		CO		0.37	lb/mmbtu
Glycol Regenerator Boilers Emission Factors		NOx		0.05	lb/mmscf
		CO		0.11	
Heaters					
Average number of heaters per well				0.37	-
Average heater size				0.53	mmbtu/hr
Average hours of operation				3,477	hr/yr
Average fuel content				1,359	btu/scf
Emission Factors		NOx		58.20	lb/mmscf
		VOC		5.50	
		CO		84.00	
		PM ₁₀		7.60	
		PM _{2.5}		7.60	
		H ₂ S mass fraction		Gas Wells	<0.01
		Oil Wells	6.50	-	
Pneumatic Devices					
No. of devices per well		Gas Wells		1.19	-
		Oil Wells		0.43	-
Weighted average bleed rate		Gas Wells		8.79	scf/hr
		Oil Wells		5.24	
VOC emission factor		Gas Wells		0.38	tpy/well
		Oil Wells		0.19	
Fugitives					
Gas Wells -Fugitives		Valves		19.00	number of components per well
		Pump Seals		2.00	
		Others		10.00	
		Connectors		43.00	
		Flanges		29.00	
		Open-ended lines		3.00	
		VOC to TOC ratio		0.14	-
Oil Wells -Fugitives		Valves		16.00	number of components per well
		Pump Seals		2.00	
		Others		10.00	

¹⁶ Gas wells only per TCEQ (2016)

¹⁷ Personal communication with the Bureau of Land Management (BLM) staff (Mary Uhl), November 12, 2015.

Parameter		Value	Unit
	Connectors	58.00	
	Flanges	12.00	
	Open-ended lines	2.00	
	VOC to TOC ratio	0.14	-
Oil Tanks			
VOC Emission Factor		1.60	lb/bbl
Fraction of Production Controlled		0.00%	%
Condensate Tanks			
VOC Emission Factor		7.07	lb/bbl
Fraction of Production Controlled		19.50%	%
Oil Tank Loading			
Mode of Operation		Submerged loading: dedicated vapor balance / Splash loading: dedicated vapor balance service	-
Saturation Factor		1.00	-
Temperature of the bulk liquid loaded		From the National Weather Service and from several state/local monitoring sites by county	degrees Fahrenheit
True Pressure		$(0.057 \times \text{temperature of liquid loaded (degrees Fahrenheit)}) - 0.58$	psia
Molecular Weight of Crude RVP 5		50.00	lb/lb-mole
Condensate Tank Loading			
Mode of Operation		Submerged loading: dedicated vapor balance / Splash loading: dedicated vapor balance service	-
Saturation Factor		1.00	-
Temperature of the bulk liquid loaded		From the National Weather Service and from several state/local monitoring sites by county	degrees Fahrenheit
True Pressure		$(0.077 \times \text{temperature of liquid loaded (degrees Fahrenheit)}) - 1.03$	psia
Molecular Weight of Gasoline RVP 7		68.00	lb/lb-mole

Parameter			Value	Unit
Pneumatic Pumps				
Methane vent rate for gas wells using Kimray pumps			1,041	scf/mmscf
Gas pumped per gas well annually with Kimray pumps per unit throughput			42.90	mmscf/well/yr
Methane vent rate for gas wells using CIP pumps			260.00	scf/mmscf
Number of hours of operation of CIP pumps at gas wells			8,760	hr/yr
Number of CIP pumps per gas well			0.14	count/well
Methane vent rate for oil wells using CIP pumps			248.00	scf/mmscf
Number of hours of operation of CIP pumps at oil wells			8,760	hr/yr
Number of CIP pumps per oil well			0.05	count/well
Molecular weight of the gas emitted by gas-actuated pumps at gas wells			21.56	g/mol
VOC molar fraction of gas emitted by gas-actuated pumps at gas wells			8.23%	%
Hydrogen sulfide molar fraction of gas emitted by gas-actuated pumps at gas wells			0.00%	%
Carbon dioxide molar fraction of gas emitted by gas-actuated pumps at gas wells			2.18%	%
Methane molar fraction of gas emitted by gas-actuated pumps at gas wells			75.00%	%
Molecular weight of the VOC emitted by gas-actuated pumps at gas wells			50.64	g/mol
Molecular weight of the gas emitted by gas-actuated pumps at oil wells			20.68	g/mol
VOC molar fraction of gas emitted by gas-actuated pumps at oil wells			7.06%	%
Hydrogen sulfide molar fraction of gas emitted by gas-actuated pumps at oil wells			0.64%	%
Carbon dioxide molar fraction of gas emitted by gas-actuated pumps at oil wells			2.08%	%
Methane molar fraction of gas emitted by gas-actuated pumps at oil wells			80.62%	%
Molecular weight of the VOC emitted by gas-actuated pumps at oil wells			53.22	g/mol
Methane to VOC weight ratio of gas emitted by gas-actuated pumps at oil wells			3.44	-
Hydrogen sulfide to VOC weight ratio emitted by gas-actuated pumps at oil wells			0.06	-
Methane to VOC weight ratio of gas emitted by gas-actuated pumps at gas wells			2.88	-
Hydrogen sulfide to VOC weight ratio emitted by gas-actuated pumps at gas wells			0.00%	%
Drill Rigs (Vertical Wells Depth <= 7,000 ft)				
Mechanical Rig Type	Draw Works	No. of Engines	1.60	-
		Average Age	7.00	yrs.
		Horsepower	442.00	hp
		Hours	30.80	hr/1000 ft drilled
		Average Load	51.80%	%
	Mud Pump	No. of Engines	1.69	-
		Average Age	6.00	yrs.
		Horsepower	428.00	hp
		Hours	29.40	hr/1000 ft drilled
		Average Load	45.90%	%

Parameter			Value	Unit
	Generator	Number of Engines	0.97	-
		Average Age	4.00	yrs.
		Horsepower	330.00	hp
		Hours	28.30	hr/1000 ft drilled
		Average Load	70.40%	%
Drill Rigs (Vertical Wells Depth > 7,000 ft)				
Mechanical Rig Type	Draw Works	Number of Engines	2.01	-
		Average Age	25.00	yrs.
		Horsepower	455.00	hp
		Hours	35.90	hr/1000 ft drilled
		Average Load	47.40%	%
	Mud Pump	Number of Engines	1.62	-
		Average Age	18.00	yrs.
		Horsepower	761.00	hp
		Hours	33.20	hr/1000 ft drilled
		Average Load	46.00%	%
	Generator	Number of Engines	2.00	-
		Average Age	10.00	yrs.
		Horsepower	407.00	hp
		Hours	19.30	hr/1000 ft drilled
		Average Load	78.70%	%
Electrical		Number of Engines	2.15	-
		Average Age	2.00	yrs.
		Horsepower	1,381	hp
		Hours	62.60	hr/1000 ft drilled
		Average Load	48.50%	%
Drill Rigs (Horizontally Drilled)				
Mechanical Rig Type	Draw Works	No. of Engines	2.00	-
		Average Age	15.00	yrs.
		Horsepower	483.00	hp
		Hours	50.10	hr/1000 ft drilled
		Average Load	41.10%	%
	Mud Pump	No. of Engines	2.00	-
		Average Age	6.00	yrs.
		Horsepower	1,075	hp
		Hours	36.40	hr/1000 ft drilled
		Average Load	42.60%	%
	Generator	No. of Engines	2.00	-
		Average Age	10.00	yrs.
		Horsepower	390.00	hp
		Hours	26.80	hr/1000 ft drilled
		Average Load	69.00%	%
Electrical		Number of Engines	2.03	-
		Average Age	2.00	yrs.
		Horsepower	1,346	hp
		Hours	47.30	hr/1000 ft drilled
		Average Load	52.50%	%

Parameter		Value	Unit
Produced Water			
VOC Emission Factor		0.01	lb/bbl
Compressor Engines			
Energy required per unit of gas production		3.21	hp-hr/mmscf
Percent Workload	Generic	6.21%	%
	2-cycle lean burn 50 to 499 Hp	7.14%	%
	4-cycle lean burn 500+ hp	28.60%	%
	4-cycle rich burn < 50 hp	0.60%	%
	4-cycle rich burn 50 to 499 hp	36.55%	%
	4-cycle rich burn 500+ hp w/NSCR	20.92%	%
Generic Emission Factors	NOx	5.51	g/bhp-hr
	VOC	0.95	
	CO	1.86	
	PM	0.15	
	SOx	<0.01	
2-cycle Lean Burn 50 to 499 hp Emission Factors	NOx	8.47	g/bhp-hr
	VOC	0.81	
	CO	1.51	
	PM	0.15	
	SOx	<0.01	
4-cycle Lean Burn 500+ hp Emission Factors	NOx	1.66	g/bhp-hr
	VOC	0.51	
	CO	2.20	
	PM	0.01	
	SOx	<0.01	
4-cycle Rich Burn < 50 hp Emission Factors	NOx	12.95	g/bhp-hr
	VOC	0.05	
	CO	1.10	
	PM	0.03	
	SOx	<0.01	
4-cycle Rich Burn 50 to 499 hp Emission Factors	NOx	15.89	g/bhp-hr
	VOC	0.16	
	CO	7.70	
	PM	0.03	
	SOx	<0.01	
4-cycle Rich Burn 500+ hp w/NSCR Emission Factors	NOx	1.28	g/bhp-hr
	VOC	0.05	
	CO	0.85	
	PM	0.03	
	SOx	<0.01	
Fracing Engines			
Horsepower (HP) of a hydraulic fracture engine		1,258	hp
Load factor of a hydraulic fracture engine		0.63	-
Number of stages per fracturing event		5.75	-
Number of hours per fracturing stage		1.50	hp/stage
Number of fracturing engines used per fracturing event		3.50	-

Parameter	Value	Unit
Initial Completions		
Volume vented per completion	0	MCF/event
Fraction of completions controlled by flare	0	-
Fraction of completions controlled by green completion techniques	0	-

4.3 Uncertainty

The findings of the literature review suggest that the TCEQ equipment/process-level wellsite input factors are the most complete and comprehensive available for most oil and gas wellsite sources in the Permian Basin while the GHGRP data are available to characterize input factors for a limited number of sources. For pneumatic pumps and fugitive leaks, we recommend that the GHGRP input factors summarized in Table 4-2 be used since these factors were developed based on actual data submitted to EPA by operators in the Permian Basin for the calendar year 2014 whereas the TCEQ data for these source categories is based on older data collected as part of Bar-Ilan et al. (2008). While limited GHGRP data is also available for pneumatic devices and compressor engines, due to the lack of pneumatic device data by well type and the lack of engine characteristics for compressor engines, we recommend that TCEQ data be used. We suggest that in the absence of New Mexico specific or complete GHGRP data, the TCEQ wellsite input factors, summarized in Table 4-4 be used to develop a New Mexico Permian Basin emission inventory for all wellsite sources except pneumatic pumps and fugitive leaks. The gas composition analysis for the Permian Basin would be obtained from the EPA Oil and Gas Tool V.2¹⁴ since TCEQ does not have information on Permian Basin natural gas composition.

We note that there is uncertainty in the input factors data for the following source categories:

- **Compressor engines:** Compressor engine emissions estimation methodology used in the TCEQ inventory for the Permian Basin does not explicitly provide compressor engine prevalence at wellsites. Typically, estimates of compressor engine prevalence and representative compressor engine activity are used to estimate compressor engine emissions. The GHGRP provides engine frequency but does not have information on engine characteristics and activity data.
- **Fugitive devices:** GHGRP data is not available at the well type level of detail, therefore the same fugitive device profile would be applied across all wells. TCEQ data is based on Bar-Ilan et al. (2008) which is dated and was not based on a robust sample of operator provided data for the Permian Basin.
- **Pneumatic pumps:** GHGRP data is not available to characterize Permian Basin pneumatic pump characteristics and activity; only pump count is available. TCEQ inventory data is based on the 2011 NEI Oil and Gas Tool which is based on Bar-Ilan et al. (2008). Bar-Ilan et al. (2008) is dated and was not based on a robust sample of operator provided data for the Permian Basin.

- **Artificial lift engines:** TCEQ inventory emissions were estimated as described in ERG (2010) based on Texas-wide assumptions rather than a survey of operators in the Permian Basin.
- **Well completion venting, blowdowns:** TCEQ inventory estimates are based on the 2011 NEI Oil and Gas Tool input factors which are based on Bar-Ilan et al. (2008). Bar-Ilan et al. (2008) is a dated study and was not based on a robust sample of operator provided data for the Permian Basin.
- **Dehydrators:** TCEQ inventory estimates are based on assumptions derived from point sources which are not specific to the Permian Basin and are not likely to have been located at wellsites.

The effects on emissions of the EPA New Source Performance Standard (NSPS) Subpart OOOO need to be accounted for in the emission inventories to be developed in the next phase of this work. NSPS Subpart OOOO requires controls on tanks emitting more than six tons of VOC per year that were new or modified after August 23, 2011 and the implementation of green completion technology for hydraulically fractured natural gas wells drilled after Aug. 23, 2011. EPA NSPS Subpart OOOO also requires the use of low-bleed pneumatic devices (i.e. pneumatic devices that are rated at 6 standard cubic-feet of gas per hour (scf/hr) or lower) from August 23, 2011 at new or modified wells. ERG (2014) has provided recommendations for incorporating the effects of the Subpart OOOO requirements into the inventory; a similar methodology should be applied to estimate the effects of controls in the next phase of this study when the New Mexico Permian Basin emission inventories are compiled.

In 2008, EPA published NSPS Subpart JJJJ that applies to new, modified and reconstructed stationary spark ignition (SI) internal combustion engines (ICE). NSPS Subpart JJJJ applies to stationary SI engines combusting any fuel (natural gas, gasoline, liquefied petroleum gas (LPG), compressed natural gas, landfill gas, digester gas, and any other applicable fuel). The NSPS Subpart JJJJ emission standards vary by horsepower range and by fuel type and apply to natural gas-fueled artificial lift and compressor engines. The data available in ERG (2010) indicated emission rates above NSPS standards for existing artificial lift engines and hence the NSPS JJJJ standards should be considered in the inventories to be developed during the next phase of this work. The TCEQ data for the compressor engines indicates that some compressor engines emission factors are lower than the NSPS JJJJ requirement and no additional control is required for those engines. For compressor engines with emission rates above the NSPS JJJJ threshold, control should be accounted for in the base year and future year emission inventory for the Permian Basin.

5.0 RECOMMENDATIONS

In the next phase of inventory development, the emission inventory inputs developed as described in this report will be used to prepare a comprehensive by county and SCC emission inventory for the Greater San Juan and Permian basins for a base year 2014 and forecasted to a future year. The inventories will be developed using the inventory input data described in this report for a 2014 baseline year and a midterm projected year.

In the next phase of this work, Permian Basin emission controls relative to NSPS OOOO and NSPS JJJJ requirements should be reviewed carefully so that to the extent possible, emissions control accurately reflect the implementation of such requirements for the 2014 base year and future year emission inventory. Oil and gas forecasts to develop future year emissions inventories for the Greater San Juan and Permian basins should also be carefully considered to capture, to the extent possible, the dynamic nature of oil and gas activity which is continually responding to both commodity prices and oil and gas exploration and production costs.

The accuracy of the emission inventory inputs developed in this study may be improved as follows:

- EPA could make all underlying data in GHGRP Subpart W reporting available (aggregate across companies by area in the case of confidentiality considerations) so that more source category inputs could be sourced from GHGRP Subpart W data;
- The accuracy of the inputs (produced gas compositions, tank flashing gas compositions, and equipment profiles and operations) could be enhanced with additional operator participation in the wellsite survey efforts.
- Operator participation in the Permian Basin to provide review of the wellsite input factors.
- It is expected that some compressor stations are missing from the current midstream permit data emissions because either these facilities do not meet state or federal reporting criteria or emissions estimates were not readily available from the state or federal agency. The inclusion of those sources through additional outreach and survey efforts would enhance inventory completeness.
- Input factors for potential fugitive emissions from oil and gas pipelines from well heads to the main compressor stations were not estimated. The collection of data on the extent of these pipelines so that fugitive emissions from them could be estimated would enhance inventory completeness.
- Per stakeholder input, survey data was not collected for certain wellsite source categories (amine units, truck loading at gas and NGL processing plants, and water disposal pits) because data was not expected to be available. The inclusion of these categories would enhance inventory completeness.

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APPENDIX A

Greater San Juan Basin Wellsite Emission Inventory Input Factors

Appendix A. Greater San Juan Basin Wellsite Emission Inventory Input Factors

Table A1. Greater San Juan Basin Input Factors.

Wellsite Emission Inventory Input Parameter			Units	Input Factor		
				Oil Wells	Gas Wells	CBM Wells
Artificial Lift Engines						
Percent of wells that have an artificial lift engine:			unitless	99%	NA	NA
Rated Horsepower:			hp/well	17		
Load Factor:			unitless	0.4		
Hours of Operation:			hr/year	7,106		
Fuel Type (Natural Gas, Gasoline, Diesel, Electric):			unitless	Natural Gas		
Natural Gas Engines: Percent that are Lean Burn:			unitless	0%		
Natural Gas Engines: Percent that are Rich Burn:			unitless	100%		
Percent of Artificial Lift Engines that are Electric:			unitless	0%		
Emission Factors	NOx		g/bhp-hr	8.3		
	CO		g/bhp-hr	12.7		
	VOC		g/bhp-hr	0.1		
	PM10		g/bhp-hr	0.1		
	SOx		g/bhp-hr	0.0		
Casinghead Flaring and Venting						
Percent of Casinghead Gas To Pipeline			unitless	99.9%	NA	NA
Percent of Casinghead Gas Flared			unitless	0.0%		
Percent of Casinghead Gas Vented to Atmosphere			unitless	0.1%		
Heating Value			Btu/SCF	1,390		
Condensate Tank						
Combined Flashing, Working and Breathing VOC Emission Factor			lb VOC/bbl	NA	4.85	NA
Fraction of Production Controlled			unitless		0.0%	
Flare Control Efficiency			unitless		98.0%	
Flaring Emission Factors	NOx		lb/MMBtu		0.07	
	CO		lb/MMBtu		0.37	
Dehydrator Venting and Flaring						
No. of Dehydrators			no. per well	0.01	0.01	0.01
Dehydrator Uncontrolled VOC Emissions			lb/MMscf	21.6	21.6	21.6
Percent of Dehydrators that are Uncontrolled			unitless	100%	100%	100%

Wellsite Emission Inventory Input Parameter			Input Factor		
			Oil Wells	Gas Wells	CBM Wells
Percent of Dehydrators that are Controlled by Flare			0%	0%	0%
Percent of Dehydrators Controlled by Routing to System			0%	0%	0%
Flaring Control Efficiency			NA	NA	NA
Heating Value of Gas			1,020	1,020	1,020
Flaring Emission Factors	NOx	lb/MMBtu	NA	NA	NA
	CO	lb/MMBtu	NA	NA	NA
Drill Rigs					
Number of Engines		no. of engines	2.1	2.7	2.0
Rated Horsepower		hp/engine	540	575	537
Load Factor		unitless	0.63	0.63	0.63
Hours of Operation		hours/spud	214	226	213
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)			Diesel	Diesel	Diesel
Emission Factors	NOx	g/bhp-hr	4.61	4.61	4.61
	CO	g/bhp-hr	1.24	1.24	1.24
	VOC	g/bhp-hr	0.38	0.38	0.38
	SOx	g/bhp-hr	0.01	0.01	0.01
	PM10	g/bhp-hr	0.24	0.24	0.24
Fracing Engines					
Percent of spuds where fracing was performed		unitless	100%	100%	100%
Number of Engines		no. of engines	3.7	5.7	3.5
Rated Horsepower		hp/engine	1,233	942	1,258
Load Factor		unitless	0.6	0.6	0.6
Hours of Operation		hours/spud	9.7	21.8	8.6
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)			Diesel	Diesel	Diesel
Emission Factors	NOx	g/bhp-hr	6.1	6.1	6.1
	CO	g/bhp-hr	1.7	1.7	1.7
	VOC	g/bhp-hr	0.5	0.5	0.5
	SOx	g/bhp-hr	0.0	0.0	0.0
	PM10	g/bhp-hr	0.3	0.3	0.3
Fugitive Components					
hours of operation		per year	8760	8760	8760
No. of devices per well	Onshore, gas service - valve	count/well	47	81	80
	Onshore, gas service - connector	count/well	147	264	256

Wellsite Emission Inventory Input Parameter		Units	Input Factor		
			Oil Wells	Gas Wells	CBM Wells
	Onshore, gas service - open-ended line	count/well	6	10	9
	Onshore, gas service - pressure relief valve	count/well	2	4	4
	Onshore, gas service - Other	count/well	0	0	0
	Onshore, light crude service - valve	count/well	5	0	0
	Onshore, light crude service - flange	count/well	10	0	1
	Onshore, light crude service - connector	count/well	6	0	1
	Onshore, light crude service - open-ended line	count/well	0	0	0
	Onshore, light crude service - pump	count/well	0	0	0
	Onshore, light crude service - other	count/well	0	0	0
	Onshore, heavy crude service - valve	count/well	0	0	0
	Onshore, heavy crude service - flange	count/well	0	0	0
	Onshore, heavy crude service - connector	count/well	0	0	0
	Onshore, heavy crude service - open-ended line	count/well	0	0	0
	Onshore, heavy crude service - other	count/well	0	0	0
	Onshore, water service - valve	count/well	1	0	0
	Onshore, water service - connector	count/well	0	0	0
	Onshore, water service - open-ended line	count/well	0	0	0
	Onshore, water service - pressure relief valve	count/well	0	0	0
	Onshore, water service - Other	count/well	12	0	0
Heaters					
Number of Heaters per well		no. of heaters/well	1.0	1.0	1.0
Heater MMBtu Rating		MMBtu/hr	0.3	0.3	0.3
Annual Heater Usage		hrs	2,763	2763	2763
Heater Cycling (fraction of the time the heater is doing work when it is turned on)		unitless	0.9	0.9	0.9
Heating Value		Btu/SCF	1,060	1,060	1,060
Emission Factors	NOx	lb/MMscf	100.0	100.0	100.0
	VOC	lb/MMscf	5.5	5.5	5.5
	CO	lb/MMscf	84.0	84.0	84.0
	SOx	lb/MMscf	0.0	0.0	0.0
	PM	lb/MMscf	7.6	7.6	7.6
Oil Tank Venting and Flaring					
Percentage of Tanks that are Uncontrolled		unitless	100%	NA	NA
Percent of Tanks that are Controlled by Flare		unitless	0%		

Wellsite Emission Inventory Input Parameter		Units	Input Factor		
			Oil Wells	Gas Wells	CBM Wells
Percent of Tanks that are Controlled by VRU		unitless	0%		
Percent of Tanks that are Controlled by Enclosed Combustion Devices		unitless	0%		
Flaring Control Efficiency		unitless	98%		
Uncontrolled Combined Flashing, Working and Breathing VOC Emission Factor		lb VOC/bbl	4.8		
Flaring Emission Factors	NOx	lb/MMBtu	0.1		
	CO	lb/MMBtu	0.4		
Pneumatic Controllers					
Number of Devices per Well	High Bleed Devices		0.1	0.2	0.05
	Intermittent Devices		1.1	2.7	2.2
	Low Bleed Device		1.4	2.5	0.1
Device Rate	High Bleed Devices	scf/hr	37.3	37.3	37.3
	Intermittent Devices		13.5	13.5	13.5
	Low Bleed Device		1.4	1.4	1.4
Annual Hours of Operation		hrs/yr	8,760	8,760	8,760
Pneumatic Pumps					
Number of Pumps per Well			0.02	1.4	NA
Annual Hours of Operation:		hr/year	8,760	8,760	
Population Emission Factors		scf/hr/pump	13.3	13.3	
Refracing Engines					
Refracing Frequency			0.05	0.05	NA
Number of Engines		no. of engines	4.5	4.3	
Total Rated Horsepower		hp/engine	1,521	1,514	
Load Factor		unitless	1.0	1.0	
Hours of Operation		hours/refrac	2.9	2.9	
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)			Diesel	Diesel	
Emission Factors	NOx	g/bhp-hr	6.1	6.1	
	CO	g/bhp-hr	1.7	1.7	
	VOC	g/bhp-hr	0.5	0.5	
	SOx	g/bhp-hr	0.0	0.0	
	PM10	g/bhp-hr	0.3	0.3	
Workover Rigs					
Workover Frequency		unitless	0.1	0.1	0.1
Total Rated Horsepower (hp)		hp/workover	666	656	459

Wellsite Emission Inventory Input Parameter		Units	Input Factor		
			Oil Wells	Gas Wells	CBM Wells
Load Factor		unitless	0.4	0.4	0.4
Hours of Operation		hours/year	46.0	47.4	18.6
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)			Diesel	Diesel	Diesel
Emission Factors	NOx	g/bhp-hr	4.8	4.8	4.8
	CO	g/bhp-hr	1.6	1.6	1.6
	VOC	g/bhp-hr	0.3	0.3	0.3
	SOx	g/bhp-hr	0.0	0.0	0.0
	PM10	g/bhp-hr	0.2	0.2	0.2
Wellsite Truck Loading					
Fraction of Total Oil Production Sent Directly to Pipeline, Not Subject to Wellsite Loading		unitless	0%	0%	NA
True vapor pressure of liquid loaded		psi	3.4	5.2	
Temperature of Liquid Loaded		°R	540	540	
Molecular Weight of Liquid Loaded (lb/lb-mole)		lb/lb-mole	50	50	
Fraction of Tanks Mode of operation: Submerged Loading of a Clean cargo tank		unitless	0%	0%	
Fraction Of Tanks Mode of operation: submerged loading: dedicated vapor balance service		unitless	1%	4%	
Fraction of Tanks Mode of operation: submerged loading: dedicated normal service		unitless	99%	96%	
Saturation Factor for Submerged Loading of a Clean cargo tank		unitless	0%	0%	
Saturation Factor for submerged loading: dedicated vapor balance service		unitless	0.6	0.6	
Saturation Factor for submerged loading: submerged loading: dedicated normal service		unitless	1.0	1.0	
Water Tank Venting and Flaring					
Directly to a Wellsite Tank		unitless	100%	100%	100%
Directly to Pipeline to Injection Well		unitless	0%	0%	0%
Directly to Pipeline to Water Disposal Pit		unitless	0%	0%	0%
Other (please specify)		unitless	0%	0%	0%
Percent of Tanks that are Uncontrolled		unitless	100%	100%	100%
Percent of Tanks that are Controlled by Flare		unitless	0%	0%	0%
Percent of Tanks that are Controlled by VRU		unitless	0%	0%	0%
Percent of Tanks that are Controlled by Enclosed Combustion Devices		unitless	0%	0%	0%
Flaring Control Efficiency		unitless	NA	NA	NA
VRU Control Efficiency		unitless	NA	NA	NA

Wellsite Emission Inventory Input Parameter		Units	Input Factor		
			Oil Wells	Gas Wells	CBM Wells
Uncontrolled VOC Emission Factor		lb/bbl	0.01	0.01	0.01
Liquid Unloading					
Percentage of Wells Vented for Liquid Unloading			1%	45%	9%
Fraction of Liquid Unloading controlled		%	0%	0%	0%
Average Natural Gas Volume per Event		MCF/event	59	3,209	617
Number of Unloading Vented to the Atmosphere per well		no. of events per well	1.0	31.9	2.1
Initial Completion Venting and Flaring					
Flaring Control Efficiency		unitless	85%	85%	NA
Number of Completion Events per Spud			0.5	0.9	1.0
Volume of Gas Vented to Atmosphere per Event (MCF/event)			1,877	626	598
Volume of Gas Sent to Flare per Event (MCF/event)			9,112	3,243	2,278
Volume of Gas Sent to Closed-loop System per Event (MCF/event)			0.0	0.0	0.0
Flaring Emission Factors	NOx	lb/MMBtu	0.1	0.1	NA
	CO	lb/MMBtu	0.4	0.4	NA
Lateral Compressor Engines					
Number of Wells per Typical Lateral Compressor Engine			NA	111	111
Rated Horsepower		hp		444	670
Load Factor		unitless		0.7	0.7
Hours of Operation		hours/engine/year		7,776	7,828
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)				Natural Gas	Natural Gas
Natural Gas Engines: Percent that are Lean Burn		unitless		48%	57%
Natural Gas Engines: Percent that are Rich Burn		unitless		52%	43%
Percent of Engines with Control				29%	33%
Type of Engine Emission Control (if applicable)				NSCR	NSCR/OC
Emission Factors	NOx	g/bhp-hr		5.4	5.0
	CO	g/bhp-hr		7.1	6.5
	VOC	g/bhp-hr		0.3	0.3
	PM10	g/bhp-hr	0.1	0.1	
	SOx	g/bhp-hr	0.0	0.0	
Water Pump Engines					
Number of Water Pump Engines Per well		no. per well	0.06	0.06	1.00
Percentage of Wells that have Electric Water Pump Engines			0%	4%	5%

Wellsite Emission Inventory Input Parameter		Units	Input Factor		
			Oil Wells	Gas Wells	CBM Wells
Total Rated Horsepower (hp)		hp/well	136	142	34
Load Factor		unitless	0.4	0.5	0.5
Hours of Operation		hours/year	2,810	2,920	8,760
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)			Natural Gas	Natural Gas	Natural Gas
Emission Factors	NOx	g/bhp-hr	1.0	1.0	1.0
	CO	g/bhp-hr	1.9	2.0	2.0
	VOC	g/bhp-hr	0.7	0.7	0.7
	SOx	g/bhp-hr	0.0	0.0	0.0
	PM10	g/bhp-hr	0.0	0.0	0.0
Wellhead Compressor Engines					
Percentage of wells that have a wellhead compressor engine		%	NA	94%	94%
Rated Horsepower		hp		110	109
Load Factor		unitless		0.75	0.75
Hours of Operation		hours/engine/year		8,262	8,288
Fuel Type (Natural Gas, Gasoline, Diesel, Electric)				Natural Gas	Natural Gas
Natural Gas Engines: Percent that are Lean Burn		unitless		10%	9%
Natural Gas Engines: Percent that are Rich Burn		unitless		90%	91%
Percent of Engines with Control				0	0
Type of Engine Emission Control (if applicable)				NSCR	NSCR
Emission Factors	NOx	g/bhp-hr		7.4	7.1
	CO	g/bhp-hr		11.2	10.8
	VOC	g/bhp-hr		0.1	0.1
	PM10	g/bhp-hr		0.1	0.1
	SOx	g/bhp-hr		0.0	0.0

DEPARTMENT OF PUBLIC HEALTH AND ENVIRONMENT

Air Quality Control Commission

REGULATION NUMBER 7

**CONTROL OF OZONE VIA OZONE PRECURSORS AND CONTROL OF HYDROCARBONS VIA OIL
AND GAS EMISSIONS
(EMISSIONS OF VOLATILE ORGANIC COMPOUNDS AND NITROGEN OXIDES)**

5 CCR 1001-9

[Editor's Notes follow the text of the rules at the end of this CCR Document.]

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IV.	Control of Emissions from Breweries in the 8-hour Ozone Control Area
PART F	Statements of Basis, Specific Statutory Authority and Purpose

Pursuant to Colorado Revised Statutes Section 24-4-103 (12.5), materials incorporated by reference are available for public inspection during normal business hours, or copies may be obtained at a reasonable cost from the Air Quality Control Commission (the Commission), 4300 Cherry Creek Drive South, Denver, Colorado 80246-1530. The material incorporated by reference is also available through the United States Government Printing Office, online at www.govinfo.gov. Materials incorporated by reference are those editions in existence as of the date indicated and do not include any later amendments.

PART D Oil and Natural Gas Operations

I. Volatile Organic Compound Emissions from Oil and Gas Operations

I.A. Applicability

I.A.1. Except as provided in Section I.A.2., this section applies to oil and gas operations that collect, store, or handle hydrocarbon liquids or produced water in the 8-hour Ozone Control Area (State Only: or any ozone nonattainment or attainment/maintenance area) and that are located at or upstream of a natural gas plant.

I.A.2. Oil refineries are not subject to Section I.

I.B. Definitions specific to Section I.

I.B.1. “Affected Operations” means oil and gas exploration and production operations, natural gas compressor stations and natural gas drip stations, to which Section I. applies.

I.B.2. “Air Pollution Control Equipment”, as used in Section I., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment, pollution prevention devices, and processes that comply with the requirements of Section I.D.4. that are approved by the Division.

I.B.3. “Approved Instrument Monitoring Method” means an infra-red camera, EPA Method 21, or other instrument based monitoring method or program approved in accordance with Section I.L.8. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection, recordkeeping, and reporting program for such operations.

I.B.4. “Atmospheric Storage Tanks or Atmospheric Condensate Storage Tanks” means a type of condensate storage tank that vents, or is designed to vent, to the atmosphere.

I.B.5. “Auto-Igniter” means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust volatile organic compound emissions.

I.B.6. “Calendar Week” means a week beginning with Sunday and ending with Saturday.

I.B.7. “Commencement of operation” means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

I.B.8. “Condensate Storage Tank” means any tank or series of tanks that store condensate and are either manifolded together or are located at the same well pad.

I.B.9. “Centrifugal Compressor” means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.

I.B.10. “Component” means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that

- I.L.8.a.(ii)(I) Documentation (e.g., field or test data, modeling) adequate to demonstrate the proposed alternative approved instrument monitoring method or program is capable of achieving emission reductions that are at least as effective as the emission reductions achieved by the leak detection and repair provisions in Section I.L.
- I.L.8.a.(iii) The Division will transmit a copy of the complete application and any other materials provided by the applicant to EPA.
- I.L.8.a.(iv) Public notice of the application is provided pursuant to Regulation Number 3, Part B, Section III.C.4.
- I.L.8.a.(v) The Division and the EPA approves the proposal. The Division will transmit a copy of the application and any other materials provided by the applicant, all public comments, all Division responses and the Division's approval to EPA Region 8. If EPA fails to approve or disapprove the proposal within six (6) months of receipt of these materials, EPA will be deemed to have approved the proposal.

II. (State Only) Statewide Controls for Oil and Gas Operations

II.A. (State Only) Definitions

- II.A.1. "Air Pollution Control Equipment," as used in this Section II., means a combustion device or vapor recovery unit. Air pollution control equipment also means alternative emissions control equipment and pollution prevention devices and processes intended to reduce uncontrolled actual emissions that comply with the requirements of Section II.B.2.e.
- II.A.2. "Approved Instrument Monitoring Method," means an infra-red camera, EPA Method 21, or other Division approved instrument based monitoring method or program. If an owner or operator elects to use Division approved continuous emission monitoring, the Division may approve a streamlined inspection and reporting program for such operations.
- II.A.3. "Auto-Igniter" means a device which will automatically attempt to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions.
- II.A.4. "Centrifugal Compressor" means any machine used for raising the pressure of natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors.
- II.A.5. "Class II Disposal Well Facility" means a facility that injects underground fluids which are brought to the surface in connection with natural gas storage operations or oil or natural gas production and that may be commingled with waste waters from gas plants which are an integral part of production operations, unless those waters are classified as a hazardous waste at the time of injection. Class II disposal well facilities do not include wells which inject fluids for enhanced recovery of oil or natural gas or for storage of hydrocarbons which are liquid at standard temperature and pressure.

- II.A.6. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).
- II.A.7. "Component" means each pump seal, flange, pressure relief device (including thief hatches or other openings on a controlled storage tank), connector, and valve that contains or contacts a process stream with hydrocarbons, except for components in process streams consisting of glycol, amine, produced water, or methanol.
- II.A.8. "Connector" means flanged, screwed, or other joined fittings used to connect two pipes or a pipe and a piece of process equipment or that close an opening in a pipe that could be connected to another pipe. Joined fittings welded completely around the circumference of the interface are not considered connectors.
- II.A.9. "Dump Valve" means a liquid-control valve in a separator that controls liquid level within the separator vessel.
- II.A.10. "Dump Event" means the opening of a dump valve allowing liquid to flow from a separator equipped with a dump valve to a storage tank.
- II.A.11. "Glycol Natural Gas Dehydrator" means any device in which a liquid glycol (including ethylene glycol, diethylene glycol, or triethylene glycol) absorbent directly contacts a natural gas stream and absorbs water.
- II.A.12. "Infra-red Camera" means an optical gas imaging instrument designed for and capable of detecting hydrocarbons.
- II.A.13. "Hydrocarbon Liquid" means any naturally occurring, unrefined petroleum liquid. Hydrocarbon liquid does not include produced water.
- II.A.14. "Natural Gas Compressor Station" means a facility, located downstream of well production facilities, which contains one or more compressors designed to compress natural gas from well pressure to gathering system pressure prior to the inlet of a natural gas processing plant.
- II.A.15. "Normal Operation" means all periods of operation, excluding malfunctions as defined in Section I.G. of the Common Provisions regulation. For storage tanks at well production facilities, normal operation includes but is not limited to liquid dumps from the separator.
- II.A.16. "Occupied Areas" means (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes; (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities; (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

II.E.3.a. Approved instrument monitoring method inspections must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.

II.E.3.a.(i) Annual approved instrument monitoring method inspections at natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must begin within ninety (90) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015. Annual inspections must be conducted through calendar year 2019.

II.E.3.a.(ii) Beginning calendar year 2020, owners or operators of natural gas compressor stations with fugitive VOC emissions greater than zero (0) but less than or equal to twelve (12) tons per year, based on a rolling twelve-month total, must conduct semi-annual approved instrument monitoring method inspections.

II.E.3.b. Approved instrument monitoring method inspections must begin within thirty (30) days after January 1, 2015, or the date the natural gas compressor station commences operation if such date is after January 1, 2015, for natural gas compressor stations with fugitive VOC emissions greater than fifty (50) tons per year.

II.E.3.c. Following the first approved instrument monitoring method inspection, owners or operators must continue conducting approved instrument monitoring method inspections in accordance with the Inspection Frequency in Table 2.

II.E.3.d. For purposes of Section II.E.3., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.

Table 2 – Natural Gas Compressor Station Component Inspections	
Fugitive VOC Emissions (rolling twelve-month tpy)	Inspection Frequency
> 0 and ≤ 12	Semi-annually
> 12 and ≤ 50	Quarterly
> 50	Monthly

II.E.4. Requirements for well production facilities

- II.E.4.a. Owners or operators of well production facilities constructed on or after October 15, 2014, must identify leaks from components using an approved instrument monitoring method no sooner than fifteen (15) days and no later than thirty (30) days after the facility commences operation. This initial test constitutes the first, or only for facilities subject to a one time approved instrument monitoring method inspection, of the periodic approved instrument monitoring method inspections. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the Inspection Frequencies in Table 3.
- II.E.4.b. Owners or operators of well production facilities constructed before October 15, 2014, must identify leaks from components using an approved instrument monitoring method within ninety (90) days of the Phase-In Schedule in Table 3; within thirty (30) days for well production facilities subject to monthly approved instrument monitoring method inspections; or by January 1, 2016, for well production facilities subject to a one time approved instrument monitoring method inspection. Thereafter, approved instrument monitoring method and AVO inspections must be conducted in accordance with the inspection frequencies in Table 3.
- II.E.4.c. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) but less than or equal to twelve (12) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, must inspect components for leaks using an approved instrument monitoring method at least semi-annually.
- II.E.4.d. Beginning calendar year 2020, owners or operators of well production facilities with estimated uncontrolled actual VOC emissions greater than or equal to two (2) tons per year as calculated in accordance with Section II.E.4.e., based on a rolling twelve-month total, and located within 1,000 feet of an occupied area must inspect components for leaks using an approved instrument monitoring method in accordance with the inspection frequency in Table 3.
- II.E.4.e. The estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).

Table 3 – Well Production Facility Component Inspections				
Thresholds (per II.E.4.d.)				
Well production facilities without storage tanks (rolling twelve-month tpy)	Well production facilities with storage tanks (rolling twelve-month tpy)	Approved Instrument Monitoring Method Inspection Frequency	AVO Inspection Frequency	Phase-In Schedule
> 0 and < 2	> 0 and < 2	One time	Monthly	January 1, 2016
≥ 2 and ≤ 12	≥ 2 and ≤ 12	Semi-annually	Monthly	* begins in 2020
> 2 and < 12, located within 1,000 feet of an occupied area	> 2 and < 12, located within 1,000 feet of an occupied area	Quarterly	Monthly	* begins in 2020
> 12 and ≤ 20	> 12 and ≤ 50	Quarterly	Monthly	January 1, 2015
> 12, located within 1,000 feet of an occupied area	> 12, located within 1,000 feet of an occupied area	Monthly		* begins in 2020
> 20	> 50	Monthly		January 1, 2015

II.E.5. If a component is unsafe, difficult, or inaccessible to monitor, the owner or operator is not required to monitor the component until it becomes feasible to do so.

II.E.5.a. Difficult to monitor components are those that cannot be monitored without elevating the monitoring personnel more than two (2) meters above a supported surface or are unable to be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to 7.6 meters (25 feet) above the ground.

II.E.5.b. Unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring.

II.E.5.c. Inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

II.E.6. Leaks requiring repair: Leaks must be identified utilizing the methods listed in Section II.E.6. Only leaks from components exceeding the thresholds in Section II.E.6. require repair under Section II.E.7.

- II.G.3.a.(iii) The date, time, and duration of the downhole well maintenance, well liquids unloading, or well plugging event.
- II.G.3.a.(iv) The best management practices used to minimize emissions.
- II.G.3.a.(v) Safety needs that prevented the use of best management practices to minimize emissions, if applicable.
- II.G.3.a.(vi) An estimate of the volume of natural gas, VOC, NOx, N2), CO2, CO, ethane, and methane emitted from the well associated with well liquid unloading activities, downhole well maintenance, and well plugging event and the emission factor or calculation methodology used to determine the volume of natural gas and emissions.

III. Natural Gas-Actuated Pneumatic Controllers Associated with Oil and Gas Operations

III.A. Applicability

This section applies to pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).

III.B. Definitions

- III.B.1. "Affected Operations" means pneumatic controllers that are actuated by natural gas, and located at, or upstream of natural gas processing plants (upstream activities include: oil and gas exploration and production operations and natural gas compressor stations).
- III.B.2. "Continuous Bleed" means a continuous bleed rate of natural gas from a pneumatic controller that is designed to bleed natural gas continuously.
- III.B.3. "Custody Transfer" means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
- III.B.4. (State Only) "Enhanced Response" means to return a pneumatic controller to proper operation and includes but is not limited to, cleaning, adjusting, and repairing leaking gaskets, and seals; tuning to operate over a broader range of proportional band; and eliminating unnecessary valve positioners.
- III.B.5. "High-Bleed Pneumatic Controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.
- III.B.6. (State Only) "Intermittent pneumatic controller" means a pneumatic controller that is not designed to have a continuous bleed rate, but is designed to only release natural gas to the atmosphere as part of the actuation cycle.
- III.B.7. "Low-Bleed Pneumatic controller" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.

- III.E.2.c. Records of maintenance of pneumatic controllers shall be maintained for a minimum of three years and readily made available to the Division upon request.

III.F. (State Only) Pneumatic Controller Inspection and Enhanced Response

III.F.1. General Requirements

- III.F.1.a. Beginning January 1, 2018, owners or operators of natural gas-driven pneumatic controllers in the 8-Hour Ozone Control Area must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.
- III.F.1.b. Beginning May 1, 2020, owners or operators of natural gas-driven pneumatic controllers state-wide must operate and maintain pneumatic controllers consistent with manufacturer's specifications, if available, or good engineering and maintenance practices.

III.F.2. Pneumatic controller inspection

- III.F.2.a. Beginning June 30, 2018, through calendar year 2019, owners or operators of natural gas-driven pneumatic controllers at well production facilities in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least
 - III.F.2.a.(i) Annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than or equal to six (6) tons per year, based on a rolling twelve-month total.
 - III.F.2.a.(ii) Semi-annually at well production facilities with uncontrolled actual volatile organic compound emissions greater than six (6) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.
 - III.F.2.a.(iii) Quarterly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
 - III.F.2.a.(iv) Monthly at well production facilities with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
- III.F.2.b. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at well production facilities must inspect pneumatic controllers using an approved instrument monitoring method at least:

- III.F.2.b.(i) Annually at well production facilities in the 8-Hour Ozone Control Area with uncontrolled actual volatile organic compound emissions greater than or equal to one (1) ton per year and less than two (2) tons per year, based on a rolling twelve-month total.
- III.F.2.b.(ii) Semi-annually at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than or equal to two (2) tons per year and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.
- III.F.2.b.(iii) Quarterly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twelve (12) tons per year and less than or equal to twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
- III.F.2.b.(iv) Monthly at well production facilities statewide with uncontrolled actual volatile organic compound emissions greater than twenty (20) tons per year, based on a rolling twelve-month total, or fifty (50) tons per year if no storage tanks storing oil or condensate are located at the well production facility, based on a rolling twelve-month total.
- III.F.2.c. For purposes of Sections III.F.2.a. and III.F.2.b., the estimated uncontrolled actual VOC emissions from the highest emitting storage tank at the well production facility determines the frequency at which inspections must be performed. If no storage tanks storing oil or condensate are located at the well production facility, owners or operators must rely on the facility emissions (controlled actual VOC emissions from all permanent equipment, including emissions from components determined by utilizing the emission factors defined as less than 10,000 ppmv of Table 2-8 of the 1995 EPA Protocol for Equipment Leak Emission Estimates).
- III.F.2.d. Beginning June 30, 2018, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations in the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:
 - III.F.2.d.(i) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.
 - III.F.2.d.(ii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.
- III.F.2.e. Beginning calendar year 2020, owners or operators of natural gas-driven pneumatic controllers at natural gas compressor stations outside the 8-Hour Ozone Control Area must inspect pneumatic controllers using an approved instrument monitoring method at least:

- III.F.2.e.(i) Semi-annually at natural gas compressor stations with fugitive volatile organic compound emissions greater than zero (0) and less than or equal to twelve (12) tons per year, based on a rolling twelve-month total.
- III.F.2.e.(ii) Quarterly at natural gas compressor stations with fugitive volatile organic compound emissions greater than twelve (12) and less than or equal to fifty (50) tons per year, based on a rolling twelve-month total.
- III.F.2.e.(iii) Monthly at natural gas compressor stations with fugitive volatile organic compounds greater than fifty (50) tons per year, based on a rolling twelve-month total.
- III.F.2.f. For purposes of Sections III.F.2.d. and III.F.2.e., fugitive emissions must be calculated using the emission factors of Table 2-4 of the 1995 EPA Protocol for Equipment Leak Emission Estimates (Document EPA-453/R-95-017), or other Division approved method.
- III.F.2.g. Where detectable emissions from the pneumatic controller are observed, owners or operators must determine whether the pneumatic controller is operating properly within five (5) working days after detecting emissions. In making this determination, owners or operators may use techniques other than approved instrument monitoring methods.
- III.F.2.h. For pneumatic controllers not operating properly, the owner or operator must conduct enhanced response or follow manufacturer specifications to return the pneumatic controller to proper operation.

III.F.3. Enhanced response and remonitoring

- III.F.3.a. Enhanced response must begin no later than five (5) working days and the pneumatic controller returned to proper operation no later than thirty (30) working days after determining the pneumatic controller is not operating properly, unless parts are unavailable, the equipment requires shutdown to complete enhanced response, or other good cause exists. If parts are unavailable, they must be ordered promptly and enhanced response conducted within fifteen (15) working days of receipt of the parts. If shutdown is required, enhanced response must be conducted during the next scheduled shutdown. If delay is attributable to other good cause, enhanced response must be completed within fifteen (15) working days after the cause of delay ceases to exist.
- III.F.3.b. Within fifteen (15) working days of completion of enhanced response, the owner or operator must verify the pneumatic controller is operating properly. In verifying proper operation, owners or operators may use techniques other than approved instrument monitoring methods.
- III.F.3.c. Pneumatic controllers found emitting detectable emissions are not subject to enforcement by the Division unless the owner or operator fails to determine whether the pneumatic controller is operating properly in accordance with Section III.F.2., perform any necessary enhanced response in accordance with Section III.F.3., keep records in accordance with Section III.F.4., or submit reports in accordance with Section III.F.5.

V.C.2.n.	Maintenance and safety, where not otherwise reported in the emissions of another emissions source category.
V.C.2.o.	Natural gas dehydration (glycol and desiccant).
V.C.2.p.	Natural gas pneumatic controllers, aggregated per facility.
V.C.2.q.	Natural gas pneumatic pumps, aggregated per facility.
V.C.2.r.	Non-road internal combustion engines.
V.C.2.s.	Pipeline segments between facilities.
V.C.2.t.	Process heaters.
V.C.2.u.	Produced water storage tanks.
V.C.2.v.	Produced water loadout.
V.C.2.w.	Reciprocating compressor leaks or vents, aggregated per facility.
V.C.2.x.	Separators (e.g., two-phase separators, three-phase separators, high/low pressure separators, heater-treaters, vapor recovery towers, etc.).
V.C.2.y.	Stationary combustion turbines.
V.C.2.z.	Stationary compression ignition internal combustion engines.
V.C.2.aa.	Stationary spark ignition internal combustion engines.
V.C.2.bb.	Temporary completion and/or workover equipment (e.g., tanks).
V.C.2.cc.	Thermal oxidizing units, where not otherwise reported in the emissions of another emissions source category.
V.C.2.dd.	Well completions (includes flowback).
V.C.2.ee.	Well workovers.
V.C.2.ff.	Wellhead bradenhead.

VI. (State Only) Oil and Natural Gas Pre-Production and Early Production Operations

VI.A. Definitions

VI.A.1. "Commencement of operation" means when a source first conducts the activity that it was designed and permitted for. In addition, for oil and gas well production facilities, commencement of operation is the date any permanent production equipment is in use and product is consistently flowing to sales lines, gathering lines, or storage tanks from the first producing well at the stationary source, but no later than end of well completion operations (including flowback).

- VI.C.2.b.(v) A summary of monitored air quality results, including time series plots as hourly or higher time resolution and a statistical summary including number of observations, maximum concentrations or levels, periodic averages, and date distributions including 5th, 25th, median, 75th and 95 percentile values.
- VI.C.2.b.(vi) A description of responsive action(s) taken as a result of monitoring results, including the date; concentration or level measured; correlations with specific events, activities, and/or monitoring thresholds; and any additional steps taken as a result of the responsive action.
- VI.C.2.b.(vii) The results of any speciated or other samples of chemical constituents identified by the Division and collected when site-specific concentrations indicate such samples are necessary.
- VI.C.2.b.(viii) A summary of meteorological data, including in the time intervals identified for concentration readings in the air quality monitoring plan during the time period of responsive action(s). If meteorological data is collected on-site, the meteorological data assessed in as close to the sampling and/or measurement intervals as possible.
- VI.C.2.b.(ix) A description of how data will be processed, if available from the manufacturer, and summarized for purposes of fulfilling monthly reporting requirements, including whether and how data will be corrected, and how missing data and values that are below detection limits will be treated in statistical summaries.
- VI.C.2.b.(x) In the last monthly report, a certification by the company representative that supervised the development and submission of the monitoring reports that, based on information and belief formed after reasonable inquiry, the statements and information in the monthly reports are true, accurate, and complete.

VI.C.3. Owners or operators must notify the Division and the local government with jurisdiction over the location of the operations, using the contact provided in Section VI.C.1.b.(iv), within forty-eight (48) hours of responsive action(s) taken as a result of recorded values in excess of the response level.

VI.D. Emission reduction from pre-production flowback vessels

VI.D.1. Control

- VI.D.1.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must collect and control emissions from each flowback vessel on and after the date flowback is routed to the flowback vessel by routing emissions to and operating air pollution control equipment that achieves a hydrocarbon control efficiency of at least 95%. If a combustion device is used, it must have a design destruction efficiency of at least 98% for hydrocarbons.

- VI.D.1.a.(i) Owners or operators must use enclosed, vapor-tight flowback vessels.
- VI.D.1.a.(ii) Flowback vessels must be inspected, tested, and refurbished where necessary to ensure the flowback vessel is vapor-tight prior to receiving flowback.
- VI.D.1.a.(iii) Owners or operators must use a tank measurement system to determine the quantity of liquids in the flowback vessel(s).
 - VI.D.1.a.(iii)(A) Thief hatches or other access points to the flowback vessel must remain closed and latched during activities to determine the quantity of liquids in the flowback vessel(s).
 - VI.D.1.a.(iii)(B) Opening the thief hatch or other access point if required to inspect, test, or calibrate the tank measurement system or to add biocides or chemicals is not a violation of Section VI.D.1.a.(ii)(A).
- VI.D.1.a.(iv) Combustion devices used during pre-production operations must be enclosed, have no visible emissions during normal operation, and be designed so that an observer, by means of visual observation from the outside of the enclosed combustion device, or by other means approved by the Division, determine whether it is operating properly.
 - VI.D.1.a.(iv)(A) Combustion devices must be equipped with an operational auto-igniter upon installation of the combustion device.

VI.D.2. Monitoring

- VI.D.2.a. Owners or operators of a well with flowback that begins on or after May 1, 2021, must conduct daily visual inspections of the flowback vessel and any associated equipment.
 - VI.D.2.a.(i) Visual inspection of any thief hatch, pressure relief valve, or other access point to ensure that they are closed and properly seated.
 - VI.D.2.a.(ii) Visual inspection or monitoring of the air pollution control equipment to ensure that it is operating.
 - VI.D.2.a.(iii) Visual inspection of the air pollution control equipment to ensure that the valves for the piping from the flowback vessel to the air pollution control equipment are open.
 - VI.D.2.a.(iv) If a combustion device is used, visual inspection of the auto-igniter and valves for piping of gas to the pilot light to ensure they are functioning properly.

- VI.D.2.a.(v) If a combustion device is used, inspection of the device for the presence or absence of smoke. If smoke is observed, either the equipment must be immediately shut-in to investigate the potential cause for smoke and perform repairs, as necessary, or EPA Method 22 must be conducted to determine whether visible emissions are present for a period of at least one (1) minute in fifteen (15) minutes.

VI.D.3. Recordkeeping

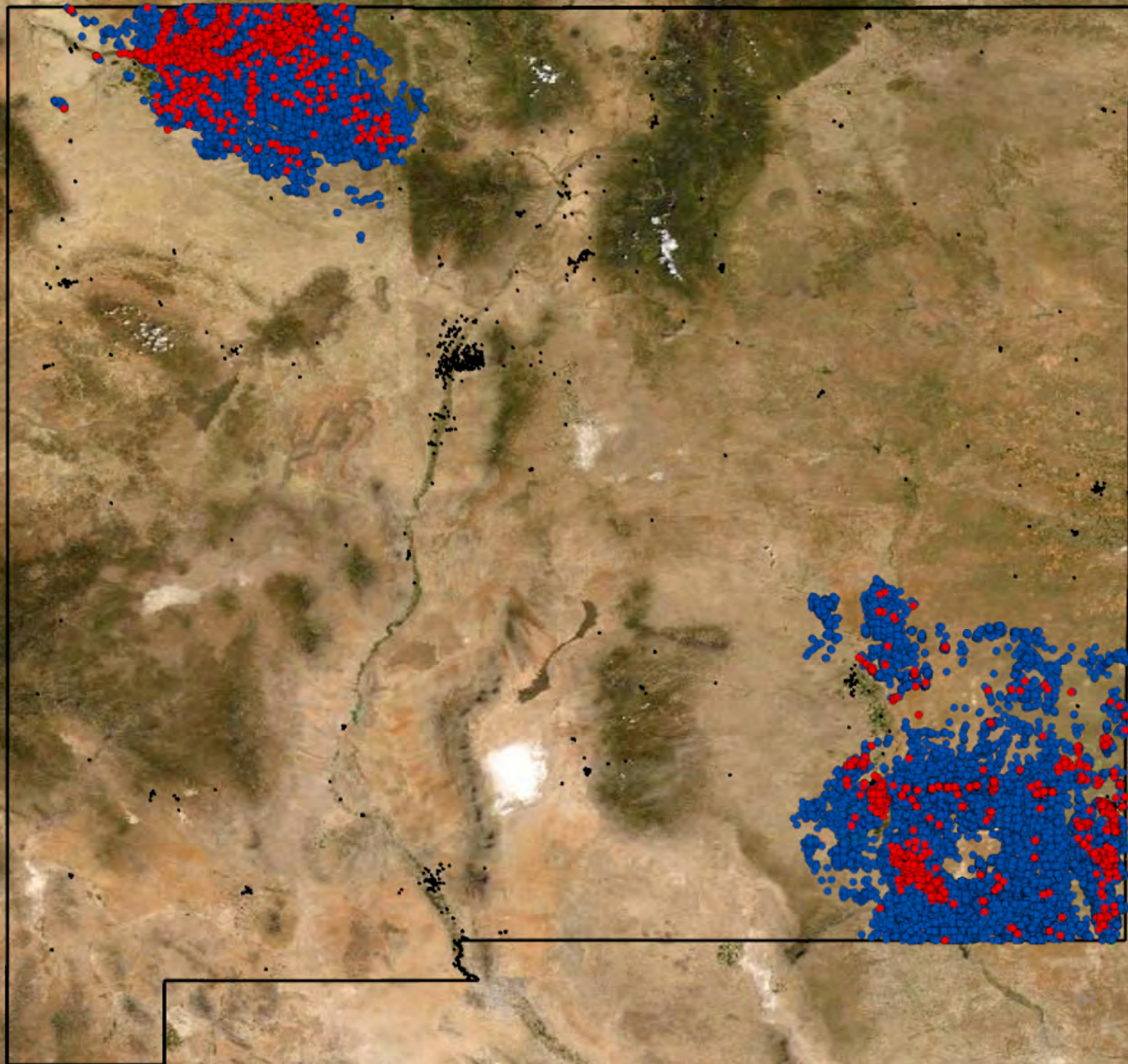
- VI.D.3.a. The owner or operator of each flowback vessel subject to Section VI.D.1. must maintain records for a period of two (2) years and make them available to the Division upon request, including
 - VI.D.3.a.(i) The API number of the well and the associated facility location, including latitude and longitude coordinates.
 - VI.D.3.a.(ii) The date and time of the onset of flowback.
 - VI.D.3.a.(iii) The date and time the flowback vessels were permanently disconnected, if applicable.
 - VI.D.3.a.(iii) The date and duration of any period where the air pollution control equipment is not operating.
 - VI.D.3.a.(iv) Records of the inspections required in Section VI.D.2. including the time and date of each inspection, a description of any problems observed, a description and date of any corrective action(s) taken, and the name of the employee or third party performing corrective action(s).
 - VI.D.3.a.(v) Where a combustion device is used, the date and result of any EPA Method 22 test or investigation pursuant to Section VI.D.2.a.(v).

PART E Combustion Equipment and Major Source RACT

I. Control of Emissions from Engines

I.A. Requirements for new and existing engines.

- I.A.1. The owner or operator of any natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower commencing operations in the 8-hour Ozone Control Area on or after June 1, 2004 shall employ air pollution control technology to control emissions, as provided in Section I.B.
- I.A.2. Any existing natural gas-fired stationary or portable reciprocating internal combustion engine with a manufacturer's design rate greater than 500 horsepower, which existing engine was operating in the 8-hour Ozone Control Area prior to June 1, 2004, shall employ air pollution control technology on and after May 1, 2005, as provided in Section I.B.



Dataset Name	Dataset Description	Keywords (if applicable)	Dataset Source
Multifamily_Properties_Assisted_NM	HUD subsidized Multifamily Housing properties	N/A	HUD
Public_Housing_Buildings_NM	Public Housing	N/A	
Hospitals_NM	Hospitals	N/A	
Hospitals_NursingHomes	Hospitals, Nursing Homes etc.	N/A	UNM RGIS
PublicSchools_NM	Public Schools	N/A	
PublicSchools_K12	Additional K-12 public schools	N/A	UNM RGIS
HigherEducation	Higher Education Facility Locations	N/A	UNM RGIS
parks	Park Locations	N/A	UNM RGIS
golf_courses	Golf Course Locations	N/A	UNM RGIS
Struct_Point	Point data, primarily government resources/related.	academy, college, hospital, Institute, Jail, LifeSupport, medical, Park, Pavilion, picnic, school, shelter, university	
New Mexico Microsoft Computer Building Footprints	NM Building Footprints	N/A	UNM RGIS
gis_osm_buildings_a_free_1	Polygon data including large variety of buildings, shops, gyms, stores, halls, etc. (data most accurate in urban areas, incomplete elsewhere)	Apartments, college, dormitory, hospital, hotel, house, jail, Jail_House, kindergarten, motel, museum, music_school, prison, residential, school, semidetached_house, shelter, sports_centre, stadium, suites, trailer, university, Academy, Sorority, Fraternity, UNM, Student, Detention, Correctional, School, University	Open Street Map

gis_osm_landuse_a_free_1	Polygon data on land use, incomplete	Park, Recreation Ground, Residential	Open Street Map

To: Rosalie Winn, EDF
From: Dana Lowell, MJB&A
Date: December 11, 2018
Re: **Analysis of OOOOa Annual Air Emission Reports**

MJB&A conducted an analysis of Air Emission Reports (AERs) submitted to EPA by oil and gas production companies in compliance with the reporting requirements of the Code of Federal regulations, Part 60, Subpart OOOOa (40 CFR 60, OOOa; New Source Performance Standards, Standards of Performance for Crude Oil and Natural Gas Facilities). Some of these reports were accessed via EPA's WebFIRE website¹, and others – which are not included on the WebFIRE site – were released by EPA in response to Freedom of Information Act (FOIA) requests². The reports analyzed, which are summarized here, are annual reports of fugitive emission sources detected at company-owned natural gas well sites during mandated Leak Detection and Repair (LDAR) surveys. The data includes reports from reporting year 2017 and reporting year 2018.

The data included in these reports indicated that:

- The average time to conduct an LDAR survey is approximately 1.25 – 1.6 hours per well, including travel time between sites. Based on this, EPA's estimate of the cost of semi-annual LDAR at oil and gas sites is likely overstated by 15% - 32%.
- At least one fugitive emission source was detected during 54% of LDAR surveys at well sites. The average number of fugitive emission sources detected was 1.7 per well site, including surveys where none were detected.
- Open thief hatches or other open vents were the most common fugitive emission sources detected during LDAR surveys, comprising 37% of all detected sources. Other major sources of fugitive emissions were leaking flanges/connectors, and leaking valves/regulators.
- All detected fugitive emission sources had been repaired by the end of the reporting period at approximately 90% of sites, with approximately one third of detected fugitive sources corrected on the same day they were detected.

¹ <https://cfpub.epa.gov/webfire/reports/eSearchResults.cfm>; Accessed on July 31, 2018.

² EPA-HQ-2018-001886
<https://www.foiaonline.gov/foiaonline/action/public/submissionDetails?trackingNumber=EPA-HQ-2018-001886&type=request>; Last accessed on October 9, 2018.

Summary of Reports Analyzed

WebFIRE Reports

As of July 31, 2018 there were 162 unique OOOOa AERs included on the WebFIRE site (not including a handful of reports repeated more than once). Of these reports, 70 are related to “Gas Plants”, 23 are related to “Compressor Stations”, 17 are related to “Processing Facilities”, 5 were submitted by “pipeline companies”, and 5 document fugitive emission sources from individual process units at a well site or other facility (i.e. a tank battery or dryer). These reports were not included in the analysis summarized here.

The remaining 42 reports (26% of total reports) each address one or more natural gas well site(s) owned by the reporting companies. The analysis summarized here is based on data in these 42 reports. All 42 reports analyzed were submitted on Excel™ spreadsheet templates provided by EPA; however, some required data elements (per the EPA template) were missing or incomplete on some reports. In addition, the different companies did not use a consistent data format when completing other required data elements.

The site information sections of these 42 reports list 1,496 unique “well sites”. These well sites are located in 15 different states³, but the vast majority (~80%) are in North Dakota and belong to only one company – Oasis Petroleum North America, LLC. Based on the descriptions provided, the majority of the reported well sites appear to be single well pads, but some “sites” identified by various companies do include more than one adjacent well pad⁴.

Not all of the “sites” listed in the site information section of a given report have corresponding data on “fugitive emission sources” at that site; of the 1,496 unique well sites included in the 42 reports analyzed, only 953 sites (64%) have any fugitives data. Of these 953 sites with fugitive data, 56% have data on one LDAR survey, and the rest have data on more than one LDAR survey (i.e. there is data on 2 – 6 separate surveys of the same site conducted on different days).

Altogether there is at least partial data describing the results of 1,597 unique LDAR surveys (unique survey date at unique site). However, the data is not complete for all of these 1,597 unique surveys. Of these, only 988 have leak data (number of leaks detected, by component) and only 358 have data on start and end time of the LDAR survey (to calculate LDAR survey time). In particular, the Oasis Petroleum report does not include LDAR survey start-end time for any of the listed sites.

Of 1,449 unique LDAR surveys for which the survey method was reported, 96.5% used Optical Gas Imaging to detect fugitive emission sources, and 3.5% used a toxic vapor analyzer in conjunction with Method 21.

Of 580 unique LDAR surveys for which repair data was reported, 96.7% reported that all detected fugitive emission sources were repaired, 0.4% reported that less than 60% of detected sources were repaired, and 2.1% reported that less than 10% of detected sources were repaired.

FOIA Reports

As of October 5, 2018, EPA has released eighty-one unique files containing OOOOa AERs in response to FOIA requests. Releases occurred on seven different dates between May 2018 and October 2018. Of the AERs included in the FOIA releases, data for four of the companies can also be found on the WebFIRE site. The remaining unique reports which are included in the FOIA releases, but which are not on the WebFIRE site, were submitted by seventy-one different companies, and cover wells in fifteen different states.

³ The states include: CA, CO, IL, KS, KY, LA, MI, ND, NE, NY, OH, PA, TX, UT, and WY

⁴ Many operators reported the “US Well ID” number(s) associated with each listed “site”. For the most part only one well ID was listed per site.

These reports summarize the results of LDAR surveys at 1,620 unique “sites” identified by the reporting company. At 530 of these sites it is not clear from the site descriptions provided how many wells the site includes, and/or survey start-end times were not noted. The remaining 1,090 “sites” (for which definitive information was provided on the number of wells surveyed, survey start - end time, and leak data) covered a total of 2,844 individual well pads.

Of the fugitive emission sources detected at these 2,844 well pads, the companies reported that 36% were corrected on the same day they were detected, and repairs were “delayed” for 15% of them.

Total Data Set

Including data from the WebFIRE and FOIA reports, the below analysis of LDAR survey times is based on LDAR surveys conducted at 3,202 unique well pads, and the analysis of detected fugitive sources is based on LDAR surveys conducted at 3,832 unique well pads.

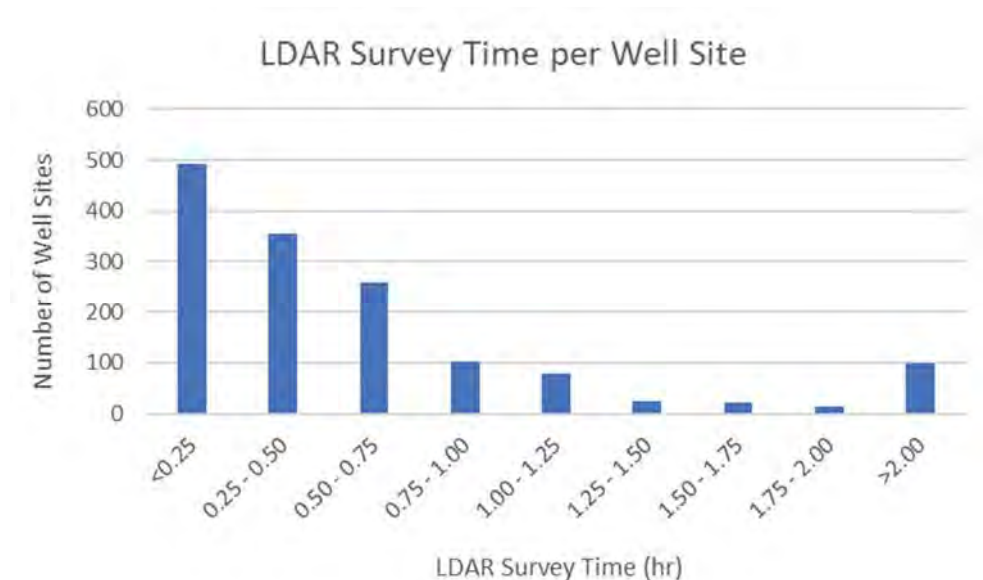
Summary of LDAR Survey Data

LDAR Survey Time per Well Site

See Figure 1 for a distribution of reported LDAR survey times at well sites. For the 1,449 well site LDAR surveys with reported start- and end-time data, 58% took less than 30 minutes to complete the LDAR survey, and 83% took less than one hour. Only seven percent of LDAR surveys took more than 2 hours per well site. The average reported time to conduct the LDAR surveys was 0.72 hours per well site across the entire data set.

Review of survey start and end times for multiple surveys conducted on the same day by the same surveyor indicates that the time between ending a survey at one site and starting a survey at the next site ranged from less than five minutes to more than 2 hours, with an average of 30 minutes. Therefore, for the LDAR surveys included in this data set the average time to conduct them, including travel time between sites, was approximately 1.25 hours per site.

Figure 1 Distribution of LDAR Survey Times at Well sites



While Oasis Petroleum did not report LDAR survey start and end time for their sites, they did report survey date and “Name of Surveyor”. Analysis of this data indicates that two different surveyors together conducted a total of

1,125 LDAR surveys for this company. On average these two surveyors were each able to conduct LDAR surveys at five different sites per day, with a high of 15 sites surveyed in one day. This implies that the average LDAR survey time for this company, including travel time between sites, was 1.3 – 1.6 hours per site, assuming a 6.5- to 8-hour work day (net of breaks). This implied LDAR survey time is consistent with the survey time data reported directly by other companies, as discussed above.

Implied LDAR Costs

In the supporting documentation for their background Technical Support Document for the proposed reconsideration of OOOOa⁵, EPA estimates that:

- the cost of semi-annual LDAR at natural gas well sites, using optical gas imaging (OGI), is \$2,333 (2016\$) per site,
- there will be an average of two wells per well site,
- OGI camera surveys will take an average of 6.1 hours per site – or an average of 3.05 hours per well per LDAR survey
- OGI camera surveys using an outside contractor will cost \$635 per survey, implying a contract cost for OGI services of \$104/hour based on a 6.1 hour/site survey
- Average labor costs for in-house personnel are \$61.21/hr

As noted above, the data submitted by oil and gas companies on their annual emission reports indicates that the average LDAR survey time was approximately 1.25 – 1.60 hours/well/survey⁶, including travel time. The AER data therefore indicates that EPA’s estimate of LDAR costs may overstate the labor effort for LDAR surveys by 2.9 – 3.6 hours per well, and 5.8 – 7.2 hours per site, per year, for semi-annual LDAR. Utilizing an average in-house labor cost of \$61.21/hr (EPA assumption), EPA’s estimate of LDAR costs for oil and gas wells may be overstated by 15% - 19% (\$355 - \$440/site/year). Utilizing an average outside contractor labor cost of \$104/hr EPA’s estimate of LDAR costs for oil and gas wells may be overstated by 26% - 32% (\$603 - \$749/site/year)

Number of Detected Fugitive Emission Sources per Well Site

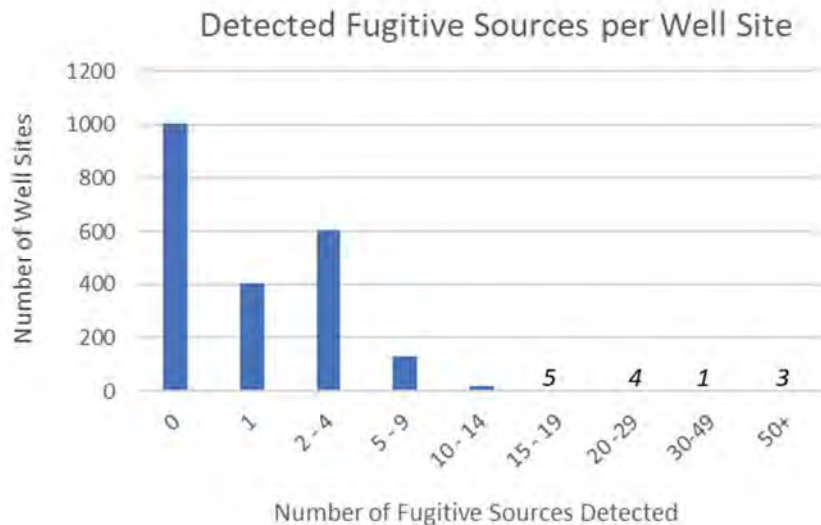
See Figure 2 for a distribution of the number of fugitive emission sources detected at well sites during the LDAR surveys. Of the 2,179 unique LDAR surveys with reported fugitive data, there were no fugitive sources detected during 46% of the surveys, and 54% of the surveys detected at least one fugitive emissions source at the surveyed well site.

Of the unique surveys with detected fugitive sources, 34% detected one source, 52% detected 2 – 4 different sources, and 14% detected 5 or more different sources at the well site. There were three well sites with more than 50 fugitive emission sources detected during a single LDAR survey. The average number of fugitive sources detected during LDAR surveys was 1.7 fugitive sources per site, including those sites with no detected sources.

⁵ <https://www.regulations.gov/document?D=EPA-HQ-OAR-2017-0483-0040>

⁶ Note that EPA assumes 2 wells per site, but the AERs submitted by oil and gas companies generally define a “site” as a single well, based on reported US Well IDs, with most companies reporting a single ID per identified site.

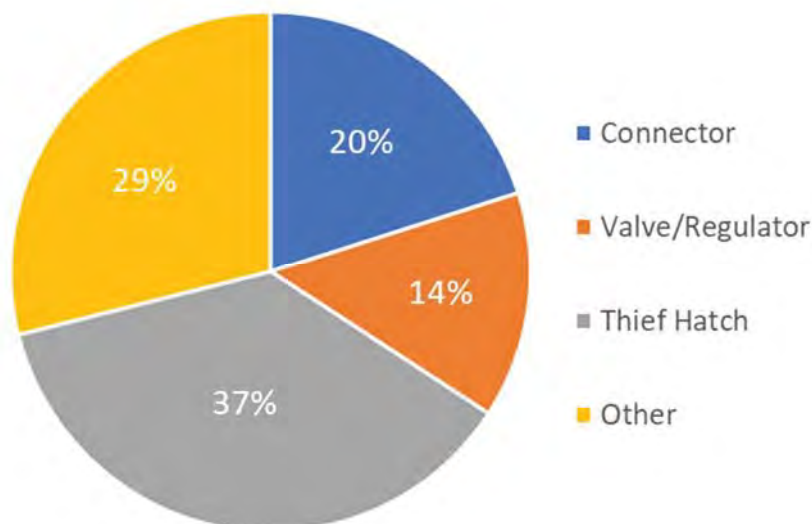
Figure 2 Distribution of Fugitive Emission Sources Detected at Well Sites During LDAR Surveys



Types of Fugitive Emission Sources Detected

See figure 3 for a summary of the types of fugitive emission sources detected during the LDAR surveys. Out of 5,271 fugitive emission sources identified by type in the reports, 37% were open thief hatches or other vents, 20% were leaking flanges or connectors, and 14% were leaking valves or regulators. The remaining 29% of fugitive emission sources were various component types for which no single type accounted for more than 1% of detected fugitive sources.

Figure 3 Types of Fugitive Emission Sources Detected During LDAR Surveys



COST-BENEFIT ANALYSIS SUBMITTED PER § 24-4-103(2.5), C.R.S.

For proposed revisions to
Colorado Air Quality Control Commission
Regulation Number 3 (5 CCR 1001-5) and
Regulation Number 7 (5 CCR 1001-9)

I. INTRODUCTION

The Colorado Air Pollution Control Division (Division) submits the following Cost-Benefit Analysis in conjunction with its proposed revisions to Colorado Air Quality Control Commission (AQCC) Regulation Number 3 (5 CCR 1001-5) and Regulation Number 7 (5 CCR 1001-9).

The proposed revisions collectively expand the air emission control requirements on oil and gas facilities in Colorado. They were developed after an extensive, year-long stakeholder process including input from diverse industry, environmental and governmental stakeholders. The proposal has received the support of several industry and environmental leaders. The Division estimates that the proposed strategies will result in substantial reductions of hydrocarbon emissions from the oil and gas industry. More specifically, the Division estimates the proposed strategies will reduce volatile organic compound (VOC) emissions by 93,500 tons per year, and methane/ethane emissions by 64,000 tons per year. The Division conservatively estimates that the annual net costs to industry of the Division's proposal will be \$42.4 million per year. This translates to approximately \$453 per ton of VOC reduced, which is very reasonable when compared to other air pollution reduction strategies adopted by the Colorado AQCC and the U.S. Environmental Protection Agency (EPA). In prehearing submittals to the AQCC, the supporters of the proposal have concluded that the Division's costs estimates are reasonable. Some opponents of the proposal have asserted that the costs may be much higher. The AQCC will consider the Division's proposal and any alternate proposals at the rulemaking hearing commencing February 19, 2014.

The proposed changes to Regulation Number 3 simplify certain air quality reporting and permitting requirements. They remove the requirements for sources with emissions below state reporting and permitting thresholds but subject to either a federal New Source Performance Standard ("NSPS") or National Emission Standard for Hazardous Air Pollutant ("NESHAP") to file an Air Pollutant Emission Notice ("APEN") and obtain a minor source permit ("catch-all provisions"). The Regulation Number 3 revisions also simplify reporting requirements for non-criteria reportable pollutant sources, and remove the permitting exemption for crude oil storage tanks.

The Regulation Number 7 rulemaking package proposes revisions that expand existing oil and gas control requirements and establish additional monitoring, recordkeeping and reporting requirements. These proposed revisions consist of the following:

- 1) Enhancing the existing control program for petroleum storage tanks by:

- a. Lowering the control requirement threshold for condensate storage tanks from 20 to 6 tons per year of uncontrolled actual volatile organic compound (VOC) emissions;
 - b. Requiring controls for crude oil and produced water storage tanks with uncontrolled actual VOC emissions that are equal or greater than 6 tons per year; and
 - c. Expanding non-attainment area requirements for tank controls during the first 90 days of production to the rest of the state;
- 2) Establishing requirements to ensure that emissions from controlled storage tanks are captured and routed to the control device;
- 3) Establishing leak detection and repair requirements for compressor stations and well production facilities, including requirements to reduce emissions from compressor seals and open ended lines consistent with current federal requirements;
- 4) Expanding the existing non-attainment area requirements for auto-igniters on flare devices to the rest of the state;
- 5) Expanding the existing ozone non-attainment area requirements for low bleed pneumatic devices to the rest of the state, and where feasible requiring no-bleed pneumatic devices; and
- 6) Requiring that the gas stream at newly constructed well production facilities either be connected to a pipeline or routed to a control device from the date of first production.
- 7) Lowering the existing control requirement threshold for existing glycol dehydrators to 6 tons per year of uncontrolled actual VOC emissions and 2 tons per year of uncontrolled actual VOC emissions for dehydrators located within 1,320 feet of a building, and establishing a 2 ton per year control threshold for all new glycol dehydrators; and
- 8) Establishing requirements for the use of best management practices both to minimize the need for downhole well maintenance and liquids unloading and to minimize emissions during well maintenance and liquids unloading events.

If adopted, these proposed revisions will result in substantial reduction of hydrocarbon emissions including volatile organic compounds (VOCs) and methane.

In addition to the Division's proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the AQCC to consider. Some of these proposals request that the AQCC adopt additional requirements that go beyond the Division's proposal, while other alternatives request that the AQCC limit aspects of the Division's proposed revisions. Copies of each of these proposals along with any economic impact analysis that the parties submitted identifying the projected costs and benefits of their particular proposals are attached to this Cost-Benefit Analysis as exhibits.

As set forth in § 24-4-103(2.5), C.R.S. this Cost-Benefit analysis shall include the following:

- (I) The reason for the rule or amendment;

Cost Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7

- (II) The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competitiveness;
- (III) The anticipated costs of the rule or amendment, which shall include the direct costs to the government to administer the rule or amendment and the direct and indirect costs to businesses and other entities required to comply with the rule or amendment;
- (IV) Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and
- (V) At least two alternatives to the proposed rule or amendment that can be identified by the submitting agency or member of the public, including the costs and benefits of pursuing each of the alternatives identified.

In connection with this Cost- Benefit Analysis, the Division has assessed the costs and benefits associated with each of the proposed strategies based on the reasonably available data. In collecting this data, the Division has sought input from various stakeholders in an effort to generate the most complete and accurate assessment of the costs and benefits of the proposed strategies. Where data was not reasonably available, the Division utilized assumptions that are set forth in this analysis.

II. THE REASON FOR THE RULE OR AMENDMENT

The Division is proposing revisions to AQCC Regulation Number 3 in order to improve the efficiency of Colorado's air quality reporting and permitting system. Under current regulation, when Colorado adopts certain federal air quality standards, all sources that are subject to these standards must report their emissions to the Division and obtain a permit. This requirement can result in the imposition of reporting and permitting burdens for very small sources of emissions. The proposed change would allow the state to adopt these federal requirements, but only require reporting and permitting for sources with emissions above established de minimis levels. The proposed revisions would also simplify reporting of non-criteria reportable pollutants, and provide that crude oil tanks must be permitted if their emissions are over the established de minimis levels. It appears that all parties to the AQCC rulemaking support the proposed revisions to Regulation Number 3.

The Division is proposing revisions to AQCC Regulation Number 7 in an effort to enhance the effectiveness of Colorado's air quality requirements for the oil and gas exploration and production sector. During the past ten years, Colorado has been a leader in developing and implementing requirements to reduce air emissions from the oil and gas sector. As a result of these efforts, Colorado now has in place a series of cost-effective requirements that significantly reduce air emissions from Colorado oil and gas facilities. Despite this success, however, the tremendous growth of oil and gas production in Colorado continues to threaten the air quality gains that we have achieved. Since 2004 gas production in Colorado has increased by 50% while oil production has more than doubled. While this growth has provided important economic benefits for Colorado, increased air emissions can have a negative impact on Colorado's public health and environment.

Specifically, VOC emissions contribute to the formation of ground level ozone. Ozone (O₃) is photochemical oxidant and known respiratory irritant. Ground level ozone is a secondary pollutant produced through the reaction of VOCs, nitrogen oxides and sunlight. Elevated levels of ground level ozone have been linked to a variety of adverse health effects including decreased lung function, increased respiratory symptoms, serious indicators of respiratory morbidity including emergency visits and hospital admissions, as well as total non-accidental and cardio-respiratory mortality. The U.S. EPA has set the current National Ambient Air Quality Standards for ground level ozone at 75 parts per billion (ppb) averaged over an 8-hour period. Based on a review of the then current health literature the Clean Air Scientific Advisory Committee concluded in 2008 that the 75 ppb standard was not sufficiently protective of public health, and recommended that the standard be set at between 60 ppb and 70 ppb. EPA is in the process of considering whether to lower the ozone standard.

Currently, the Denver Metro/North Front Range area is out of attainment with federal health-based ground level ozone standards. This includes much of the Denver/Julesberg oil field. Other areas of the state have also experienced elevated ozone levels recently, with one monitor in Western Colorado showing concentrations above 75 ppb and a number of other monitors showing levels between 60 ppb and 75 ppb.

Addressing oil and gas emissions is a critical component of Colorado's efforts to lower ozone levels since this sector represents the largest source of VOC emissions in the state. Based on the most recent inventory (2011), 54% of the anthropogenic VOC emissions in the state come from the oil and gas sector, which is roughly triple the amount of emissions from the next largest source. Moreover, because of the ongoing growth in the oil and gas industry and the projected decline in VOC emissions from other sectors, the share of VOC emissions attributable to the oil and gas sector will likely increase over the foreseeable future. The proposed emission reduction strategies will further enhance existing public health and environment protections on both a local and regional scale.

In addition to VOC emissions, oil and gas operations are a large source of methane. Methane is a potent greenhouse gas, which contributes to global climate change. In addition to reducing VOCs that contribute to regional ozone pollution, the Division's proposed strategies will reduce methane, and thereby play a role in Colorado's overall efforts to reduce greenhouse gas emissions. Methane is also a valuable natural resource (natural gas), and reducing leaks will benefit Colorado's environment and economy.

III. ANTICIPATED ECONOMIC BENEFITS

The proposed changes to Regulation Number 7 are projected to result in substantial reductions of hydrocarbon emissions (including both VOCs and methane/ethane) from the oil and gas industry. For VOCs, the Division has calculated that based on 2013 emissions, the proposed strategies will reduce VOC emissions from the oil and gas sector by approximately 93,500 tons per year or 257 tons per day. To put this in context, 257 tons per day represents approximately 45% of the total oil and gas related VOC emissions in 2011 and nearly 25% of the total 2011 VOC emissions

from all anthropogenic sources in Colorado. Additionally, the proposed strategies are projected to reduce methane/ethane emissions by approximately 64,000 tons per year.

These VOC reductions will aid Colorado's efforts to bring the Denver Metro/North Front Range area (DMA/NFR) into compliance with the current ozone NAAQS, as well as serve as a proactive step in addressing future lower ozone standards. As noted above, ground level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. According to EPA, attaining the current ozone standard throughout the nation will result in between \$6.9 billion and \$18 billion in annual health benefits. For lower standards the health benefits are even greater. For example, EPA projects that achieving a 70 ppb standard will result in between \$13 billion and \$37 billion in annual health benefits, and for a 65 ppb standard the benefits will increase to between \$22 billion and \$61 billion per year. EPA does not report these health benefits by state, but since the population of the DMA/NFR accounts for approximately 2.5% of the total national population living in areas that are in violation of the current NAAQS, the health benefits attributable to Colorado are likely to be substantial.

In addition to impacting human health, elevated levels of ozone can have a negative impact on crop production. For example, EPA's analysis indicates that reducing ozone levels to 70 ppb will increase winter wheat yields in a number of Front Range counties, including an increase of between 1% and 2% in Weld County.

Separate from the beneficial impacts of reducing ozone, the proposed rules will also produce substantial benefits associated with reducing greenhouse gases. As part of this rulemaking the Environmental Defense Fund (EDF) has engaged an expert to estimate the benefits of the rulemaking based on the social cost of carbon. Based on this analysis, EDF projects that the total annual benefit from the projected methane reductions is between \$104 million and \$318 million in 2016 and between \$132 million and \$404 million in 2025.¹

In addition to the benefits associated with reductions of VOCs and methane, the proposed rules will produce additional economic benefits in the form of increased product capture and the creation of new jobs associated with the implementation of the new requirements. As discussed more fully in Section IV below, the proposed rules are expected to result in the capture of approximately \$16.8 million dollars worth of natural gas each year that would otherwise be lost to the atmosphere. Additionally, a significant portion of the overall costs associated with the proposed rules is for additional inspections of oil and gas facilities by company employees or contractors. Based on the total calculated inspection time, the proposed requirements will necessitate the hiring of approximately 150 additional employees or contractors to conduct inspections. The remaining costs of the proposal are associated with the purchase, installation and maintenance of equipment along with supervisory oversight and required recordkeeping and reporting. These expenditures will likely result in additional job creation, but the actual number of these jobs has not been calculated.

IV. ANTICIPATED COSTS

¹ A copy of the analysis is attached hereto as Exhibit O.

As set forth below, the Division has assessed the direct and indirect costs to the regulated community for each of the proposed strategies in Regulation Number 7. These costs are set forth in Sections A through H below and include equipment costs, labor costs, maintenance costs, supervision costs, travel costs, and costs associated with recordkeeping and reporting. Section I discusses the costs to government associated with administering the proposed Regulation Number 7 revisions. Finally, Section J details the costs to the regulated community and government administration costs associated with the proposed revisions to Regulation Number 3.

As detailed below, the Division estimates that the total annual costs to the regulated community as a result of the proposed strategies will be approximately \$59.2 million. In addition, as discussed in Section III above, the proposed strategies are expected to result in the capture of additional product worth approximately \$16.8 million, for a total net cost of \$42.4 million per year. In addition to these direct costs, implementation of the proposed strategies could potentially result in the shut-in of a few marginally producing wells, resulting in indirect costs in the form of lost revenues to oil and gas companies, loss of jobs associated with these facilities, lost royalty payments, and lost severance taxes. Based on available information the Division cannot reasonably calculate the amount of oil and gas that could be shut-in due to the proposed rules, but believes that the amount is likely to be very small due to the low costs attributable to small, marginally producing facilities.² An analysis by an economist hired by certain industry parties has suggested that these indirect costs could be quite large.³ This information will be considered by the AQCC as part of the rulemaking hearing.

A. Control Requirements for Petroleum Storage Tanks

Commencing in 2004 the AQCC has adopted a series of requirements aimed at reducing emissions from petroleum storage tanks at well production facilities, compressor stations and gas processing plants. Currently, condensate tanks with uncontrolled actual emissions of 20 tons per year or greater of VOC must be equipped with a control device that has a control efficiency of at least 95%. Additionally, with certain exceptions, operators in the non-attainment area must achieve a 90% system-wide reduction of VOC emissions from condensate tanks during the period from May 1 through September 30, and 70% during the period from October 1 through April 30. These current requirements only apply to tanks that store condensate, which is defined in the AQCC's Common Provisions regulation as ~~hydrocarbon liquids~~ . . . with an API gravity of 40 degrees or greater.” While most of the petroleum liquid produced in Colorado qualifies as condensate, there are heavier hydrocarbon liquids, typically referred to as crude oil, with an API gravity below 40 degrees that are not subject to the current control requirements. Additionally, there are a number of high volume produced water tanks that have VOC emissions above 6 tons per year that are not currently regulated under the existing requirements.

While Colorado has achieved considerable success in controlling emissions from condensate tanks since 2004, petroleum storage tanks at oil and gas production and midstream facilities

² See discussion in Section V below.

³ See Attached Exhibit B.

continue to be the most significant source of VOC emissions from this sector. To address this emission source the Division is proposing the following strategies: 1) reducing the control threshold from 20 tons per year VOC to 6 tons per year; 2) eliminating the distinction between condensate and other liquids and requiring controls strictly based on emission levels; and 3) extending the current requirement that all condensate tanks in the non-attainment area be controlled during the first 90 days of production to storage tanks throughout the state. In order to meet each of these three strategies, the Division assumes that owners and operators will equip tanks with enclosed flares, as is the typical practice under the existing tank control requirements. The estimated costs associated with installing and maintaining an enclosed flare are set forth in subsection 1 below. Utilizing the calculated flare costs, the estimated costs and benefits for each of the three tank control strategies are discussed in subsections 2-4 below.

1. General Cost Estimates for Flares

The estimated cost for a flare control device is based on identified costs from a 2008 oil and gas cost study⁴ adjusted for inflation. Based on this data, the estimated annualized cost of a flare control device with auto-igniter⁵ is about \$6,287.⁶

Table 1: Flare Control Device with Auto Igniter – Annualized Cost Analysis*				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	\$18,169			
Freight/Engineering		\$1,648		
Flare Installation		\$6,980		
Auto Igniter	\$1,648			
Pilot Fuel**			\$768	
Maintenance			\$2,197	
Subtotal Costs	\$19,817	\$8,628	\$2,965	
Annualized Costs***	\$2,747	\$575	\$2,965	\$6,287

**Control cost evaluation based on 2008 Ozone Rulemaking cost survey and producer data. Control device costs were developed based on an oil and gas cost study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.⁷*

⁴ See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process. For reference or background purposes the Division has cited herein certain information that has been submitted to the AQCC as part of the rulemaking; however, it is not necessarily included with this Cost-Benefit Analysis as an exhibit.

⁵ Currently only flares in the non-attainment area are required to have auto-igniters. Under the current proposal, the auto-igniter requirement would be extended statewide. For the purposes of this cost analysis, it is assumed that auto-igniters will be required statewide. The cost and benefits associated with equipping existing flares outside the non-attainment with auto-igniters are discussed below in Section D.

⁶ Certain parties to the rulemaking have asserted that the actual cost per combustion device is higher based on EPA’s cost analysis conducted in accordance with NSPS OOOO. Based on a review of EPA’s analysis it appears that additional costs were included for surveillance systems that are not applicable to the proposed rule. Additionally, unlike the analysis in NSPS OOOO, the costs that the Division has identified are based on a Colorado specific cost analysis.

** Pilot fuel costs \$3.41/MMBtu (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

2. Lowering Statewide Condensate Tank Control Threshold (from 20 tpy to 6 tpy)

The Division is proposing to lower the uncontrolled VOC emission control threshold from 20 tpy down to 6 tpy on condensate storage tanks statewide. Based on an analysis of the Air Pollution Emissions Notice (APEN) database, the Division estimates that statewide there are 588 uncontrolled condensate tank batteries with VOC emissions over six tons per year. Of these 588 tanks, 396 are outside the non-attainment area (NAA) and the remaining 192 are within the current non-attainment area.

Table 2: Condensate Tank Battery Analysis

Tank Battery Type	Ozone NAA [count]	Outside NAA [count]	Cancelled Tanks [count]	Total Statewide Tanks [count]
Controlled Tanks	4,971	490		5,461
Uncontrolled Tanks	1,451	1,132	36	2,619
All Tanks	6,422	1,622	36	8,080
Uncontrolled Tanks (≥ 6 tpy)	192	396		588

Based on the reported uncontrolled actual VOC emissions for these 588 tanks, and assuming both that 75% of the VOC emissions are captured and sent to the flare,⁸ and that the flare has a 95% destruction efficiency, the total VOC emission reduction associated with lowering the condensate tank threshold statewide is 5,162 tons per year.

Table 3: Condensate Tank Battery Emissions Analysis for Lowering Statewide Threshold

Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
NAA Uncontrolled Tanks (≥ 6 tpy)	2,355	677*	1,678
Outside NAA Uncontrolled Tanks (≥ 6 tpy)	4,890	1,406*	3,484
Totals:	7,245	2,083	5,162

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

⁷ It has been suggested that the Division should have used the Producer Price Index to calculate an escalation from 2008 to 2013 costs. From 2008 to 2013, however, the Producer Price Index for the oil and gas field equipment sector grew at a slower rate than the CPI. Accordingly, the Division's analysis may actually overstate the increase in cost from 2008 to 2013.

⁸ The costs and benefits associated with improving the capture percentage for controlled storage tanks are discussed below in Section B.

The annualized cost of installing 588 flare control devices is about \$3.7 million dollars with an average cost effectiveness of about \$716 per ton of VOC reduced. For the smallest individual tank battery subject to controls (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 4: Tanks over 6 tpy – Control Cost Estimates for Flare Control Devices

Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$/ton]
588	\$6,286.8	\$3,696,638	5,162	\$716

In addition to VOC reductions, this strategy will significantly reduce methane and ethane emissions from currently uncontrolled tanks. To calculate methane and ethane emission reductions, the Division determined the relative proportion of VOCs to methane and ethane based on reported average values from 30 natural gas liquid analyses submitted to the Division. Based on these analyses, methane/ethane emissions from condensate storage tanks are about 38% of the VOC emissions by weight. Accordingly, projected methane/ethane emission reductions from this proposed strategy are 1,963 tons per year or \$1,884 per ton of methane/ethane reduced.

3. Requiring Controls for Produced Water and Crude Oil Tanks

As discussed above, the Division is proposing to eliminate the distinction between condensate tanks and other storage tanks. If the AQCC adopts this proposal, crude oil tanks and produced water tanks with uncontrolled actual VOC emissions of six tons per year or greater will require controls. Because produced water and crude oil tanks are identified separately in the Division's APEN data base, the costs and benefits for these two types of storage tanks are broken out separately.

The Division is proposing that all statewide produced water tanks with uncontrolled VOC emissions over 6 tons/year be required to install emission controls. Some uncontrolled produced water tanks could be co-located at sites with condensate or crude oil tanks that have flare controls, but pressure and flow differences may require the installation of a separate flare control device for the water tank. Consequently, the control costs are based on the assumption that each water tank battery will install a new flare control device. Based on an analysis of the APEN database, the Division estimates that statewide there are 52 uncontrolled produced water tank batteries with VOC emissions over 6 tons/year.

Table 5: Produced Water Tank Battery Analysis

Tank Battery Type	Total Statewide Water Tanks
Controlled Water Tanks:	338
Uncontrolled Water Tanks:	530
Total:	868

Table 5: Produced Water Tank Battery Analysis	
Tank Battery Type	Total Statewide Water Tanks
Uncontrolled Tanks (≥ 6 tpy)	52

Based on the reported uncontrolled actual emissions, the Division estimates that the total VOC emission reduction associated with controlling these produced water tanks statewide is 457 tons per year.

Table 6: Produced Water Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥ 6 tpy)	641.4	184.4*	457

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing 52 flare control devices is about \$327,000, with an average cost effectiveness of about \$715 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 7: Produced Water Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
≥ 6 tpy	52	\$6,286.8	\$326,914	457	\$715

The Division is proposing that all statewide hydrocarbon liquid storage tanks with VOC emissions over six tons/year must install emission controls. Based on a recent analysis of 2013 APEN data, there are 67 reported crude oil tanks batteries statewide. Thirty seven of the tank batteries are already equipped with controls. Of the remaining thirty, eight are over the proposed six tons/year threshold. Given that approximately 5% of the total wells in the state report crude oil production to the Colorado Oil and Gas Conservation Commission (COGCC),⁹ it appears likely that the Division's APEN database may be undercounting crude oil tanks, either because these tanks have not been reported or because they are being reported as condensate tanks.¹⁰

⁹ Based on an analysis of 2010 COGCC data.

¹⁰ Prior to 2008 crude oil storage tanks were exempt from APEN reporting requirements, which may explain in part the small numbers of tanks identified in the system.

Table 8: Crude Oil Tank Battery Analysis	
Tank Battery Type	Total Statewide Crude Oil Tanks
Controlled Crude Oil Tanks	36
Uncontrolled Crude Oil Tanks	29
Total:	65
Uncontrolled Tanks (≥ 6 tpy)	8

The total VOC emission reduction associated with controlling these 8 crude oil tanks statewide is 118 tons per year.

Table 9: Crude Oil Tank Battery – Emissions Analysis			
Tank Battery Type	Uncontrolled VOC Emissions [tons/year]	Controlled VOC Emissions [tons/year]	VOC Emission Reduction [tons/year]
Uncontrolled Tanks (≥ 6 tpy)	165.2	47.5*	117.7

*Emission reduction estimated by accounting for 75% capture and 95% destruction efficiency.

The annualized cost of installing eight flare control devices is about \$50,294 dollars with an average cost effectiveness of about \$427 per ton of VOC reduced. For the smallest individual tank battery (6 tons/year), the flare cost effectiveness is estimated at \$1,471 per ton of VOC reduced.

Table 10: Crude Oil Tanks – Control Cost Estimates for Flare Control Devices					
Tank Size	Affected Tanks [count]	Each Flare Annualized Cost	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
≥ 6 tpy	8	\$6,286.8	\$50,294.4	117.7	\$427

4. Requiring Controls During the First 90 Days of Production Statewide

Under current requirements owners and operators of new and modified storage tanks outside the non-attainment area have 90 days after the date of first production to determine if emissions from the tank trigger the requirement to install a control. Because production is typically at its highest during this initial period, significant emissions can occur before controls are installed. To address this issue in the non-attainment area, the AQCC mandated in the 2008 Ozone Action Plan that all condensate tanks be controlled during the first 90 days. The Division is now proposing to expand this requirement to storage tanks throughout the state.

To calculate the cost effectiveness of this strategy, the Division first determined the number of new and modified storage tanks outside the non-attainment area based on reported APEN data for the period of 2010-2012. Based on this APEN data, there are on average 141 new and modified tanks each year, with yearly reported uncontrolled actual emissions of 7,370 tons VOC. Assuming that emissions during the first 90 days equal 1/4th of the annual reported emissions,¹¹ total uncontrolled actual VOC emissions from these tanks during the first 90 days is 1,842.5 tons. Assuming enhanced capture efficiency for these new tanks (see Section B below) the flare control efficiency is 95%, and thus the calculated benefit from expanding the first 90 day control requirement to tanks outside the non-attainment area will be 1,750.4 tons per year.

While the Division estimates that there are 141 new and modified storage tanks outside the non-attainment area each year, the majority of these, 84, will require control devices regardless of this strategy since their uncontrolled actual emissions are over six tpy. For these 84 tanks, the cost of operating a flare during the first 90 days will be approximately 25% of the total annualized cost, or \$1,571.70 per tank. For the remaining 57 tanks with emissions less than six tons/year, because controls for these tanks will only need to be in place for 90 days, the Division assumes that each flare can control 3 tanks per year, which means that 19 new flares are required to comply with this proposed strategy. For other applications, the annualized cost of a flare is estimated to be \$6,287. Since flares required for this application will be relocated three times a year, the Division assumes an additional \$3,000 in annual relocation costs, for a total annualized cost of about \$9,287 per flare. Based on the emission reductions calculated above, the total cost effectiveness of this requirement is \$176/ton of VOC reduction.

Table 11: Control Cost Estimates for Flare Control Devices Required During the First 90 Days of Production

Storage Tank Threshold [tpy]	Number of New Storage Tanks	Number of New Flares	Annualized Cost Each Flare	Total Flare Cost	Total VOC Reduction [tons/year]	VOC Control Cost [\$ /ton]
<6	57	19	\$9,286.8	\$176,449.2	44.7	\$3,947
≥6	84	84	\$1,571.7	\$132,022.8	1,705.7	\$77
	141			\$308,472	1,750.4	\$176

Using the methodology discussed in subsection A.2 above the projected methane/ethane emission reductions from this strategy is 665.5 tons per year or \$464 per ton of methane/ethane reduced.

B. Emission Capture Requirements for Controlled Petroleum Storage Tanks

In order for storage tank control requirements to be effective, emissions from the tank must be routed to the control device. Historically the Division has assumed that 100% of a tank's

¹¹ Because reported emissions typically are based on a calculation assuming a standard rate of production decline after the first 90 days, actual emissions during the first 90 days could be much higher.

emissions will be captured and routed to the control device, typically a flare, resulting in a 95% reduction of emissions. Field observations using infra-red (IR) cameras and other methodologies indicate that in actuality emissions from controlled storage tanks often escape through the thief hatches and pressure relief valves (PRV) and therefore are not being combusted in the flare. This occurs when the tank cannot adequately contain the flashing emissions that occur when pressurized liquids from the separator are dumped into the atmospheric tank. To address this issue, the Division is proposing new regulatory language clarifying that all emissions from controlled storage tanks must be routed to the control device and that these tanks must be operated without venting emissions from thief hatches, PRVs and other openings, except when venting is reasonably necessary for maintenance, gauging, or safety of personnel and equipment.

To assure compliance with these capture standards, the Division's proposal requires that owners and operators of controlled storage tanks implement a Storage Tank Emission Management (STEM) plan. Pursuant to the STEM plan, owners and operators must evaluate and employ appropriate control technologies and/or operational practices designed to meet the proposed capture requirements, and certify that these technologies and/or operational practices are designed to minimize emissions from the tank. The Division's STEM proposal also requires implementation of a two-pronged monitoring strategy involving a weekly¹² auditory, visual, and olfactory (AVO) inspection for all controlled tanks, and a periodic instrument based monitoring for tanks using EPA Reference Method 21, an IR camera or other Division approved monitoring device or method. As proposed, the frequency of this instrument based monitoring will depend on the level of uncontrolled actual emissions from the tank.

Table 12: Proposed Tiering for Instrument Based Tank Inspections

Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
≥ 6 tpy to ≤ 12 tpy	Annually
> 12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

In assessing the cost effectiveness of the proposed requirements, the Division first calculated the costs associated with implementing technological and/or operational changes at controlled tanks. For the purposes of this analysis the Division assumed that all tanks with uncontrolled actual emissions greater than or equal to 6 tons per year would need to be controlled consistent with the Division's proposal discussed in Section A above. Based on reported data, there are currently 5,310 storage tanks statewide with emissions greater than or equal to 6 tons per year. While the Division's proposal does not specify the type of technology or operational practices that operators will use, for the purposes of this analysis the Division assumed that buffer bottle

¹² There is an exception for the weekly inspection requirement where the operator loads out liquids from the storage tank on less than a weekly basis. In these circumstances the operator must conduct the inspection whenever liquids are loaded out, but no less often than every 30 days. Typically liquids are loaded out multiple times in a given week, meaning that for the majority of the tanks AVO inspections will be required weekly.

technology would be installed on each of the subject tanks.¹³ The buffer bottle technology utilizes a small tank that is installed after the separator which allows for a secondary flash of pressurized liquids prior to dumping into the storage tank. The second-stage flash reduces the pressure of the liquids going to the tank and thereby helps to ensure that the tank can adequately handle the flashing emissions that occur when the liquids are brought to atmospheric pressure. Based on industry provided information, the estimated annual cost of a buffer bottle is set forth in Table 13.¹⁴

Table 13: Annualized Cost Analysis for Buffer Bottle				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Buffer Bottle	\$11,500			
Freight/Engr		\$600		
Installation		\$2,280		
Maintenance			\$2,500	
Subtotal Costs	\$11,500	\$2,880	\$2,500	
Annualized Costs*	\$1,593.8	\$192	\$2,500	\$4,285.8

* Annualized over 15 years at 5% ROR

The Division also calculated the costs associated with conducting enhanced inspections. Based on the proposed tiering, operators will need to conduct 24,840 tank inspections per year.¹⁵

Assuming that each inspection takes two hours and utilizing a \$103/hour¹⁶ in-house inspection cost and a \$134/hour contractor inspection cost (30% profit added to in-house rate), the total annual cost associated with conducting enhanced inspections under the proposed rule is \$5,392,010, which equates to \$1,015.4 per year for each tank that will be subject to STEM.

¹³ Based on discussions with industry representatives during the stakeholder process there may be other less costly technologies and operational practices that could be used to ensure good emission capture from tanks such as replacing seals, more frequent maintenance, changing the size of piping going to the storage tank, and timing well dumps to avoid overloading the separator. There may also be other options for new facilities that allow for the capture and sale of additional gas such as the installation of high-low pressure separators or utilizing a liquids gathering system that eliminates atmospheric storage tanks at well sites.

¹⁴ For this Cost-Benefit Analysis the Division increased the capital and maintenance costs for buffer bottles based on input from industry stakeholders.

¹⁵ In practice, many operators are already conducting IR camera inspections at storage tanks, however, the Division does not have information regarding how many inspections are currently occurring.

¹⁶ The hourly inspection cost is discussed below in Table 20.

Table 14: Instrument Based Tank Inspections Based on Proposed Tiering

Tank Uncontrolled Actual VOC Emissions	Inspection Type/Hourly Rate	Number of Tanks	Inspection Frequency	Number of Inspections	STEM Inspection Costs
>6 tpy to ≤ 12 tpy	In-House/\$103	1,085	Annually	1,085	\$223,510
>12 tpy to ≤ 50 tpy	In-House/\$103	2,595	Quarterly	10,380	\$2,138,280
> 50 tpy	In-House/\$103	745	Monthly	8,940	\$1,841,640
Subtotal:		4,425		20,405	\$4,203,430
>6 tpy to ≤ 12 tpy	Contractor/\$134	323	Annually	323	\$86,564
>12 tpy to ≤ 50 tpy	Contractor/\$134	329	Quarterly	1,316	\$352,688
> 50 tpy	Contractor/\$134	233	Monthly	2,796	\$749,328
Subtotal:		885		4,435	\$1,188,580
Total:		5,310		24,840	\$5,392,010

The Division also considered whether additional costs should be included for conducting periodic AVO inspections. Because these activities are already required for controlled storage tanks under existing regulation, the Division did not include these costs in determining the total cost of the proposed capture requirements. The Division also did not include costs associated with certifying that selected technologies and/or operational practices are designed to minimize emissions, since costs for certifying capture efficiency are already included in the annualized cost of required flares.¹⁷ Accordingly, the total projected annual cost of the proposed capture requirements based on the use of a buffer bottle and enhanced monitoring requirements is \$5,301.2 per tank.

To calculate the projected emissions reduction from the proposed capture requirements, the Division assumed a current capture rate of 75% for controlled tanks based on analytical work that the Division, EPA and others have performed. Based on this capture rate, the Division calculated the emissions reduction that would occur if the capture rate were increased to 100% using the following equation:

$$\text{Emission reduction} = [\text{uncontrolled VOC} * (1 - (0.75 * 0.95))] - [\text{uncontrolled VOC} * (1 - 0.95)],$$

Using this equation as applied to the reported uncontrolled actual emissions from the 5,310 storage tanks statewide with emissions greater than or equal to six tons per day, the projected emission reduction from the proposed capture requirements is 53,386 tons per year. Included in the total are 33 existing crude oil tanks with flare controls (>6 tpy) and 8 crude oil tanks that would need flare controls (>6 tpy).

¹⁷ See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008, at pg. 8.

Table 15: STEM Emission Control Analysis (Statewide)

Number of Tanks ≥ 6 tpy	Uncontrolled VOC [tons/year]	Controlled VOC (@ 71.25% Control) [tons/year]	Controlled VOC (@ 95% Control) [tons/year]	VOC Reduction [tons/year]
5,269	221,569	63,701	11,078	52,623
41	3,213	924	161	763
5,310	224,782	64,625	11,239	53,386

Applying this reduction to the costs calculated above, the cost effectiveness of these proposed requirements is \$527/ton of VOC.

Table 16: STEM Control Cost Estimates (Statewide)

Type of Technology	Number of Tanks	Each Device Annualized Costs [\$ /year]	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
Buffer Bottle	5,310	\$5,301.2	\$28,149,372	53,386	\$527.3

Using the average ratio of VOC to methane/ethane emissions from storage tanks, the projected methane/ethane reduction from this strategy is 20,287 tons per year, which equates to \$1,388 per ton of methane/ethane reduced.

During the Division stakeholder process leading up the AQCC rulemaking hearing, certain parties raised questions about the Division's assumption that currently controlled tanks have a 75% capture efficiency. In light of this the Division has also calculated cost effectiveness based on the assumption that current capture efficiency is 50% and 95%. For the 50% case, current controlled emissions would be 118,011 tpy VOC. Accordingly, the emission reduction benefit from increasing capture to 100% would be 106,772 tons per year (118,011-11,239) and the cost effectiveness would be \$264/ton VOC¹⁸. For the 95% capture scenario, current controlled emissions would be 21,916 tons per year VOC and the emission reduction would be 10,677 tons per year (21,916-11,239). Under this scenario, the cost effectiveness would be \$2,636/ton VOC¹⁹.

While the buffer bottle technology offers a good alternative in a retrofit situation for reducing pressures to the tank and increasing emission capture, for new facilities, installation of a high-low pressure (HLP) separator to satisfy STEM may prove to be a better performing option. This equipment allows for two stages of separation of the gas and the liquids instead of the single stage separation accomplished in traditional separators. By adding a second stage of separation, the pressure of the liquids sent to the tank is significantly reduced, thereby helping to ensure

¹⁸ This may overestimate the cost effectiveness given that if the current capture rate were only 50% additional costs could be required to increase the capture rate to 100%.

¹⁹ This is a conservative calculation given that if the current capture rate were 95% it is likely that the control costs to increase the capture rate to 100% would be significantly less.

complete capture of flashing emissions instead of venting a portion of the emission stream through the thief hatch or PRV. Additionally, rather than being routed to the flare, as in the case of the buffer bottle technology, gas from the second stage of separation can be sent to a vapor recovery unit (VRU), recompressed and sent to the sales line, resulting in increased product recovery. Based on information provided from industry, the Division has calculated that the annual cost of a HLP separator w/VRU is about \$19,341.

Table 17: Annualized Cost Analysis for HLP Separator

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
HLP/VRU	\$90,000			
Freight/Engr		\$1,648		
HLP/VRU Installation		\$11,154		
Maintenance			\$9,396	
VRU Recovered NG *			\$(3,382)	
Subtotal Costs	\$90,000	\$12,802	\$6,014	
Annualized Costs**	\$12,474	\$853	\$6,014	\$19,341

* Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013) and average tank battery size of 63.2 tpy – based on 3-yr average of APEN data on storage tanks ≥ 6 tpy (uncontrolled VOC).

** Annualized over 15 years at 5% ROR

Unlike the retrofit situation analyzed above where the emission controls are already in place, it is appropriate in new installations to aggregate the cost of the HLP separator w/VRU with the costs of the control unit (flare) to determine the overall cost of controlling emissions from the tank. Based on the \$6,286.8 annual cost of a flare and annual instrument based monitoring costs of \$1,015.4 per tank, the total annual control costs for a new tank will be \$26,643 per year.

Based on an analysis of reported data for new tanks during the past three years, the average uncontrolled actual emissions of a new tank is 63.2 tpy. Assuming a 95% overall control efficiency, equipping a tank with an HLP separator and a flare will reduce the emissions from an average new tank by 60 tpy. This yields a cost effectiveness of \$444 per ton VOC reduced. If instead, the highest cost scenario (using a six tpy tank) is assumed, the cost effectiveness is \$4,674 per ton VOC. For methane ethane the cost per ton is \$1,168 per ton reduced on average.

C. Leak Detection and Repair Requirements for Compressor Stations and Well Production Facilities

AQCC Regulation Number 7 requires owners and operators of gas processing plants in Colorado to implement leak detection and repair programs to identify and repair fugitive emission leaks from components at these facilities. Under this requirement, owners and operators must conduct

periodic inspections using EPA Reference Method 21²⁰ and repair leaks within a prescribed time frame.

Although component leaks at compressor stations and well production facilities in Colorado are also a significant source of VOC and methane emissions, Regulation No. 7 does not currently include leak detection and repair requirements for these facilities.²¹ To address these emissions, the Division is proposing regulatory changes that would establish leak detection and repair requirements for compressor stations and well production facilities. Pursuant to this proposal, owners and operators of compressor stations and well production facilities will be required to conduct periodic leak inspections, and repair identified leaks. As specified, required inspections may be done either in accordance with Method 21 or utilizing an infrared (IR) camera. The proposed language also allows the Division to approve other inspection methods as new leak detection technologies are demonstrated to be effective.

The proposed regulation establishes a tiered system to determine inspection frequency. For compressor stations the tiering is based on the uncontrolled actual leak emissions at the facility as follows:

<i>Table 18: Proposed Tiering for Leak Inspections at Compressor Stations</i>	
Component Leak Uncontrolled Actual VOC Emissions	Inspection Frequency
≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

For well production facilities the proposed tiering is based on uncontrolled actual emissions from the largest emitting storage tank at the facility as set forth in Table 19. The tiering is based on tank emissions rather than uncontrolled actual leak emissions in order to create a Method 21/IR camera monitoring schedule that is consistent with the monitoring schedule proposed as part of the STEM emission capture requirements discussed in Section B above.²²

²⁰ While Method 21 sets performance standards for inspection equipment rather than specifying technology, typically Method 21 inspections utilize photo ionization detectors (PIDs) to assess leak levels.

²¹ Although leak detection is not currently required at most of these facilities, some operators currently conduct voluntary leak detection and repair programs. Additionally, the Division has issued a limited number of permits that include some leak detection requirements. For the purposes of this analysis, however, the Division assumes that there is no leak detection occurring at well production facilities and compressor stations. Accordingly the actual additional costs that operators may incur may be less than the costs calculated in this analysis.

²² Because there may be a limited number of instances where well production facilities don't have storage tanks, the proposal also provides that for tank-less facilities, the inspection schedule will be based on the facility's total VOC emissions. This provision is intended to apply to large facilities that utilize a liquids gathering system for transporting petroleum liquids to a centralized facility. These facilities are not included in the facility count used in this Cost-Benefit Analysis, but because the number of these facilities in Colorado is extremely small this exclusion should have a negligible impact on the overall costs and emission reduction benefits of the proposed LDAR requirement. Additionally, because the costs and benefits from the proposed LDAR program increase at roughly the

Table 19: Proposed Tiering for Leak Inspections at Well Production Facilities	
Tank Uncontrolled Actual VOC Emissions	Inspection Frequency
< 6 tpy	One Time (and Monthly AVO)
≥ 6 tpy to ≤ 12 tpy	Annually
>12 tpy to ≤ 50 tpy	Quarterly
> 50 tpy	Monthly

The Division utilized a multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.²³ To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in Table 20 below, the total annual cost for each inspector will be \$193,629, which equates to an hourly inspection rate of \$103.

Table 20: Leak Detection and Repair (LDAR) Inspector – Annualized Cost Analysis			
Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	\$122,000		
FLIR Camera Maintenance/Repair		\$7,500	
Photo Ionization Detector	\$5,000		
Vehicle (4x4 Truck)	\$22,000		
Inspection Staff		\$75,000	
Supervision (@ 20%)		\$15,000	
Overhead (@10%)		\$7,500	
Travel (@15%)		\$11,250	
Recordkeeping (@10%)		\$7,500	
Reporting (@10%)		\$7,500	
Fringe (@30%)		\$22,500	
Subtotal Costs	\$149,000	\$153,750	
Annualized Costs*	\$39,879	\$153,750	\$193,629
*over 5 years at 6% ROR	Annualized Hourly Rate		\$103

The Division initially assumed that conducting inspections in-house would be the lowest cost option since it would not involve additional profit to be paid to a contractor. For smaller companies that cannot fully utilize an IR camera, however, conducting inspections in-house may

same rate, the cost effectiveness of the program for these facilities should mirror the cost effectiveness of the program as applied to facilities with tanks.

²³ This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

not be the most cost effective option. To account for this in the Cost-Benefit Analysis the Division assumed a 30% profit margin for contractors, which it added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection (\$134 per hour).

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would take 50% of the time required for a Method 21 inspection.²⁴

For compressor stations, the Division used reported component counts for compressor stations within each of the tiers identified in Table 18 above. Based on these counts, and the inspection times per component discussed above, the Division calculated that the total inspection time per compressor station facility tier are as follows:

<i>Table 21: Calculated Inspection Time Compressor Station Leak Inspections</i>		
Component Leak Uncontrolled Actual VOC Emissions	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	21.2 hours	10.6 hours
>12 tpy to ≤ 50 tpy	56.2 hours	28.1 hours
> 50 tpy*		

* there are currently no compressor stations in Colorado with calculated leaks at this level

For well production facilities, the Division has limited data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the non-attainment area and well production facilities outside the non-attainment area. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 22.

<i>Table 22: Calculated Inspection Times for Well Production Facility Leak Inspections</i>		
Area	Method 21 Inspection	IR Camera/ Hybrid

²⁴ Based on the Division's own IR camera inspections, and reports from various parties during the stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

		Inspection
Non-Attainment Area	12.2 hours	6.1 hours
Rest of the State	6.8 hours	3.4 hours

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 20, for the purposes of this Cost-Benefit Analysis the Division also assumed an additional three hours in travel time for each inspection outside the non-attainment area. This assumption reflects the fact that certain well sites in basins outside the non-attainment area may be remote, requiring additional travel.

Next, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported emission data to determine the number of facilities that will be subject to annual, quarterly and monthly inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For compressor stations the Division assumed that all inspections would be conducted by 3rd party contractors. For well production facilities, the Division assumed that any company with 500 or more inspections per year would conduct inspections in-house, and that companies with less than 500 inspections per year would use contractors.²⁵ Because the proposed rule also requires owners and operators of well production facilities that are not subject to monthly instrument monitoring to conduct monthly AVO inspections the Division considered whether additional costs should be included for these inspections. Based on information provided during the stakeholder process it appears that operators already routinely conduct such inspections and repair leaks identified during these AVO inspections. Additionally, while the proposed rule may impose recordkeeping and reporting requirements associated with these AVO inspections, given the relatively small number of leaks that are expected to be identified, and the fact that any recordkeeping can be readily included in existing inspection and maintenance records the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In its Initial Economic Impact Analysis to the AQCC, the Division did not include the cost to repair leaking components or re-monitor these components post-repair to verify that the repair was effective, assuming that the cost to repair and re-monitor would be offset by the cost savings from capturing additional product as a result of repairs. Based on information that the Conservation Groups submitted as part of their Pre-Hearing Statement to the AQCC, it appears that the Division's assumption in the Initial EIA was reasonable. See Exhibit A to CG-PHS, Testimony of David McCabe at pg. 8. Nevertheless, for this Cost-Benefit Analysis, the Division has included both repair costs and estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a \$66.24 hourly rate to repair components, and an average repair time of between 0.17

²⁵ Based on this assumption, 3,545 inspections per year will be conducted using 3rd party contractors.

hours and 16 hours, depending on the both type of component and the complexity of the repair.²⁶ To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.18% leaking component rate for facilities subject to annual inspections.²⁷ To account for the projected additional emission reductions from quarterly and monthly inspection schedules the Division used annual leaking component rates of 1.77% for facilities with quarterly inspection schedules and 2.36% for facilities with monthly inspection schedules. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to MCF of natural gas, with a price of \$3.50/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible.

Based on this methodology, the calculated annual inspection costs for compressor stations are set forth in Table 23.

Table 23: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Annual Inspection Frequency	Time per IR Camera Inspection [hours]	Total Annual Inspection Time [hours]	Total Annual Inspection Cost
≤ 12 tpy	147	1	10.6	1,558.2	\$208,799
>12 to ≤ 50 tpy	53	4	28.1	5,957.2	\$798,265
≥ 50 tpy	0	12			
Total:	200			7,515.4	\$1,007,064

Repair costs associated with these inspections are set forth in Table 24 and fuel savings associated with these repairs are set forth in Table 25.

Table 24: Compressor Station Leak Repair Costs					
Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Leak Repair Rate [\$ /hr]	Number of Leaks per Compressor Station	Total Leak Repair Time per CS [hours]	Total Annual Repair Cost
≤ 12 tpy	147	\$66.24	30.1	23.0	\$223,957.4

²⁶ See –Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards,” Bradley Nelson and Heather Brown, April 17, 2012; –Analysis of Emissions Reduction Techniques for Equipment Leaks,” Cindy Hancy, December 21, 2011.

²⁷ This leaking component rate is consistent with the rate that the Louis Berger Group used in their Initial Economic Impact Analysis for Industry’s Proposed Revisions to Colorado’s Air Quality Control Commission Regulation No. 7 (DGS-PHS Ex. C), and is based on the leak rate utilized by Nelson and Brown in their analysis of leak reduction costs and benefits (See footnote 26).

Table 24: Compressor Station Leak Repair Costs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Leak Repair Rate [\$/hr]	Number of Leaks per Compressor Station	Total Leak Repair Time per CS [hours]	Total Annual Repair Cost
>12 to ≤ 50 tpy	53	\$66.24	119.4	85.2	\$299,113.3
≥ 50 tpy	0	\$66.24	-	-	-
Total:	200				\$523,071

Table 25: Compressor Station Recovered Natural Gas Value from Leak Repairs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Recovered Natural Gas per CS [tons/year]	Value of Natural Gas [\$/MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	147	10.2	\$3.5	35.8	\$187,875
>12 to ≤ 50 tpy	53	36.4	\$3.5	35.8	\$241,729
≥ 50 tpy	0		\$3.5	35.8	-
Total:	200				\$429,604

The total net costs for compressor station LDAR are set forth in Table 26.

Table 26: Compressor Station Net Leak Inspection and Repair Costs

Compressor Station Fugitive VOC Tier [tpy]	Number of Compressor Stations	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≤ 12 tpy	147	\$208,799	\$223,957.4	\$187,875	\$244,882
>12 to ≤ 50 tpy	53	\$798,265	\$299,113.3	\$241,729	\$855,650
≥ 50 tpy	0		-	-	-
Total:	200	\$1,007,064	\$523,071	\$429,604	\$1,100,531

For well production facilities the estimated annual inspection costs are set forth in Table 27.

Table 27: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled	O&G	Number	Annual	Total	Inspection	Total Annual

VOC at Storage Tank Battery Tier [tpy]	Basin*	of Facilities	Inspection Frequency	Number of Inspections	Time Per Inspection [hours]	Inspection Cost
In-House Inspections at \$103/hour						
> 6 to ≤12	DJ/NAA	945	1	945	6.1	\$593,744
> 12 to ≤ 50	DJ/NAA	2,447	4	9,788	6.1	\$6,149,800
> 50	DJ/NAA	693	12	8,316	6.1	\$5,224,943
Subtotal:		4,085		19,049		\$11,968,487
In-House Inspections at \$103/hour						
> 6 to ≤12	ROS	173	1	173	6.4**	\$114,042
> 12 to ≤ 50	ROS	176	4	704	6.4	\$464,077
> 50	ROS	115	12	1,380	6.4	\$909,696
Subtotal:		464		2,257		\$1,487,815
Contract Inspections at \$134/hour						
> 6 to ≤12	DJ/NAA	150	1	150	6.1	\$122,610
> 12 to ≤ 50	DJ/NAA	153	4	612	6.1	\$500,249
> 50	DJ/NAA	118	12	1,416	6.1	\$1,157,438
Subtotal:		421		2,178		\$1,780,297
Contractor Inspections at \$134/hour						
> 6 to ≤12	ROS	140	1	140	6.4**	\$120,064
> 12 to ≤ 50	ROS	148	4	592	6.4	\$507,699
> 50	ROS	52	12	624	6.4	\$535,142
Subtotal:		340		1,356		\$1,162,905
Total:		5,310		24,840		\$16,399,504

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Repair costs associated with these inspections are set forth in Table 28 and fuel savings associated with these repairs are set forth in Table 29.

Table 28: Well Production Facility Leak Repair Costs

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Number of Leaks per Tank	Total Leak Repair Time per Tank [hours]	Total Annual Repair Cost
> 6 to ≤12	DJ/NAA	1,095	17.0	11.8	\$855,887
> 12 to ≤ 50	DJ/NAA	2,600	25.5	17.7	\$3,048,365
> 50	DJ/NAA	811	34.1	23.6	\$1,267,807
Subtotal:		4,506			\$5,172,059
> 6 to ≤12	ROS	313	9.7	7.7	\$159,645
> 12 to ≤ 50	ROS	324	14.5	11.6	\$248,956
> 50	ROS	167	19.4	15.4	\$170,356
Subtotal:		804			\$578,957
Total:		5,310			\$5,751,016

Table 29: Well Production Facility Recovered Natural Gas Value from Leak Repairs

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities	Total Recovered Natural Gas per tank [tons/year]	Value of Natural Gas [\$ /MCF]	Conversion Factor [MCF/ton]	Total Annual Value of Recovered Natural Gas
> 6 to ≤12	DJ/NAA	1,095	4.6	\$3.5	35.8	\$631,136
> 12 to ≤ 50	DJ/NAA	2,600	7.0	\$3.5	35.8	\$2,280,460
> 50	DJ/NAA	811	9.3	\$3.5	35.8	\$945,050
Subtotal:		4,506				\$3,856,646
> 6 to ≤12	ROS	313	4.6	\$3.5	35.8	\$180,407
> 12 to ≤ 50	ROS	324	6.8	\$3.5	35.8	\$276,061
> 50	ROS	167	9.1	\$3.5	35.8	\$190,418
Subtotal:		804				\$646,886
Total:		5,310				\$4,503,532

The total net costs for well production facility station LDAR are set forth in Table 30.

Table 30: Well Production Facility –Net Leak Inspection and Repair Costs

Uncont. VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Total Annual Inspection Cost		Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
		In-House	Contractor			
> 6 to ≤12	DJ/NAA	\$593,744	\$122,610	\$855,887	\$631,136	\$941,105
> 12 to ≤ 50	DJ/NAA	\$6,149,800	\$500,249	\$3,048,365	\$2,280,460	\$7,417,954
> 50	DJ/NAA	\$5,224,943	\$1,157,438	\$1,267,807	\$945,050	\$6,705,138
Subtotal:		\$11,968,487	\$1,780,297	\$5,172,059	\$3,856,646	\$15,064,197
> 6 to ≤12	ROS	\$114,042	\$120,064	\$159,645	\$180,407	\$213,344
> 12 to ≤ 50	ROS	\$464,077	\$507,699	\$248,956	\$276,061	\$944,671
> 50	ROS	\$909,696	\$535,142	\$170,356	\$190,418	\$1,424,776
Subtotal:		\$1,487,815	\$1,162,905	\$578,957	\$646,886	\$2,582,791
Total:		\$13,456,302	\$2,943,202	\$5,751,016	\$4,503,532	\$17,646,988

Additionally, based on information in the Division's APEN reporting system, there are 2,799 well production facilities with uncontrolled actual storage tank emissions less than or equal to 6 tons per year that will be subject to a one-time instrument based inspection. The one-time cost for inspecting these facilities is estimated to be \$1,639,239.²⁸

Table 31: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled VOC at Storage Tank Battery Tier [tpy]	O&G Basin	Number of Facilities and Inspections	Inspection Time Per Inspection [hours]	Inspection Type/Hourly Rate	Total Annual Inspection Cost
≤ 6	DJ/NAA	1,598	6.1	In-House/\$103	\$1,004,023
≤ 6	ROS	500	3.4	In-House/\$103	\$175,100
Subtotal:		2,098			\$1,179,123
≤ 6	DJ/NAA	389	6.1	Contractor/\$134	\$317,969
≤ 6	ROS	312	3.4	Contractor/\$134	\$142,147
Subtotal:		701			\$460,116

²⁸ To calculate these costs the Division used the same methodology applicable to periodic inspection costs, except that it did not include additional travel time for facilities outside the non-attainment area based on the assumption that companies could coordinate these one-time inspections with visits to the facilities for other purposes.

Total: 2,799

\$1,639,239

The Division recognizes that there are likely additional facilities not included in the APEN database that will be subject to this one-time inspection requirement, thereby increasing the overall cost of the one-time inspection requirement. Roughly speaking the additional cost for one-time inspections will be proportional to the number of additional facilities, so that if there are twice the number of facilities, the overall cost will be approximately double. However, because the expected emission reduction benefit will increase roughly at the same rate as the cost of inspections, the overall cost-effectiveness of the one-time inspection requirement should remain approximately the same regardless of the number of facilities.

Finally, the Division calculated the cost effectiveness of the proposed leak detection and repair requirements based on the costs identified above and the projected emission reductions. To determine emission reductions the Division first calculated pre-inspection program VOC and methane emissions based on the reported component counts, standard emission factors for these components, and the average fraction of VOC and non-VOC emissions (methane/ethane). Based on EPA reported information, the Division calculated a 40% reduction for annual inspections, a 60% reduction for quarterly inspections, and an 80% reduction for monthly inspections.

Using this information the Division calculated that the total emission reductions from leaks at compressor stations will be 1,107 tpy VOC and 2,321 tons per year methane/ethane.

Table 32: Compressor Station Leak Inspection Emission Reductions

Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	LDAR Program Reduction %	Fugitive VOC Emissions for each CS tier [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each CS tier [tpy]	Total Methane-Ethane Reduction [tpy]
≤ 12	147	40%	10.1	588.0	15.5	911.4
> 12 to ≤ 50	53	60%	16.4	519.4	44.3	1,409.8
> 50		80%				
	200			1,107.4		2,321.1

Based on these reductions, the cost effectiveness of conducting leak inspections at compressor stations is estimated to be \$994/ton VOC and \$474/ton methane/ethane.

Table 33: Compressor Station Leak Inspection Cost Effectiveness using IR Camera/Method 21							
Comp. Station Fugitive VOC Tier [tpy]	Number of Comp Stations	Total Net Annual Inspection & Repair Cost	LDAR Program Reduction %	Total VOC Reduction [tpy]	VOC Control Cost [\$ /ton]	Total Methane-Ethane Reduction [tpy]	Methane-Ethane Control Cost [\$ /ton]
≤ 12	147	\$244,882	40%	588.0	\$416	911.4	\$269
> 12 to ≤ 50	53	\$855,650	60%	519.4	\$1,647	1,409.8	\$607
> 50			80%				
	200	\$1,100,531		1,107.4	\$994	2,321.2	\$474

For well production facilities the total emission reductions is estimated to be 14,015 tpy VOC and 21,927 tpy methane/ethane.

Table 34: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier [tpy]	Number of Facilities	LDAR Program Reduction %	Fugitive VOC Emissions for each Tank Battery [tpy]	Total VOC Reduction [tpy]	Fugitive Methane-Ethane Emissions for each Tank Battery [tpy]	Total Methane-Ethane Reduction [tpy]
DJ/NAA						
> 6 to ≤ 12	1,095	40%	4.6	1,971.0	7.0	3,066.0
> 12 to ≤ 50	2,600	60%	4.6	7,280.0	7.0	10,920.0
> 50	811	80%	4.6	3,000.7	7.0	4,541.6
Subtotal:	4,506			12,251.7		18,527.6
Remainder of State						
> 6 to ≤ 12	313	40%	3.9	500.8	7.5	939.0
> 12 to ≤ 50	324	60%	3.9	745.2	7.5	1,458.0
> 50	167	80%	3.9	517.7	7.5	1,002.0
Subtotal:	804			1,763.7		3,399.0
Total:	5,310			14,015.4		21,926.6

Based on these reductions, the cost effectiveness of conducting ongoing instrument based inspections at well production facilities is estimated to be \$1,259/ton VOC and \$805/ton methane/ethane.

Table 35: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21							
Uncont. VOC at Tank	Number of Tanks	Total Net Annual Leak	LDAR Program	Total VOC	VOC Control	Total Methane-	Methane-Ethane

Battery Tier [tpy]		Inspection & Repair Cost	Reduction %	Reduction [tpy]	Cost [\$/ton]	Ethane Reduction [tpy]	Control Cost [\$/ton]
DJ/NAA							
> 6 to ≤ 12	1,095	\$941,105	40%	1,971.0	\$477	3,066.0	\$307
> 12 to ≤ 50	2,600	\$7,417,954	60%	7,280.0	\$1,019	10,920.0	\$679
> 50	811	\$6,705,138	80%	3,000.7	\$2,235	4,541.6	\$1,476
Subtotal:	4,506	\$15,064,197		12,251.7	\$1,230	18,527.6	\$813
ROS							
> 6 to ≤ 12	313	\$213,344	40%	500.8	\$426	939.0	\$227
> 12 to ≤ 50	324	\$944,671	60%	745.2	\$1,268	1,458.0	\$648
> 50	167	\$1,424,776	80%	517.7	\$2,752	1,002.0	\$1,422
Subtotal:	804	\$2,582,791		1,763.7	\$1,464	3,399.0	\$760
Total:	5,310	\$17,646,988		14,015.4	\$1,259	21,926.6	\$805

Additionally, for the 2,799 well production facilities with uncontrolled actual storage tank emissions equal to or less than 6 tons per year that will be subject to a one-time instrument based inspection, the calculated one-time benefit is 4,876 tons VOC and 8,000 tons methane/ethane, assuming a 40% reduction. Based on these reductions, for the one-time inspections of well production facilities with tanks that are less than six tons per year the cost effectiveness of the proposed rule is calculated to be \$409/ton VOC and \$249/ton methane/ethane.

In addition to the component leak detection and repair requirements for compressor stations and well production facilities, the Division's proposal includes additional requirements designed to reduce leaks from open ended lines and valves, reciprocating compressors, and wet seal centrifugal compressors. These requirements mirror existing cost-effective requirements set forth in NSPS OOOO and other federal rules.

For open ended valves and lines at well production facilities and compressor stations, the proposal requires that each such valve or line be equipped with a cap, blind flange, plug or second valve commencing January 1, 2015. Alternatively, the Division's proposal allows operators to treat open-ended lines and valves as components and monitor them in accordance with the proposed LDAR requirements. As part of its LDAR cost effectiveness analysis detailed above, the Division included the costs of inspecting and repairing open ended lines and valves in its overall calculation. While the Division has not identified specific information regarding the costs and emission reduction benefits from equipping open ended lines with a cap, blind flange, plug or second valve, it notes that the requirement has been included in a multitude of federal air quality rules, including NSPS VV, NSPS VVa, MACT H, MACT CC, MACT TT, MACT YY, MACT GGG, MACT III, and MACT MMM, dating back as far as 1983. Based on this widespread prevalence in federal rules the Division believes that the proposal represents a simple

and cost-effective strategy to reduce emissions from open-ended lines and valves. However, to the extent that it is not cost effective in a specific case operators can employ the monitoring option allowed for under the proposed rule.

For centrifugal compressors, the Division's proposal requires that hydrocarbon emissions from wet seal fluid degassing systems be reduced by 95% beginning January 1, 2015. In its updated technical support document for NSPS OOOO, EPA analyzed the cost-effectiveness of this strategy and found that accounting revenues from the capture of additional product, implementation of this strategy would on a per unit basis reduce VOC emissions by 19.5 tpy, methane emissions by 216.2 tpy, and result in a net cost savings of \$46,974.²⁹

With respect to reciprocating compressors, the Division's proposal requires that commencing January 1, 2015, the rod packing for reciprocating compressors located at compressor stations be replaced every 26,000 hours of operation or every 36 months. As with the requirement for centrifugal compressors, EPA analyzed this proposed strategy as part of the adoption of NSPS OOOO and found that it was a cost-effective way to reduce VOC and methane emissions. Specifically, EPA found that per compressor the strategy reduces VOC emissions by 1.9 tons per year and methane emissions by 6.8 tons per year, at a net cost of \$43 per ton of VOC reduced and \$12 per ton of methane reduced.³⁰

D. Auto Igniter Requirements on Existing Flare Control Devices Outside the Non-Attainment Area

Unlike the non-attainment area, flares used to control emissions at condensate tank batteries and glycol dehydration units outside the NAA are not required to have auto-igniters. The Division is proposing that all flares used to control emissions at condensate tank batteries and glycol dehydration units statewide should have auto igniters. Based on an analysis of the APEN database, the Division estimates the statewide number of existing flare control devices without auto-igniters on condensate tank batteries, glycol dehydration, produced water tanks, and crude oil tanks is 796. The reported uncontrolled actual emissions from these units are 53,101.1 tons per year VOC.

The estimated annualized cost for an auto-igniter is \$475 based on information that the industry provided to the Division in 2008, adjusted for inflation.³¹

Table 36: Auto Igniter Control Device – Retrofit Cost Analysis

Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs

²⁹ See APCD-PHS Ex. HHHH pp. 6-1—6-3

³⁰ See initial technical support document for NSPS OOOO (submitted as DGS-PHS Ex. NN) at pp. 6-12—6-17.

³¹ See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008.

Auto Igniter	\$1,648			
Freight/Engineering		\$200		
Flare Installation		\$500		
Maintenance			\$200	
Subtotal Costs	\$1,648	\$700	\$200	
Annualized Costs*	\$228.4	\$46.7	\$200	\$475

* Annualized over 15 years at 5% ROR

The Division estimates that a flare without an auto-igniter could experience about 3% pilot light downtime (262.8 hours) over a one year period. During the downtime period, any VOC emissions routed to the flare control device are uncontrolled. Based on the total uncontrolled actual emissions of 53,101.1 tons per year VOC from units equipped with flares without auto-igniters, the emissions during this downtime period will be 1,593.1 tons of VOC. The Division assumes that as a result of the installation of an auto-igniter, the amount of downtime can be eliminated, for a total emission reduction of 1,251.7 tons/year. Given that the annualized cost of installing 796 auto-igniters is about \$378,100 the estimated cost effectiveness of this strategy is about \$302 per ton of VOC reduced.

Table 37: Auto Igniter Emission Reduction Estimates

Source Type for Existing Flare Controls	Number of Auto Igniters	Uncontrolled VOC [tpy]	Uncontrolled VOC Using 3% Downtime [tpy]	Total VOC Reduction [tpy]
Condensate Tanks	490	31,170.6	935.1	666.3
Dehydrators	131	16,372.0	491.2	466.6
Produced Water Tanks	172	4,842.2	145.3	103.5
Crude Oil Tanks	3	716.3	21.5	15.3
	796	53,101.1	1,593.1	1251.7

* Dehydrator flares assumed to have 100% capture and 95% destruction – thus 95% control. Tank flares are assumed to have 75% capture and 95% destruction – thus 71.25% control.

Table 38: Auto Igniter Control Cost Estimates (Outside NAA)

Number	Each Auto-Igniter Annualized Costs	Total Annualized Costs	VOC Reduction* [tons/year]	Control Costs [\$ /ton]
796	\$475	\$378,100	1,251.7	\$302

E. Expanding Low Bleed Pneumatics Requirements Statewide

As part of the 2008 Ozone Action Plan the AQCC adopted regulatory requirements mandating the use of low bleed pneumatic controllers in the non-attainment area. The current proposal would expand this requirement statewide.

To estimate the costs and benefits of this proposed strategy, the Division estimated the number of high-bleed pneumatic devices based on Independent Petroleum Association of the Mountain States (IPAMS) survey data from 2006, which identified the average number of such devices per well. The Division then scaled this number up based on 2012 Colorado Oil and Gas Conservation Commission (COGCC) well count data. Based on this methodology, there are 9,877 high-bleed pneumatic devices outside the nonattainment area. Assuming a 95% replacement rate, the proposed rule will result in the replacement of 9,384 high bleed devices with low bleed devices. Based on this count, and the average emission reductions per device replaced identified in the IPAMS survey, the projected benefit from the proposed expansion of the current non-attainment area low bleed pneumatic rule will be approximately 14,921 tons per year VOC (40.9 tons per day). Based on this information and assuming an 80/20 ratio of methane/ethane to VOC by volume, the estimated methane/ethane reduction from this strategy is 17,100 tons per year.

The average retrofit cost of a high-bleed pneumatic device is based on costs from the 2008 cost study³² adjusted for inflation. Utilizing this methodology, the annualized cost for each replaced device is \$169. However, because the reduced bleed rate results in more natural gas being sold, operators will receive additional revenue as a result of the installation of a low bleed device. Based on the emission reduction data from the IPAMS survey and August 2013 spot prices for natural gas, the estimated average value of the recovered gas will be \$1,268 for each device replaced. As a result, the net annual gain is \$1,084 per replaced device. Based on this projected net gain, this strategy will pay for itself in approximately one year and two months.

<i>Table 39: Replace High-Bleed Pneumatics with Low-Bleed Pneumatics – Annualized Cost Analysis*</i>				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Low/No Bleed Device*	\$1,033			
Labor		\$387		
Value of NG Saved**			\$(1,268)	
Maintenance			\$16	
Subtotal Costs	\$1,033	\$387	\$(1,253)	

³² See “Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination,” Lesair Environmental, Inc., June 2008.

Annualized Costs***	\$143	\$26	\$(1,253)	\$(1,084)

* Control device costs were developed based on an Oil and Gas Cost Study and information submitted by industry in 2008. However, those costs were escalated by 9.85% to reflect CPI-U increases that have occurred since 2008.

** Recovered NG fuel costs \$3.5/MCF (Henry Hub Spot Price - Aug. 2013)

*** Annualized over 15 years at 5% ROR

Assuming 9,384 total devices replaced, adoption of this strategy will result in \$10,169,441 in annual cost savings.

Table 40: Low Bleed Pneumatic Control Cost Estimates (Outside NAA)				
Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
9,384	\$(1,084)	\$(10,169,441)	14,921	NA

The proposed rule also requires the use of no-bleed pneumatic devices if it is technically and economically feasible and where on-site electrical grid power is being used. Use of no-bleed pneumatic devices will further reduce emissions relative to the use of low bleed devices. Since the Division does not have information indicating the number of no-bleed pneumatic devices that could be required, it is not possible to calculate the cost effectiveness of this particular provision. However, because the proposed requirement expressly provides that use of no-bleed pneumatics is only required where economically feasible the Division assumes that any use of no-bleed pneumatic devices pursuant to the proposed rule will be cost effective.

F. Require Newly Constructed Gas Wells be Connected to a Pipeline or Route Emissions to A Control Device

Currently in Colorado, natural gas produced at oil and gas sites is typically routed to a transmission pipeline. With the advent of new drilling technologies, additional areas of the state without established pipeline infrastructure may experience oil and gas exploration and production. This can lead to instances where produced gas is vented or flared instead of being put into a transmission line. To date the Division has identified 61 instances in Colorado where this is occurring. To address this, the proposed regulation provides that for newly constructed, hydraulically fractured, or recompleted wells, the gas stream must either be connected to a pipeline or routed to a control device achieving 95% control efficiency. Currently all of the sites that are not routed to a pipeline are flaring their gas. Additionally, because venting the gas at such sites would create a safety issue, the Division assumes that in the limited future instances where the gas stream is not routed to a pipeline, operators will route the emissions to a flare or other control device. Accordingly, adoption of this portion of the proposed regulation will likely not result in any additional costs.

G. Control Requirements for Glycol Dehydrators

The Division is proposing to revise the control requirements applicable to glycol natural gas dehydrators statewide. Currently any glycol natural gas dehydrator with uncontrolled actual VOC emissions of 2 tons per year or greater that is located at a facility where the sum of uncontrolled actual emissions from all of the dehydrators at the facility is greater than 15 tons per year, must be equipped with a control device that reduces emissions by at least 90%. Under the Division's proposal, all existing dehydrators with uncontrolled actual emissions of 6 tons per year or greater VOC must be controlled with air pollution control equipment achieving at least 95% reduction. The proposal also provides that existing dehydrators with uncontrolled actual emissions of two tons per year or greater VOC must be controlled if they are located within 1,320 feet of a building unit or designated outside activity area. Finally, the proposal requires that all new dehydrators with uncontrolled actual emissions of two tons per year or greater VOC be controlled. The Division assumes that newly subject glycol dehydrators will be controlled using flares that achieve a 95% destruction efficiency. The annual cost for these units is \$6,286.80 per unit. See Section IV.A.1. above.

Based on industry reported APEN data, there are currently 433 uncontrolled dehydrators at sites with total dehydrator uncontrolled actual VOC emissions below 15 tpy. Of these, 217 have uncontrolled actual emissions greater than or equal to two tons per year. The total uncontrolled actual emissions for these 217 dehydrators are 1,827.5 tpy VOC. There are 148 dehydrators with uncontrolled actual VOC emissions greater than or equal to 6 tons per year. The total uncontrolled actual emissions for these 148 dehydrators are 1,549.7 tpy VOC. Currently, the Division does not have information regarding the location of these uncontrolled dehydrators relative to a building unit or designated outside activity area. Assuming, however, that all of the 2 to 6 ton dehydrators are located within 1,320 feet of a building unit or designated outside activity area and thus will require a control, the proposed requirement will reduce 1,736 tpy of VOC at a cost effectiveness of \$786/ton VOC. For the smallest dehydrator subject to the proposed rule (2 ton/year) the cost effectiveness is estimated to be \$3309 per ton of VOC reduced.

Table 41: Dehydrator Control Cost Estimates (2 TPY Control Threshold)

Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
217	\$6,286.8	\$1,364,236	1,736	\$786

Conversely, if it is assumed that none of the 2 to 6 ton existing dehydrators will require controls the proposed requirement will reduce 1,472 tpy of VOC at a cost effectiveness of \$632/ton VOC.

Table 42: Dehydrator Control Cost Estimates (6 TPY Control Threshold)				
Number	Each Device Annualized Costs	Total Annualized Costs	VOC Reduction [tons/year]	Control Costs [\$ /ton]
148	\$6,286.8	\$930,446	1,472	\$632

H. Control Requirements for Downhole Well Maintenance and Liquids Unloading Events

Historically, Colorado has not regulated air emissions from temporary activities such as well completions and well maintenance at well production sites. Recently, however, EPA, Colorado and other jurisdictions have identified these activities as potentially large sources of emissions from the oil and gas sector. In recognition of this, the Colorado Oil and Gas Conservation Commission and more recently EPA have adopted requirements for green completions to reduce hydrocarbon emissions during well completion activities. The Division is now proposing additional regulatory requirements designed to reduce emissions during well maintenance.

Well maintenance is required when, over time, liquids build up inside the well and reduce gas and oil flow out of the well. To remove these liquids and improve flow, the liquids are blown out of the well under pressure. This process is typically referred to as liquids load-out or well blow-down. Historically emissions from well blow-downs are vented to the atmosphere. EPA has established emission factors for liquid unloading based on fluid equilibrium calculations to calculate the amount of gas needed to blow down a column of fluids blocking a well and Natural Gas STAR partner data on the amount of additional venting after a blow-down. Based on its calculations, EPA estimated that in the United States the combined methane emissions for liquid unloading and well completions in 2009, was 217 billion cubic feet, and that liquid unloading may account for 33% of the uncontrolled methane emissions from the natural gas industry.³³ For Colorado, the Division has calculated that emissions from well blow-downs in 2008 were approximately 9,306 tons of VOC per year.

To address these emissions, the Division is proposing a two pronged requirement aimed at reducing the number of required liquids unloading events and reducing the amount of emissions vented to the atmosphere during these events. Under the Division's proposal operators shall use best management practices to minimize the need for venting associated with downhole maintenance and liquids unloading. For example, EPA's Gas Star program advocates the use of a plunger lift system to reduce the need for liquids unloading. According to EPA, use of a plunger lift will on average pay for itself in less than one year through the capture of additional product. The Division's proposal also provides that emissions during well maintenance and liquids unloading shall be captured or controlled using best management practices to limit venting during well blow-downs to the maximum extent practicable. Based on information provided by Environmental Defense Fund, application of these requirements could result in annual VOC reductions of 2,881 tons and methane reductions of 19,207 tons per year. Given the

³³ See EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks, 1990-2009*, April, 2011.

wide variety of practices that this could entail, the Division currently does not have information about the precise cost-effectiveness of this provision. Given the fact that the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

I. Division Regulation Number 7 Implementation Costs

The Division will largely implement the provisions of its proposal through its oil and gas inspection team. This team currently consists of 9 full time inspectors and 4 term limited inspectors. In 2012, in response to the growth in the oil and gas industry in Colorado, the legislature approved increasing the size of the inspection team from 6 inspectors to 9. In 2013, the legislature appropriated additional funds to hire 4 term limited inspectors to conduct infra-red camera inspections at well production facilities in Colorado. The term for these positions runs through June of 2015, but could be extended by the legislature if warranted. The additional inspectors provided during the 2012 and 2013 legislative sessions has significantly expanded the capabilities of the oil and gas inspection team, which will further enable the Division to implement and enforce the proposed requirements if the AQCC chooses to adopt the Division's proposal. The total projected annual cost to the Division for the oil and gas inspection team in fiscal year 2013-14 is \$1,305,304, which includes salary costs, fringe benefits, operating costs (including vehicles, field equipment, and office equipment), travel training and indirect costs.

J. Regulation Number 3 Costs

The proposed revisions to Regulation remove the requirement for sources subject to either a NSPS or NESHAP/MACT adopted into Regulation Number 6, Part A or Number 8, Parts A, C, D, and E to file an APEN and obtain a minor source permit regardless of whether their emissions exceed the reporting or permitting thresholds ("catch-all provisions"). They also simplify the non-criteria reportable pollutant de minimis determination to 250 pounds per year of any individual non-criteria reportable pollutant; and remove the crude oil storage tank permitting exemptions. There is little to no economic impact to the regulated community due to these revisions.

Catch-all Provisions

Removal of the catchall provisions will reduce permitting, reporting and associated cost burdens for the regulated community. By reducing permitting and reporting, the proposed revision will also reduce costs to the Division associated with these activities. There are no anticipated costs to either the regulated community or the government associated with this proposed revision.

Non-Criteria Reportable Pollutants

Revision of the threshold for non-criteria reportable pollutants could result in either cost savings or additional costs to the regulated community depending on the source. Sources that are required to report non-criteria reportable pollutants must pay an emission fee of \$152.90 per ton. Currently Regulation Number 3 contains a complex reporting formula involving multiple and different thresholds, some of which are above and some of which are below the proposed 250 pound threshold. Accordingly, changing the threshold will reduce costs for some sources, while increasing costs for other sources. Based on an analysis of reported emissions, the proposed threshold change will reduce industry fees paid to the Division by \$47,702 per year. Because the emissions from sources that are not currently reporting is unknown it is not possible to calculate the additional costs to sources that will be required to report for the first time under the new proposed threshold.

Additionally, beyond the actual emission fees, the current reporting system is very complex resulting in numerous hours being spent by both the regulated community and Division staff in determining whether reporting is required. Simplifying the reporting system will eliminate the costs associated with this analysis.

Crude Oil Storage Tanks

There are minimal direct costs projected for the affected businesses and industrial sector associated with the removal of the crude oil storage tank permitting exemption. Stationary sources with crude oil storage tanks whose uncontrolled actual emissions exceed the minor source or operating permit thresholds would be required to obtain a permit. In 2008, the Commission removed the reporting exemption for crude oil storage tanks to improve the inventory of uncontrolled actual emissions. Based on the reported data, removal of the crude oil storage tank minor source permitting exemption would require these tanks to obtain minor source permits at a cost of approximately \$19,500. Additionally, permitting these sources will result in some costs to the Division. Given the small number of these sources and the fact that permitting fees offset most of the costs associated with drafting permits, the anticipated cost to the Division is minimal.

V. ADVERSE EFFECTS ON THE ECONOMY

The oil and gas industry plays an important role in Colorado's economy. The industry is a significant employer of highly skilled and well-paid employees. The industry generates large revenues and pays significant taxes in the state. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, emissions from the oil and gas industry represent a significant portion of the total VOC emissions both in the non-attainment area and throughout the rest of the state. The Division's proposal is intended to achieve significant reductions in air emissions without imposing unreasonable costs that could stifle economic activity.

As discussed above, the Division's proposal is projected to result in a net annual cost to the industry of approximately \$42.4 million. As with any increase in costs, the costs associated with the Division's proposal could have some adverse impact on economic activity associated with the oil and gas industry in Colorado. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. Moreover, given the relative size of the costs of the current proposal to the overall size of the industry, the total impact of these costs will likely be minimal. In 2012, for example, oil and gas producers in Colorado sold 48,450,717 barrels of oil and 1,661,073,176 MCF of natural gas. Based on the current price of oil, \$96 per barrel, and assuming a price for natural gas of \$3.5/MCF³⁴, annual revenue from the sale of oil and gas in Colorado based on 2012 production levels is approximately \$10.5 billion. Accordingly, the net cost of the Division's proposal is approximately 0.4% of the annual revenues. Given this small percentage, the Division's proposal is unlikely to have any appreciable impact on the economic competitiveness of the industry as a whole. This conclusion is bolstered by the fact that several of the largest oil and gas companies in the state (Anadarko Petroleum Corp., Noble Energy, Inc., Encana Oil and Gas USA, and DCP Midstream) fully support the Division's proposed revisions. Collectively, the Division estimates that these companies will bear approximately 75% of the total annual cost of the proposed rules.

While it is unlikely that the costs associated with the proposed revisions will have any meaningfully adverse impacts on the competitiveness of the industry as a whole in Colorado, the costs could incrementally add to the current costs associated with operating marginally producing wells. This could potentially lead to some wells being shut in and the resultant economic consequences of these shut-ins including lost production revenue, lost royalties, lost severance taxes and potentially lost jobs. To mitigate against this possibility, the Division's has crafted a tiered proposal that triggers requirements based on emission thresholds that are directly tied to production. Based on this, the truly small facilities are subject to less requirements and less costs; for example, only a one-time instrument-based leak inspection, which the Division estimates will cost approximately \$712 .

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful negative impact on the general public or small businesses that purchase natural gas and other petroleum products. Oil and natural gas are sold on international and national markets, making it extremely unlikely that any increase in production costs in Colorado will be reflected in prices for Colorado consumers.

VI. ALTERNATIVE PROPOSALS

In addition to the Division's proposal, various parties to the rulemaking have submitted 6 different alternative proposals for the AQCC to consider. Some of these proposals request that the AQCC adopt additional requirements that go beyond the Division's proposal, while other

³⁴ The Division assumed a price per MCF of \$3.50 throughout its analysis; however, natural gas prices are currently around \$5 per MCF, suggesting that the Division has underestimated the value of gas saved by the proposal.

alternatives request that the AQCC limit aspects of the Division's proposed revisions. In some cases, the parties submitting the proposals included analyses estimating the costs and benefits associated with their proposals. The section below identifies each of the submitted proposals, discusses how the proposals differ from the Division's proposal, and addresses the projected costs and benefits of each proposal.³⁵

Joint Industry Work Group

A collection of oil and gas companies and industry trade groups have submitted an alternative proposal seeking to limit the requirements set forth in the Division's proposal.³⁶ Specifically, the Joint Industry Work Group request that the AQCC limit the Division's proposal in the following respects: 1) restrict all proposed requirements to the front range ozone non-attainment area; 2) reduce the required frequency proposed for leak inspection and repair; 3) eliminate the proposed requirements for dehydrators; 4) limit proposed requirements for compressor seals and open-ended lines to compressor stations; and 5) eliminate proposed requirements related to well maintenance and liquids unloading. In addition to these proposed limitations, the Joint Industry Work Group have proposed a number of additional changes, which could have some minimal additional impacts on the costs and benefits of the proposal.

Since the Joint Industry Group did not submit an economic analysis detailing the projected costs and benefits of their alternative proposal,³⁷ the Division has conducted an analysis of the Joint Industry Work Group alternative proposal utilizing the same methodologies and assumptions detailed in Section IV above. Based on this analysis, the Division estimates that the Joint Industry Work Group alternative proposal would have a net cost³⁸ to the regulated community of approximately \$32.2 million, and would reduce emissions of VOCs by 56,525 tons per year and methane/ethane by 33,058 tons per year. The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new

³⁵ In instances where a party submitted an analysis of the costs and benefits associated with their proposal, such analysis is attached. Where parties submitted proposal without an analysis of their own proposal, the Division has endeavored to analyze the costs and benefits of these proposals using the same methodologies used to analyze the costs and benefits of the Division's proposal.

³⁶ A copy of this alternative proposal is attached to this Cost Benefit Analysis as Exhibit A.

³⁷ The group did submit an analysis of the Division's proposal showing substantially higher costs than reflected in the Division's analysis. A copy of this analysis is attached hereto as Exhibit B. It should be noted that while the Joint Industry Work Group predicts much higher costs from the Division's proposals, Anadarko Petroleum Corporation, Noble Energy, Inc. and Encana Oil and Gas USA have submitted information during the rulemaking supporting the reasonableness of the Division's cost and benefit calculations. Submissions from these companies can be found at the following link.

<http://ft.dphe.state.co.us/apc/aqcc/REBUTTAL%20STATEMENTS,%20EXHIBITS%20%26%20ALT%20PROPOSAL%20REVISIONS/>

³⁸ Net cost reflects the cost of implementing the proposed strategy less the value of the additional product captured as a result of the proposed strategies.

inspector jobs attributable to the proposal. Finally, because the Joint Industry Work Group proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section III above would be reduced.

WPX Energy

WPX is the largest natural gas producer in the state. In the current rulemaking WPX has offered an alternative proposal that would decrease the total number of leak inspections by allowing well production facilities with low leak rates during two consecutive inspections to reduce inspection frequency from monthly to quarterly, or from quarterly to annually depending on the size of the facility.³⁹ While it is difficult to predict in advance how many facilities would be able to take advantage of this reduced inspection rate, for the purposes of this Cost Benefit Analysis the Division assumes that one half of the facilities would be able to utilize the reduced frequency. Based on this assumption, adoption of WPX's alternative proposal would reduce the total net annual cost of the proposed revisions from approximately \$42.4 million to approximately \$36.8 million. This change would also decrease the amount of emission reductions from the Division's proposal by 1,845 tons per year of VOC and 2,757 tons per year of methane/ethane.

The decrease in net costs should have some positive impact on the indirect costs associated with potential well shut-ins, but the Division is unable to reasonably calculate this impact. Given the relatively small difference in net costs between the two proposals, any positive impact should be fairly small. The decrease in costs relative to the Division's proposal includes a decrease in the number of facility inspections, which would result in fewer new inspector jobs attributable to the proposal. Based on the number of inspection hours for each proposal, the number of new inspector jobs would decrease. Finally, because the WPX proposal would result in less VOC and methane emission reductions, the economic benefits associated with these reductions discussed in Section III above would be reduced.

Conservation Groups

As part of the rulemaking a number of conservation groups have submitted an alternative proposal requiring additional leak detection inspections for well production facilities and compressor stations relative to the Division's proposal. In addition, the Conservation Groups' alternative proposal increases the number of pneumatic devices that would need to be retrofitted. A copy of the Conservation Groups' alternative proposal is attached as Exhibit D. Additionally, their analysis of the costs and benefits associated with their alternative proposal is attached as Exhibit E.

³⁹ In addition to this change, WPX has proposed a limited number of additional changes and clarifications that do not impact the cost and benefit calculations conducted for the Division's proposal. A copy of WPX's alternative proposal is attached as Exhibit C.

Local Community Organizations

A group of local community organizations have submitted an alternative proposal aimed at increasing the stringency of the Division's proposal for facilities that are located within 1,320 feet of a building unit or designated outdoor activity area. Specifically, for such facilities the Local Community Organizations' alternative proposal would decrease the threshold for controls from petroleum storage tanks from 6 tons per year (as proposed by the Division) to two tons per year. Additionally, facilities located within 1,320 feet of these designated areas would be subject to a more stringent leak inspection schedule. Copies of the Local Community Organizations' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits F and G.

Local Government Coalition

The Local Government Coalition consists of a number of county and city governments including Adams County, Boulder County, La Plata County, Pitkin County and San Miguel County, Fort Collins, the City of Boulder, and the City and County of Denver. In their alternative proposal, the Local Government Coalition seeks to increase the number of leak detection inspections for compressor stations and well production facilities relative to the Division's proposal. The Local Government Coalition also seeks to require that well production facilities be tied in to a gas gathering line within 90 days after the date of first production, unless the Division approves an extension of this deadline. Copies of the Local Government Coalition's alternative proposal and documents assessing the costs and benefits of that proposal are attached hereto as Exhibits H through L.

Worldwide Liquid Solutions, LLC

Worldwide Liquid Solutions (WLS) is a manufacturer of emission reduction technology designed to control VOC emissions from petroleum storage tanks. According to WLS, their emission reduction technology cannot control methane and ethane and therefore cannot meet the control standards for tanks reflected in the Division proposal. To address this, WLS has submitted an alternative proposal that would only require reductions of VOCs from tanks and not methane/ethane. As an alternative to their alternative, WLS has proposed rejecting all of the proposed changes to Regulation No. 7 set forth in the Division's proposal. Copies of WLS' alternative proposal and their assessment of costs and emission reduction benefits are attached as Exhibits M and N.

Conclusion

The Division has in good faith developed this comprehensive Cost-Benefit Analysis that complies with all requirements of 24-4-103(2.5.), C.R.S. The Division believes that the proposal before the AQCC reflects a balanced approach that includes proven and cost effective strategies to reduce emissions from the oil and gas sector, while enabling the sector to continue to grow in

a responsible and protective manner. The Division looks forward to the AQCC's consideration of its proposal and alternate proposals of other parties at the February 2014 hearing.

Attachment 2

**Summary of Cost, Emissions,
and Cost per Ton using the 20 year and 100 year GWP, respectively**

Provision	Annual Cost	Annual Savings	Reductions using 20 year GWP (MT CO ₂ e)	Cost per Ton using 20 year GWP (\$ / MT CO ₂ e reduced)	Cost per Ton using 20 year GWP with Savings (\$ / MT CO ₂ e reduced)	Cost per Ton using 100 year GWP (\$ / MT CO ₂ e reduced)	Cost per Ton with Savings using 100 year GWP (\$ / MT CO ₂ e reduced)
VRU for Tanks	\$4,700,000	\$500,000	540,000	\$9	\$8	\$25	\$23
Reciprocating Compressors	\$260,000	\$180,000	68,000	\$4	\$1	\$11	\$3
LDAR	\$12,900,000	\$1,300,000	490,000	\$26	\$23	\$75	\$68
Pneumatic Devices	\$1,200,000	\$840,000	320,000	\$4	\$1	\$10	\$3
Well Stimulations	\$460,000	\$0	5,000	\$91	\$91	\$262	\$262
Centrifugal Compressors	\$6,000	\$9,000	3,500	\$2	(\$1)	\$5	(\$2)
Monitoring Plan	\$10,600,000	\$0	0	NA	NA	NA	NA
Total	\$30,100,000	\$2,800,000	1,400,000	\$21	\$19	\$62	\$56

Notes:

Bolded numbers indicate changes from the ISOR.

The cost for the LDAR provision went up by almost 30% due to: 1) the cost of inspecting idle wells, which, although already covered under the regulation, was not included in the ISOR Economic Analysis; and 2) using a higher, stakeholder-supplied cost for recordkeeping and reporting. The emission reductions and annual cost savings from gas saved both went down less than 20%, due to correcting the reductions based on the methane content of the gas saved. The cost per MT of CO₂e reduced increased accordingly due to the cost and emission reduction changes described above.

The cost for the Underground Natural Gas Storage Monitoring Plan provision went up by more than 20% due to: 1) the addition of a third stakeholder-supplied scenario; 2) higher cost estimates for ambient monitoring equipment; and 3) using a higher, stakeholder-supplied cost for recordkeeping and reporting across all scenarios.

The proposed regulation's overall total costs, savings, reductions, and cost per MT of CO₂e reduced all changed accordingly due to all of the changes described above.

Revised emission and cost estimates for the Leak Detection and Repair provision

The proposed regulation requires oil and gas facilities to implement a Leak Detection and Repair program (LDAR) for their components, conducting inspections on a quarterly basis. To determine the cost of this segment of the measure, staff estimated the number of components that would be inspected and estimated the cost of performing these inspections.

To determine emissions and costs for LDAR, staff relied on a number of sources for information. Staff used ARB's 2009 Survey (ARB, 2013) for the number of components and discussions with LDAR contractors for cost information. Estimates for emissions from this segment are derived from emission factors and 'super leaker' data from CAPCOA's Implementation Guidelines for Estimating Mass Emissions of Fugitive Hydrocarbon Leaks at Petroleum Facilities (CAPCOA, 1999). According to the 2009 ARB Survey (ARB, 2013), there are about 1,307,931 components that will be affected by the proposed regulation. This includes components for facilities involved in natural gas processing, onshore natural gas production, and natural gas storage. Reciprocating compressors are also part of the LDAR program for our proposed regulation, including compressors at natural gas transmission compressor stations. Based upon assumptions resulting from stakeholder input there would be 11 components per compressor subject to the LDAR program; thus, 979 reciprocating compressors are assumed to have a total of 10,769 components.

Owners and operators are also required to measure natural gas flow from well casing vents located in the field. Accordingly, in order to account for the costs of going into the field for measuring and reporting well casing vent emissions, staff assumed that each well casing vent would count as a component, even though they are not subject to LDAR, but do still have costs comparable to the per-component costs previously mentioned. As a result of assumptions made from stakeholder input, an estimated 20,485 components from well casing vents at heavy oil facilities were added to the component total in the ISOR. Because this is only a reporting requirement, no emissions or reductions were associated with the well casing vent components, so these are not included in the emission calculation. These component counts and costs were accounted for and identified in the ISOR on pages B-34 through B-41.

In addition to these components, idle wells will be inspected. There are an estimated 877 idle wells for dry gas and gas storage and 4,368 idle wells for light oil. Based on data from EPA's 2011 TSD for Oil and Natural Gas sectors, which was the best available data for component counts at a single well site, 9 valves, 37 connectors and 1 open ended line were attributed to each well. This added 41,219 components for the idle dry gas and gas storage wells, and 205,296 components for the idle light oil wells. The total amount of components is 1,585,700, as shown in Table 1.

Table 1

Number of Components	
LDAR Components from Survey	1,307,931
Reciprocating Compressors	10,769
Well Casing Vents	20,485
Idle Dry Gas and Gas Storage Wells	41,219
Idle Light Oil Wells	205,296
Total	1,585,700

Costs of the Leak Detection and Repair Provision

The cost to inspect LDAR components was based on discussions with contractors that perform LDAR inspections and repairs. The per hour cost estimates from contractors for LDAR inspections are summarized in Table B-8 of the ISOR. This cost is estimated to be \$60 per hour for labor, and \$1,500 per facility to account for setup costs. In order to derive an annual cost, staff estimated the number of components that could be inspected in an hour. As stated in the ISOR, staff contacted a number of contractors who perform LDAR work and estimated that, on average, about 34 components per hour can be inspected during an eight hour day, when accounting for travel and preparation time. This also takes into account making a first attempt at a repair if a leak is detected (if accounting only for measurement time, approximately 50 components could be inspected per hour). Following the methodology from the ICF report, the capital cost of larger repairs is not included based upon the assumption that these repairs would need to be made regardless of an LDAR program; because the operator would repair these parts regardless of the LDAR program, the program serves to identify equipment failures sooner, benefiting the operator above and beyond business as usual. Thus only those repairs that are made on a first attempt are accounted for in this estimate, and are reflected in the 34 components per hour value.

Given the estimated average inspection rate of 34 components per hour combined with an estimated person year (PY) at 2,080 work hours per year, a total of 70,720 components that can be inspected during a PY. The total number of PYs required to inspect the components identified in Table 1 is determined by dividing the total number of components by 70,720, then multiplying by four to account for a quarterly inspection. About 89.7 PYs would be needed to inspect the 1,585,700 components quarterly.

Recordkeeping and reporting costs are estimated using ICF's cost estimate for an LDAR program (ICF, 2014). The recordkeeping and reporting estimate is \$15,000 for each PY for an annual program. Since the ARB program is quarterly, the ICF annual

figure is multiplied by four, and then multiplied by the number of PYs estimated above at 89.7. The total recordkeeping and reporting cost is about \$1.3 million annually.

This differs from the recordkeeping and reporting costs in the ISOR, which were estimated by multiplying a small cost per recordkeeping and reporting event by the number of businesses or facilities impacted. The ISOR estimate was less than 20% of the \$1.3 million figure explained above. This change in the method of estimating recordkeeping and reporting costs was based on stakeholder input.

Emissions

Emissions were estimated using emission factors from CAPCOA's guidelines (CAPCOA, 1999), which also accounted for 'super leaker' components. These are components that leak at a rate several times the rate of what is expected from a typical component, and make up the majority of emissions^{1,2,3,4}. Several studies that have reported measurements of CH₄ emissions from natural gas production sites share a common observation - the existence of skewed emissions distributions, where a small number of sites or facilities account for a large proportion of emissions. Such skewed distributions can make estimating and attributing emissions more difficult and in turn can impact the effectiveness of emission reduction policies. Emissions are estimated to be 821,314 MT CO₂e, and reductions are expected to be about 492,789 MT CO₂e using a GWP of 72. Reductions are 60% of the total emissions for quarterly inspections, as estimated in the 2014 ICF report.⁵ Detailed LDAR emission estimates are included in Tables A-1, A-2, and A-3 at the end of this text.

Emissions were initially calculated in the ISOR using the emission factors for total hydrocarbons, but have been modified by taking into account the estimated methane content by multiplying these results by 78.8%, which is the default amount of methane in production gas (API, 2009).

The emissions and costs are summarized in Table 2.

¹ Brandt, A. R., et al. 2014. Methane Leaks from North American Natural Gas Systems. Science. Vol. 343.

² Lamb, Brian K., et al. 2015. Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States.

³ Zavala Araiza, Daniel, et al. 2015. Reconciling Divergent Estimates of Oil and Gas Methane Emissions. Proceedings of the National Academy of Sciences.

⁴ Zavala Araiza, Daniel, et al. 2015. Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites. Environmental Science & Technology. Vol. 49, Pages 8167-8174.

⁵ The ICF report cites research by Colorado and EPA as the basis for this reduction. The EPA citation is the 2011 Technical Support Document for Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards. This document then references EPA's 1995 Protocol for Equipment Leak Emission Estimates, EPA-453/R-95-017

Table 2

Cost and Emissions for LDAR

	Number of Components	Emissions (MT CO2e)	Reductions (MT CO2e)	Quarterly Inspection Cost	Set Up Cost	Recordkeeping and Reporting	Total Cost
Dry Gas, Gas Storage and Gas Processing	1,339,185	774,468	464,681	\$9,453,071	\$1,198,500	\$1,136,186	\$10,864,912
Idle Dry Gas and Gas Storage Wells	41,219	23,122	13,873	\$290,958	\$36,889	\$34,971	\$334,413
Idle Light Oil Wells	205,249	23,724	14,234	\$1,448,816	\$183,687	\$174,137	\$1,665,201
Total	1,585,653	821,314	492,789	\$11,192,845	\$1,419,076	\$1,345,294	\$12,864,526

The Quarterly Inspection cost is calculated as:

Inspection Cost

$$= \frac{\text{Number of Components} \times \$60 \text{ per hour} \times 2080 \text{ hours per year} \times 4 \text{ inspections per year}}{70,720 \text{ Components per PY}}$$

The Set Up cost is calculated as:

$$\text{Set Up Cost} = \frac{\$1,500 \text{ per facility} \times \text{Number of Components} \times 799 \text{ Facilities}}{1,339,185 \text{ Components from Survey}}$$

The Recordkeeping and Reporting cost is calculated as:

$$\text{Recordkeeping and Reporting Cost} = \frac{\$15,000 \times 4 \times \text{Number of Components}}{70,720 \text{ Components per PY}}$$

Savings from the LDAR Provision

Since gas that is emitted from a leaking component comes directly from the process of production, processing, transmission, or storage, all reductions are counted as cost savings. Converting the methane reductions into saved pipeline natural gas by assuming pipeline gas is 94.9 % CH₄ (PG&E, 2016), staff estimates that about 375

million standard cubic feet (scf) of gas will be saved with the LDAR program in the proposed regulation. Using a price of \$3.44 per mscf of pipeline gas results in a savings of about \$1,293,380.

Cost per Ton of the LDAR Provision.

Cost per Ton is estimated to be about \$26 per MT CO₂e reduced, or about \$23 per MT CO₂e reduced with savings, using a GWP of 72. This increased from the estimates of \$17 per MT CO₂e reduced and \$14 per MT CO₂e reduced with savings, which are identified in the ISOR. This increase is due to an increase in recordkeeping and reporting costs, adjusted reductions based on methane content, and the inclusion of components from idle light oil wells, which have fewer emissions and reductions than dry gas production, underground gas storage, and gas processing components. Cost effectiveness with savings was determined by subtracting the amount of savings from the estimated total cost.

Local Air District Costs

A local air district may decide – but is not obligated -- to be the primary agency responsible for enforcing the provisions of the proposed regulation. This includes issuing permits for new control equipment, registration and inspection of equipment, and enforcing the LDAR portion of the regulation. Originally, the cost to districts was estimated to be approximately \$1,300,000 in initial costs in the first year, and approximately \$660,000 in annual ongoing costs. Since this estimate made in the ISOR, components from idle wells were added, bringing the total number of components to 1,585,700 from 1,339,185, representing an 18.5% increase. Assuming there would be a corresponding proportional increase in district costs, an 18.5 % increase brings the estimated cost to districts to \$1.54 million in initial costs, and \$780,000 in ongoing costs.

Table A-1
Emissions of LDAR Components from the ISOR

Emission Factors of Fugitives

% of Components that are High Leaking

2.22%

Fugitives source					
Components <10,000 ppmv	g CH4 per Component per Year	Number of Components	Total g CH4 per Year	MT CH4 per Year	MT CO2e Per Year
Valves	241.92	236,131	57,123,958	57.12	4,112.9
Connectors	82.74	870,766	72,047,168	72.05	5,187.4
Flanges	193.06	158,486	30,597,316	30.60	2,203.0
Open end lines	1014.94	692	702,612	0.70	50.6
Pump seals	1014.94	2,312	2,347,002	2.35	169.0
Others (compressors, hatches, etc.)	1014.94	21,008	21,321,492	21.32	1,535.1
Well Casings		20,485	-		-
Components >=10,000 ppmv			-		-
Valves	959504.26	5,367	5,149,296,884	5,149.30	370,749.4
Connectors	178784.59	19,790	3,538,170,914	3,538.17	254,748.3
Flanges	378968.11	3,602	1,365,026,296	1,365.03	98,281.9
Open end lines	952597.44	16	14,987,533	14.99	1,079.1
Pump seals	952597.44	53	50,064,288	50.06	3,604.6
Others (compressors, hatches, etc.)	952597.44	477	454,812,356	454.81	32,746.5
Total		1,339,185	10,756,497,818	10,756	774,468
Reductions 60%				6,454	464,681

Table A-2

Emissions of LDAR Components from Idle Dry Gas and Gas Storage Wells

Emission Factors of Fugitives

% of Components that are High Leaking

2.22%

Fugitives source					
Components <10,000 ppmv	g CH ₄ per Component per Year	Number of Components	Total g CH ₄ per Year	MT CH ₄ per Year	MT CO ₂ e Per Year
Valves	241.92	7,718	1,867,011	1.87	134
Connectors	82.74	31,728	2,625,167	2.63	189
Flanges	193.06	0	-	-	-
Open end lines	1014.94	858	870,326	0.87	63
Pump seals	1014.94	0	-	-	-
Others (compressors, hatches, etc.)	1014.94	0	-	-	-
	0.00		-		-
Components >=10,000 ppmv	0.00		-		-
Valves	959504.26	175	168,297,047	168.30	12,117
Connectors	178784.59	721	128,919,583	128.92	9,282
Flanges	378968.11	0	-	-	-
Open end lines	952597.44	19	18,565,066	18.57	1,337
Pump seals	952597.44	0	-	-	-
Others (compressors, hatches, etc.)	952597.44	0	-	-	-
Total		41,219	321,144,200	321	23,122
Reductions 60%				193	13,873

Table A-3
Emissions of LDAR Components from Light Oil Idle Wells

Emission Factors of Fugitives

% of Components that are High Leaking 0.86%

Fugitives source					
Components <10,000 ppmv	g CH4 per Component per Year	Number of Components	Total g CH4 per Year	MT CH4 per Year	MT CO2e Per Year
Valves	104.92	38,965	4,088,354	4.09	294.4
Connectors	55.22	160,189	8,846,147	8.85	636.9
Flanges	132.54	0	-	-	-
Open end lines	99.40	4,329	430,353	0.43	31.0
Pump seals	1463.41	0	-	-	-
Others (compressors, hatches, etc.)	723.42	0	-	-	-
	0.00		-		-
Components >=10,000 ppmv	0.00		-		-
Valves	390426.89	338	131,966,554	131.97	9,501.6
Connectors	129221.91	1,390	179,564,109	179.56	12,928.6
Flanges	1435799.04	0	-	-	-
Open end lines	122595.15	38	4,604,208	4.60	331.5
Pump seals	491485.06	0	-	-	-
Others (compressors, hatches, etc.)	39208.36	0	-	-	-
Total		205,249	329,499,726	329	23,724
Reductions 60%				198	14,234

Revised Cost Estimates for the Natural Gas Underground Storage Facility Monitoring Requirements Provision

Under the proposed regulation, operators of underground natural gas storage facilities will be required to submit a plan for approval that includes continuous or daily monitoring of storage wells, and continuous ambient air monitoring. There are a total of 14 underground natural gas storage facilities operated by six businesses that will be impacted by the provision. According to DOGGR, there are 452 active natural gas storage wells located at the 14 facilities (DOGGR, 2016).

The cost estimate for this provision uses three possible scenarios to estimate the cost of implementation. Implementation includes four major costs: continuous ambient air monitoring, daily or continuous wellhead monitoring, repairs, and recordkeeping. The cost estimates for each scenario and the average of the three is presented in Table 1.

Continuous Ambient Air Monitoring

Staff anticipates that the ambient monitoring stations that are used to detect methane concentrations and installed to comply with the ambient air monitoring requirements will be similar to ARB stations currently in use.

Scenario 1 uses a cost estimate provided by SoCal Gas (SoCal Gas, 2016). The cost of ambient air monitoring is estimated to be \$400,000 per facility with an ongoing cost of \$52,000 per year. This \$52,000 includes estimated costs for maintenance, calibration, spare parts, etc., assumes an estimated 5% of monitors are replaced each year, and includes \$10,000 for annual operation and maintenance per monitor. The SoCal Gas cost estimate also included a cost for labor to respond to false alarms triggered by the monitoring system on a continuous basis. Staff is proposing to add into the regulation an appropriate baseline and threshold to trigger an alarm, based on stakeholder comments. Because this proposed revision will prevent these false alarms, this cost has been excluded.

The cost estimate for the ambient air monitoring for scenarios 2 and 3 is estimated as the costs that are currently in use by existing ARB monitoring stations. These monitoring stations, employing a device such as a Piccaro methane detector, would be used to detect methane concentrations in the ambient air at the facility. Based on conversations with ARB's Monitoring and Laboratory Division (MLD) which already uses such devices, the cost of one of these detectors is estimated at \$175,000 with \$89,500 ongoing costs (ARB, 2016). Two stations were assumed to be needed at each facility at a capital cost of \$350,000 and an ongoing cost of \$179,000 per facility.

Daily or Continuous Wellhead Monitoring

Compliance with the continuous or daily well monitoring requirement can be accomplished with a manual inspection using Method 21, optical gas imaging (OGI)

devices, or other leak detection equipment. Given the higher cost of manual inspection, it is expected that most operators will choose to use an automated detection method, which would significantly reduce labor costs. This could involve a sensor, OGI cameras, or other technology. The cost was estimated using a subset of these devices based upon conversations with two businesses that are expected to provide this service. The cost was estimated for three scenarios; the first using OGI cameras based on a cost estimate provided by SoCal Gas; the second using ultrasonic monitors in conjunction with optical monitors; and the third based on using OGI cameras mounted on a permanent fixture. The second two were included in the original ISOR Economic Analysis but have been updated based upon input from stakeholders. All capital costs are amortized over 10 years, which is consistent with the amortization period of most other capital equipment used to comply with the provisions of the regulation.

Scenario 1 uses a cost estimate provided by SoCal Gas. The cost of the capital equipment is estimated to be \$77,000 per well. This represents 2 pairs of IR model 5500 cameras at each well plus a 10% contingency. SoCal Gas notes that this is a conservative installed cost. An ongoing cost of \$5,000 is estimated for maintenance of the OGI cameras, calibration, reporting, data review, and data compilation for external audiences. This \$5,000 estimate assumes 5% of equipment is replaced each year plus \$3,500 annual operation and maintenance per well.

SoCal Gas also provided an estimate that was based on manual inspections using OGI cameras at an estimated \$17.3 million in labor per year for all 452 wells. Since ARB anticipates that operators will choose to have an automated system for performing these inspections, this estimate was not included in this analysis.

Similarly, Scenario 2 assumes that wells are not checked manually, but rather with an automated system. This scenario is based on conversations with a manufacturer of an ultrasonic monitor. This estimate assumes that three ultrasonic monitors at a cost of \$20,000 each, and three IR detectors at a cost of \$11,500 each (Caltrol, 2016) would be used at each well, for a total cost of \$94,500 per well. An ongoing cost of \$5,000 annually per well is assumed for this scenario.

Scenario 3 assumes that the well monitoring is completed with an automated system. This scenario is based on a cost estimate of installing OGI cameras mounted on a fixed platform to continuously monitor wells. These are estimated to cost \$90,000 each (Pixel, 2016), and be able to detect leaks at three wells, and be able to cover 90% of the wells at a facility. The remaining 10% of wells would need to be inspected manually, and this was estimated to cost \$123,839 for each of the 14 facilities. This estimate is found by taking the SoCal gas estimate for performing manual inspections using OGI cameras for all wells (\$17,336,788), multiplying it by 0.1 to obtain an estimate for 10% of wells only, then dividing the cost among the 14 facilities.

Recordkeeping and Reporting

Recordkeeping and reporting costs were assumed to be the same in all three scenarios. The total cost for recordkeeping and reporting was provided by SoCal Gas, and is estimated to be \$1,385,360. This includes the annual cost of reporting (\$20,800) for each of six business, as well as recordkeeping (\$83,200) for each of 14 facilities. In addition, for each facility there is a one-time amortized cost of \$20,000 for monitoring plan development and an annual \$4,000 cost for monitoring plan updates.

Repairs

Consistent with ARB's LDAR cost estimates, the cost estimates for Scenarios 2 and 3 do not include repair costs, assuming that these are repairs that would be made by the operator as part of regular facility maintenance, and the monitoring simply alerts the operator to this need. SoCal Gas however, estimates that the capital and labor costs to screen and repair detected leaks, and the materials to repair these leaks, should be included. This annual cost is estimated to be \$134,682 per facility (SoCal Gas, 2016). We included the cost of repairs in Scenario 1 to show the SoCal Gas estimate in full, but do not believe those are extra costs attributable to the proposed regulation.

Total Annualized Cost

Total annual costs for each scenario are calculated by the following equations with the values in Table 1.

$$J = (D \times A \times C) + (E \times A) + (F \times B \times C) + (G \times B) + (H \times A) + I$$

For Scenario 1

$$\begin{aligned} &(\$400,00 \times 14 \times .13) + (\$52,000 \times 14) + (\$77,000 \times 452 \times .13) \\ &\quad + (\$5,000 \times 452) + (\$134,682 \times 14) + (\$1,385,360) \\ &= \$11,511,428 \end{aligned}$$

For Scenario 2

$$\begin{aligned} &(\$350,00 \times 14 \times .13) + (\$179,000 \times 14) + (\$94,500 \times 452 \times .13) \\ &\quad + (\$5,000 \times 452) + (\$0 \times 14) + (\$1,385,360) \\ &= \$12,341,180 \end{aligned}$$

For Scenario 3

$$J = (D \times A \times C) + (E \times A) + (F \times B \times C)/3 + (G \times A) + (H \times A) + I$$

$$\begin{aligned}
 &(\$350,00 \times 14 \times .13) + (\$179,000 \times 14) + \left(\frac{\$90,000 \times 452 \times .13}{3}\right) \\
 &+ (\$123,834 \times 14) + (\$0 \times 14) + (\$1,385,360) \\
 &= \$8,024,836
 \end{aligned}$$

Table 1

Cost Estimate of Monitoring Plan Provision

		Scenario 1	Scenario 2	Scenario 3	
A	Facilities	14	14	14	
B	Wells	452	452	452	
C	Capital Recovery Factor	0.13	0.13	0.13	
D	Capital Cost of Ambient Air Monitoring Equipment per Facility	\$400,000	\$350,000	\$350,000	
E	Ongoing Cost of Ambient Air Monitoring Equipment per Facility	\$52,000	\$179,000	\$179,000	
F	Capital Cost of Well Monitoring Equipment	\$77,000 per well	\$94,500 per well	\$90,000 per 3 wells	
G	Ongoing Cost of Well Monitoring Equipment	\$5,000 per well	\$5,000 per well	\$123,834 per facility	
H	Ongoing Cost for Repairs per Facility	\$134,682	NA	NA	
I	Total Recordkeeping and Reporting	\$1,385,360	\$1,385,360	\$1,385,360	
J	Total Annual Cost	\$11,511,428	\$12,341,180	\$8,024,836	Average of the three scenarios \$10,625,815

External Scientific Peer Review of the Flash Analysis Test Procedure

<https://www.arb.ca.gov/cc/oil-gas/peerreview/peerreview.htm>

COST-BENEFIT ANALYSIS

In performing a cost-benefit analysis, each rulemaking entity must provide the information requested for the cost-benefit analysis to be considered a good faith effort. The cost-benefit analysis must be submitted to the Office of Policy, Research and Regulatory Reform at least ten (10) days before the administrative hearing on the proposed rule and posted on your agency's web site. For all questions, please attach all underlying data that supports the statements or figures stated in this cost-benefit analysis.

DEPARTMENT: Colorado Department of Public Health
& Environment

AGENCY: Air Quality Control Commission

CCR: 5 CCR 1001-9

DATE: September 4, 2020

RULE TITLE OR SUBJECT:

Regulation Number 7
Control of Ozone via Ozone Precursors and Control of Hydrocarbons via Oil and Gas Emissions

INTRODUCTION

The Colorado Air Pollution Control Division (Division) submits the following Cost-Benefit Analysis in conjunction with its proposed revisions to Colorado Air Quality Control Commission (Commission) Regulation Number 7 (5 CCR §1001-9). The proposed revisions are intended to address requirements under Senate Bill 19-181 (SB 19-181), the Clean Air Act ozone National Ambient Air Quality Standards (NAAQS) attainment program, the second planning period for the Regional Haze program, and nitrogen deposition at Rocky Mountain National Park (RMNP).

The proposed revisions to Regulation Number 7 will reduce emissions from natural gas fired reciprocating internal combustion engines (RICE) and further minimize emissions from the oil and gas sector, including requiring air quality monitoring at pre-production and early production oil and gas operations, and requiring the control of emissions from flowback vessels, and reducing emissions and requiring reporting from class II disposal well facilities. The Division has proposed standards for the oil and gas industry that will result in substantial reductions of oxides of nitrogen (NO_x), methane, and non-methane hydrocarbon emissions.

The Division estimates the NO_x control program for natural gas RICE will reduce state-wide NO_x by 2,361 tons per year (tpy). The proposed rule addresses multiple engine configurations, each with a suite of available control technologies, which achieve varying control efficiencies at a range of costs. Because the Division is proposing emission rate limits, as opposed to specific control technologies, the control costs range from \$9.3 to \$33 million/year, depending on the number of engines controlled and the selected control technologies for each engine. This results in an average cost of \$8,655 per ton of NO_x reduced. In recognition of the potentially high cost of retrofitting controls on certain engines, the Division's proposal includes a company-wide plan that allows each operator to choose which engines to control or replace, as long as the company-wide reductions are equal to or better than the reductions that would be achieved through controlling each engine to the proposed emission threshold.

In order to inform future rulemakings for pre-production and early production monitoring requirements, the Division's proposal requires operators to submit a monitoring plan. This monitoring plan must be approved by the Division, and operators must then conduct monitoring according to the approved monitoring plan. Producers will incur a minor cost in developing these monitoring plans and submitting them to the Division for approval, though the Division has not estimated these potential costs. Also, the

proposal does not mandate a specific monitoring technology, therefore, the Division has not provided annualized monitoring cost estimates. However, this analysis contains a brief summary of a report on different monitoring technologies that provides estimates of sensor costs ranging from less than \$2,500 to over \$400,000 depending on the sensor capabilities (accuracy, precision, monitoring frequency, ability to speciate emissions, etc.) Since this proposal concerns monitoring, it may not by itself lead to emission reductions. However, the information gathered by operators will provide the necessary information for future Division proposals that will require guaranteed monitoring performance and could reduce leaks of methane and volatile organic compounds (VOCs), which negatively impact health as GHGs and ozone precursors.

As part of its proposal, the Division is also requiring operators to use vapor-tight flowback vessels. These flowback vessels are used to collect sand, liquids, and dissolved gases that are pumped back out of a well post fracturing (fracking). Based on the Division's research, vapor-tight flowback tanks are readily available and allow for cost effective capture and transmission of vapor emissions to an emission control device, most likely an enclosed combustion device (ECD). Division research indicates that a fleet of twelve flowback tanks will be required at a well production facility and the tanks will be reused at 10 pre-production operations per year, for 15 years. Based on this, the fleet of vapor-tight flowback tanks will reduce methane emissions by 21.0 – 71.8 tons per year for 15 years, at a cost of \$57,958 per year. This results in an overall cost effectiveness of approximately \$54 to \$184 per ton of methane reduced.

Additionally, the Division is clarifying that class II disposal well facilities are subject to storage tank controls and expanding hydrocarbon liquid loadout controls and reporting requirements. The December 2019 Regulation 7 rulemaking included revisions to storage tank controls that required VOC controls for any storage tanks with uncontrolled emissions of at least 2 tons per year, a decrease from the previous threshold of 6 tons per year. Although the Division's analysis for the December 2019 rulemaking included class II disposal well facilities storage tanks, some facilities may not have installed controls due to a perceived ambiguity in Regulation 7 language. The proposed updates may therefore result in additional class II disposal well facilities that will install a new flare and conduct associated inspections and recordkeeping. The Division estimates that the installation of a flare at a class II disposal well facility for storage tank control will reduce VOC emissions by 2.3 – 4.2 tons per year at each facility, at a cost of \$35,982 annually. This includes potential tank replacements. This resulting cost effectiveness is \$15,150 - \$8,417 per ton of VOC reduced.

The Division is also proposing to expand the December 2019 Regulation 7 rulemaking requirements to control VOC emissions during hydrocarbon liquids loadout at class II disposal well facilities. The proposed revisions further delineate the need for a flare for VOC control at class II disposal well facilities performing hydrocarbons liquid loadout. The flare for loadout control is anticipated to cost \$17,537 annually and to reduce VOC emissions by 1.4 – 5.2 tons per year at each facility. This includes supplemental propane fuel for the flare, but the Division does not anticipate tanks will need to be replaced for this proposal. The cost effectiveness for the liquids loadout revision is therefore \$12,307 - \$3,356 per ton of VOC reduced. Based on Air Pollution Emission Notice (APEN) data, the Division estimates there are 33 class II disposal well facilities statewide that are loading out hydrocarbon liquids by truck. The hydrocarbon liquids loadout control requirements would apply to hydrocarbon liquid loadout to transport vehicles at class II disposal well facilities where loadout emissions are greater than or equal to two tpy.

The Division is also proposing additional reporting requirements. The Division has not estimated a cost for this reporting, but it anticipates that operators will be able to collect and submit the additional data with minimal additional time from existing staff. Therefore, the cost should be minimal. This additional reporting requirements should inform any future proposals for class II facilities.

Lastly, the Division is proposing additional greenhouse gas (GHG) reporting for oil and gas operators. As a result of the December 2019 Regulation 7 rulemaking, operators must report VOC, NOx, CO, ethane, and methane emissions to the Division on an annual basis. The proposed revisions in this Regulation 7

update will require reporting of CO₂ and N₂O emissions, as well. The Division has not estimated the cost for this reporting, but has worked with operators to develop the reporting forms, finalized July 2020, that include CO₂ and N₂O and, therefore minimize the cost and staff time required to submit the emissions data required by this rulemaking and the December 2019 Regulation 7 rulemaking. The Division notes that industry has agreed to the reporting of N₂O and CO₂ emissions, which are listed on the reporting form that was finalized in July 2020. The transmission and storage segment has also agreed to the reporting of N₂O and CO₂ emissions, reporting form to be completed fall 2020.

Per the provisions of 24-1-103(2.5)(a), Colorado Revised Statutes, the cost-benefit analysis must include the following:

1. The reason for the rule or amendment;

The proposed revisions are required to address state and federal statutory requirements including SB 19-181, ozone NAAQS attainment, the second planning period for the Regional Haze program, and nitrogen deposition at RMNP.

The proposed NO_x controls for natural gas RICE provides a strategy to reduce emissions from oil and gas operations, as required by SB 19-181. This strategy will benefit ozone NAAQS attainment, the Regional Haze program, and nitrogen deposition in RMNP. Reducing NO_x emissions from natural gas fired engines provides progress toward ozone attainment in the Denver Metro/North Front Range (DMNFR) ozone nonattainment area (NAA), reduces the likelihood of additional nonattainment areas across the state, reduces NO_x emissions that contribute to visibility impairment in Colorado's class I areas, and reduces NO_x emissions that form nitrogen particulates that deposit in RMNP.

The proposed requirement for vapor-tight flowback vessels will reduce methane and VOC emissions which provides another path to reduce oil and gas sector emissions, as required by SB 19-181. Reducing VOC and methane emissions also limits ozone formation, which addresses nonattainment status in the DMNFR and may help prevent additional nonattainment designations across the state in the future. Finally, reducing emissions of methane, a powerful GHG, also helps Colorado in reaching the GHG reduction targets set forth in House Bill 19-1261 (HB 19-1261).

The proposed requirement for an emissions monitoring plan during pre-production and early production will provide information that will allow the Division to make better informed proposals for additional monitoring or control strategies required under SB 19-181. The monitoring requirements will also help quickly identify hydrocarbon emissions, including both VOCs and methane/ethane, which contribute to ozone formation and cardio-respiratory health risks.

The proposed clarifications to tank control and additional requirements for truck loadout control for class II disposal well facilities will reduce VOC emissions at class II disposal well facilities. Again, these reductions will lower ozone formation to address NAAQS attainment and will also provide additional emission reductions from the oil and gas sector, as required under SB 19-181. The class II disposal well facility storage tanks were included in the Division's analysis for the December 2019 rulemaking. However, the proposed revisions remove any perceived ambiguity in the rules that may have resulted in class II disposal well facilities without appropriate VOC controls.

The proposed additional emissions reporting requirements for class II disposal well facilities emissions are necessary for the Division to better understand the emissions at these facilities. Using this information, the Division will be able to develop future proposals to monitor and control emissions to address requirements under SB 19-181. Any future proposals that address VOC and methane emissions at class II disposal well facilities will help address ozone NAAQS attainment and help Colorado reach the GHG reduction targets.

Finally, the reporting requirement for CO₂ and N₂O emissions from oil and gas activities is necessary to develop a more accurate GHG inventory that will be used to track progress toward the GHG reduction targets in HB 19-1261. This additional GHG emission data from the oil and gas sector will be used in the development of additional reporting and GHG reduction strategies implemented under the new Regulation 22, which was approved in May 2020.

2. The anticipated economic benefits of the rule or amendment, which shall include economic growth, the creation of new jobs, and increased economic competitiveness;

The proposed changes to Regulation 7 are projected to result in substantial reductions of NO_x and hydrocarbon emissions, including both VOCs and methane/ethane, from the oil and gas industry. The Division predicts that the NO_x controls for natural gas RICE will reduce state-wide NO_x by 2,361 tons per year. The proposal includes new testing and monitoring requirements for affected RICE. These requirements may result in increased jobs related to performance and portable analyzer testing, as well as outsourced work for engine upgrades and increased business for engine leasing companies that have newer and better performing engines in stock.

The Division projects that a fleet of vapor-tight flowback tanks, each consisting of twelve tanks, will result in annual methane reductions of approximately 24.3 – 82.9 tpy, spread across ten well production facilities.

The Division expects that controlling tank emissions at class II disposal well facilities will reduce annual VOC emissions by 2.3- 5.2 tpy at each facility, though these reductions were anticipated to be achieved through the Commission's revision of Regulation 7 in December 2019 (and were accounted for in that rulemaking's economic analysis). Controlling hydrocarbon liquids loadout emissions at class II disposal well facilities is estimated to further reduce VOC emissions by 1.4 – 5.2 tpy at each facility.

The remaining proposed revisions to Regulation 7 include additional monitoring and reporting requirements. These will not lead to immediate emission reductions, but provide critical data on compliance assurance and will provide information on oil and gas emissions including pre-production, early production, and class II disposal well facilities. This information is essential to developing effective emission reduction strategies for VOCs and GHGs.

The reductions achieved by the proposed revisions will aid Colorado's efforts to bring the DMNFR into compliance with the 2008 and 2015 ozone NAAQS, as well as serve as a proactive step in addressing future lower ozone standards and reduce the likelihood of additional nonattainment area designations throughout the state. Ground-level ozone contributes to a number of health conditions, up to and including premature mortality from cardio-respiratory mortality. Attaining the 2008 and 2015 ozone standards will likely result in substantial health benefits.

In addition to impacting human health, elevated levels of ozone can have a negative impact on crop production and NO_x emissions can lead to unnatural fertilization that alters sensitive ecosystems, including those at RMNP. Reduced levels of ozone will likely increase crop yields in the DMNFR. Separate from the beneficial impacts of reducing ozone, the proposed rules will also produce substantial benefits associated with reducing GHGs.

The proposed NO_x reductions from natural gas RICE will also reduce the formation of visibility impairing nitrate particulates. Reducing nitrate pollution helps Colorado make reasonable progress toward natural visibility conditions in the state's twelve class I areas (including RMNP, Mesa Verde, and the Great Sand Dunes) for the Regional Haze program. Visibility impairment reduces visitor enjoyment and may lead to

decreases in tourism to Class 1 areas.¹ Tourism is a key economic driver in Colorado, according to Colorado's Office of Economic Development and International Trade, with 82.4 million visitors in 2016 who spent a total of \$19.7 billion here, generating \$1.2 billion in state and local taxes.²

Lastly, there may be additional jobs for companies that develop and deploy monitoring technology, for consultants to develop monitoring plans or to compile and submit emissions reporting data to the Division, and for field personnel or contractors to maintain emissions monitoring and control equipment.

3. The anticipated costs of the rule or amendment, which shall include the direct costs to the government to administer the rule or amendment and the direct and indirect costs to business and other entities required to comply with the rule or amendment;

A. General Discussion of Cost Effectiveness Analysis

The Division's assessment of the costs and benefits for each of the proposed strategies is set forth below. For each strategy, these assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements. Finally, the Division considered whether there would be any additional costs for the Division to implement the proposed requirements beyond current expenditures and determined that the Division's proposed revisions could be implemented using existing resources.

B. Controls for Natural Gas Fired Reciprocating Internal Combustion Engines

The Division is proposing new regulatory provisions aimed at reducing NO_x emissions from natural gas fired RICE. These provisions complement existing control requirements adopted in Colorado for oil and gas facilities which primarily focus on reducing VOC and other hydrocarbon emissions. For the purposes of this analysis, the Division assumes that operators will use a combination of technologies to control emissions from engines, depending on the type of engine, the amount of emission reductions needed to meet the proposed standards, and the technical and economic feasibility to achieve those standards. This analysis focuses on NO_x; however, the Division includes standards for CO and VOC in this proposal because for some type of controls, particularly lean burn engines, decreasing NO_x can lead to increases in the other two pollutants. The Division's proposal ensures that NO_x limits are appropriately balanced with these other pollutants.

The Division's proposal only impacts engines rated at least 1,000 horsepower (HP) and includes two paths to compliance. The first path assumes that each engine will achieve the standard for the applicable engine type: two-stroke lean burn (2SLB), four-stroke rich burn (4SRB), or four-stroke lean burn (4SLB). The second path allows operators to more broadly evaluate emission reductions and costs for their entire fleet of engines to achieve the same or better emission reductions without necessarily updating each engine. This latter path is referred to as the Alternative Company-Wide Compliance Plan (Company-Wide Plan). Based on information collected by the Division and provided by industry members, the Division expects the Company-Wide Plan approach to reduce costs to operators, while resulting in the same or better expected emissions benefit. This analysis focuses on the costs of installing additional controls for each engine, and is therefore anticipated to provide a conservatively high estimate of the costs to achieve the estimated emission reductions.

¹ "Introduction to Visibility." Malm, William. Air Resources Division - National Park Service at <https://www.epa.gov/sites/production/files/2016-07/documents/introvis.pdf>

² "Key Industries: Tourism." Colorado's Office of Economic Development and International Trade at <https://choosecolorado.com/key-industries/tourism/>

For 2SLB, operators will likely need to use individualized combinations of controls generally termed “unit upgrades,” which are described in detail below based on an industry study³.

For 4SRB, operators have comparatively few options for reducing NOx, depending on the amount of reduction needed. Options include ignition related controls, usually termed high energy ignition systems, which usually reduce NOx emission by around 10%, and non-selective catalytic reduction (NSCR) controls, usually in combination with an air to fuel ratio controller (AFR). NSCR combined with an AFR has been installed on a large number of engines, in both new and retrofit applications, across the United States and can reduce NOx by 90-99%.

For 4SLB, there are a number of options commercially available to help control NOx emissions, most of which are related to efforts to operate with acceptable levels of very lean air/fuel mixtures. These options include installing high energy ignition systems (about 10% control), performing turbocharger additions or upgrades (60-70% control), installing high pressure fuel injection systems (90% control in some engines), use of ignition pre-chambers (90% control in some engines), and the addition of selective catalytic reduction (SCR) (50-95% control). There are often significant differences in design characteristics between engine manufacturers’ designs that results in varied control effectiveness and application. Most 4SLB engines should be responsive to most control options; however, it appears that actual achievable NOx emission rate (g/bhp-hr), would tend to be engine-specific. Regardless, retrofit options have the potential to achieve an approximate range of NOx emissions from 2.0 g/bhp-hr to 0.5 g/bhp-hr, depending on the make and model of the engine. In some cases, site specific installation issues may cause technical feasibility concerns or not be cost effective. These issues are addressed by the Division’s Company-Wide Plan proposal, which provides appropriate flexibility for consideration of site specific and technical feasibility issues.

To determine appropriate standards, as well as potential reductions and costs, the Division used the most recent APEN-provided data as of July 2019. The Division provided this data to stakeholders in December 2019. Concerns were raised during stakeholder meetings regarding data accuracy. Industry provided feedback on the Division’s inventory in April 2020. This feedback did not reveal significant discrepancies in the data that the Division used in this proposal, but rather technical misunderstandings of how the data was reported, as well as how it screened and then used to determine the standards. The Division understands that operators do not consistently report actual engine emission data and that the inventory contains a mixture of actual and allowable engine emissions; however, with the Company-Wide Plan proposal, there is sufficient flexibility for operators to achieve emission reductions within the proposed standards and potential emission reductions. The Division recognizes that the Company-Wide Plan approach includes more detailed information to be provided to the Division for review, thus increasing the burden on the Division to review the plans and evaluate compliance. The Division expects to be able to handle this additional burden with existing and anticipated staff.

The Division’s proposal also includes a requirement that certain of the engines subject to the new emission standards will undertake a performance test, and that all engines will subsequently perform at least semi-annual portable analyzer testing. In their request for the Cost Benefit Analysis and Regulatory Impact Analysis, the Colorado Oil and Gas Association and American Petroleum Institute - Colorado asked for a discussion about the costs and benefits of engine performance testing and portable analyzer testing. Industry provided the Division with estimated costs for conducting performance testing, as well as portable analyzer testing. Performance testing was estimated to cost \$3,800 in the DMNFR and \$4,400 in the rest of the state. Portable analyzer testing costs \$1,300 in the DMNFR and \$1,900 in the rest of the state. The higher costs in the rest of the state reflect increased time and fuel for testing personnel to travel to remote sites. In the Regulation 7 Statement of Basis and Purpose (SBAP), the Division discusses the benefits of performance testing and portable analyzer testing. Performance testing

³ “ELRE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR-NOx” 5/21/2009”, prepared by a technical group for the Pipeline Research Council International, May 2009.

establishes a baseline for assessing an engine's current performance. This evaluation enables an operator to determine whether the engine was meeting the standards already or how much action might be required to meet the standards. The majority of engines subject to this rule have not undergone an EPA reference method performance test in years, if ever. To conserve the resources of both the Division and the operators, the Division proposes to allow operators to rely on performance testing conducted under New Source Performance Standard (NSPS) JJJJ, a permit, or testing conducted voluntarily after January 1, 2020. The Division also amended its proposal to exempt those engines that are subject to requirements to perform at least semi-annual portable analyzer testing. The Division has proposed semi-annual portable analyzer testing requirements, which ensure that an engine's emission controls are properly maintained to ensure continued compliance with the proposed standards. The portable analyzer monitoring must commence within twelve (12) months of the performance test. The Commission intends that operators will conduct two portable analyzer tests in 2021, the first of which must be completed by June 30, 2021.

i. Two-Stroke Lean Burn Engines $\geq$ 1,000 HP

The Division is proposing a statewide 3.0 g/bhp-hr NO_x standard for all 2SLB engines with a rating of at least 1,000HP. Table 1 indicates that, based on July 2019 Division inventory data, there are 47 2SLB burn engines $\geq$ 1,000 HP across the state. All 2SLB engines are located outside of the DMNFR NAA. All 47 engines are operational and 33 of the 47 are already operating below the 3.0 g/bhp-hr NO_x standard. Of the 14 engines currently operating above the standard, nine (9) will require less than a 10% emission reduction to meet the standard, four (4) will require a 10-25% emission reductions, and one (1) will be required to reduce emissions by 36% to meet the 3.0 g/bhp-hr standard. The Division estimates the additional controls will reduce annual NO_x emissions by 556 tons per year with just over half of the total reductions derived from the engines requiring the lowest level of emission reduction (<10%).

Table 1: Statewide 2SLB Engine counts and potential NO_x reductions (tpy)			
	# Engines	Potential NO _x reductions (tpy)	Average NO _x reduction per engine (tpy)
# of engines not operating	0	n/a	n/a
# of engines currently below proposed standard	33	n/a	n/a
# of engines needing $\leq$ 10% control to meet standard	9	289	32
# of engines needing >10 to $\leq$ 25% control to meet standard	4	223	56
# of engines needing > 25 to $\leq$ 50% control to meet standard	1	44	44
# of engines needing >50 to $\leq$ 100% control to meet standard	0	0	0
Total # of 2SLB engines	47	n/a	n/a

Subtotal # of 2SLB engines needing control to meet standard	14	556	40

As stated above, reducing NOx emissions from 2SLB requires a combination of individual controls which modify combustion and airflows. These controls may include installation and/or upgrade of turbochargers and intercooling, pre-chamber ignition, improved fuel injection control, and air to fuel ratio control. The Division assumes these controls will be implemented on an engine in multiple stages, in most cases, and these stages are labeled as first unit upgrade and follow on unit upgrade in Table 2 below. Table 2 lists the minimum annualized cost of first and follow on unit upgrades costs which are based on identified costs from a 2009 oil and gas cost study⁴ adjusted for inflation⁵. The operations and maintenance (O&M) costs in Table 2 were estimated using engine rulemaking conducted by the Division in 2008 adjusted for inflation. The 2009 study analyzed three different 2SLB engine makes and models, with varying first and follow on unit upgrade costs. The Division also included depreciation for control equipment costs as well as industry-provided performance testing and portable analyzer testing costs, which include costs for testing of NOx, CO, and VOCs, and a one-time mobilization cost assuming all engines at one site require testing and will be tested with one trip. Additional costs may be incurred if all engines at a site cannot be tested in one trip. Industry provided different costs for performance testing and portable analyzer testing for the DMNFR ozone NAA versus the rest of the state. As noted previously, all 2SLB engines are located outside the DMNFR ozone NAA, and therefore Table 2 only includes costs for the rest of the state. The minimum annualized cost per engine is \$415,698, as shown below in Table 2, while the maximum annualized cost per engine is \$674,933 and is not shown.

Table 2: Minimum 2SLB engine annualized control costs, including follow on upgrades*						
Item	Capital costs (one time)	Depreciation expenses**	Book value of asset at year end	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs

⁴ See "ELRE Cost Study of the Retrofit Legacy Pipeline Engines to Satisfy ½ g/BHP-HR-NOx" 5/21/2009", prepared by a technical group for the Pipeline Research Council International, May 2009. Referenced in the Ozone Transport Commission's "Draft Technical Information Oil and Sector Significant Stationary Sources of NOx Emissions", May 2012.

⁵ Inflation adjustment over the period 2009-2019 was estimated at 17.30% using US Department of Labor CPI-U annual data. Similarly, operating and maintenance costs were estimated from a previous 2008 AQCC engine rulemaking with an estimated inflation adjustment rate of 21.10%.

Engine (first unit upgrade cost)	\$2,404,650					\$415,698
Engine (follow on unit upgrade cost)				\$2,170,050		
Performance testing				\$4,400		
Operation & maintenance* **					\$9,166	
Subtotal costs	\$2,404,650	\$2,404,650		\$2,174,450	\$9,166	
Annualized costs ****	\$238,052	\$120,233	\$297,810	\$108,503	\$9,166	

*All the engine control device costs were escalated by 17.3% to reflect CPI-U increases that have occurred since the 2009 study.

**Depreciation expenses are for equipment costs, and assume a 5% interest rate, a 20-year amortization period, a residual value of the end of asset life of \$0, and straight line depreciation.

***Operation & maintenance costs were escalated by 21.1% to reflect CPI-U increases that have occurred since the Division's 2008 engine rulemaking. Operation and maintenance costs include portable analyzer testing. As noted above, all 2SLB engines are located outside the DMNFR Ozone NAA. For the rest of the state, industry reported portable analyzer costs are \$1,900 annually. These costs do not include potential additional trips up to \$1,400 for portable analyzer testing.

****Annualized costs are over a 20-year period assuming a 5% rate of return.

Table 3 shows the average NOx control efficiency, the total number of engines that need to be controlled, the minimum annualized cost per engine (from Table 2), the minimum total engine cost (for all affected engines), the potential NOx reduced per year from these engines, and the minimum dollar per ton (\$/ton) cost. The minimum estimated annualized cost of a two-stroke engine upgrade with a follow on unit upgrade has been adjusted linearly to account for the differences in the emission study's⁶ emission target of 0.5 g/bhp-hr versus the Division's proposed standard of 3.0 g/bhp-hr. Based on this information, costs conservatively range from \$7,534 to \$12,232 per ton of NOx reduced, depending on the make and model of the engine.

Table 3: Minimum 2SLB engine total cost, including follow on upgrades					
Average NOx control efficiency	Number of engines	Min annualized cost per engine	Min total engine cost	Total NOx reduction (tpy)	\$/ton minimum
32%	14	\$415,698	\$5,819,778	556	\$10,464

⁶The ELRE study and OTC draft notes that combustion related modifications have the potential to achieve from 60% to 90% reduction in NOx emissions, or 3.0 g/bhp-hr to 0.5 g/bhp-hr, depending on the make/model configuration of the engine.

Linear adjustment for control efficiency to 60%*	\$4,190,240	556	\$7,534

**In the 2009 study, costs were based on achieving reductions to 0.5 g/bhp-hr (60-90% reduction). The Division's proposal is for 3.0 g/bhp-hr. On average, 2SLB engines will need to reduce NOx emissions by 32% to achieve the standard. The difference between 60% and 32% is 28%. The Division assumed a linear relationship and that costs will decrease 28% to achieve these reductions at a higher standard. The Division assumed the low end of the study's reduction of 60% to be conservative.*

If operators do not need follow on unit upgrades to meet the standard, annualized costs for an initial unit upgrade are estimated only at \$5,568 - \$8,991 per ton of NOx reduced, depending on the make and model of the engine (adjusted linearly). This can be calculated by removing the one-time follow on unit upgrade included in Table 2, which lowers the annualized costs from \$415,698 to \$307,196.

The Division estimates that the minimum total annualized cost for all operators with affected two-stroke lean burn engines is about \$3,096,535, which includes only first unit upgrades for the lowest cost engine model. The maximum cost is about \$6,803,330, based on first and follow on unit upgrades for the highest cost engine model.

ii. Four-Stroke Rich Burn Engines $\geq$ 1,000 HP

The Division is proposing a statewide 0.8 g/bhp-hr NOx standard for all 4SRB engines with a rating of at least 1,000HP. Table 4 indicates that, based on July 2019 Division inventory data, there are 207 4SRB burn engines $\geq$ 1,000 HP across the state. 29 engines are not currently operating and they will require performance testing before returning to operation to determine the emission reduction required to meet the proposed 0.8 g/bhp-hr standard. 104 of the 207 engines, 50%, are already operating below the proposed standard. The remaining 74 engines, 14 in the DMNFR ozone NAA and 60 in the rest of the state, will require additional controls. Of the 74 engines currently operating above the standard, 37 (50%) will require less than a 10% emission reduction to meet the standard, sixteen (16) will require a 10-25% emission reduction, nine (9) will be required to reduce emissions by 25-50%, and twelve (12) will require a 50-70% emission reduction to meet the 0.8 g/bhp-hr standard. The maximum required control % on any 4SRB engine is estimated at 70%. The Division estimates the additional controls will reduce annual NOx emissions by 626 tons per year with nearly two-thirds of the total reductions derived from the engines requiring emission reductions of the 25% or less.

Table 4: Statewide 4SRB Engine counts and potential NOx reductions (tpy)			
	# Engines	Potential NOx reductions (tpy)	Average NOx reduction per engine (tpy)
# of engines not operating	29	n/a	n/a
# of engines below proposed standard	104	n/a	n/a
# of engines needing $\leq 10\%$ control to meet standard	37	232	4
# of engines needing >10 to $\leq 25\%$ control to meet standard	16	170	11
# of engines needing > 25 to $\leq 50\%$ control to meet standard	9	74	8
# of engines needing >50 to $\leq 70\%$ control to meet standard	12	149	12
Total # of 4SRB engines	207	n/a	n/a
Subtotal # of 4SRB engines needing control to meet standard	74	626	9

As described earlier, 4SRB engines generally have fewer options for reducing NOx emissions when compared to 2SLB or 4SLB engines. High energy ignition systems are one of the lowest cost control options, but may only reduce NOx emissions by 10%. Non-selective catalytic reduction (NSCR), often combined with an air to fuel ratio (AFR) controller, can achieve 90-99% NOx reductions at a higher cost. It's likely that some of the engines may be able to meet the proposed 0.8 g/bhp-hr utilizing only a high energy ignition system, but the Division opted for a conservative cost estimate that assumes all engines will utilize NSCR and an AFR. Table 5 includes the Division's estimate of the annualized cost of NSCR using an April 28, 2006, memo from Alpha-Gamma Technologies to the USEPA, "Control Costs for Reciprocating Internal Combustion Engines at Major and Area Sources." This memo estimates capital and annual operating costs in accordance with EPA's Control Cost Manual methodology which provides a single cost estimate using standardized equations. The Division believes the resulting cost estimate is an average cost for NSCR. The Division also included depreciation for control equipment costs as well as industry provided performance testing and portable analyzer testing costs, which include costs for testing of NOx, CO, and VOCs, and a one-time mobilization cost assuming all engines at one site can be tested with one trip. Additional costs may be incurred if all engines at a site cannot be tested in one trip. Industry provided different costs for performance testing and portable analyzer testing for the DMNFR ozone NAA versus the rest of the state. As noted above, fourteen (14) of the 4SRB engines are located in the DMNFR ozone NAA, while sixty (60) are throughout the rest of the state. Table 5 only includes costs for the rest of the state which has higher O&M and testing costs versus the DMNFR NAA. These costs are

overestimated given that not all engines will be subject to new performance testing or portable analyzer testing requirements. The annualized cost per engine is \$13,860 for an engine located outside the DMNFR ozone NAA.

Table 5: 4SRB annualized control costs for an engine outside the DMNFR ozone NAA*

Item	Capital costs (one time)**	Depreciation expense***	Book value of asset at year end	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
NSCR	\$35,633			\$35,633		\$13,860
Performance testing				\$4,400		
Operation & maintenance*					\$7,221	
Subtotal costs	\$35,633	\$35,633		\$40,033	\$7,221	
Annualized costs***	\$4,939	\$1,782	\$4,638	\$2,002	\$7,221	

*All the engine controls and associated costs as well as operation and maintenance costs were escalated by 27.1% to reflect CPI-U increases that have occurred since the 2006 estimates.

**All capital and operation/maintenance costs were averaged per applicable Colorado specific engine (from Division's inventory as of July 2019). For the DMNFR Ozone NAA, industry provided performance testing costs of \$3,800 (one time) and portable analyzer testing costs (annually) of \$1,300. For the rest of the state, industry reported portable analyzer costs are \$1,900 annually. These costs do not include potential additional trips of \$800-\$1,400 for portable analyzer testing (ozone NAA versus the rest of the state).

***Depreciation expenses are for equipment costs, and assume a 5% interest rate, a 20-year amortization period, a residual value of the end of asset life of \$0, and straight line depreciation.

**** Annualized costs are over a 20 year period assuming a 5% rate of return.

Table 6 shows the average NOx control efficiency, the total number of engines that need to be controlled, the average annualized cost per engine, the total engine cost (for all affected engines), the potential NOx reduced per year from these engines, and the average dollar per ton (\$/ton) cost.

Table 6: 4SRB engine total statewide cost (broken down by ozone NAA and rest of state)

Average NOx control efficiency	Number of engines		Annualized average cost per engine	Total engine cost	NOx reduction (tpy)	\$/ton
21%	DMNFR Ozone NAA	14	\$13,230	\$185,227	154	\$1,201
	Rest of state	60	\$13,860	\$831,628	472	\$1,763
	Total	74		\$1,016,855	626	

Based on this information, the estimated average annualized cost of a four-stroke rich engine NSCR control installation and maintenance will be about \$1,201 per ton of NOx reduced in the DMNFR ozone NAA and \$1,763 per ton of NOx reduced in the rest of the state. The Division estimates that the estimated total annualized average cost for all operators with affected four-stroke rich burn engines is about

\$1,016,855.

4SRB NO_x controls are more cost effective than the 2SLB controls discussed earlier. Additionally, controlling NO_x emissions from 4SRB engines will also lead to larger total NO_x reductions, 626 tons per year, versus 2SLB controls, 556 tons per year. However, the 4SRB standard includes additional controls for five times the number of engines, with much smaller reductions per engine. As previously noted, some engines will likely be able to meet the 0.8 g/bhp-hr standard with lower cost controls than the NSCR and AFR combination that the Division used in its cost assumptions. Utilizing NSCR will allow many engines to exceed the proposed standard since NSCR achieves such high control efficiencies, and will also provide multi-pollutant benefits, simultaneously reducing VOCs and GHGs. The Division recognizes that reducing VOCs will help Colorado progress in attaining the ozone NAAQS standards, may help reduce the likelihood of additional ozone nonattainment areas across the state, and will provide public health benefits. Reducing GHG emissions will help Colorado in reaching the GHG reduction targets set forth in HB 19-1261. The Division has not estimated the dollar value of these additional pollutant benefits.

iii. Four Stroke Lean Burn Engines $\geq$ 1,000 HP

The Division is proposing a statewide 1.2 g/bhp-hr NO_x standard for all 4SLB engines with a rating of at least 1,000HP. Table 7 indicates that, based on July 2019 Division inventory data, there are 589 4SLB burn engines $\geq$ 1,000 HP across the state. 76 engines are not currently operating and they will require performance testing before returning to operation to determine the emission reduction required to meet the proposed 1.2 g/bhp-hr standard. 378 of the 589 engines, approximately two-thirds, are already operating below the proposed standard. The 135 engines that require additional controls, 5 are located in the DMNFR ozone NAA and 130 throughout the rest of the state. Of the 135 engines currently operating above the standard, sixty-four (64) engines, nearly 50% require at most a 25% emission reduction to meet the 1.2 g/bhp-hr standard. The vast majority of NO_x reductions from 4SLB engines will result from 25-90% emission reductions from the remaining 71 engines. The maximum required control % on any 4SLB engine is estimated at 89%. The Division estimates the additional controls will reduce annual NO_x emissions by 1,179 tons per year with nearly 40% of the total reductions derived from a small number of engines requiring at least 50% emission reductions.

Table 7: Statewide four-stroke lean burn engine counts and potential NO_x reductions (tpy)			
	# Engines	Potential NO _x reductions (tpy)	Average NO _x reduction per engine (tpy)
# of engines not operating	76	n/a	n/a
# of engines below proposed standard	378	n/a	n/a
# of engines needing $\leq$ 10% control to meet standard	29	92	3
# of engines needing >10 to $\leq$ 25% control to meet standard	35	119	3
# of engines needing > 25 to $\leq$ 50% control to meet standard	67	512	8
# of engines needing >50 to $\leq$ 90% control to meet standard	4	456	114

Total # of 4SLB engines	589	n/a	n/a
Subtotal # of 4SLB engines needing control to meet standard	135	1,179	9

There are many commercially available NO_x control options for 4SLB engines, especially compared to 4SRB engines. Similar to 4SRB engines, high energy ignition systems are one of the lowest cost control options for 4SLB engines, but may only reduce NO_x emissions by 10%. Adding an advanced air to fuel ratio (AFR) controller and upgrading the electronic ignition system may reduce emissions by up to 30% at a relatively low cost. Low emission combustion (LEC) technology and selective catalytic reduction (SCR) can potentially achieve over 90% emission reductions at higher costs. LEC technology is the term used for a combination of control technologies that including turbocharger and intercooler installations or upgrades, changes to the air intake and filtration system, changes to the exhaust and muffler system, AFR changes, and combustion chamber changes including the use of a pre-combustion chamber. Due to the extensive engine modifications involved, LEC is often the most effective control option, but also the highest cost. The subsequent tables focus on the costs and control efficiencies of AFR, SCR, and LEC, but operators may be able to employ other control options that achieve similar reductions.

Table 8 includes the Division's estimate of the maximum annualized cost of low emission combustion (LEC) overhaul and installation based on information from the Illinois EPA's 2007 "Technical Support Document for Controlling Emissions from Stationary Reciprocating Internal Combustion Engines and Turbines." This report estimates capital costs plus a 15% allowance for engine overhauls. These overhaul costs are listed in the non-recurring costs column in Table 8. The Division's estimate also includes operation and maintenance costs based on the 2008 Division engine rulemaking, and updated for inflation. The Division also included depreciation for control equipment costs as well as industry provided performance testing and portable analyzer testing costs, which include costs for testing of NO_x, CO, and VOCs, and a one-time mobilization cost assuming all engines at one site can be tested with one trip. Additional costs may be incurred if all engines at a site cannot be tested in one trip. Industry provided different costs for performance testing and portable analyzer testing for the DMNFR ozone NAA versus the rest of the state. Only four (4) of the 4SLB engines are located in the DMNFR NAA, while sixty-seven (67) are throughout the rest of the state. Table 8 only includes costs for the rest of the state which has higher O&M and testing costs versus the DMNFR NAA. The annualized cost per engine is \$366,535 for an engine located outside the DMNFR NAA.

Table 8: Example Maximum 4SLB engine annualized control costs, based on LEC for engines outside DMNFR ozone NAA						
Item	Capital costs (one time)*	Depreciation expense**	Book value of asset at	Non-recurring	O&M costs (recurring)	Annualized total costs

			year end	costs (one time)		
LEC (maximum costs)	\$2,594,336			\$389,150		\$366,535
Performance testing				\$4,400		
Operation & maintenance ***					\$9,166	
Subtotal costs	\$2,594,336	\$2,594,336		\$393,550	\$9,166	
Annualized costs****	\$269,672	\$129,717	\$337,691	\$14,715	\$9,166	

*All engine control device costs were escalated by 33.2% to reflect CPI-U increases that have occurred since the Illinois 2004 estimates.

** Depreciation expenses are for equipment costs, and assume a 5% interest rate, a 20-year amortization period, a residual value of the end of asset life of \$0, and straight line depreciation.

***Operation & maintenance costs were escalated by 21.1% to reflect CPI-U increases that have occurred since the Division's 2008 engine rulemaking. Operation and maintenance costs include portable analyzer testing. For the DMNFR Ozone NAA, industry provided performance testing costs of \$3,800 (one time) and portable analyzer testing costs (annually) of \$1,300. For the rest of the state, industry reported portable analyzer costs are \$1,900 annually. These costs do not include potential additional trips of \$800-\$1,400 for portable analyzer testing (ozone NAA versus the rest of the state).

*** Annualized costs are over a 20 year period assuming a 5% rate of return.

In addition to the maximum LEC costs included in Table 8, the Division also estimated minimum and maximum potential costs for AFR adjustments with electronic ignition (Table 9), selective catalytic reduction (SCR, Table 10), and low emission combustion (LEC, Table 11) scenarios. Tables 9, 10, and 11 demonstrate the NOx control efficiency (and range if applicable), the total number of engines that need to be controlled, the minimum and maximum annualized cost per engine, the associated total engine cost (for all affected engines), the potential NOx reduced per year from these engines, and the dollar per ton (\$/ton) cost ranges for AFR adjustments with electronic ignition, SCR installation or LEC installation, accordingly. The Division believes that some engines already contain AFR controllers as part of the engine design, but the Division's inventory does not clearly designate which engines have these controllers and whether these existing AFRs can reduce NOx emissions with adjustments. Therefore, the Division assumed in its AFR cost estimates that all engines that require a 25% emission reduction, or less, will install a new AFR. Regarding SCR and LEC options, both technologies achieve similar emission reductions and operators will choose between installing SCR or LEC depending on specific engine considerations; they will not need to install SCR and LEC on the same engine to meet the proposed standard. Because the Division is not requiring a particular control technology for each engine, the estimated costs in Tables 10 and 11 use the same number of engines for both control categories as a conservative approach. In order to avoid double counting, the Division's estimates assume that 50% of the higher NOx engines (those requiring >25% emission reduction) will utilize SCR and 50% will use LEC.

Table 9: 4SLB total engine cost (AFR adjustments)*

AFR adjustments w/electronic ignition**	NOx control efficiency	Number of engines		Annualized cost per engine	Total engine cost	NOx reduction (tpy)	\$/ton
Minimum costs	5-30%	Ozone NAA	1	\$21,178	\$21,178	3	\$7,933
		Rest of state	63	\$21,808	\$1,373,896	208	\$6,607
		Total	64		\$1,395,074	211	
Maximum costs	5-30%	Ozone NAA	1	\$35,915	\$35,915	3	\$13,454
		Rest of state	63	\$36,545	\$2,302,344	208	\$11,073
		Total	64		\$2,338,259	211	

* Includes all Colorado 4SLB engines that need < = 10% to < = 25% control

** For AFR installations, the Division assumed \$200 for annual maintenance costs

The minimum annualized costs for AFR adjustments are about \$21,178-\$21,808 per engine, depending on whether the engine is located in the DMNFR NAA or the rest of the state. This equates to \$7,933-\$6,607 per ton of NOx reduced while the maximum annualized costs as shown in Table 9 are about \$35,915-\$36,545 per engine, which equates to \$13,454 in the DMNFR NAA and \$11,073 in the rest of the state.

Table 10: 4SLB total engine cost (SCR)*

SCR	NOx control efficiency	Number of engines		Annualized cost per engine	Total engine cost	NOx reduction (tpy)	\$/ton
Minimum costs	90%	Ozone NAA	4	\$92,648	\$370,590	456	\$813
		Rest of state	67	\$93,278	\$6,249,599	512	\$12,201
		Total**	71		\$6,620,190	968	
Maximum costs	90%	Ozone NAA	4	\$274,825	\$1,099,301	456	\$2,411
		Rest of state	67	\$275,455	\$18,455,507	512	\$36,031
		Total**	71		\$19,554,808	968	

* Includes all Colorado 4SLB engines that need > 25% to 90% control

** This total assumes all 71 engines utilize SCR. The Division's proposal does not require specific control technology for each engine and the Division's overall cost estimate assumed 50% would utilize SCR and 50% would utilize LEC.

Table 11: 4SLB total engine cost (LEC)*							
LEC	NOx control efficiency	Number of engines		Annualized cost per engine	Total engine cost	NOx reduction (tpy)	\$/ton
Minimum costs	70-93%	Ozone NAA	4	\$11,617	\$46,466	456	\$102
		Rest of state	67	\$12,247	\$820,520	512	\$1,602
		TOTAL**	71		\$866,986	968	
Maximum costs	70-93%	Ozone NAA	4	\$365,905	\$1,463,620	456	\$3,210
		Rest of state	67	\$366,535	\$24,557,847	512	\$47,944
		TOTAL**	71		\$26,021,467	968	

* Includes all Colorado 4SLB engines that need > 25% to 90% control

** This total assumes all 71 engines utilize LEC. The Division's proposal does not require specific control technology for each engine and the Division's overall cost estimate assumed 50% would utilize SCR and 50% would utilize LEC.

As stated above, the Division determined that SCR and LEC have similar control effectiveness, but the costs differ significantly between the two options and both options have a wide range of costs (the difference between the minimum and maximum costs for a particular control technology). As shown in Table 10, the minimum annualized costs for SCR range from \$92,648 to \$93,278 per engine, which equates to about \$813 to \$12,201 per ton of NOx reduced, for the DMNFR NAA and the rest of the state, respectively. For SCR, the maximum annualized costs range from \$274,825 in the DMNFR NAA to \$275,455 in the rest of the state, per engine, about three (3) times as much as the minimum per engine costs. For SCR, this equates to about \$2,411 per ton of NOx reduced in the DMNFR NAA and \$36,031 in the rest of the state.

The range of costs for LEC are much wider than for SCR. Table 11 shows both the minimum and maximum costs for implementing LEC on 4SLB engines. The minimum annualized costs for LEC range from \$11,617 to \$12,247 per engine, which equates to about \$102 to \$1,602 per ton of NOx reduced, for the DMNFR NAA and the rest of the state, respectively. For LEC, the maximum annualized costs per engine range from \$365,905 in the DMNFR NAA to \$366,535 in the rest of the state, which equates to about \$3,210 per ton of NOx reduced in the DMNFR NAA and \$47,944 in the rest of the state, about thirty (30) times as much as the minimum per engine costs for LEC. The maximum per engine costs for LEC are also about 33% higher than the maximum per engine costs for SCR.

The Division estimates that the minimum total annualized cost for all operators with affected 4SLB engines will range from about \$9,252,051 to \$32,946,581. This assumes that 50% of operators install SCR and 50% install LEC, as described earlier in this section and in the notes for Tables 10 and 11, and includes the costs of the initial performance testing, annual maintenance, and ongoing portable analyzer testing.

In addition to the new research and cost estimates prepared by the Division for the proposed updates to Regulation 7, the Division also compiled a summary of cost ranges from applicable Reasonably Available Control Technology (RACT) analyses submitted to the Division in 2018 to support the rulemaking for the 2008 moderate area ozone state implementation plan (SIP) for the DMNFR area. These analyses reviewed numerous existing lean burn engines and a variety of potential control options in the DMNFR. The control options included in the RACT analysis include similar options to the Division's review – many

of which are included in the LEC control option: replacing engine heads; adding turbochargers and/or pre-combustion chambers, and electronic pre-combustion chamber check systems; installing an AFR control system and exhaust expansion chambers; implementing adaptive algorithm-based AFR strategy; installing hyperbalance technology; upgrading fuel injector technology, and SCR. Control costs varied widely from clean burn (AFR/turbochargers) to achieve 2.0 g/bhp-hr at about \$3,098 per ton of NOx reduced to packages that included multiple controls (turbocharger upgrades, hyperbalance) to achieve 1.0 g/bhp-hr at almost \$90,000 per ton of NOx reduced. On average, these RACT analyses estimated \$30,000 to \$35,000 per ton of NOx reduced to achieve 1.0 g/bhp-hr. In addition to expressing concern over cost effectiveness, multiple RACT analyses asserted that permitted levels below 1.0 g/bhp-hr are not technically feasible because engines operating at these low emission levels are unable to provide sufficient natural gas compression rates. The combination of insufficient compression performance, potentially very high control costs, and possible increases in other pollutants lead the Division to stand by its proposed emission thresholds.

In order to account for these high and widely variable potential costs, the Division is providing the Company-Wide Plan option as part of the proposal, which provides appropriate flexibility for consideration of site specific and technical feasibility issues. The Division contends that the Company-Wide plan offers a cost effective option that allows operators to achieve emissions reductions that are equal to or greater than those achieved by installing new controls on every individual engine, likely at a much lower cost than individual engine controls. The Division requested additional input from industry comparing the potential cost savings, but did not receive any specific cost estimates.

iv. Consideration of Other Pollutants

During the proposal development process, the Division received feedback indicating that some emission control technologies can lead to increases in other pollutant levels. In order to ensure the proposed engine requirements effectively balance any potential emission trade-offs, the Division thoroughly reviewed the impacts of NOx control technologies on other pollutants. Oxidation catalysts are required for any lean burn engines greater than 500 HP in the ozone nonattainment area⁷. These control devices control both CO and non-methane hydrocarbons (NMHC). At NOx levels of 0.5 g/bhp-hr or less, CO emissions will increase due to the air to fuel ratio and combustion balance required to properly operate a lean burn engine. In addition to impacts on CO emissions, the Division also studied the impact of lean burn NOx controls on VOC emissions. This is a very important factor to consider due to the impact of VOCs on the state's ozone attainment status. The Division's inventory and multiple manufacturer specifications suggest that although VOC emissions may increase when NOx emissions decrease, this phenomenon is most apparent at or below 0.5 g/bhp-hr. Based on the engine makes and models in the Division's inventory, VOC emissions do not consistently increase and, in some cases decrease, at the proposed standard of 1.2 g/bhp-hr for 4SLB engines. Based on this information, CO and VOC emissions are not anticipated to increase significantly for engines under this proposal.

As discussed in detail earlier, the Division's cost analysis for 4SRB assumed that most operators would install non-selective catalytic reduction (NSCR) to meet the proposed 0.8 g/bhp-hr standard. NSCR controls reduce not only NOx emissions, they significantly reduce all three major pollutants that are emitted from engines – NOx, CO, and hydrocarbons, which include VOCs. Additionally, NSCR also decreases GHG emissions. The Division did not estimate the dollar value of these pollutant or GHG reductions, but it expects these will provide health benefits, improved visibility for Regional Haze, and reduce ozone levels. Considering only NOx reductions, 4SRB engines were already the most cost effective engine category to control. Once the additional pollutant reductions are included, the controls become much more economically feasible. Other rich burn control options, such as high energy ignition systems that may be installed on engines requiring low NOx reductions, are not anticipated to significantly change engine operations nor increase CO or VOC emissions.

⁷ Colorado Air Quality Control Commission Regulation 7, Part E, Section I.B.2

Stakeholders raised concerns that additional engines may be needed to meet compression demands, which could ultimately increase GHG emissions. However, the Division determined that due to the wide variety of control options available, including the potential for replacing lean burn engines with controlled rich burn engines to comply with the proposed standards, as well as electrification and the flexibility provided in the Company-Wide Plan option, that this scenario is very unlikely and not an issue.

Based on this information, the Division does not anticipate that this proposal will impose additional costs resulting from increases in other pollutants. The Division requested that owners or operators of potentially impacted operations provide Colorado specific information concerning the proposed revisions and their potential effects on emissions of other pollutants or GHGs, but none was provided.

v. Effect of the engine proposal on the growth of the affected industry sectors with and without implementation of the proposal; and how the proposal may effect or alter the growth of the affected industry sector

The Division believes that this proposal may increase costs to affected operators that are retrofitting controls on existing engines and potentially increase the cost of new engines sold in Colorado. However, the Division received feedback from engine manufacturers that there is not a large cost differential in ordering engines specified to meet a required g/bhp-hr standard. The Division does not anticipate a significant impact on new oil and gas drilling in Colorado as a result of the natural gas RICE proposal. The Division recognizes that the oil and gas industry has seen a sharp downturn since the beginning of 2019 due to commodity surpluses and decreased demand as a result of behavioral changes during the pandemic.⁸ This is reflected by a drop in oil rig counts from around 30 in June 2019 to approximately 20 in early March 2020, just before economic shutdowns from the pandemic, to the current total of 5 drilling rigs in Colorado.⁹ Although Colorado has seen multiple oil and gas companies, including Whiting Petroleum, file for bankruptcy this year, these appear to be driven by low oil and gas prices and companies with high debt levels, rather than regulatory burden.¹⁰ Since 2010, the Division has conducted multiple rulemakings to reduce emissions from the oil and gas sector, and despite industry concern over excess regulatory burden, oil and gas production has experienced significant growth in Colorado. The Division anticipates that the industry will continue its pre-pandemic growth trend in the future with minimal impact from additional compliance costs for the Division's proposed revisions to Regulation Number 7, including the RICE NOx reductions.

C. Oil and gas operations: Pre-production monitoring and controls

In addition to the NOx reduction rules for natural gas engines, the Division is proposing additional requirements for pre-production and early production emissions monitoring, which will inform future emission reduction strategies and monitoring efforts.

i. Pre-production and early production monitoring

Section 25-7-109(10)(a), CRS, directs the Commission to adopt rules to minimize emissions from natural gas exploration and production facilities and natural gas facilities in the processing, gathering and boosting, storage, and transmissions segments of the natural gas supply chain. Section 25-7-109(10)(b)(I)(C), CRS, further directs the Commission to consider a requirement that oil and gas operators install and operate continuous methane emissions monitors. The statute also confirmed the Commission's authority to address emissions during the pre-production stage, including drilling and completion.

⁸ "Wyoming Insight - Economic Analysis Division" (July 2020) at <http://eadiv.state.wy.us/creg/WyInsight.pdf>

⁹ Baker Hughes Rig Count at <https://rigcount.bakerhughes.com/static-files/4e95863a-7611-468a-9e2e-12919a54dda1>

¹⁰ Whiting Petroleum Aims to Exit Bankruptcy at <https://news.bloomberglaw.com/bankruptcy-law/whiting-petroleum-aims-to-exit-chapter-11-by-august>

Although air monitoring technologies are still developing, air monitoring systems that provide accurate, real-time data are being deployed. EPA¹¹, other state agencies, and industry operators have been evaluating sensor technologies for a variety of uses; however, there is no one-size-fits-all sensor or system. Nor has EPA approved a low-cost sensor to collect regulatory-grade monitoring data. Regulatory agencies, the general public, and facilities often must weigh trade-offs between accuracy, ease of use, and costs. Regulatory-grade air quality monitors measure a limited number of pollutants with a high precision and accuracy, but are often expensive to purchase and may require highly experienced operators to operate and maintain.¹² This caliber of monitoring is typically used for NAAQS compliance or installed as a result of a compliance agreement following an episodic emission event. At the other end of the spectrum are consumer-grade sensors, which are lower cost and easier to operate. However, consumer-grade sensors may provide insufficient accuracy or precision, may have high detection limits, and may be unable to speciate emissions such as VOCs. In addition, electrochemical cell, which are used in some low-cost monitors, degrade over time and must be frequently replaced. To develop an air quality monitoring system, the user must first decide what they are trying to accomplish by collecting air quality data. The system design decisions include:

- identifying the pollutant(s) of interest (methane, NMHC, H₂S, total VOCs, a speciated list of VOCs, BTEX, etc.);
- field conditions (temperature, humidity, access to power, etc.);
- device specifications (detection limit, accuracy, precision, physical size, etc.);
- determining the duration of data collection and storage required;
- type of measurements needed (real-time continuous, periodic sampling, etc.); and,
- quality of the measurements (regulatory reporting, community warning for exceeding a threshold, etc.).

The sensor user may select one of a multitude of sensor technologies based on the answers to questions like these. Additionally, the chosen technology may differ depending on the phase of the oil and gas operation (baseline, preproduction, early production, etc.) and the activity and pollutant(s) being monitored.

In recognition of the variety of potential monitoring system designs and to allow for innovation from monitoring technology suppliers and operators, the Division is proposing a collaborative approach to monitoring systems development that will help inform the next steps in meeting the statutory directives for monitoring. As an initial step in this process, the Division is proposing to require owners or operators to submit an air quality monitoring plan to the Division prior to implementing Division-approved air quality monitoring at and around pre-production operations (i.e., drilling, fracking, drill-out, flowback) through early production operations. To address the request of multiple local governments for further local government engagement, the Division revised its proposal to require the operator to simultaneously submit the plan to the local government with jurisdiction over the location of the facility. This adds no extra costs.

The air quality monitoring plan must specify, among other things, which pollutant(s) will be monitored, the frequency of measurements, the limitations of the monitoring equipment, the quality control and quality assurance procedures, and the data acquisition system. This air quality monitoring will help to better inform the understanding about emissions from pre-production and early-production oil and gas operations and monitoring options.

As stated earlier and in the Division's rebuttal documents, the Division anticipates working with stakeholders to develop a monitoring plan template, which will reduce cost and staff time in developing

¹¹ EPA "Air Sensor Toolbox" at <https://www.epa.gov/air-sensor-toolbox>

¹² EDF/Ramboll. "Technology Assessment Report: Air Monitoring Technology near Upstream Oil and Gas Operations", published December 2017. at <https://www.edf.org/sites/default/files/Ramboll-report.pdf>

these monitoring plans and submitting them to the Division for approval, though the Division has not estimated these potential costs. Since this proposal is for monitoring, it is not expected to lead to immediate emission reductions. However, the information gathered by operators will inform future Division monitoring proposals. Further, the Division expects that if operators observe emissions, the operators will take actions as appropriate to address them, which will have real time reductions not accounted for in the Division's analysis. The Division anticipates that these future proposals will set forth specific monitoring system performance standards and the resulting data will allow industry to more rapidly respond to detected emissions of methane and VOCs, which negatively impact climate and health as GHGs and ozone precursors.

a. Industrial and business sectors that will be impacted by the proposal

As highlighted in the Baker Hughes rig counts above, the oil and natural gas markets have seen downturns in the last year due to multiple factors. Based on this, the Division believes that current 2020 pre-production operations facility data may not accurately predict Colorado's future oil and gas production. Instead, the Division has evaluated production based on 2017-2019 data from the Division's permits and information from the Colorado Oil and Gas Conservation Commission (COGCC). Table 11 shows that an average of 107 permitted well production facilities during 2017-2019. The Division estimates that around 107 pre-production facilities per year may incur costs to submit monitoring plans to the Division. The Division has not received updated projections from industry.

Table 11: Estimation of future pre-production operations			
	Division – permitted well production facilities	COGCC – spud count	COGCC - completions
2017	173	1,839	1,937
2018	86	1,805	1,814
2019	62	1,467	1,437
3-year Average	107		

b. Cost to the primary affected business or industrial sector

As discussed in the Division's Final EIA, costs of the proposed monitoring plan revisions will vary widely based on the sensor technology and monitoring plans selected by each operator. In response to industry requests, the Division is providing some additional estimates on upfront sensor costs. Note that these are one-time costs, and not the annualized costs generally provided by the Division. Pre-production and early production operations are short-term activities, therefore monitoring costs may not even exceed one year. Based on the Ramboll report, "Technology Assessment Report: Air Monitoring Technology near Upstream Oil and Gas Operations" cited earlier, gas monitoring technologies can be grouped into the following broad categories

- Open Path Optical/Laser Absorption Spectroscopy
- Extractive (nonopen path) Optical/Laser Absorption Spectroscopy
- Chromatography
- Ionization
- Reactive

According to the Ramboll report, depending on the specific type of sensor, open path spectroscopy can be used to continuously measure methane, benzene, and non-methane organic compounds (NMOCs) over long distances, up to hundreds of meters, often with high accuracy for multiple compounds simultaneously. These open path sensors are often used for regulatory fenceline monitoring and may cost

\$15,000 to over \$400,000, depending on the technology and manufacturer. Open path sensors are the only technology discussed here that allows for monitoring large distances with a single sensor; all other technologies would likely require an array of multiple sensors. Nonopen path spectroscopy can also be used for continuous methane, benzene, and NMOC monitoring, though these sensors do not measure over long distances and generally only measure one compound at a time. Costs for nonopen path sensors may range from \$1,000 to \$150,000. Chromatographs can accurately measure methane, benzene, and NMOCs simultaneously, and though the measurements are near real-time, they are not continuous. Traditional bench top chromatographs utilizing mass spectrometry are relatively large and have higher power consumption. Combined with costs of \$20,000 - \$60,000 (specialty units for measuring natural gas in pipelines may cost well over \$100,000); these traditional chromatographs may be more suited to mobile, vehicle-based monitoring than remote field installations. Newer, portable gas chromatographs are much more suited to rugged environments and may cost \$5,000 - \$25,000. Photoionization sensors, which may be included in portable chromatographs, can continuously monitor benzene and other air toxics, but are unable to measure methane or take readings. Photoionization sensors are relatively low cost at \$1,000 - \$10,000. Finally, reactive sensors including electrochemical (EC), metal oxide semiconductor (MOS), and pellistor offer the lowest monitoring cost, with transmitters costing less than \$2,000 and replacement sensor heads often costing below \$500. Unfortunately, reactive sensors typically have low accuracy and may be sensitive to sensor poisoning or changes in temperature, air pressure, and humidity. Despite these issues, a large array of reactive sensors may be sufficient for certain monitoring situations. As discussed above, air monitoring options range from very expensive, accurate monitors that may be hundreds of thousands of dollars to low-cost sensors that may cost less than \$2,500, but have limited accuracy.¹³

California's South Coast AQMD Air Quality Sensor Performance Evaluation Center (AQ-SPEC) program provides another valuable source of air monitoring sensors information, including PM sensors which were not discussed in the Ramboll report. The AQ-SPEC program has compiled a gas-phase sensor evaluation table that summarizes data on twenty-two gas-phase (O₃, NO₂, CO, SO₂) sensors that ranging from \$200 to \$10,000.¹⁴ AQ-SPEC's PM sensor evaluations summary table lists 50 PM sensors ranging in estimated costs from \$100 to \$7,000.¹⁵ Similarly, Methane Observation Networks with Innovation Technology to Obtain Reductions (MONITOR) projects on Advanced Research Projects Agency-Energy's (ARPA-E) website list monitoring systems ranging from \$300 to \$3,000.¹⁶ In addition, while real-time data air monitoring during oil and gas production has only been occurring in recent year, refineries have been monitoring air quality for several years. EPA revised its National Emission Standard for Hazardous Air Pollutants (NESHAP) from Petroleum Refineries, 40 CFR Part 63 Subpart CC, in 2015 to include a fence line monitoring work practice standard to improve the management of fugitive emissions. EPA evaluated a fence line passive diffusive tube monitoring requirement and estimated the annualized costs for three model plants at \$41,000 (18 monitoring sites), \$47,600 (26 monitoring sites), and \$52,500 (32 monitoring sites) per year.¹⁷

The sensor descriptions and cost data provided above is intended to provide a high-level summary of some of the technologies available in the market, but is not intended as an endorsement of a particular technology, manufacturer, or monitoring method. Although the Division will review and ultimately approve

¹³ MDPI, "Low-Cost Air Quality Monitoring Tools: From Research to Practice (A Workshop Summary)", published October 2017 at <https://www.mdpi.com/1424-8220/17/11/2478>

¹⁴ South Coast AQMD, "AQ-SPEC Air Quality Sensor Performance Evaluation Center, Summary of Gas Phase Sensors" at <http://www.aqmd.gov/aq-spec/evaluations/summary-gas>

¹⁵ South Coast AQMD, "AQ-SPEC Air Quality Sensor Performance Evaluation Center, PM Sensor Evaluations" at <http://www.aqmd.gov/aq-spec/evaluations/summary-pm>

¹⁶ ARPA-E, "Listing of MONITOR Projects" at <https://arpa-e.energy.gov/?q=program-projects/MONITOR>

¹⁷ See EPA's Fence Line Monitoring Impact Estimates for Final Rule, EPA-HQ-OAR-2010-0682 (June 4, 2015). For the small model plant, purchased equipment total capital costs were \$86,650 (\$89,270 for the medium model plant, \$90,880 for the large model plant) and included a meteorological station, installation, ancillary planning/selecting costs, and shipping. Annualized operating costs were \$28,680 (\$34,910 for the medium model plant, \$39,550 for the large model plant) and included equipment maintenance/insurance, sampling collection, sampling analysis, recordkeeping, and reporting.

the monitoring proposals submitted by operators, it fully expects to see a number of different solutions that will be tailored to specific site locations, stages of operation, performance targets, and other specific requirements. The Division believes that this approach will collect a variety of air pollutant emissions data and will further the development of monitoring technology. The data and knowledge gained about various monitoring technologies may inform future monitoring programs and requirements.

Additionally, the Division believes that monitoring approaches that employ short-sampling intervals (high-sampling frequency) may provide earlier notifications of potential emissions, which may reduce product losses and partially offset the upfront and ongoing costs of monitoring.

c. Economic impact of the monitoring plan proposal on the supporting business and industrial sectors associated with the primary affected business or industry sectors

The Divisions anticipates additional sales for manufacturers and installers of monitoring technologies and data systems because the proposed revisions will increase usage of their products and services. The proposal could also lead to a slight increase in employment for monitoring system installers and maintenance employees. However, the Division is unable to quantify the potential sales or employment increases because the monitoring proposal does not require the usage of technologies provided by specific companies.

The Division requested Colorado-specific information on costs and benefits to manufacturers and sellers of monitoring and data storage systems, but did not receive any additional information.

ii. Flowback vessels

In order to further reduce emissions throughout the oil and gas sector, the Division is proposing emissions control and monitoring requirements for flowback vessels and associated equipment. These requirements include using vapor-tight flowback tanks and conducting periodic visual inspections of the flowback tanks and associated equipment. These requirements would apply to owners of operators of pre-production operations. The benefits of vapor-tight flowback tanks are discussed below.

Flowback tanks are used during oil and gas pre-production activities and can lead to uncontrolled methane and VOC emissions if the tanks are not designed to contain these vapors. Oil and gas pre-production operations involve well development activities occurring before the date of commencement of operation including drilling, hydraulic fracturing, and flowback. The completion process (i.e., fracking through flowback) prepares the well for continuous production through the flowback of sand and various liquids injected into the well during the hydraulic fracturing process. The liquids and dissolved gases from well flowback operations are sent to a fleet of flowback vessels which are often portable tanks, and may currently be open topped or covered. Open topped flowback tanks do not adequately capture and control those vapors. Therefore, the Division is proposing a new requirement for vapor-tight flowback tanks which can control these emissions.

The Division has received reports of pre-production activities around the state which suggest that flowback vessels generally do not appear to be vapor-tight. In addition, EPA's NSPS OOOOa does not subject well completion vessels to the storage tank control requirements during the reduced emissions completion (REC) process. The lack of widespread use of vapor-tight flowback tanks is not due to commercial availability or technical constraints; Division research indicates that vapor-tight flowback tanks are manufactured, available, and technically feasible for flowback operations. In addition to the vapor-tight tanks, steel piping is necessary to connect all the active flowback vessels to a common manifold for routing vapors to the enclosed flare and a liquid knockout vessel may be required for safety. This additional equipment is also widely available and technically feasible to install and operate.

The Division's cost estimates assume that most operators will choose to utilize temporary flowback tanks. However, the proposed changes to Regulation Number 7 allow for the usage of permanent production

storage tanks for flowback operations, based on stakeholder feedback. The Division requested more information on the feasibility, practicality, and limitations of using permanent production storage tanks for flowback operations. Stakeholders commented that the use of permanent storage tanks may be feasible but not preferable, due to the quantity and quality of the liquids from flowback. If operators use their permanent storage tanks for flowback, operators may save the costs of renting temporary flowback tanks. The stakeholders did not provide estimated costs or savings associated with utilizing permanent storage tanks versus temporary flowback tanks, and the Division has not independently estimated these costs/savings.

Regulation Number 7, Part D, Section II.C.1.c., requires that all owners and operators of storage tanks in the state with uncontrolled VOC emissions greater than or equal to 2 tons per year collect and control emissions with air pollution control equipment that achieves 95% control efficiency. Most operators comply with the control requirement by installing an enclosed combustion device (ECD). Most newly completed wells at well production facilities with storage tanks on site would be expected to have uncontrolled VOC emissions well above the 2 tons per year threshold. Further, operators are likely to have an ECD onsite during pre-production operations due to the REC requirements in EPA's NSPS OOOOa. Accordingly, the Division is not including the cost of an ECD in the flowback analysis because Regulation Number 7 requires emission controls at the majority of well production facilities with tanks after the well begins production.

The Division provides example costs of flowback vessels, based on stakeholder input. Flowback vessels, which are often referred to as frac tanks, may be smooth wall, corrugated wall, insulated, round bottom, or V bottom. A typical 500 BBL open top frac tank with gas buster is \$39,500.¹⁸ A gas buster "is a vessel containing a series of baffles with a liquid exit on the bottom and a gas vent line at the top of the vessel. It rids the vessel of invaded gas or air including CO₂, H₂S, methane and many others found in the oilfield."¹⁹ However, these flowback vessels can be enclosed, including pressure relief valves and level gauging. A typical closed top, 500 BBL vapor-tight frac tank is \$30,500.²⁰ In addition, used tanks range from \$19,750 to \$7,000.²¹ It's important to note that these frac tanks are portable and will be moved from one pre-production facility to the next. Therefore, the complete tank costs cannot be associated with reducing emissions from just one flowback operation and the Division cannot precisely estimate the \$/ton of emission reduced from these tanks. The Division provides a range of \$/ton estimates including a high estimate that assumes all costs are assigned to a single well production facility (shown in Table 16 below), and a more realistic scenario where the flowback tanks are reused at multiple well production facilities each year (shown in Table 17 below). Flowback service providers would likely absorb some of the costs but would need to distribute the additional costs of providing vapor-tight tanks to operators. Nevertheless, the Division estimates that a typical well production facility with 10 wells can have around 10 to 15 flowback vessels, each tank has a 500 bbl capacity, on site during typical well completion activities. The actual number of flowback tanks could vary depending on whether outflow is managed through direct pipe to a centralized facility or the frequency of truck loadouts. The number of wells under active development at the well production facility could also affect the number of flowback tanks needed day-to-day, but the Division assumes that the flowback tanks would be periodically pumped to reduce the need to bring in extra tanks. Accordingly, the Division estimates that a fleet of about 12 enclosed vapor-tight flowback vessels would be needed to support a typical well production facility during well completion activities. Enclosed flowback tanks are assumed to have a useful life of about 15 years.

¹⁸ Dragon Products, Ltd. "Frac Tanks" at <https://dragonproductsltd.com/tanks-2/>

¹⁹ Frac Tank Rentals, "Single Gas Buster Flow Back Tanks" at http://www.fractankrentals.com/Single_Gas_Buster_Flow_Back_Tanks.htm

²⁰ Dragon Products, Ltd. "Frac Tanks" at <https://dragonproductsltd.com/tanks-2/>

²¹ Dragon Products, Ltd. "Used Frac Tanks" at <https://dragonusedequipment.com/used-frac-tanks/>

Based on a study²² involving 10 flowback operations in the Rocky Mountain Region, the Division estimates that each flowback operation releases on average about 24.4 thousand cubic feet (Mcf) of methane. Flowback activities likely emit other hydrocarbons, including VOCs, although the Division does not have sample data to understand the magnitude of the VOC emissions.

As discussed earlier, fluctuations in commodity prices, combined with the impact of the global pandemic have led to significant downturns in the oil and natural gas markets over the past year. Based on this, the Division believes that current 2020 well production data is not the best representation of historical trends in statewide activity. Therefore, the Division is providing Figures 1 and 2 below which show historic oil and gas production data from the Colorado Oil and Gas Conservation Commission (COGCC) that it believes provides a more representative indication of potential future development.

Figure 1 – Colorado oil production in barrels per year (bbl/yr)

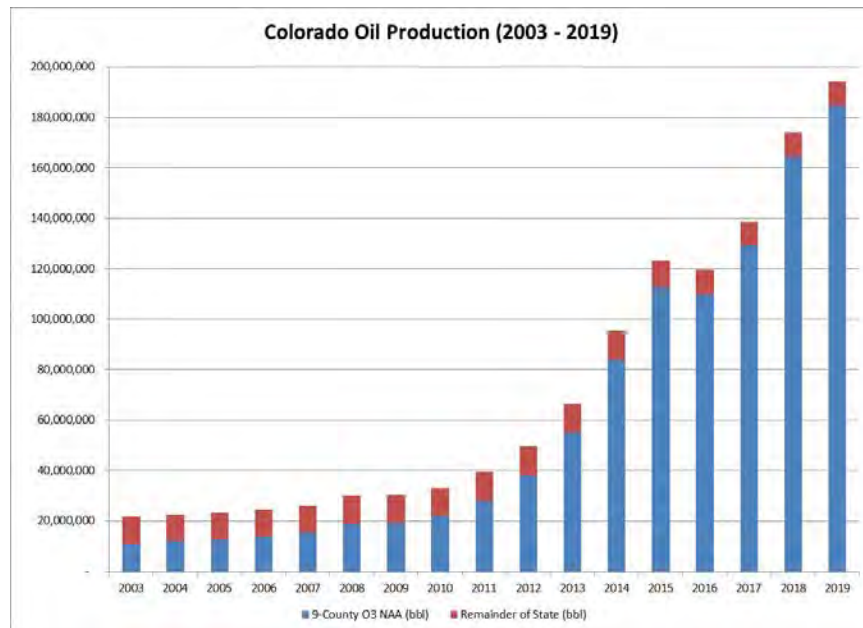
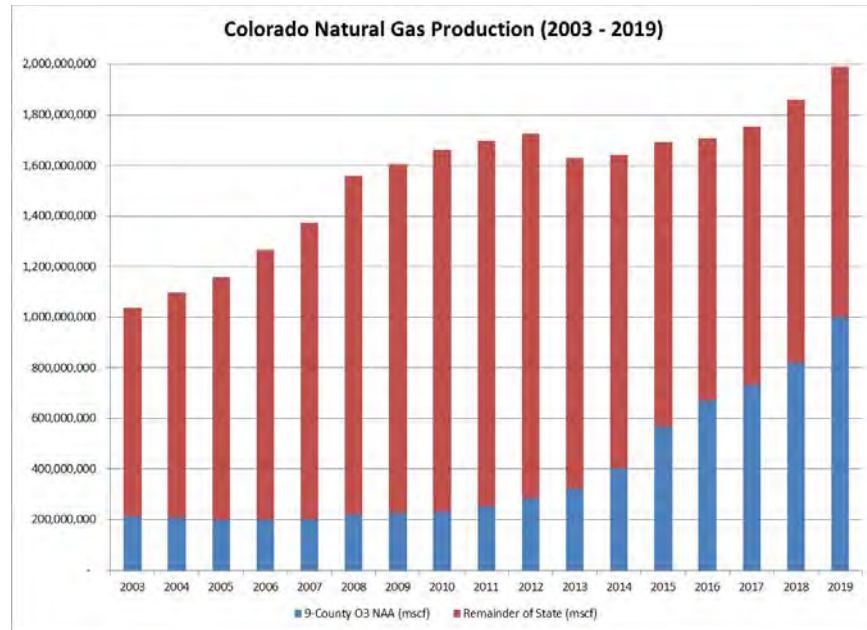


Figure 2 – Colorado natural gas production in thousand cubic feet per year (Mcf/yr)

²² Allen et. Al. "Measurements of methane emissions at natural gas production sites in the United States - Supplemental Information", published 2013 at <https://www.pnas.org/content/pnas/suppl/2013/09/11/1304880110.DCSupplemental/sapp.pdf>



The production data from COGCC suggests that past economic downturns or price fluctuations cause slight temporary pauses in statewide production but the general trend continues to increase.²³ To further support the demonstration of these trends, Table 12 below provides historical data on the annual number of well production facilities permitted by the Division, the number of well completions based on COGCC data, and estimates on average number of well completions per well production facility for different averaging periods along with estimates of average methane emissions.

Year	Annual number of permitted WPFs *	Annual number of well completions**	Average number of well completions per WPF	Average methane from each well completion event (Mcf)	Total methane from average number of well completions at each WPF (Mcf)
2009	568	2,303			
2010	620	3,047			
2011	1,311	3,261			
2012	722	2,435			
2013	458	1,926			
2014	395	2,125			
2015	307	1,467			
2016	162	905			
2017	173	1,937			
2018	86	1,814			
2019	62	1,437			
3-yr Average:	107	1,729	16.16	24.46	395.25
5-yr Average:	158	1,512	9.57	24.46	234.07
10-yr Average:	430	2,035	4.73	24.46	115.76

²³ E&E News, "Groups Bullish on Future Growth, Call Pandemic a 'Blip'", May 26, 2020 at <https://www.eenews.net/eenewspm/2020/05/26/stories/1063241095>

* Number of well production facilities is based on Division's permit tracking system data

** Number of well completions is based on data from Colorado Oil and Gas Conservation Commission

Clearly there is a downward trend in the number of well production facilities permitted each year, but the number of well completions remains fairly steady. The shorter 3-year averaging period shows that the number of well completions is higher than the 5-year average but below the 10-year average. Considering the rapid change experienced in the oil and gas sector over the past decade, including the transition from vertical wells to horizontal wells, the Division uses the most recent 3-year average for projecting the future number of well completions statewide.

The total methane reductions in the last column of Table 12 are in Mcf per year, but these need to be converted to tons per year in order to ultimately determine the \$/ton cost of the vapor-tight flowback tank proposal. Table 13 shows the results of this unit conversion. The Division converted from Mcf to tons using the molar weight of methane, the ideal gas law conversion from scf to pounds, % of the molar weight due to methane, based on gas analysis, and the number of pounds in a short ton. This results in the methane emissions of 7.5 – 2.2 tons per year (tpy). Assuming the flare reduces methane emissions by 95%, results in the methane reductions are shown in the last column of Table 13.

Table 13: Number of well production facilities (WPF) and number of well completions			
Averaging period	Total methane from average number of well completions at each WPF (Mcf)	Total estimated methane emissions from well completions at each WPF (tpy)	Total estimated methane reduced by flaring at each WPF (tpy)
3-yr average (2017-19):	395.25	7.56	7.18
5-yr average (2015-19):	234.07	4.48	4.25
10-yr average (2009-19):	115.76	2.21	2.10

Table 14 lists the estimated annualized cost for a single vapor-tight flowback tank. The estimate is based on the vessel cost, provided by Dragon Products, along with nominal costs for purchasing and installing steel piping from the tank to the ECD, and annual maintenance. The annualized cost, as shown in Table 14, is about \$4,830.

Table 14: Enclosed Vapor-tight Flowback Vessel – annualized cost analysis				
Item	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
Enclosed Flowback Tank	\$30,500			
Steel Piping to ECD	\$500			
Steel Pipe Installation		\$500		
Maintenance			\$500	
Subtotal costs	\$31,000	\$500	\$500	
Annualized costs*	\$4,296	\$33	\$500	\$4,830

* Annualized costs are over a 15 year period assuming a 5% rate of return

As discussed earlier, the Division recognizes that the number of flowback tanks required at a well production facility will vary, but assumes that an average of 12 500 bbl tanks will be required per well production facility. Using the annualized cost per flowback tank, approximately \$4,830, calculated in Table 14 leads to an annualized cost of \$57,958 per well production facility, which is shown in Table 15.

Table 15: Annualized Total Cost for Twelve Enclosed Vapor-tight Flowback Vessels		
Number of Enclosed Tanks at WPF	Annualized Cost of each Enclosed Tank	Total Annualized Cost for all Enclosed Tanks
12	\$4,829.80	\$57,958

As mentioned earlier, the Division expects that most operators will utilize portable flowback tanks that provide vapor control at multiple well production facilities each year. Nevertheless, the Division has estimated the cost effectiveness assuming that the fleet of 12 tanks is dedicated to a single well production facility each year. This estimate overstates the costs of the vapor-tight flowback tank proposal, but is useful to provide a worst-case cost effectiveness estimate. The single well production facility estimate is calculated by dividing the annualized tank fleet cost, from Table 15, by the annual methane reductions per well production facility, from Table 13. The results, as shown in Table 16, estimate the annual methane control costs ranging from \$6,988 to \$23,860 per ton of methane reduced, depending on which of the three different O&G production data averaging periods are utilized. The Division contends that the 3-yr average is likely the most representative estimate of future production trends.

Table 16: Number of Well Production Facilities (WPF) and Number of Well Completions					
Averaging Period for Number of WPFs and Number of Well Completions	Total Methane from Average Number of Well Completions at each WPF (Mcf)	Total Estimated Methane Emissions from Well Completions at each WPF (tpy)	Total Estimated Methane Reduced by Flaring at each WPF (tpy)	Total Annualized Cost for all Enclosed Tanks (\$)	Annual Control Costs (\$/ton of Methane Reduced)
3-yr Average:	395.25	7.56	7.18	\$57,957.60	\$8,069.05
5-yr Average:	234.07	4.48	4.25	\$57,957.60	\$13,625.07
10-yr Average:	115.76	2.21	2.10	\$57,957.60	\$27,551.01

The Division has also estimated the cost effectiveness assuming that each fleet of flowback tanks will be used at 10 well production facilities each year. The Division believes that this is a much better representation for how the flowback tanks will actually be utilized. To calculate this estimate, the Division multiplies the annual methane reductions per well production facility, from Table 13, by 10 well production facilities to determine the total annual methane reductions of 71.8 to 21.0 tons per year, for the 3-year and 10-year production averages. Because the Division estimates that the vapor-tight tanks will reduce emissions for 15 years, the annual methane reductions are multiplied by 15, resulting in the total methane reductions listed in the fourth column of Table 17. The total annualized tank fleet costs, from Table 15, are divided by the 15-year total methane reductions. This results in significantly lower \$/ton estimates, as shown in the last column of Table 17, \$54 to \$184 per ton of methane reduced, depending on which of the three different O&G production data averaging periods are utilized.

Table 17: Overall Cost Effectiveness of Flowback Tank Controls					
Averaging Period for Number of WPFs and	Total Estimated Methane Reduced by	Total Estimated Methane Reduced at	Total Estimated Methane	Total Annualized Cost for all	Annual Control Costs (\$/ton of Methane Reduced)

Number of Well Completions	Flaring at each WPF (tpy)	Ten WPFs per year (tpy)	Reduced over 15 year period (tpy)	Enclosed Tanks (\$)	
3-yr Average:	7.18	71.83	1,077.41	\$57,957.60	\$53.79
5-yr Average:	4.25	42.54	638.06	\$57,957.60	\$90.83
10-yr Average:	2.10	21.04	315.55	\$57,957.60	\$183.67

iii. Class II disposal well facilities

The Division proposal clarifies that storage tanks at class II disposal well facilities are subject to the storage tank control requirements in Part D, Sections II.B and II.C.; expands the hydrocarbon liquids loadout requirements in Part D, Section II.5. to include hydrocarbon liquids loadout from tanks at class II disposal well facilities; and clarifies and expands the annual emissions reporting requirements in Part D, Section V. for class II disposal well facilities. The cost discussion below focus on costs per facility because the Division lacks an accurate inventory of the total number of class II disposal well facilities that have not yet installed storage tank controls. Lowering VOC emissions will reduce ozone precursors to address ozone NAAQS attainment and will also provide additional emission reductions from the oil and gas sector, as required under SB 19-181.

a. Storage tank controls

The Division has analyzed the costs and emission reductions associated with controlling emissions from storage tanks many times since 2004. Most recently, the Division analyzed the costs and emission reductions associated with lowering the state wide storage tank (i.e., hydrocarbon liquids and produced water) control threshold from 6 tpy to 2 tpy in 2019.²⁴ These prior analyses looked at all storage tanks in the Division's inventory with uncontrolled VOC emissions equal to or greater than 2 tpy, including storage tanks at class II disposal well facilities. However, given the pushback from some subject facilities as to the question of whether tanks must install controls, the Division is now clarifying that the state-wide storage tank control requirements in Part D, Section II apply to storage tanks at class II disposal well facilities.

In addition to disputing whether previously approved tank control provision applied to class II disposal facilities, parties also state that it is technically infeasible to control emissions from class II disposal well facility storage tanks.²⁵ This argument is premised on the "high water vapor, low VOC content, and low pressure at these facilities" resulting in a low BTU content gas stream.²⁶ In 2019, the Commission afforded operators an off-ramp from the storage tank control requirements in Part D, Section II if the operator could demonstrate that it would need to use supplemental fuel to operate the control device. This existing off-ramp addresses the infeasibility concerns raised by parties. This demonstration remains available to class II disposal well facilities.

The JIWG also takes issue with the Division's EIA concerning class II disposal well facility storage tank controls, providing its own analysis in the JIWG Exhibit 005. As an initial matter, the Division evaluated the costs and benefits of storage tank control requirements in 2014 and again in 2019. This Cost Benefit Analysis need not address the issue, and any objection by stakeholders to the older analyses is untimely and unavailing. However, the Division has nonetheless reviewed the JIWG cost analysis and, while the Division appreciates the JIWG's data sharing, the Division finds some cost components appear to be overestimated.

For example, class II disposal well facilities handle produced water with low VOC concentrations; thus a smaller emissions control device (ECD) might be used for controlling these vapors. The capital cost of a 30" low pressure ECD could be \$8,000 less than a 48" ECD.

²⁴ See 2019 final Economic Impact Analysis.

²⁵ See, for example, JIWG_PHS, pp. 16-18.

²⁶ Id. at pg. 18.

Second, the Division understands from stakeholder comments that class II disposal well facilities triggering the storage tank control requirements are always staffed and the flare maintenance cost is associated with the staff time involved in checking and managing the fluid level in the drip pot. Therefore, attributing staff time costs to flare maintenance, the JIWG's estimated costs of \$30,128 per year, is excessive given automated methods for frequent draining the drip pot are available and feasible. The Division recognizes that some nominal maintenance of the flare is necessary, and costs for maintenance have been included in past rulemakings at levels around \$2,500.

Third, the Division understands from stakeholder comments that the \$10,000 power extension cost is associated with providing direct power to the auto-igniter. However, recognizing that these facilities are staffed but apparently do not have power at the ECD, this cost seems to be very expensive compared to using a more economic option involving solar power and batteries, which is likely one tenth of the cost. The JIWG's analysis fails to recognize these practical considerations.

Fourth, based on 2019 operator reported APEN data for class II disposal well facilities, the average number of produced water tanks on site is about four tanks with an average storage capacity of about 3,000 barrels. Consequently, the number of fiberglass produced water tanks that require upgrade to steel tanks, twenty tanks per facility in the JIWG analysis, is greatly exaggerated. Moreover, the existing fiberglass tanks will likely have some salvage value or be relocated to other sites, which is ignored in the JIWG's estimated tank upgrade costs. The Division also questions whether it is appropriate to consider the full tank replacement cost at facilities with anticipated emissions near or above the control threshold when operators elect to use non-pressure rated tanks for economic reasons. Nevertheless, if an average of four 750 BBL tanks per facility are assumed and a salvage value of \$1,000 per fiberglass tank is considered, the Division estimates the rescaled capital cost for four tanks at about \$98,168, in contrast to the JIWG's estimate of \$510,840. If the above suggested corrections are applied to the JIWG cost analysis, the annualized control cost is estimated at about \$35,982, as shown in Table 18.

Table 18: Class II Disposal Well Site: Flare control for Tanks – annualized cost analysis				
Item	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
Flare (30" Diameter)	\$20,000			
Freight/engineering		\$7,500		
Flare installation		Included above		
Auto igniter	\$1,817			
Propane Pilot Fuel			\$9,619	
Maintenance			\$2,500	
Propane Transport			\$1,620	
Solar Power with Battery Backup for Flare		\$1,000		
Vapor manifold pipes and fittings		\$30,000		
Replacement of four 750 BBL Tanks	\$98,168			
Knock-out Pot	\$20,000			
Install of Propane Tank and Barrier	\$1,500	\$1,000		
Subtotal costs	\$141,485	\$39,500	\$13,739	
Annualized costs**	\$19,609.1	\$2,633.3	\$13,739	\$35,981.5

* Pilot fuel costs based on \$1.58/gal and 6,088 gal/yr, per JIWG PHS Exhibit 005

** Annualized costs are over a 15 year period assuming a 5% rate of return

The Division recalculated the JIWG's Exhibit 005 summary table using this more accurate control costs. The emission reductions are based on uncontrolled emissions halfway between the upper and lower bounds (2.5, 3.5, 4.5, or 5.5 tpy) and 95% control efficiency, as required for ECDs in Regulation Number 7. As shown in Table 19, the Division estimates annualized costs ranging from \$8,417 to \$15,150 per ton of VOC controlled, depending on current uncontrolled emissions from the storage tanks.

Table 19: Class II Disposal Well Site: Storage Tank controls - cost effectiveness analysis			
Tank uncontrolled actual VOC emissions	Annualized flare cost	VOC emission reduction (tpy)	Annualized VOC cost control (\$/ton)
> 2 tpy ≤ 3 tpy	\$35,981.5	2.38	\$15,150.1
> 3 tpy ≤ 4 tpy	\$35,981.5	3.33	\$10,821.5
> 4 tpy ≤ 5 tpy	\$35,981.5	4.28	\$8,416.7

* These figures do not include the benefit of methane reductions.

These figures assume that four tanks will need to be replaced for every control device installed. If, instead, only one tank needs to be replaced per installed controlled device, the capital cost would be approximately \$25,000 and the total annualized costs would be much closer to the typical tank control cost where replacement of the tank itself is not needed. Finally, while the JIWG states that these facilities may utilize fiberglass tanks that would need to be replaced, in the Division's experience these fiberglass tanks are used for produced water and are not typically employed for oil storage. The Division's inventory records indicate that many of the tanks at these facilities with emissions over the control threshold are oil tanks where oil that is separated from the water is stored. In these instances, operators should not incur the additional cost of replacing the tanks.

b. Truck loadout of hydrocarbon liquids

In 2019, the Division analyzed the costs and emission reductions associated with controlling emissions from the loadout of hydrocarbon liquids to transport vehicles at well production facilities, compressor stations, and processing plants.²⁷ Because the Division's proposal did not require owners or operators to use a specific control device, cost estimates varied based on the facility configuration and control system installed and ranged from \$6,269 to \$19,794 per ton of VOC reduced.

The Division has used a similar analysis to estimate the cost/ton reduced to control loadout emissions at class II disposal well facilities. Based on APEN and permitting data, the Division estimates that there are thirty-three (33) class II disposal well facilities statewide performing hydrocarbon liquids loadout.

Generally, many class II disposal well facilities are permitted with a default emission factors that can be adjusted later based on collecting site specific data. Therefore, it is difficult to draw a general correlation between the oil loadout volume and the facility loadout uncontrolled VOC emissions. Because the Division is proposing a higher applicability threshold of 2 tpy from loadout versus the current 5,000 barrel threshold, it is appropriate to require owners or operators to control emission from the loadout of hydrocarbon liquids from all storage tanks, not just controlled storage tanks. The Division is proposing a loadout threshold for applicability in contrast to the throughput threshold as class II disposal well facilities may not be as likely to already have a combustion device installed and available at the facility, therefore the higher threshold results in a cost per ton analysis that reflects the potential higher costs related to a dedicated flare in relation to the higher emissions associated with the loadout threshold that will be reduced. These costs are discussed in greater detail in the Division's Final EIA.

²⁷ See 2019 final Economic Impact Analysis.

Operators of class II disposal well facilities have suggested that for sites without an ECD, the most important consideration is whether the facility has well gas to supply the flare combustion device. Based on stakeholder input for class II disposal well facilities without a supply of well gas, the Division has provided a revised cost analysis for total cost of installing an ECD including the firing of the pilot light with propane. The revised total cost estimate is \$17,537.3, as shown in Table 20. The estimated costs for class II disposal well facilities range from \$1,244 to \$4,563 per ton of VOC reduced, for facilities with access to onsite pilot fuel gas.

Table 20: Class II Disposal Well Site: Flare control for Loadout – annualized cost analysis				
Item	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
Flare (30" Diameter)	\$20,000			
Freight/engineering		\$7,500		
Flare installation		Included above		
Auto igniter	\$1,817			
Propane Pilot Fuel			\$9,619	
Maintenance			\$2,500	
Propane transport			\$1,620	
Install of propane tank and barrier	\$1,500	\$1,000		
Subtotal costs	\$23,317	\$8,500	\$13,739	
Annualized costs**	\$3,232	\$567	\$13,739	\$17,537.3

* Annualized costs are over a 15 year period assuming a 5% rate of return

Utilizing the annualized flare control costs from Table 20, the Division estimated the \$/ton cost for controlling emissions from hydrocarbon liquids loadout utilizing an ECD. The emission reductions are based on uncontrolled emissions halfway between the upper and lower bounds (2.5, 3.5, 4.5, or 5.5 tpy) and 95% control efficiency, as required for ECDs in Regulation Number 7. The annualized cost of controlling loadout emissions by installing an ECD with a pilot light fueled by propane for various uncontrolled tanks ranges from \$3,356 to \$12,306.9 per ton of VOC reduced, as shown in Table 21 below. These VOC reduction estimates do not include the emissions associated with opening of the thief hatch for purposes of loadout (and associated sampling, if required), and are therefore underestimated, depending on the frequency of loadout.

Table 21: Class II Disposal Well Site: Loadout controls - cost effectiveness analysis			
Tank Loadout uncontrolled actual VOC emissions	Annualized flare cost	VOC emission reduction (tpy)	VOC cost control (\$/ton)
> 1 tpy ≤ 2 tpy	\$17,537.3	1.43	\$12,306.9
> 2 tpy ≤ 3 tpy	\$17,537.3	2.38	\$7,384.1
> 3 tpy ≤ 4 tpy	\$17,537.3	3.33	\$5,274.4
> 4 tpy ≤ 5 tpy	\$17,537.3	4.28	\$4,102.3
> 5 tpy ≤ 6 tpy	\$17,537.3	5.23	\$3,356.4

Further, because the Division's cost analysis reflects the installation of a dedicated flare, the argument that the loadout requirements should only apply to loadout from *controlled* storage tanks²⁸ does not hold the same weight as when the Commission adopted loadout requirements for well production facilities and natural gas compressor stations using a throughput from control storage tanks threshold. In 2019, the Commission considered a range of control costs due to three primary options available to owners or

²⁸ See Caerus_PHS, p. 3, JIWG_PHS, p. 22, Weld_PHS, pp. 4-5.

operators to control loadout emissions: the addition of a vapor line to existing infrastructure; the addition of a vapor line and vapor control system upgrades; and the addition of a dedicated loadout control system. As discussed in 2019, the Division estimated uncontrolled loadout emissions at 5,000 BBLs a year at 0.59 tons per year (tpy). The most cost effective, but unspecified option, was to route the loadout emissions back to the storage tank. If the storage tank was uncontrolled, those emissions could just vent to atmosphere. In this proposal, the Division determined that adding a flare to control loadout emissions is cost-effective, given that controls will only be required if loadout emissions are 2 tpy or greater. Therefore, while owners or operators could still route loadout emissions to a controlled storage tank, the Division anticipates that class II disposal well facilities may have to install a flare, which, again, the Division has estimated to be a cost-effective control strategy. Therefore, it is unnecessary to limit the control of loadout emissions to controlled storage tanks.

c. Reporting

The federal Safe Drinking Water Act contains regulatory requirements for class II wells related to the construction, operation, and monitoring of the well. However, the Safe Drinking Water Act does not require reporting of air pollution emissions from class II disposal well facilities. Therefore, the Division is clarifying and proposing additional annual emissions reporting requirements in Regulation Number 7 which will apply to class II disposal well facilities. This information will help inform the Division's emissions inventories and potential future proposals aimed at achieving targeted emissions reductions from these facilities.

The Division recognizes that the proposed reporting requirements will impose some reporting and recordkeeping costs on owners or operators of class II disposal well facilities. However, these reports may partially reduce future reporting burden in other areas including emission inventory development for ozone and other modeling efforts, and measuring progress in GHG emissions reductions associated with Senate Bill 19-096 and House Bill 19-1261. In some cases, these reports may include information that is already provided by owners and operators for air pollutant emissions notice (APEN) requirements. The Division will continue to identify ways to streamline the reporting requirements in future rulemakings. The Division did not estimate these costs in the Final EIA. It requested additional cost information from industry, but did not receive feedback until after the Final EIA submission, as discussed below.

In its rebuttal statement, the JIWG suggests that the reporting requirements for class II disposal well facilities proposed by the Division will require significant industry investment without any clear emission reduction benefits. As discussed earlier, these reporting requirements are not intended to directly reduce emissions.²⁹ Further, not every regulation must result in direct emissions benefits to be approvable under the Colorado Air Pollution Prevention and Control Act and the Administrative Procedure Act. Like the proposed monitoring plan requirement, the class II disposal well facility emission information submitted by operators will inform future Division emissions inventories and emission reduction strategies.

Additionally, JIWG's rebuttal expressed concerns about the time needed for operators to implement data systems for this emission information. Specifically, the comments stated that operators of class II disposal well facilities, that are not currently controlling vapor emissions, may require additional time to work with the Division on developing appropriate emissions factors, emissions inventory spreadsheets, and other documentation appropriate to class II disposal well facilities. JIWG also claimed that owners and operators need additional time to develop the database and recording systems. The Division has revised its proposal to provide additional time for the Division to work with operators to develop the reporting forms.

²⁹ ²⁹ See CRS 25-7-106(6) The commission may require the owner or operator, or both, of any air pollution source to: (a) Establish and maintain reports as prescribed by the commission; (b) Install, use, and maintain monitoring equipment or methods as prescribed by the commission; (c) Record, monitor, and sample emissions in accordance with such methods, at such locations, at such intervals, and in such manner as the commission shall prescribe; (d) Provide such other information as the commission may require.

iv. Annual emissions reporting

In 2019, the Commission adopted annual emissions reporting requirements for Colorado's oil and gas sector in Part D, Sections II.G., IV., and V. Owners and operators are required to report VOC, NOx, CO, ethane, and methane emissions to the Division annually. The Division has proposed expanding the reporting requirements to include CO2 and N2O emissions from Colorado's oil and gas sector. The Division is proposing the changes to meet the GHG reporting requirements in SB 19-096, which requires GHG emitting entities to annually report emissions of many GHGs including CO2 and N2O. The proposed changes also improve the accuracy of Colorado's GHG inventory, which is necessary for tracking progress toward the GHG reduction targets in HB 19-1261. The Division worked with industry to develop the reporting forms and associated instructions, which were finalized in July 2020. The Division also continues to work with the transmission and storage segment to develop segment specific reporting forms, which will be finalized fall 2020. These collaborations included discussing additional GHG reporting. Based on these discussions, the Division anticipates that reporting N2O and CO2 emissions will incur minimal additional cost to the owners and operators of oil and gas facilities. The Division also notes that the EIA for Regulation Number 22, which was approved by the Commission in May 2020, also argued that the costs of reporting GHG emissions from the oil and gas sector were essentially accounted for in the implementation costs of the 2019 Regulation Number 7 reporting requirements. The Division requested oil and gas industry feedback with specific cost information for GHG reporting, but did not receive any cost estimates during the development of the Final EIA or in prehearing statements.

D. Division Regulation Number 7 Implementation Costs

The Division expects increased workload to process the engine testing reports, pre/early production monitoring plans, annual reporting, and other documentation resulting from the proposed revisions. However, the Division anticipates this additional workload can be addressed with current and planned staffing and other resources.

E. Summary of Costs

The Division anticipates that many of the proposed revisions may increase costs for impacted owners or operators of oil and gas facilities. However, these proposals will also achieve significant reductions in NOx, VOCs, and methane. The Division believes its proposed changes are cost effective based on the costs and benefits discussed in this analysis.

The proposed revisions will reduce emissions from natural gas fired engines (RICE), require air quality monitoring at pre-production and early production oil and gas operations, control emissions from flowback vessels, and reduce emissions and require reporting from class II disposal well facilities.

The proposed RICE standards are expected to reduce state-wide NOx emissions from 2SLB, 4SRB, and 4SLB engines by 2,361 tons per year. The Division estimates that if operators choose to control each engine to the proposed standards, the average cost effectiveness is \$8,655 per ton of NOx reduced. Alternatively, operators can adopt the company-wide plan to achieve equal to or greater emission reductions with lower anticipated costs.

Another proposed revision will require owners and operators to develop an emissions monitoring plan for pre-production and early production that must be approved by the Division before the owner or operator commences monitoring. The Division anticipates monitoring approaches for a range of different pollutants utilizing different monitoring approaches with sensor costs which may range from less than \$5,000 to over \$400,000, based on a technology report from Ramboll. The Division expects the data gathered during this process will provide valuable information on the types and quantities of pollutants emitted during pre-production and early production, as well as real-world sensor performance results. All of this will inform future Division monitoring and emission reduction proposals.

The Division's proposal also includes a requirement for vapor-tight flowback vessels. The Division estimates that a fleet of twelve tanks can be used for flowback operations at multiple well production facilities each year for fifteen years. A fleet of tanks is predicted to reduce methane emissions by about 21 – 72 tons per year, with an overall cost effectiveness of approximately \$54 to \$184 per ton of methane reduced.

Other proposed revisions will require controls of hydrocarbon liquids loadout emissions at class II disposal well facilities. Installing a new ECD for loadout control would reduce VOC emissions by 1.4 – 5.2 tpy at a cost of \$12,307 - \$3,356 per ton of VOC reduced. The proposal also clarifies that the December 2019 control requirement for storage tanks with uncontrolled emissions above 2 tpy applies to class II disposal well facilities. The Division estimates that each class II facility that installed a new ECD as a result of the clarification would reduce VOC emissions by 2.3 – 4.2 tpy at a cost of \$15,150 - \$8,417 per ton of VOC reduced.

Lastly, the Division is proposing additional emissions reporting requirements for class II disposal well facilities and additional GHG reporting for oil and gas facilities. These emission reporting requirements will provide additional detail for emissions inventories that can inform future rulemakings and are not anticipated to provide immediate emission reductions. The Division estimates minimal costs related to reporting and continues to work with industry to streamline reporting requirements. The Division also notes that industry has approved the final GHG reporting forms and which will comply with the reporting and GHG inventory development requirements of SB 19-096 and to track GHG reduction progress for HB 19-1261.

4. Any adverse effects on the economy, consumers, private markets, small businesses, job creation, and economic competitiveness; and

The oil and gas industry plays an important role in Colorado's economy. The industry is a significant employer of highly skilled and well-paid employees. The industry generates large revenues and pays significant taxes in the state. It produces valuable domestic resources that help keep prices low while adding to national stability and security. At the same time, the 2017 National Emissions Inventory data indicates that the oil and gas industry represent the largest source of anthropogenic VOC emissions and the third largest source of anthropogenic NOx (on-road light duty motor vehicles were the largest NOx source and coal-fired EGUs were number 2), both in the nonattainment area and throughout the rest of the state.³⁰ The 2017 GHG data from EPA's Facility Level Information on Greenhouse gases Tool (FLIGHT) shows that oil and gas was the 3rd largest emitter of methane (landfills were number 1 and coal mines were number 2).³¹ VOC and NOx emissions contribute to Colorado's continued ozone nonattainment issues, while methane is a GHG that contributes to climate change. The Division's proposal is intended to achieve reductions in air emissions without imposing unreasonable costs that could stifle economic activity.

As discussed above, the Division estimates that there will be cost impacts to the oil and gas industry and these costs could have some adverse impact on economic activity associated with the oil and gas

³⁰ EPA, "2017 National Emissions Inventory (NEI)" at <https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data>

³¹ EPA, "2017 FLIGHT – Methane Sources" at <https://ghgdata.epa.gov/ghgp/main.do#/listFacility/?q=Find%20a%20Facility%20or%20Location&st=CO&bs=&et=&fid=&sf=11001000&lowE=-20000&highE=230000000&g1=0&g2=1&g3=0&g4=0&g5=0&g6=0&g7=0&g8=0&g9=0&g10=0&g11=0&g12=0&s1=1&s2=1&s3=1&s4=1&s5=1&s6=1&s7=1&s8=1&s9=1&s10=1&s201=1&s202=1&s203=1&s204=1&s301=1&s302=1&s303=1&s304=1&s305=1&s306=1&s307=1&s401=1&s402=1&s403=1&s404=1&s405=1&s601=1&s602=1&s701=1&s702=1&s703=1&s704=1&s705=1&s706=1&s707=1&s708=1&s709=1&s710=1&s711=1&s801=1&s802=1&s803=1&s804=1&s805=1&s806=1&s807=1&s808=1&s809=1&s810=1&s901=1&s902=1&s903=1&s904=1&s905=1&s906=1&s907=1&s908=1&s909=1&s910=1&s911=1&si=&ss=&so=0&ds=E&yr=2017&tr=current&cyr=2018&ol=0&sl=0&rs=ALL>

industry in Colorado. The Division also recognizes the downstream, and indirect, impacts to local governments that rely on the oil and gas industry for tax revenue. However, over the past decade Colorado's oil and gas industry has experienced unprecedented growth, even as Colorado has enacted regulatory measures to ensure that development continues in a protective and responsible manner. For example, the Commission has conducted ten rulemakings potentially impacting the oil and gas sector since 2014, yet based on information from the Energy Information Administration (EIA), Colorado's oil production has quadrupled since 2010 and its natural gas production has doubled since 2000.³² Further, no party has to this point presented any evidence that these regulations will result in the widespread shut-in of wells. To the contrary, evidence suggests that operators make such decisions based upon the price of oil (or gas), and not to the incremental cost of additional regulatory burden.

While the costs of the proposed revisions are unlikely to have a seriously deleterious effect on the overall competitiveness of Colorado's oil and gas industry, some operators may find it more challenging to continue operating marginally producing wells. If some of these marginal wells are shut in, revenue could be reduced for producers, royalty payments to royalty owners, severance tax revenue for the state, and potentially local industry jobs. To mitigate against these potential economic consequences, the Division has created a proposal package that allows for some implementation flexibility. For example, the engine proposal includes a company-wide plan that allows each operator to identify the lowest cost combination of engine controls or replacements that achieves the necessary NOx reductions. The monitoring plan requirement allows each operator to develop an innovative monitoring approach for pre-production and early production, rather than requiring a specific monitoring technology or method. Also, owners or operators can choose to utilize temporary or permanent vapor-tight flowback tanks, along with different options for emission control devices. Finally, the Division has worked with industry to develop the emissions reporting form and instruction to minimize the administrative burden and related reporting costs.

Finally, it does not appear that the costs associated with the Division's proposal will have any meaningful, adverse impact on the general public or small businesses that purchase natural gas and other petroleum products. Oil and natural gas are sold on international and national markets, making it extremely unlikely that any increase in production costs in Colorado will be reflected in prices for Colorado consumers.

5. At least two alternatives to the proposed rule or amendment that can be identified by the submitting agency or a member of the public, including the costs and benefits of pursuing each of the alternatives identified.

A. Natural Gas Fired RICE Alternatives

The Division evaluated several alternative methods for achieving significant NOx emission reductions from RICE in Colorado during development of the proposed rule. Initially, the Division assessed all active, APEN-reportable RICE in Colorado as of July 2019. Grouping the RICE by horsepower, the Division then considered the NOx emission reduction impact of tightening emissions limits on small RICE (less than 100 HP), small-medium RICE (100 to less than 500 HP), medium RICE (500 to less than 1,000 HP) and large RICE (1,000 HP or greater) state-wide. According to the data set, large RICE comprise 52% of actual controlled NOx emissions from all RICE statewide. For comparison, RICE equal to 100 HP and up to less than 1,000 HP comprise 15% of actual controlled NOx emissions statewide from all RICE. Therefore, in terms of achieving the greatest emission reductions, the Division chose to focus on the large RICE subcategory for this particular rulemaking. Furthermore, the large RICE are all operated by the oil and gas industry, which significantly narrowed the scope of the impacted industries for the proposal and further supported this approach.

³² Energy Information Administration (EIA), "Colorado - State Profile" at <https://www.eia.gov/state/analysis.php?sid=CO>

The Division also evaluated different emissions standards for each subcategory of RICE and the potential impact on NO_x emissions. The Division reviewed various standards set by other states and determined that using Colorado-specific data based on controlled NO_x emissions from RICE subtypes was appropriate for this rulemaking. The Division recommended the proposed emission standards for RICE by working directly with stakeholders, analyzing the impact on the regulated community, and determining the potential NO_x emissions reductions that could be achieved with the least incurred cost.

The request for CBA submitted by industry groups did not request a discussion of any specific alternative RICE proposals for the Division to analyze. Therefore, the Division selected the two options below.

i. Alternative #1 – No New Provisions

One potential alternative to the proposed NO_x controls for natural gas fired RICE would not require operators to install any additional controls. This would save money for owners and operators who would not be required to retrofit controls to existing engines or purchase new engines that meet tighter emissions thresholds. However, the Division believes that its proposal includes cost effective emission controls for most engines, and the Division also allows operators to utilize the company-wide plan to further reduce costs while achieving the same emission or greater emission reductions.

Further, the Division rejected this option because it would prevent progress in reducing emissions to comply with state and federal requirements. SB 19-181 requires the Commission to consider rules that reduce emissions from the oil and gas sector. The engine NO_x proposal is an effective option to help meet the requirements under SB 19-181. The proposal is also intended to make progress on ozone NAAQS attainment, prevent additional ozone NAAs, reduce regional haze in Class I areas, and reduce nitrogen deposition in RMNP.

ii. Alternative #2 – No Allowance for Company-Wide Plan Alternative

The Division also considered requiring mandatory controls for every engine greater than or equal to 1,000HP, without an optional company-wide plan. During the proposal development process, the Division recognized, through its own analysis and engagement with stakeholders, that some individual engines might require very expensive control retrofits to meet the proposed NO_x standards. The Division developed the company-wide proposal with stakeholder input to enable the state to achieve the necessary NO_x reductions in the most cost-effective manner. Earlier in this analysis, the Division provided cost estimates for a RICE NO_x reduction plan without the company-wide proposal. As stated in this analysis, the Division considers individual control retrofits to be cost effective for most engines, but the wide range of potential control retrofit costs suggests that requiring every engine to meet the proposed standards is not always the lowest cost alternative. In some cases, it may be less expensive for operators to replace existing, high-emissions engines with new, low-emissions engines, or to replace the engine with an electric motor. As long as the alternative achieves emission reductions that are equal to or greater than installing additional controls on every engine, the Division encourages owners and operators to select the cost-minimizing approach that provides health and environmental benefits while reducing regulatory compliance costs.

B. Pre-production Monitoring

SB 19-181 added a requirement that the Commission review and considering adopting more stringent provisions for air quality monitoring at oil and gas facilities. The specific language adds, “A requirement that oil and natural gas operators must install and operate continuous methane emissions monitors at facilities with large emissions potential, at multi-well facilities, and at facilities in close proximity to occupied dwellings.” However, the legislature allows the Commission discretion in the implementation of any emission monitoring requirements. Therefore, as an initial step, the Division has proposed a flexible approach that allows owners and operators to develop air quality monitoring that specify which pollutant(s) will be monitored, which monitoring technologies will be utilized, and the performance (accuracy, precision, etc.) and record-keeping requirements for the monitoring system. The Division must

approve any proposed monitoring plan before it is implemented. The Division believes this approach will provide a wealth of information on the capabilities and potential limitations of monitors located operating in a range of site-specific conditions as well as potential emissions from pre-production and early production activities. In prehearing statements, the Division received feedback requesting monitoring of a specific pollutant or utilizing a specific technology. A couple of these potential alternatives are discussed below.

i. Alternative #1 – Methane-specific Monitoring

One alternative suggested by stakeholders would require operators to only monitor for methane emissions. Single pollutant monitoring would reduce the data collection burden on industry, at the expense of valuable information for both the Division and the general public. The Division rejected this approach since it would severely limit its ability to better characterize the amounts and types of air emissions during pre-production and early production oil and gas activities. As stated previously, the Division's proposal is intended as a first step. The Division intends to use the information it gathers to inform future proposals for additional monitoring, inventory, and emission reductions. Without a broad range of monitoring approaches from well production facilities statewide, these future proposals may lack the necessary information to adequately protect public health and the environment.

In addition, this single pollutant approach would not necessarily reduce costs. As discussed in the Ramboll report referenced earlier, there are many potential technologies capable of monitoring methane levels with varying degrees of accuracy and costs. The cost of the system would depend on the requirements proposed by the Division, such as accuracy, emission sampling frequency, data storage requirements, etc. As an example of the possible options, open path spectroscopy technologies could provide very high accuracy and low detection limits at high cost (potentially \$100s of thousands). At the other extreme, MOS or non-open path spectroscopy could be installed at low cost (less than \$5,000), but might only be designed for detecting much higher methane levels. These low cost sensors might protect employees from explosive atmospheres (Lower Explosive Limit, or LEL, detection), but the monitoring frequency and sensitivity might be too low for regulatory-grade monitoring. The Division did not consider this alternative further because it would not achieve the Division's goals for information gathering and it would not guarantee lower costs for industry.

ii. Alternative #2 – Canister Fenceline Monitoring

A second alternative the Division considered would be requiring operators to monitor emissions at the fenceline by capturing a sample using a canister. This would likely reduce the monitoring burden for industry which could collect a single sample over a longer period. The Division rejected this approach for multiple reasons. First, sample canisters are not collected or analyzed quickly enough to provide timely information to the public or the Division in case of a sudden emissions event. Therefore, this approach would fail to achieve the goal of continuous or near real-time monitoring. Second, this approach also restricts the Division's ability to better understand the amounts and types of air emissions during pre-production and early production. The types of emissions that can be monitored with this approach are based on the sample collection and handling quality and the capabilities of the lab analysis equipment, which are largely static. The Division does not gain any insight into developing monitoring technology costs or capabilities, and the breadth and depth of its emission inventories cannot evolve. The canister sampling approach not only limits the Division's ability to gather information to inform future proposals for additional monitoring, inventory, and emission reductions in Colorado. It also limits Colorado's contributions to a broader scientific understanding of oil and gas emissions that could help other states reduce their emissions which may be impacting Colorado's air quality. The Division did not consider this alternative further because it would not achieve the Division's goals for information gathering and it would not achieve the intent of SB 19-181.

C. Vapor-tight Flowback Tank Alternatives

The Division is proposing emissions control and monitoring requirements for flowback vessels and associated equipment to achieve additional methane and VOC emission reductions throughout the oil and gas sector. These requirements include using vapor-tight flowback tanks and conducting periodic visual inspections of the flowback tanks and associated.

The Division has received reports that flowback vessels, which capture liquids and dissolved gases during oil and gas pre-production activities, generally do not appear to be vapor-tight. Based on research and stakeholder discussions, vapor-tight flowback are readily available and cost effective. The Division estimates that a fleet of 12 vapor-tight flowback vessels can control methane emissions at a total annualized cost just under \$58,000. These tanks can be transported to multiple well production facilities per year and have an expected lifetime of at least 15 years, resulting in extremely low costs of \$53.79 - \$183.67 per ton of methane reduced.

The request for CBA submitted by industry groups did not request a discussion of any specific alternative flowback proposals for the Division to analyze. Therefore, the Division selected the two options below.

i. Alternative #1 – No New Provisions

One potential alternative to the proposed vapor-tight flowback vessel requirements would allow owners and operators to continue using open flowback vessels. This would save owners and operators from purchasing new flowback vessels. However, the Division notes that owners and operators could rent temporary flowback vessels from flowback companies or utilize permanent tanks for flowback. Both tank rentals and permanent tanks could potentially lower costs, but stakeholders expressed concerns with using permanent tanks for flowback due to the variability of flowback liquids and solids. Nonetheless, owners and operators are allowed to utilize vapor-tight permanent tanks for flowback, if they so choose.

The Division ultimately discarded this alternative after revising its cost analysis using vendor-specific data. During the development of the Initial EIA, the Division provided a large range of annualized costs for vapor-tight flowback tanks, based on capital costs from \$50,000 to \$1,000,000. In some cases this led to control costs over \$20,000/ton, higher than previous oil and gas proposals approved by the Commission. During the development of the Final EIA, the Division obtained pricing for vapor-tight flowback tanks indicating the capital cost of one brand-new vapor-tight tank was less than \$40,000. This led to the \$/ton estimates of about \$54 to \$184 per ton of methane reduced. Based on the very low control costs, the Division decided that controlling vapor emissions during flowback is necessary and cost effective, and vapor-tight flowback tanks are an effective method of reducing methane emissions, which benefits Colorado's climate and makes progress toward the GHG reduction targets in HB 19-1261. In addition, the Division believes that vapor-tight flowback tanks will reduce VOC emissions, which will help in ozone NAAQS attainment, but it did not estimate these reductions due to a lack of available data on VOC emissions during flowback activities.

ii. Alternative #2 – Closed-loop Emission Control

The Division also considered requiring a closed-loop system to control emissions during flowback, a process that is currently utilized by some operators in Colorado. This alternative would further reduce methane and other emissions, including NO_x and CO₂, compared to the ECD controls modeled in the Division's analysis. However, the Division did not have the necessary cost data to perform a thorough analysis of this approach. In addition, the Division notes that its current proposal does not mandate an ECD or any other emission control methodology; operators can select from any emission reduction that achieves at least 95% control efficiency, as required in Regulation Number 7. The Division ultimately rejected this option for the current proposal which provides greater control option flexibility for operators and is cost effective, as indicated by the Division's analysis.

D. Class II Disposal Well Facilities

The Division proposal clarifies that storage tanks at class II disposal well facilities are subject to the storage tank control requirements in Part D, Sections II.B and II.C., therefore no additional analysis is necessary. The Division proposal also expands the hydrocarbon liquids loadout requirements in Part D, Section II.5. to include hydrocarbon liquids loadout from tanks at class II disposal well facilities.

The request for CBA submitted by industry groups did not request a discussion of any specific alternative loadout proposals for the Division to analyze. Therefore, the Division selected the two options below.

i. Alternative #1 – No New Provisions

One potential alternative to the proposed hydrocarbon liquids loadout control requirements would not require class II disposal well facilities to control loadout emissions. This could save money for owners and operators who would not be required to install control devices. However, the Division believes that its proposal is cost-effective and allows operators to select the appropriate control strategy for their loadout activities.

The Division's Final EIA estimated the costs for controlling emissions from hydrocarbon liquids loadout at class II disposal well facilities assuming that operators have access to well gas for pilot fuel. Assuming access to well gas, the annualized cost for an ECD for liquids loadout control was estimated at \$6,502, leading to cost effectiveness estimates of \$1,244 to \$4,563 per ton of VOC reduced. The Division received feedback from operators of class II disposal well facilities that perform hydrocarbon liquids loadout regarding the cost of supplemental fuel to operating a new ECD. Based on stakeholder input, the Division provided a revised cost analysis for the total cost of installing an ECD including the firing of the pilot light with propane. Table 20 above indicates that the cost of supplemental propane and associated equipment increase the annualized cost to \$17,537. This leads to liquids loadout costs of \$3,356 - \$12,307 per ton of VOC reduced. The Division notes that although the cost to control loadout emissions are higher when supplemental fuel is required, these costs assume the operator installs a dedicated flare. Previous Division analysis indicated that operators of class II disposal well facilities with existing controlled storage tanks with an ECD could lower costs by routing emissions to the controlled storage tank.

Therefore, the Division rejected this option because the Division determined it to be cost-effective and it would further progress in reducing emissions to comply with state and federal requirements. SB 19-181 requires the Commission to consider rules that reduce emissions from the oil and gas sector. The class II disposal well facility loadout control proposal is an effective option to help meet the requirements under SB 19-181. The proposal is also intended to make progress on ozone NAAQS attainment and prevent additional ozone NAAs.

ii. Alternative #2 – LACT

The Division also considered that operators might choose to install a lease automated custody transfer (LACT) unit for hydrocarbon liquid loadout. A LACT unit provides automatic measurement, sampling, and transfer of liquids which reduces VOC emissions from the tank and reduces emissions from flare combustion. The Division has not estimated the emission reductions from reduced flaring and the following cost analysis is based solely on the VOC emission reductions. The following costs are based on the Final EIA submitted November 5, 2019, for the December 2019 Regulation Number 7 rulemaking hearing.³³ Depending on the LACT unit design including pipe size, flow meter type, flow conditioning, additional instrumentation and automation, and meter proving capability, the cost of a LACT unit can vary widely. The Division considers the \$350,000 estimate listed in Table 22 to be an average cost, though

³³ See 2019 Final Economic Impact Analysis.

some LACT units may cost more, which would lead to a higher \$/ton cost to control VOC emissions. The Division assumed that the engineering, freight, and installation costs for a LACT unit are similar to these same costs for a flare. This assumption may underestimate the cost to transport and install a large LACT unit skid. As shown in Table 22, the Division estimates the annualized cost of a LACT unit is approximately \$58,608.

Table 22: Class II Disposal Well Site: LACT unit control for Loadout – annualized cost analysis				
Item	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
LACT unit **	\$350,000			
Freight/engineering		\$7,500		
LACT installation		Included above		
Maintenance ***			\$9,600	
Subtotal costs	\$48,508	\$7,500	\$9,600	
Annualized costs**	\$48,508	\$500	\$9,600	\$58,608.3

* Annualized costs are over a 15 year period assuming a 5% rate of return

** LACT unit capital cost estimate from Final EIA, Nov 5, 2019, page 31

*** LACT unit maintenance costs of \$800 monthly (\$9,600 annually) from Final EIA, Nov 5, 2019, page 31

Utilizing the annualized flare control costs from Table 22, the Division estimated the \$/ton cost for controlling emissions from hydrocarbon liquids loadout utilizing a LACT unit. For the sake of comparison, the emission reductions are assumed to be the same as the ECD analyzed in Table 22. However, a LACT unit may achieve slightly greater emission reductions by reducing the need to open a thief hatch and by eliminating flaring emissions. As shown in Table 23, the Division estimated much higher annualized cost for a LACT unit, ranging from \$11,206 to \$40,985 per ton of VOC reduced. The Division's proposal allows operators to utilize a LACT unit for hydrocarbon liquid loadout, but the Division did not propose mandatory LACT units based on this \$/ton estimate.

Table 23: Class II Disposal Well Site: LACT Loadout controls - cost effectiveness analysis			
Tank Loadout uncontrolled actual VOC emissions	Annualized LACT cost	VOC emission reduction (tpy)	VOC cost control (\$/ton)
> 1 tpy ≤ 2 tpy	\$58,608.3	1.43	\$40,984.8
> 2 tpy ≤ 3 tpy	\$58,608.3	2.38	\$24,625.3
> 3 tpy ≤ 4 tpy	\$58,608.3	3.33	\$17,600.1
> 4 tpy ≤ 5 tpy	\$58,608.3	4.28	\$13,693.5
> 5 tpy ≤ 6 tpy	\$58,608.3	5.23	\$11,206.2

E. Annual Emissions Reporting

There is generally consensus around the annual reporting requirements, especially the addition of CO₂ and N₂O reporting. Stakeholders generally agree that the Division's proposal is a reasonable step to implement SB19-181, HB19-1261, and SB19-096. SB 19-096 requires GHG emitting entities, including oil and gas operations, to monitor and report GHG emissions to the state. SB 19-096 further clarifies that GHG emissions includes emissions of carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF₆) and nitrogen trifluoride (NF₃). Because the Division's proposal includes reporting of CO₂ and N₂O from oil and gas operations, as directed in approved legislation, the Division believes its proposal is reasonable and necessary. Therefore, it is not analyzing any alternatives for this portion of the proposed annual reporting requirements.

The Division has also proposed additional emission reporting requirements for class II disposal well facilities, and will work with stakeholders in developing the annual inventory reporting form to specify the appropriate sampling protocols and emission estimates for various facility designs and throughput. To avoid potential retroactive compliance issues, the Division has clarified in its proposal to exclude the class II disposal well facility specific data elements from the current 2020 data collection requirements. The clarification notes that owners or operators of class II disposal well facilities will begin collecting data May 1, 2021. Because the Division has addressed compliance data concerns for class II disposal well facilities, and is continuing to work with owners and operators on the reporting form and required data elements, it does not have additional alternatives to discuss.

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Education

Ph.D. Chemical Engineering, University of Texas at Austin, December 2008

- Thesis title: *Evaluating the Design of Emissions Trading Programs Using Air Quality Models*, Advisor: Prof. David T. Allen

BS Chemical Engineering, University of Florida, December 2002 with Honors

- 4.0/4.0 GPA

Professional Experience

Senior Air Quality Scientist, Environmental Defense Fund, Feb. 2019 - Present

- Develop and evaluate modeling tools to identify contribution of sources to air pollution at a hyper-local scale
- Design and oversee modeling studies with a focus on the human health impacts of oil and gas production and transportation

Environmental Policy Analyst, Congressional Research Service Library of Congress, July 2018 – Feb. 2019

- Respond to Congressional inquiries on topics related to air pollution and climate
- Developed reports on background ozone, methane, and contributions of LNG to air pollution

Science & Technology Policy Fellow, American Association for the Advancement of Science, Sept. 2016 – July 2018

- Published a review of global climate models in context of updating estimates of the Social Cost of Carbon
- Lead a team of EPA researchers to evaluate opportunities to reduce High Ozone Days in the Northeast U.S. under the current policy framework
- Working with Federal Land Managers to evaluate the state of science of emissions inventory estimations for NEPA
- Authored a white paper on the state of the science of reactive nitrogen source apportionment
- Lead a speaker series as Co-chair of AAAS Energy/Climate Affinity Group
- Co-convened a symposium on Ecosystem Services: From Concept to Policy

Research Scientist II, Colorado State University, Cooperative Institute for Research in the Atmosphere, May 2013 – Aug. 2016

- Worked with scientists from academia, and local, state and federal agencies to identify strategies to improve air quality in and around our National Parks
- Improved the representation of the nitrogen cycle in regional chemical transport modeling
- Investigated the impacts of energy development activity and increased availability of natural gas on air quality
- Evaluated the sensitivity of chemical transport model performance to meteorological modeling in complex terrain

Post Doctoral Associate, Massachusetts Institute of Technology, Joint Program for the Science and Policy of Global Change, Sept. 2010 – April 2013

- Developed integrated assessment capabilities for/ and conducted evaluations of potential human health co-benefits associated with air quality changes resulting from global change and climate policy
- Serve as the in house regional air quality and regional modeling expert, including mentoring grad students on modeling tools
- Evaluated the impact of model resolution on the uncertainty associated with human health impacts from changes in ozone and particulate matter

Post Doctoral Associate, University of Texas at Austin, Center for Energy and Environmental Resources, Jan. 2009 – Sept. 2010

- Evaluated impacts of transportation modeling assumptions and Texas on-road mobile source emission scenarios
- Worked with Austin Industry Leaders to design and implement policies to reduce local ozone
- Evaluated Smart Energy Grid Ideas for air quality impacts as part of Austin's Pecan Street Project

Graduate Researcher, University of Texas at Austin, Center for Energy and Environmental Resources, Sept. 2003 – Dec. 2008

- Integrated Air Quality and Economic models of Electricity Generating Units for the Northeast United States to maximize benefits obtained from regional cap and trade program
- Modeled Air Quality Impacts of Plug-In Hybrid Electric Vehicles using existing capacity in the Northeast and Texas
- Proposed policy changes to improve the viability of VOC emissions trading markets in Houston. Recommendations are based on analysis of historical emissions and air quality modeling done to test the impacts of temporal and spatial variability of emissions on the 8hr ozone attainment demonstration

Air Quality Team Leader, United States Agency International Development, Lima, Peru, Aug. 2006 – Feb. 2007

- Designed and developed an Air Quality model to estimate the air quality benefits of a switch to Natural Gas from traditional fuels
- Traveled to Lima to present findings and train Peruvian Environmental workers on the model

Independent Consultant

- Earth Justice: Served as an Expert Witness speaking to atmospheric chemistry and meteorological conditions that, along with oil and gas emissions, lead to high ozone events in the Colorado Front Range, Oct. 2017
- Clean Air Task Force: Evaluated proposed methane controls for regional air quality and human health co-benefits, Nov. 2015 – Aug. 2016
- Environmental Defense Fund: Served as an Expert Witness reporting and discussing the potential air quality impacts of statewide controls on hydrocarbon emissions from Oil and Gas Production in Colorado, Nov. 2013 – Feb. 2014
- National Parks Conservation Association: Evaluated the potential impacts on visibility in Class 1 Areas in the Southwest of emissions from select point source facilities in Texas, Feb. 2012
- Sierra Club: Evaluated the potential air quality impacts of a proposed and existing emissions point sources in Texas, March – Feb. 2012
- Perimeter Counties Industrial Group: Determined the extent of the contributions of emissions from both Harris county and the perimeter counties outside Harris to the ozone non-attainment status of the South-East Texas area, 2005-2006

Intern, United States Environmental Protection Agency Chemical Engineering Branch, Washington DC, June 2004 – Dec. 2004

- Determined the environmental and worker safety of new to the market chemicals during the production, transport, storage and use of the chemical's life cycle, using EPA developed software, ChemSTEER, as part of the Pre Manufacture Notice program (PMN)
- Helped to develop a Generic Scenario for a Refinery, used to estimate the type, location and quantity of emissions at a Refinery

Tool set includes: CAMx and CMAQ air quality models, WRF and Hysplit meteorological models, MOVES2010 and MOBILE6 on-road emissions models, Global climate models, EPS3 and SMOKE emissions preprocessing systems, GIS, python, R, fortran, oracle, perl and unix.

Service and Memberships

Appointed to the Denver Metropolitan Area Regional Air Quality Council by Governor John Hickenlooper in April 2014

Member: American Geophysical Union, American Meteorological Society

Reviewer: Atmospheric Environment, Energy Policy, Environmental Science & Technology, Atmospheric Chemistry & Physics Technical Committee Member, Three State Air Quality Study, January 2014 – Aug. 2016

Grant Review Panel Member, EPA SBIR, November 2013

Publications (Peer Reviewed)

1. **Thompson, T. M.** " Modeling the climate and carbon systems to estimate the social cost of carbon" *WIREs Climate Change*, 9(5), e532, 2018.
2. Zhang, R., **Thompson, T.M.**, Barna, M.G., Hand, J.L., McMurray, J.A., Bell, M.D., Malm, W.C., Schichtel, B.A. "Source regions contributing to excess reactive nitrogen deposition in the Greater Yellowstone Area (GYA) of the United States", *Atmospheric Chemistry and Physics Discussions* 1–38, 2018.
3. **Thompson, T.M.**, Shepherd, D., Stacy, A., Barna, M.G., Schichtel, B.A. "Modeling to Evaluate Contribution of Oil and Gas Emissions to Air Pollution" *Journal of the Air & Waste Management Association*, 67, 445–461, 2017.

4. Li, Y., **Thompson, T.M.**, Van Damme, M., Chen, X., Benedict, K.B., Shao, Y., Day, D., Boris, A., Sullivan, A.P., Ham, J., Whitburn, S., Clarisse, L., Coheur, P.-F., and Collett Jr., J.L. "Temporal and spatial variability of ammonia in urban and agricultural regions of northern Colorado, United States", *Atmospheric Chemistry and Physics*, 17, 6197–6213, 2017.
5. Saari, R.K., **Thompson, T.M.**, Selin, N.E. "Human Health and Economic Impacts of Ozone Reductions by Income Group" *Environmental Science & Technology*, 51, 1953–1961, 2017.
6. **Thompson, T.M.**, Rausch, S., Saari, R.K., Selin, N.E. "Air quality co-benefits of subnational carbon policies" *Journal of the Air & Waste Management Association*, 66, 988–1002, 2016.
7. Malm W.C., Rodriguez M.A., Schichtel B.A., Gebhart K.A., **Thompson T.M.**, Barna M.G., Benedict K.B., Carrico C.M., Collett Jr. J.L. "A hybrid modeling approach for estimating reactive nitrogen deposition in Rocky Mountain National Park", *Atmospheric Environment* 126, 258–273, 2016.
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11. **Thompson T.M.**, Saari, R.K., Selin, N.E. "Air Quality Resolution for Health Impacts Assessment: Influence of Regional Characteristics", *Atmospheric Chemistry & Physics*, 14, 969-978, 2014.
12. **Thompson T. M.** and Selin N. E. "Influence of air quality model resolution on uncertainty associated with health impacts", *Atmospheric Chemistry & Physics*, 12(20), 9753–9762, 2012.
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2. **Thompson T.M.**, Barna M.G., Schichtel B.A., Gebhart, K. "Sensitivity of Source Apportionment in Rocky Mountain National Park to Meteorological Modeling", Speaker at the Community Modeling and Analysis System (CMAS) Conference, Chapel Hill, NC, October 6, 2015.
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PREVENTING DISEASE THROUGH HEALTHY ENVIRONMENTS

EXPOSURE TO BENZENE: A MAJOR PUBLIC HEALTH CONCERN

Human exposure to benzene has been associated with a range of acute and long-term adverse health effects and diseases, including cancer and aplastic anaemia. Exposure can occur occupationally and domestically as a result of the ubiquitous use of benzene-containing petroleum products, including motor fuels and solvents. Active and passive exposure to tobacco smoke is also a significant source of exposure. Benzene is highly volatile, and exposure occurs mostly through inhalation.¹⁻³ Public health actions are needed to reduce the exposure of both workers and the general population to benzene.

Sources of exposure to benzene

Benzene is highly volatile, and most exposure is through inhalation. Benzene is degraded rapidly in the upper atmosphere. Because of its solubility in water, a minor amount may be removed by rain to contaminate surface waters and soil. However, it is not persistent in surface water or soil, either volatilizing back to air or being degraded by bacteria.

Industrial processes

As benzene occurs naturally in crude petroleum at levels up to 4 g/l, human activities using petroleum lead to exposure. These activities include processing of petroleum products, coking of coal, production of toluene, xylene and other aromatic compounds, and use in industrial and consumer products, as a chemical intermediate and as a component of petrol (gasoline) and heating oils. The presence of benzene in petrol and as a widely used industrial solvent can result in significant occupational exposure and widespread emissions to the environment. Automobile exhaust accounts for the largest source of benzene in the general environment. Off-gassing from building materials and structural fires lead to increased atmospheric benzene levels. Industrial discharge, landfill leachate and disposal of benzene-containing waste are also sources of exposure.²

Indoor residential air

Benzene has been detected at high levels in indoor air. Although some of this exposure might be from building materials (paints, adhesives, etc.), most is from cigarette smoke in both homes and public spaces. Levels of benzene are higher in homes with attached garages than in those with detached garages. Levels are increased in homes close to petrol filling stations.² Benzene may be released to indoor air from unflued oil heating and from the use of benzene-containing consumer products in residences. People spending more time indoors, such as children, are likely to have higher exposure to benzene.

Inside vehicles

Benzene has been measured in air inside vehicles at levels higher than those in residential air, but substantially lower than those at petrol filling stations.⁴

Food and water

Waterborne and foodborne benzene contributes only a small percentage of the total daily intake in non-smoking adults.²

World Health Organization (WHO) benzene guidelines

Drinking-water

0.01 mg/l (guideline values corresponding to the upper 95% confidence limit of modelled excess lifetime cancer risks of 10^{-4} , 10^{-5} and 10^{-6} are 0.1, 0.01 and 0.001 mg/l, respectively).^{5,6} An excess lifetime cancer risk of 10^{-4} , 10^{-5} or 10^{-6} means the risk of one new cancer case above background levels per 10 000, 100 000 or 1 million people, respectively.

Air

No specific guideline value has been developed for air. Benzene is carcinogenic to humans, and no safe level of exposure can be recommended. For general guidance, the concentrations of airborne benzene associated with an excess lifetime risk of leukaemia of 10^{-4} , 10^{-5} and 10^{-6} are 17, 1.7 and 0.17 $\mu\text{g}/\text{m}^3$, respectively.⁴

Health effects

Acute effects

- Acute occupational exposure to benzene may cause narcosis: headache, dizziness, drowsiness, confusion, tremors and loss of consciousness.² Use of alcohol enhances the toxic effect.⁷
- Benzene is a moderate eye irritant and a skin irritant.²

Effects following chronic exposure

- Benzene is a well-established cause of cancer in humans.^{1,3} The International Agency for Research on Cancer has classified benzene as *carcinogenic to humans* (Group 1).^{1,3} Benzene causes acute myeloid leukaemia (acute non-lymphocytic leukaemia), and there is limited evidence that benzene may also cause acute and chronic lymphocytic leukaemia, non-Hodgkin's lymphoma and multiple myeloma. Individuals who have experienced benzene poisoning requiring treatment show a substantially increased risk of mortality from leukaemia.³
- Chronic exposure to benzene can reduce the production of both red and white blood cells from bone marrow in humans, resulting in aplastic anaemia.²
- Both B-cell proliferation and T-cell proliferation are reduced by benzene. Decreased host resistance to infection has been reported in several laboratory animals exposed to benzene. However, other measures of immunotoxicity have not been studied.²

- Chromosomal aberrations in human peripheral lymphocytes are associated with occupational exposure to benzene. Chromosomal aberrations, micronuclei, sister chromatid exchange and sperm head abnormalities have been seen in laboratory species treated in vivo. Chromosomal aberrations and mutations were seen in human cells in vitro and in laboratory animal cells in some in vitro studies.^{1,2}
- Benzene is fetotoxic in mice and rabbits following maternal exposure by inhalation, causing a reduction in birth weight.² It is not, however, teratogenic in experimental animals, even at maternally toxic doses.

Monitoring exposure

- Estimates of benzene exposure can be made through measurement of urinary inorganic and organic sulfate conjugates. Measurement of urinary phenol levels has historically been the standard bioassay for benzene exposure, despite the well-described limitations of this test.²
- The haematological effects of chronic benzene poisoning in exposed workers can be detected by monitoring blood counts at regular intervals. For example, the United States Occupational Safety and Health Administration recommends monthly blood counts and removal of workers from areas with high benzene exposure if they have white blood cell counts below 4000/mm³ or erythrocyte counts below 4 000 000/mm³.⁸

Risk mitigation recommendations

Eliminate use

- Promote the use of alternative solvents in industrial processes, glues and paints.
- Develop and implement policies and legislation to remove benzene from consumer products.

Reduce exposure

- Reduce exposure at petrol filling stations as far as possible by following best practices in location, design and extraction.
- Minimize emissions from vehicle exhausts by improved design and regular monitoring of engine settings.
- Separate dwelling spaces from areas where vehicles and benzene-containing products are kept. In particular, isolate children from indoor exposure to vehicle emissions.
- Avoid domestic use of benzene-containing products.
- Discourage indoor use of unflued oil and gasoline heating.
- Prohibit smoking inside buildings.

Education

- Raise public awareness regarding sources of exposure to benzene and risk mitigation measures.
- Conduct educational activities to discourage the use of benzene or petrol for cleaning and degreasing in industry and domestically.

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- Mar. 2007-Apr. 2010 **Southwestern Energy Company, Houston, Texas – Fayetteville Shale Completion Manager**
Managed a team of up to 75 professionals and was responsible for the completion of over 1200 horizontal wells. Annual completion budgets were in excess of \$500,000,000. Team coordinated activity with drilling, geology, geophysics, land, and production. Shared technical and operational expertise at numerous industry conferences. Served on initial committee that ultimately developed our Model Regulatory Framework.
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United States Air Force – B-52H Navigator and Radar Navigator

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COLORADO

Air Pollution Control Division

Department of Public Health & Environment

Dedicated to protecting and improving the health and environment of the people of Colorado

Pneumatic Controller Task Force Report to the Air Quality Control Commission

Pneumatic Controller Field Study and Recommendations

June 1, 2020

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1 Introduction

This report was developed in response to a December 2017 rulemaking, in which the Colorado Air Quality Control Commission (AQCC) established a pneumatic controller (PC) ‘Find and Fix’ program for oil and gas well production facilities and natural gas compressor stations located in the ozone non-attainment area (NAA). The AQCC recognized that continuous bleed and intermittent pneumatic controllers are designed to have emissions but these emissions can be excessive when the controllers are not operating properly. The AQCC adopted the Find and Fix program to reduce excess emissions from such natural gas-driven pneumatic controllers.

As part of the Statement of Basis and Purpose (SBAP), and at the request of industry and other stakeholders, the AQCC adopted a “reassessment” provision for the Find and Fix program. The reassessment was to follow an Air Pollution Control Division (Division) led study of pneumatic controller emission reduction options, including the rate, type, application, and causes of pneumatic controllers found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also directed that more information on “good engineering and maintenance practices” should be gathered during the pneumatic controller study and implementation of the Find and Fix program to inform the reassessment. As part of the reassessment, industry agreed to participate in a study focused on the Denver-Julesburg (DJ) Basin that would collect data on the types of PCs in service, those PCs determined to be operating improperly, what caused the PCs to not operate properly, and the repairs taken to return the PCs to proper operation across a representative cross section of well production facilities and natural gas compressor stations in the NAA.

The AQCC directed the creation of a Pneumatic Controller Task Force (PCTF) comprised of representatives of the Division, operators and industry trade groups, local governments, and conservation groups. The PCTF was to brief the AQCC annually and make recommendations in this report, and each participant was to have the opportunity to contribute to the briefings and report. The AQCC also recognized that the pneumatic controller study and inspection program might inform the strategies for cost-effective hydrocarbon emission reductions for pneumatic controllers, including zero emission pneumatic controllers, under consideration by the Statewide Hydrocarbon Emission Reduction (SHER) team. The AQCC also established the SHER team through the SBAP for the December 2017 rulemaking.

The PCTF convened for the first time on January 25, 2018. The group held bi-weekly meetings for several months to develop and design the study. Field inspections of production facilities selected for the study started on May 1, 2018. Afterwards, meetings were held bi-monthly to check on the progress of field inspections and updates on data management until the data was submitted to the Division in December 2018. The group met in January 2019 to discuss initial data analysis, finalize the project plan, and revisit goals. The PCTF briefed the AQCC on February 21, 2019 on its progress. Throughout the spring of 2019, industry PCTF members developed and responded to questionnaires to document and assess the effectiveness and costs of inspection techniques as well as to understand opportunities for expanded use of no-bleed PCs. The PCTF and the SHER team held a joint meeting on June 11, 2019, to hear presentations on Canadian regulation of pneumatic controllers.

In April 2019, the legislature adopted Senate Bill 19-181, which directs the AQCC to “review its rules for oil and natural gas well production facilities and compressor stations and specifically consider adopting more stringent provisions, including . . . a requirement to reduce emissions from pneumatic devices. The AQCC shall consider requiring oil and gas operators, under appropriate circumstances, to use pneumatic devices that do not vent natural gas.” The PCTF was effectively put on hold in the summer of 2019 to allow its members to focus on regulatory proposals to be addressed during the December 2019 SB 19-181 Rulemaking. In that rulemaking, the AQCC adopted the SHER team’s proposal to (1) expand the Find and Fix program statewide, (2) include language in the SBAP directing continued work to evaluate the use of zero-bleed pneumatic devices, and (3) provide for a compliance assistance approach for operators outside the nonattainment area while those operators get up to speed on the Find and Fix program. In the SBAP, the AQCC directed the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the AQCC in 2020 their recommendations on the use of zero-bleed pneumatic devices.

Members of the PCTF were requested in April 2020 to review and complete this report.

1.1 2017 AQCC Reg 7 Oil and Gas CTG Rulemaking and Pneumatic Inspection Program

Below is a summary from the Statement of Basis and Purpose prepared for the 2017 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2017 rulemaking and the direction given to the Division to convene a PCTF.

1.1.1 Background

On May 4, 2016, the U.S. Environmental Protection Agency (“EPA”) published a final rule that determined that Colorado’s Marginal ozone NAA failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard (“NAAQS”). EPA, therefore, reclassified the Denver Metro North Front Range (“DMNFR”) area to Moderate and required attainment of the NAAQS no later than July 20, 2018, based on 2015-2017 ozone data.

As a result of the reclassification, on May 31, 2017, Colorado submitted to EPA revisions to its State Implementation Plan (“SIP”) to address the Clean Air Act’s (“CAA”) Moderate NAA requirements, as set forth in CAA § 182(b) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). As a Moderate NAA, Colorado revised its SIP to include Reasonably Available Control Technology (“RACT”) requirements for each category of volatile organic compound (“VOC”) sources covered by a Control Technique Guidelines (“CTG”) for which Colorado has sources in the DMNFR that EPA finalized prior to a NAA’s attainment date. EPA finalized the CTG for the Oil and Natural Gas Industry (“Oil and Gas CTG”) on October 27, 2016, with a state SIP submittal deadline of October 27, 2018. Given this timing, the November 2016, SIP revisions did not include RACT for the oil and natural gas source category and Colorado needed to further revise its SIP.

The Oil and Gas CTG recommends controls that are presumptively approvable as RACT and provide guidance to states in developing RACT for their specific sources. In many cases, Colorado had similar, or more stringent, regulations comparable to the recommendations in the Oil and Gas CTG, though many of these provisions were not currently in Colorado’s Ozone SIP. Therefore, on November 16, 2017, the AQCC adopted RACT for the oil and gas sources covered by the Oil and Gas CTG (CTG as of October 27, 2016) into the Ozone SIP. In order to make additional progress towards attainment of the NAAQS, the AQCC also adopted State Only revisions to require owners or operators of oil and gas well production facilities and

compressor stations with natural gas-driven PCs in the DMNFR area to inspect and maintain these PCs.

1.1.2 PC Find and Fix program

The AQCC adopted an inspection and enhanced response (e.g., maintenance) program for natural gas-driven PCs. While the Oil and Gas CTG notes the value of PC inspection and maintenance, the Oil and Gas CTG does not specify PC inspection and maintenance as presumptive RACT. The AQCC therefore created a new program that requires that natural gas-driven PCs at well production facilities and natural gas compressor stations in the DMNFR be inspected periodically to determine whether the PC is operating properly. The program requires that owners or operators inspect PCs for proper operation as part of routine LDAR regulatory programs at well production facilities annually, semi-annually, quarterly, or monthly, depending on the well production facility VOC emissions, and at natural gas compressor stations quarterly or monthly, depending on the natural gas compressor station fugitive emissions.

This PC inspection and enhanced response process was intended to be a multi-step process. First, the owner or operator must inspect all natural gas-driven PC using an approved instrument monitoring method (AIMM) to screen for detectable emissions. This first step allows owners or operators to narrow potential response efforts to only those PCs with detected emissions. Second, the owner or operator must determine whether the PCs with detected emissions are operating properly. Use of an AIMM is not required during this second step; the AQCC did not lay out a process for how owners or operators are to determine if their PCs are operating properly. During this second step, if an owner or operator determines that the PC is operating properly, no further action is necessary. Third, where an owner or operator determines the PC is not operating properly, the owner or operator must take actions to return an improperly operating PC to proper operation. Fourth, general recordkeeping and reporting requirements apply broadly to the number of facilities inspected and number of inspections. More detailed recordkeeping and reporting is required for those PCs that the owner or operator determined not to be operating properly. Similar to the LDAR records, owners or operators must keep records of the date the PC was returned to proper operation and a description of the types of actions taken.

1.1.3 Reassessment Provision

The reassessment provision is explained as follows in the SBAP for the 2017 Reg 7 CTG rulemaking.

The AQCC adopted a “reassessment” provision for this inspection and enhanced response program following a Division led study of PC emission reduction options, including the rate, type, application, and causes of PCs found operating improperly; inspection and repair techniques and costs; available preventative maintenance methods; appropriateness of the definitions of enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller; and other related information. The AQCC also recognized that owners and operators may have limited information on “good engineering and maintenance practices” for PCs and intended that more information on these practices are gathered during the pneumatic study and implementation to inform the reassessment of the inspection and enhanced response program. The data collection effort will include data from a representative cross-section of well production facilities and natural gas compressor stations in the DMNFR. In accordance with industry’s proposal, a task force was directed to convene by January 30, 2018, consisting of

representatives from industry, the Division, local governments, environmental groups, and other interested parties. Data collection was scheduled to commence no later than by May 1, 2018. The task force *will* brief the AQCC annually and make any recommendations on its findings in a report (this document) to the AQCC due May 1, 2020. The AQCC *intends* that the Division, industry, local government, and environmental group task force participants each have the opportunity to contribute to the final report and provide one representative to speak during the briefings to the AQCC. The AQCC intended that this information be used to reassess the natural gas-driven PC requirements of Regulation Number 7 that will remain in effect until rescinded, superseded, or revised.

1.1.4 2019 Rulemaking Directives

Below is an excerpt from the Statement of Basis and Purpose prepared for the 2019 AQCC Regulation 7 rulemaking that explains the actions taken by the AQCC for the 2019 rulemaking and the direction given to the PCTF and SHER Team:

“Pneumatic Controllers (Part D, Section III.)

SB 19-181 also directed the Commission to consider a requirement to reduce emissions from pneumatic devices. In the 2017 emissions inventory for the Moderate area ozone nonattainment SIP, pneumatic devices were identified as the second largest oil and gas area source (after tanks). In 2017, the Commission convened the Statewide Hydrocarbon Emission Reduction (SHER) team, to consider measures – both regulatory and voluntary – to reduce hydrocarbon emissions from the oil and gas sector. The Commission, at the same time, also established the Pneumatic Controller Task Force (PCTF), with a mission to collect and review data about pneumatic controllers and identify ways to reduce emissions from that equipment. After almost two years of work, the SHER team developed an early recommendation concerning pneumatic controllers, which the Commission has now adopted.

The SHER team supported a three-prong approach. First, the expansion of the pneumatic controller inspection and enhanced response program state-wide. Second, the SHER team recommended including language in this Statement of Basis and Purpose, directing the continued work to evaluate the use of zero-bleed pneumatic devices. Third, the SHER team supported a compliance assistance approach for operators outside the nonattainment area, while those operators get up to speed on the pneumatic controller inspection and enhanced response program that has been implemented in the nonattainment area since 2018.

The Commission approves of this approach and commends both the SHER team and PCTF for their work since 2017, building the knowledge that informed provisions of this rulemaking. The Commission has therefore expanded the pneumatic controller inspection and enhanced response program state-wide. At the same time, the Commission recognizes that there is much to learn about the inspection and maintenance of natural gas-driven pneumatic controllers outside the nonattainment area, which highlights the need for enforcement discretion. The Commission intends that for operations outside the nonattainment area, the determination of whether a pneumatic controller is operating properly will be made by the owner or operator, with minimal oversight by the Division for the first year of implementation.

The Commission further directs the SHER team and PCTF to continue their work on the mandates established in 2017, and to bring back to the Commission in 2020 their recommendations on the use of zero-bleed pneumatic devices. Specifically, the Commission continues to direct the PCTF to make recommendations on its findings in a report to the Commission in May 2020. However, the Commission revises its directive to the SHER team to present recommendations by no later than January 2020, to by no later than July 2020. This revised timeline will provide additional time for the SHER team to make any additional recommendations on cost-effective hydrocarbon emission reduction strategies evaluated by the SHER team. The Commission anticipates that the SHER team will also evaluate continuous methane emission monitoring and engage in discussions to determine actual leak rate percentages of components at oil and gas facilities for use in future rulemakings.”

2 Pneumatic Controllers

This section provides some basic information regarding PCs, with a focus on the PCs studied recently in Colorado.

2.1 What is a PC, what does it do?

PCs are found widely on oil and natural gas production facilities in Colorado. PCs are used to automate and regulate process control variables such as temperature, pressure, liquid level, and to maintain critical safety fail-safe functions. PCs operate by sensing a condition and then sending a signal to a valve actuator that in turn controls a valve that controls the process parameter in question. For instance, a liquid level controller will sense liquid levels in a separator and send a signal (in the form of natural gas pressure) to a valve actuator on a dump valve which in turn opens the dump valve and lowers the liquid level in the separator. It is important to note that the PC, the valve actuator, and the valve are all different components of the control system. It is not uncommon for the PC to be located several feet away from the valve actuator and the valve it is controlling. Finally, it is important to realize that the valve being controlled by the PC is a component that is already subject to the LDAR provisions of Regulation Number 7. Similarly, there are many connectors associated with PCs and valve actuators - each of which is also a component subject to the LDAR provisions. As such, it is important to distinguish emissions from leaking components that are routinely found and repaired in an LDAR program, from emissions caused by an improperly operating PC.

2.2 Types of PCs

As part of their normal function, PCs emit natural gas when they actuate, either intermittently or continuously. Continuous and intermittent PCs are the two broad categorizations of PCs that were the focus of the 2018 PCTF field study. The categorization refers to how the PC is expected to emit under normal operation. A continuous PC is designed to emit at a steady rate, commonly referred to as a bleed rate. The bleed rate may change during actuation. Contrastingly, an intermittent PC is only expected to emit above a de minimis level during actuations and hence they do not have a bleed rate per se. Some intermittent PCs actuate very frequently and some only rarely. For instance, a liquid-level

controller on a new high producing well may actuate many times within an hour. There may be significant emissions associated with this normal, intended operation.¹

There are also non-emitting controllers, often referred to as “no-bleed,” “zero-bleed” or “zero-emitting”² PCs. These devices do not emit natural gas to the atmosphere during any phase of normal operation. Many of these devices are inherently non-emitting because they are driven by electricity or pressurized air, rather than pressurized natural gas. Since the intent of this field study was to examine emissions associated with natural gas-driven PCs, non-emitting PCs were not included in the scope of the 2018 PCTF field study.

Contained within the continuous PC category are high-bleed and low-bleed PCs. High-bleed PCs are designed to emit over 6 standard cubic feet per hour (scf/hr) of gas between actuations. Low-bleed devices emit less than 6 scf/hr. As of 2020, the Division believes that there are no high-bleed devices in use within the State of Colorado and all continuous-bleed PCs reported during this study were low-bleed.

2.3 Improper operation

Numerous studies have identified that a small number of improperly operating PCs are typically responsible for the majority of emissions from the PC population^{3,4,5}. This information is what originally prompted the AQCC to adopt a PC find and fix program. The PCTF took a similar approach with the field study by focusing on “proper” vs “improper” operation.

2.3.1 Causes

Improper operation could be caused by any number of issues affecting a PC. These causes range from small amounts of debris keeping the controller from reseating properly to broken internal parts or defects in the housing for the PC. The causes specifically identified in the field study included: abnormal operation parameters, corrosion, debris, diaphragm failure, seal failure, spring failure, and wet supply gas.

2.3.2 Effects and Indicators

Operator personnel utilize AIMM (typically an OGI camera) to detect emissions from production facilities during LDAR inspections. Identification of a PC that is not operating properly requires additional knowledge regarding the types of PCs and their emission characteristics during normal operation in order to distinguish improper operation with an OGI camera.

Common tell-tale signs of PC improper operation include: loss of or improper control of the process parameter the PC is supposed to control; continuous emissions from an intermittent PC; excess emissions, as compared to normal operation, as identified via audio, visual, and olfactory (AVO) inspections or AIMM, from a controller; or obvious signs of significant staining

¹ Stovern, 2020: Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging, Journal of the Air & Waste Management Association.

² Simpson, 2014. Pneumatic controllers in upstream oil and gas. Oil Gas Facil. 3(5):83-96.

³ Allen, 2014. CH₄ emissions from process equipment at natural gas production sites in the United States: Pneumatic controllers. Environ. Sci. Technol. 49 (1):633-40.

⁴ Luck, 2019. Multi-day measurements of pneumatic controller emissions reveal frequency of abnormal emissions behavior at natural gas gathering stations. Environ. Sci. Technol. Letters 6:348-52.

⁵ Thoma, 2017. Assessment of Uinta basin oil and natural gas well pad pneumatic controller emissions. J. Environ. Prot. 8:394.

or corrosion. A subset of improperly operating PCs may also be able to be identified by field personnel using their AVO senses; however, all inspections in this study used AIMM and did not solely rely on AVO observations.

3 PC Task Force

3.1 PCTF Goals

The PCTF members established the following goals for the PC study:

- Identify and collect natural gas-actuated PC data from a representative subset of well production facilities and compressor stations in the NAA
 - Set parameters of “improper operation” for each type of PC
 - Develop, document, and assess the effectiveness and costs of inspection techniques
 - Document malfunction rates and causes for types, makes, and models of PCs in different types of service
 - Document the effectiveness and costs of repair techniques and preventative maintenance
 - Estimate the number of PCs typically associated with a separator or other grouping of equipment
- Gather information regarding “good engineering and maintenance” practices
- Evaluate the appropriateness of the definitions in Regulation No. 7 for enhanced response, intermittent pneumatic controller, no-bleed pneumatic controller, self-contained pneumatic controller, and pneumatic controller
- Gather information about the current applications, cost, effectiveness, current applications and opportunities for expanded use for no-bleed and self-contained PCs
- Produce timely annual presentations and a report to the AQCC

3.2 Implementation Plan

The PCTF formed three distinct groups to address different elements of designing the field study: a main core group and two subgroups. One subgroup selected representative facilities and the second subgroup developed a field data form. Members of the PCTF provided several technical presentations to grow the shared knowledge base during the study development phase.

Once the field inspection campaign commenced on May 1, 2018, bimonthly meetings were held to check on the progress of field inspection and subsequent data management until the compiled and blinded data was submitted to the Division in December 2018. The two subgroups disbanded once 2018 sampling began while the main core group continued to meet.

4 PC Field Study

4.1 Participating Stakeholders

The field study was designed with the help of all PCTF stakeholders. These stakeholders include: the Division, the American Petroleum Institute (API), the Colorado Oil and Gas

Association (COGA), nine upstream oil and gas well production operators, one midstream operator, the Clean Air Task Force (CATF), Earthjustice (EJ), the Environmental Defense Fund (EDF), Boulder County Public Health (BCPH), Denver Public Health and Environment (DDPHE), Colorado Communities for Climate Action (CC4CA), and the Regional Air Quality Council (RAQC).

The field study was implemented and conducted with the participation of nine upstream oil and gas well production facility operators in the DJ Basin. The study also surveyed PCs at the only two known natural gas compressor stations within the DJ Basin that operate natural gas-actuated PCs.

4.2 Study Design

4.2.1 PC Inspection Method Utilized

All PC inspections conducted at the facilities selected for this field study utilized an OGI camera to monitor and identify improperly operating PCs. Some operators also noted whether an improperly operating PC could have been identified using only AVO methods (e.g. visible staining or corrosion or audible hissing when not actuating).

4.2.2 Field Data Form Development

A subgroup was formed to develop the field data forms (Attachment A) that would be used by operators during PC inspections of the selected facilities to collect consistent metadata across operators and facilities. These forms were based on forms utilized by the Stovern et al (2020) study and amended to reflect the different data collection goals of the PCTF inspection process. The final data forms include general, inventory, inspection, and repair information. The data form options include PC type (including manufacturer and model), function, application, depressurization method, and type of service. The forms determine “improper operation” causes, including description(s). The forms note primary causes of improper operation such as debris, corrosion, equipment failures, broken or missing parts, or abnormal operational parameters; there is also an option for other causes.

Industry representatives provided extensive instructions (Attachment B) for field staff that detailed each item on the form step-by-step. The final data forms were available in paper and electronic form. Operators that utilized paper forms tabulated the data into the electronic form once the paper forms were returned to office staff. All data was submitted to the Division in electronic form.

4.2.3 Facility Selection

The PCTF extensively examined appropriate cross-sectional data for well production facilities and natural gas compressor stations. For well production facilities, the Division initially estimated about 7,000 well production facilities in the NAA counties. The group discussed how to appropriately divide the facilities into cohorts in order to identify which facilities should be sampled for the study. The factors discussed included type of drilling (horizontal vs. vertical), operation size based on production levels, facility age, and separator types. Ultimately, the subgroup decided that production level (barrels/day) was most appropriate and representative of the other variables being considered.

Industry then provided “snapshot” daily average production data from December 2017 for each of the nine participating operators to the Division on February 21, 2018, with subsequent updates based on stakeholder meeting discussions. This snapshot dataset for the nine participating operators represented approximately 80% of all well production facilities located

in the NAA. The original dataset was grouped by level of production (barrels/day), and a 50 percent “Plug and Abandon” (P&A) rate for wells in the 0 - 10 bbls production level cohort was assumed, as these wells were largely older vertical wells likely to be shut-in or scheduled for P&A. This P&A rate assumption is based on multiple factors including, but not limited to, line pressure, economic considerations, lease agreement issues, and land use matters.

Industry updated the dataset on March 21, 2018, with more accurate information from the two largest participating operators, which decreased the P&A rate and provided a conservatively low estimate of the number of PCs to be surveyed at each well production facility, based on its level of production. This analysis was conducted to demonstrate that the study would sample a sufficient number of selected facilities in each production cohort, to provide an adequate data set for the study.

After further meetings and discussion, the PCTF decided on the following cross-sectional sample of well production facilities to be subject to PC inspections starting May 1, 2018, shown in Table 1:

Table 1: Preliminary DMNFR Ozone NAA Well Production Facility Dataset (2018 Sampling Estimate)

Production Buckets	Estimated number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Estimated # of controllers
>250 bbls/day	50	104	13	14	700
10-250 bbls/day	20	553	7	39	780
0-10 bbls/day	5	2,509	5	125	625
TOTAL		3,166		178	2,105

The actual sampling that took place resulted in one extra facility inadvertently being surveyed by one of the operators. Additionally, because operator PC count estimates were intentionally conservative, a significantly higher number of controllers were actually surveyed during the study. The actual final 2018 well sampling facility and PC numbers inspected are shown below in Table 2.

Table 2: Final DMNFR Ozone NAA Well Production Facility Dataset (May - October 2018)

Production Buckets	Average number of controllers per facility	Total No. of Facilities	Proposed Sample %	Proposed No. of Sample Facilities	Final # of controllers
>250 bbls/day	98	104	13	14	1,378
10-250 bbls/day	34	553	7	39	1,319
0-10 bbls/day	9	2,509	5	126	1,141
TOTAL		3,166		179	3,838

For natural gas compressor stations, the Division initially requested industry feedback on potential data for inclusion in the May 2018 sampling. After further stakeholder discussion, the Division conducted an independent analysis using its databases to determine the number of active natural gas compressor stations in the NAA and gathered industry feedback by facility. The final analysis showed 58 active natural gas compressor stations operated by eight companies. The Division received feedback on 86% of the stations (50 stations) by June 2018 (four out of eight operators). Of these, 48 stations are currently operating or under construction to operate on instrument air, or have been depressurized and are not included in the field inspections. Two natural gas compressor stations were confirmed to use natural gas-driven PCs and were included in the study. These two natural gas compressor stations were sampled in the summer of 2018. Nine compressor stations are operated by non-participating operators and are of an unknown status at the time of the study. It is likely that at least some of these natural gas compressor stations are operated on instrument air since 4% (two out of 50) of the participating stations use natural gas-driven PCs; however, this is assumed and not verified.

4.3 Field Campaign Summary

The PCTF field study began in May 2018 and data collection was finished by October 2018. On August 1, 2018, and September 11, 2018, Patrick Murphy (formerly of Boulder County) and Jeramy Murray (APCD) attended field surveys at four Noble Energy and two PDC Energy facilities to observe how industry field staff were implementing the study design.

4.3.1 Field Data Compilation

Spirit Environmental (Spirit) was retained by COGA to assist with implementation of the PCTF study plan, including facility selection, field data form development, and data validation and compilation. Once the representative cross-section criteria was developed, Spirit generated a randomly selected list of facilities to be inspected by participating operators. If a facility was not available for inspection, Spirit randomly chose a replacement facility that met the original criteria for that operator. Reasons for assigning a designating a site as unavailable included: depressurized, shut-in, P&A, divested sites, sites operating with instrument air, sites with landowner access restrictions, or incorrectly categorized sites.

4.3.2 Completeness and Consistency Review

All data collected by operators was compiled and blinded by Spirit Environmental before electronic submission to the Division. The data also went through a completeness and consistency check performed by Spirit, where operators were consulted to complete missing

data fields and to better account for information provided, thereby improving field data reporting consistency between operators. For transparency, industry provided the compiled field data in both uncorrected and corrected spreadsheets that were made available to all stakeholders in the PCTF.

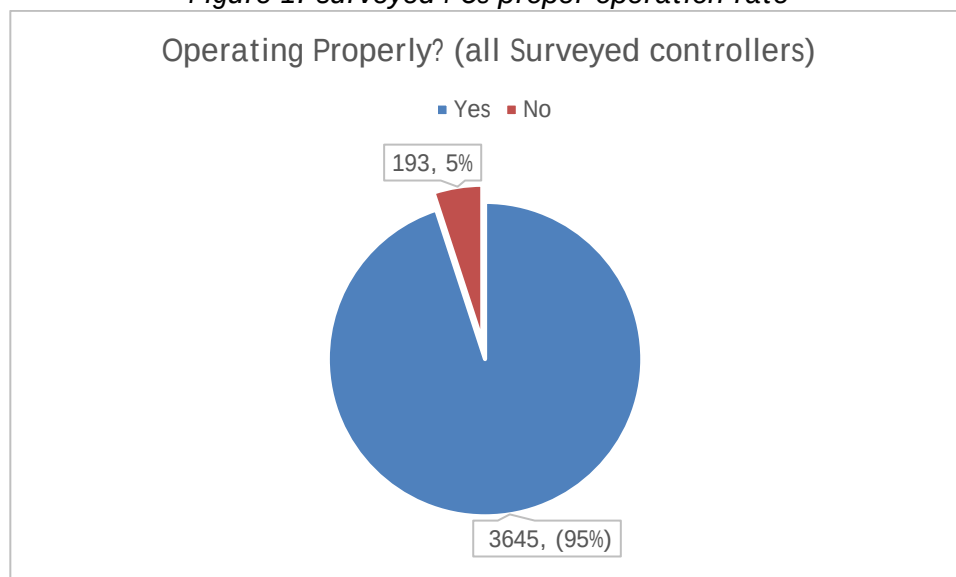
4.4 PCTF Study Data

The following sections contain summaries of key data collected during the PCTF field study. A full spreadsheet with all data collected in the program is available to stakeholders for analysis through the Division.

4.4.1 Oil and Gas Production Facility Data

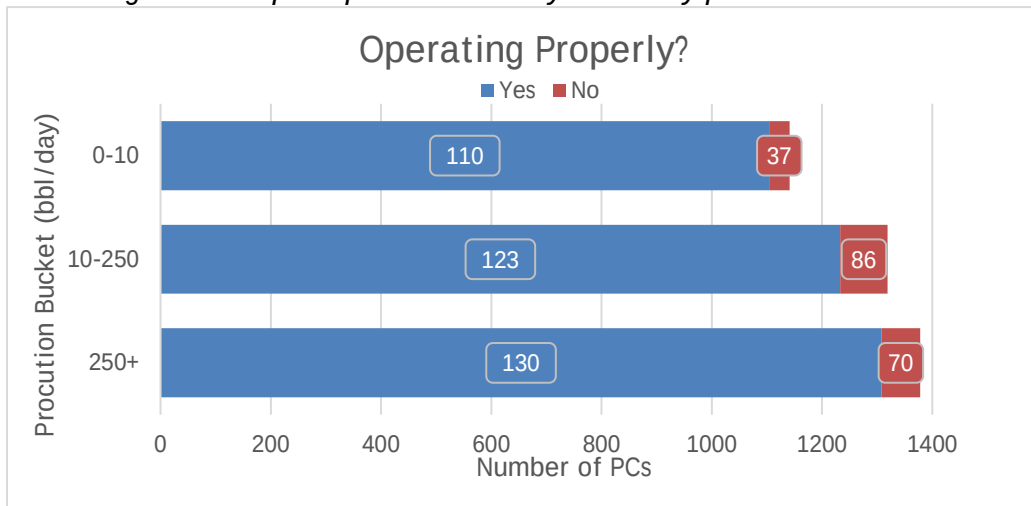
The study resulted in data points based on inspections for over 3800 PCs in the DJ Basin. Of the PCs observed, approximately 5% were observed to be improperly operating.

Figure 1. Surveyed PCs proper operation rate



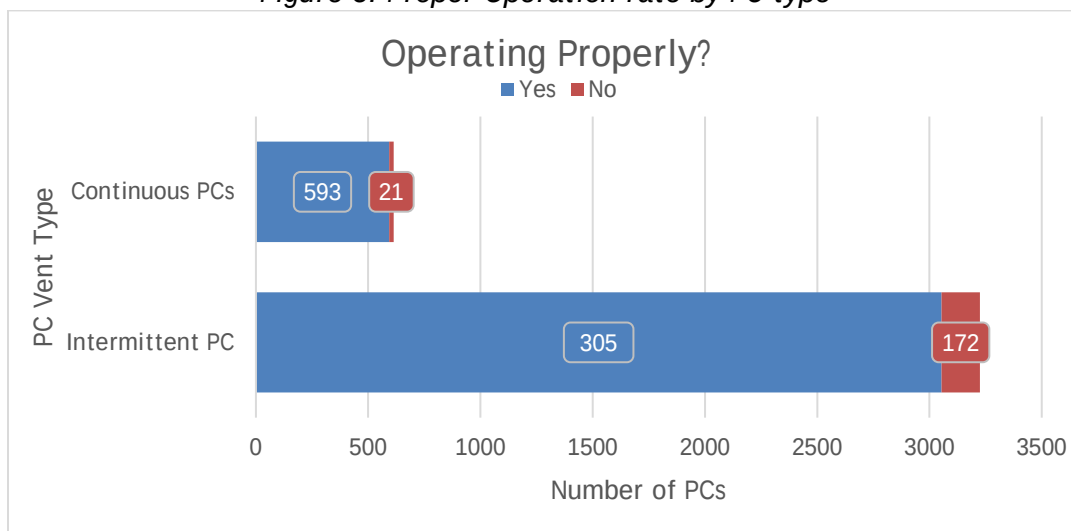
This data was also broken down by the three predetermined inventory production buckets. In the 0-10 bbl/day production bucket, 3.2% of all PCs were improperly operating. In the 10-250 and 250+ bbl/day buckets, 6.5 and 5.1% of PCS respectively were found to be improperly operating.

Figure 2. Proper Operation rate by inventory production bucket



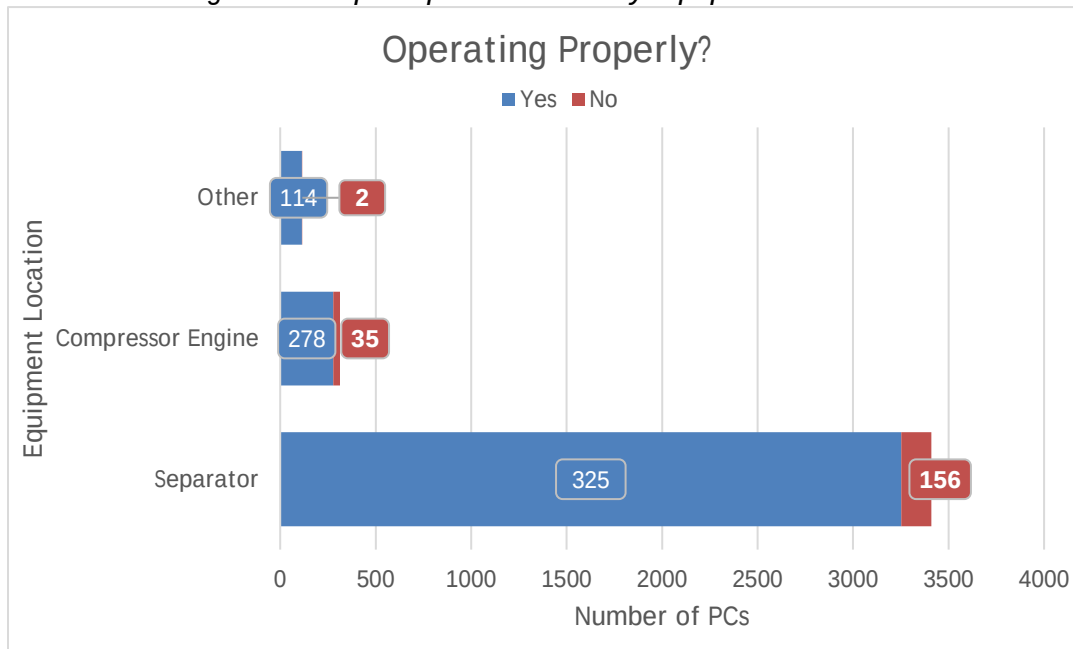
Breaking down the data by PC type (continuous vs. Intermittent) is also a useful way to look at the data. Continuous PCs were found to have an improper operation rate of 3.5% and intermittent controllers had a rate of 5.6%.

Figure 3. Proper Operation rate by PC type



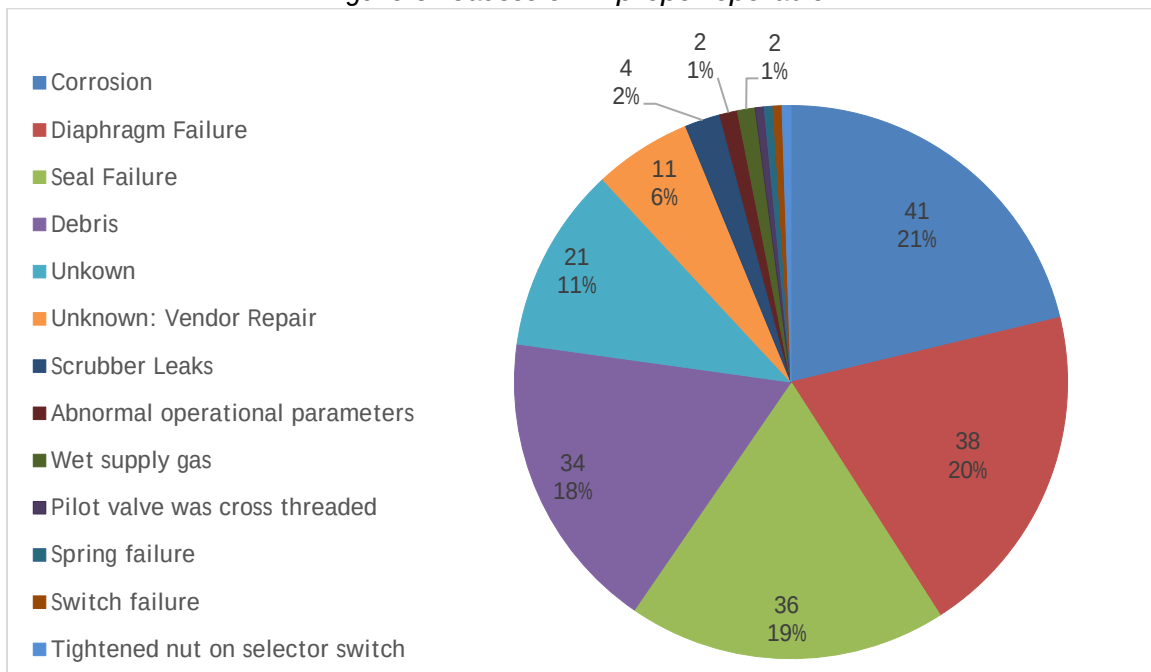
Operators tracked the facility equipment associated with each PC in the study. The majority of PCs are in-service on separation vessels. About 5% of PCs on separators were found to be improperly operating. The second most common PC equipment location was on the compressor engines. PCs on compressor engines had a relatively high improper rate of 12.3%. PCs found on all other equipment had a 2% improper operation rate.

Figure 4. Proper Operation rate by equipment location



The study revealed that there were a myriad of reasons that a PC might operate in an improper manner. The four largest causes were attributed to corrosion, diaphragm failure, seal failure, and debris blocking the internal mechanism from reseating.

Figure 5. Causes of improper operation

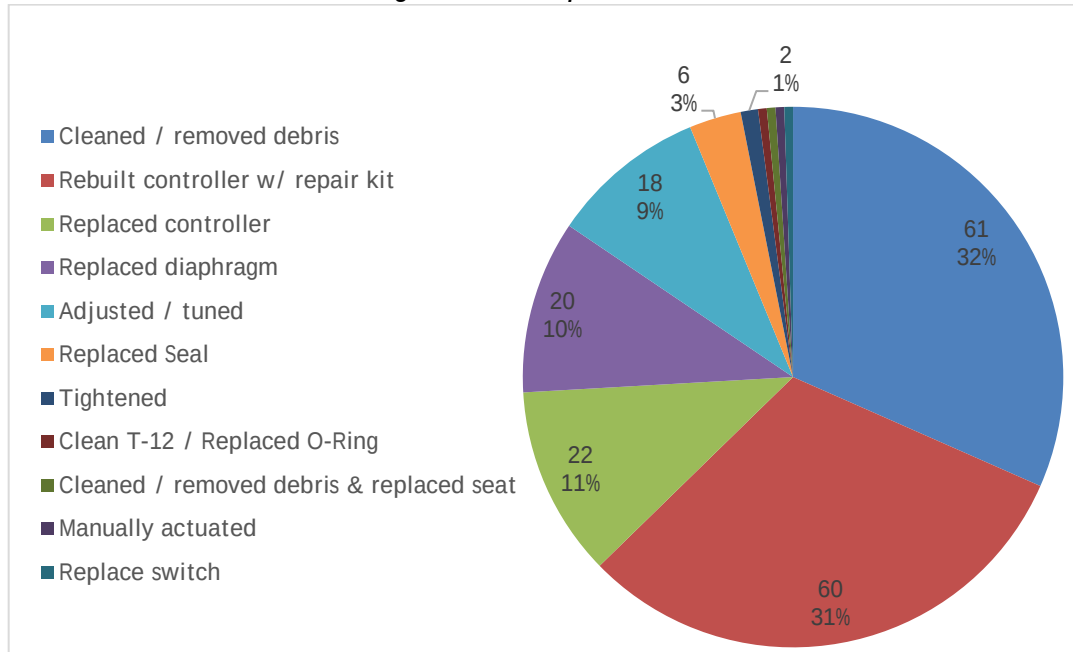


Operators made attempts to return all PCs to proper operation at the time of inspection if possible. Fifty (26%) of the 193 improperly operating PCs were repaired immediately. Ninety-

two PCs that needed repair were done on the same day of the inspection. 101 of the repairs were made at least a day later, with an average lag time of 4 days later.

Some repairs required a shut down or replacement of the PC. Those types of repairs take longer to complete and may have to be scheduled for repair soon thereafter or during the next planned shutdown of the facility. The majority of repairs were simply cleaning the PC and/or removing debris. Another common repair was to rebuild the PC with spare parts provided in a manufacturer repair kit.

Figure 6. PC repair actions



4.4.2 Midstream Data

As discussed previously, only two natural gas compressor stations of the 50 operated by participating companies use natural gas-driven PCs and were surveyed by the participating operator. All other natural gas compressor stations in the NAA owned by these participating operators utilized air-driven controllers and so therefore were not part of this study. The inspections of the two subject natural gas compressor stations occurred over two days in late August and early September. A total of 23 PCs were inspected. Four (4) models of PCs were documented. None of the surveyed PCs were found to be operating improperly. The PCs were used to monitor and control liquid levels and pressure.

4.5 PCTF Study Findings and Conclusions

The key findings and conclusions from the PCTF study are summarized below in narrative form. Additional findings are provided in the industry surveys of PC inspection costs and effectiveness, and use of no-bleed PCs, provided in Section 5.

4.5.1 Key Findings

PC Survey

- The most common manufacturers of PCs surveyed for this study were Kimray (43%), Wellmark (36%), and Fisher (15%).

- The most common models of PCs surveyed for this study were Wellmark 7400 Snaptrol (32%), Kimray T-12 (21%), Fisher 4660 (14%), Kimray 230 SGT (7%), Murphy LS200N (3%), and Norriseal 1001A (2%).
- Intermittent PCs comprise 84% and low bleed, continuous PCs comprise 16% of the 3838 PCs surveyed for this study.
- For equipment location, the PCs surveyed were found as follows:
 - o 89% on separators
 - o 8% on compressor engines
 - o 1.4% on liquid knockouts
 - o <1% on various equipment

PC Improper Operation

- The rate of PC improper operation varied:
 - o by facility production:
 - Ranging from 5.1% for greater than 250 bbl/day, to 6.5% for 10-250 bbl/day, and 3.2% for 0-10 bbl/day.
 - o by controller type:
 - 4.3% for pilot PCs and 8.0% for integrated PCs.
 - o by controller vent type:
 - 5.3% for intermittent PCs and 3.4% for continuous PCs.
 - o by controller enclosure:
 - 3.1% for enclosed PCs and 7.9% for non-enclosed PCs
 - o by equipment location:
 - 4.9% for separators, 11% for compressor engines, 0% for liquid knockouts, and varying percentages for those few PCs that serviced various types of equipment.
- Overall, the observed rate of improper operation for all surveyed PCs was 5%.
- Actuations of PCs were observed only for 33% of the PCs surveyed.
- PC emissions were observed at the following locations and frequencies:
 - o Vent port – 79%
 - o Body – 20%
 - o Vent port and body – 1%
- The following frequencies of common indicators of PC improper operations were reported.
 - o 86% - Continuous bleed from vent port of intermittent PC
 - o 11% - More venting than normal from continuous PC based on inspector's judgement
 - o 1% - Continuous bleed from vent port of intermittent PC and PC was making unusual sound

Causes of PC Improper Operation

- The following frequencies of common causes of PC improper operations were reported:
 - o Corrosion – 21%
 - o Diaphragm failure - 20%
 - o Seal failure – 19%
 - o Debris – 18%
 - o Other: Unknown - - 11%
 - o Other: Vendor repair – 6%

- o Other: Scrubber leaks – 2%
- o Abnormal operations parameters – 1%
- o Other: Wet supply gas – 1%
- o Various - <1%

PC Repairs

- The following frequencies of common types of repairs of PCs that were not operating properly were reported:
 - o Cleaned/removed debris – 32%
 - o Rebuilt PC – 31%
 - o Replaced PC – 11%
 - o Replaced diaphragm – 10%
 - o Adjusted/tuned PC – 9%
 - o Replaced seal – 3%
 - o Tightened – 1%
 - o Various - <1%
- Double block and bleed was performed for 36% of the PC repairs.
- Equipment shutdown was performed for 37% of the PC repairs. Shutdown of a well was performed for 24% of the repairs.
- The time to make a PC repair varied by the type of repair, yet the average time for all types of repairs was less than 30 minutes.

4.5.2 Conclusions

This PCTF study represents the largest sample set of PC inspections in the nation to date, with 3838 PCs surveyed during the facility inspections conducted during the spring and summer of 2018. The 5% rate of improper PC operation found in the 3838 PCs inspected for this study based on emissions observed using an OGI camera demonstrates that typically (~95% of the time) PCs sampled in this study were found to be operating properly.

This study also demonstrated that an OGI camera can identify improperly operating natural gas-driven PCs. Detection of improper operation of an intermittent PC is largely determined by the observation of continuous emissions between actuations. Given that 84% of the PCs surveyed consist of intermittent PCs, the use of an IR camera is particularly effective in identifying excess emissions from intermittent PCs. Discerning improper operation of a low bleed continuous PC is less straightforward and is subject to the experience and judgement of the inspector in discerning excess emissions from improper operation.

Additionally, where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven PCs to the inspections adds minimal incremental inspection costs. Repairs of improperly operating PCs are readily made by cleaning the PC of corrosion and debris, replacing broken parts and adjusting/tuning the PC and the supply gas pressure.

4.6 Separate EPA/CDPHE Study on PCs in Denver-Julesburg Basin

4.6.1 Overview

Over a similar time period as the PCTF inspection study, EPA and CDPHE conducted a parallel study on natural-gas actuated PC emissions in the DJ Basin. The results of this parallel study were published in early 2020 in the Journal of the Air and Waste Management Association in a

paper by Stovern et al. entitled “Understanding oil and gas pneumatic controllers in the Denver-Julesburg basin using optical gas imaging.”

Briefly, the Stovern et al. paper focused on a smaller sample size of PCs (500 controllers servicing 102 wells at 31 facilities operated by seven different companies) and included counts and observations of intermittent and continuous low bleed PCs. The PCs were inspected with OGI, and the emission rate from a small subset of the inspected PCs was quantified using high-volume sampling. Although measurements required to quantify actuation volumes were outside the scope of this study, the OGI camera survey provided limited information on the frequency of occurrence for actuations. This study was performed in the spring 2018 over a period of 10 field days.

4.6.2 Study Design

Stovern et al identify two objectives for this study: 1) gather information on the types and uses of PCs employed by randomly selecting facilities representative of the overall basin and 2) investigate the use of an expeditious and less invasive PC emissions survey approach based on optical gas imaging (OGI) camera that could help inform PC operational and maintenance states.

An important aspect of the PC survey was to confirm that the exhaust port of the PC was visible during the OGI inspection so that any continuous emission through the PC pilot could be assessed. A FLIR GF320 camera was utilized to monitor emission profiles of PC for this study, which has a normal or “auto” imaging mode and a high sensitivity mode (HSM), where onboard differential image processing can enhance an operator’s ability to identify lower emission rates approaching 0.5 scf/hr natural gas or even lower under ideal conditions. Comparisons between the auto and high sensitivity mode imaging were made in monitoring PC emissions to explore their differences in detection capability as a rough indicator of emission level. An extended OGI observation time of 60 sec for each PC was used to enhance detection capability, to look for anomalous temporal emission profiles indicative of potential malfunctions, and to document short time duration PC actuation events as activity data where possible. If an actuation event or unusual temporal profile was observed, the observation time was increased to 120 seconds to bound actuation frequency and further diagnose potential malfunction issues.

The well production facilities ranged in production and complexity from small facilities with minimal equipment (such as one wellhead, one separator, and one or two tanks) to larger facilities with multiple wellheads, separators including second and third stage separation vessels, complex tank batteries with vapor capture systems, multiple control devices, gas lift compressor engines, and vapor recovery units. Of the 31 well production facilities selected, the wells were 50.0% vertical, 33.3% horizontal and 16.7% directional. This distribution is consistent with the overall well type distribution for the 24,220 actively producing wells in the basin of 42.1% vertical, 38.9% horizontal, and 19% directional.

Information gathered for each pneumatic system (PS)/PC included: process working status (in use or shut-in), PS/PC identification (make/model), motive gas type, PC configuration and operational mode, process function (control, safety, or both), process equipment application (separator, combustor, compressor, etc.), and sensed process variables (e.g. temperature, pressure, and liquid level). PC-specific information such as model configuration variables, retrofit status, installation date, actuator components, and supply line pressures were also documented to the extent possible.

4.6.3 Findings

Stovern et al. (2020) reported the following findings for the EPA/CDPHE PC study:

Survey of PCs at Facilities

- A total of 615 process control pneumatic systems (PSs) were found at the 31 facilities with 59 of these being of the electronic variety that does not use gas-emitting PC pilots.
- Of the 556 PSs with gas-emitting PC pilots, 38 of these were instrument air-driven. Natural gas was found to be the exclusive motive gas type at 30 of the 31 facilities surveyed. One facility used instrument air on 38 out of 52 PCs with the natural gas models at that facility primarily serving back pressure regulation functions. Operations of instrument air-driven PCs were not further studied by Stovern et al.
- Of the 518 natural gas-driven PCs, 18 (3.5%) of these comprised a “no-vent” design where the natural gas emitted from the pilot is fully captured. These integrated pilot-actuator PCs have the potential to emit natural gas only by diaphragm or connector leaks that would be classified as equipment leaks and therefore were not further studied by Stovern et al.
- A total of 500 natural gas emitting PCs were found at 31 facilities servicing 102 wells (average of 4.9 PCs/well).
- A total of 453 of the 500 natural gas-driven PCs were found to be in service (i.e. not shut-in or depressurized); this number represents the primary count of the PCs assessed for proper operation. Of this total, 377 (83%) of the PCs were intermittent and 76 (17%) were continuous.
- A total of 447 PCs were monitored with an OGI camera for emissions as six intermittent PCs were not surveyed due to wind speeds exceeding the 9 m/s method limit.

PCs with Maintenance Issues

- Of the 371 intermittent PCs monitored, 42 (11.3%) were observed with continuous emissions and 22 were observed with actuations (5.9%). This 11.3% represent intermittent PCs experiencing some level of maintenance issue. The severity of the maintenance issues is unknown without emission rate measurement. The authors note that due to the fact that some controllers were observed in the less sensitive “auto” mode of the OGI camera (see below), the true level of maintenance issues among the intermittent PCs they surveyed was probably higher. They estimate that the true frequency of maintenance issues in this population was 11.6 to 13.6%.
- Of the 76 continuous PCs, 28 (37%) were found to have continuous emissions. Yet, it is unknown what portion of these emitting continuous PCs reflect a potential maintenance issue, since they may have been operating as designed. As described below, at least one continuous PC had measured emissions above the State regulatory standard (6 scf/hr).
- It was critical to determine the design type of the PC (intermittent or continuous) during the on-site survey because the type assignment played a role in the assessment of potential maintenance issue conditions.

PC Emission Measurements

- Emission measurements were conducted on 18 total PCs (14 intermittent PCs and 4 continuous PCs) with continuous emissions detected during the OGI camera survey. In general, the measurements were conducted on PCs that appeared to have the most significant gas signature.
- 36.8% of continuous low-bleed PCs (28 controllers) had continuous emissions that were observable with the OGI camera. Emissions were measured from four of these continuous PCs with a high-flow sampler. Measured emission rates ranged from 0.7 to 9.9 scf/hr with an average ER of 4.2 scf/hr. Three of the continuous PCs exhibited emission rates above 1.39 scf/hr; one was considered to be malfunctioning as it was emitting in excess of the 6 scf/hr State regulatory limit. Two of the measured continuous PCs had measured emissions above 1.39 scf/hr and below 6 scf/hr.
- Snapshot measurements were conducted on 14 intermittent PCs that were observed using an OGI camera to have continuous emissions (not including actuations). Three of the measurements were near or below the estimated method detection limit of the technique at (0.1 scf/hr). Observed emissions rates ranged from 0.1 up to 31.3 scf/hr (mean = 2.8 scf/hr).
- In two cases, the intermittent PCs were cycling between actuations with the OGI camera video showing steadily increasing emissions prior to actuating, followed by a sharp drop in emissions below the OGI detection threshold. These significantly variable (heavy ramping and temporally sustained) emissions were categorized as maintenance issues for these snap-acting intermittent PCs.
- The highest measured intermittent PC emission rate (31.3 scf/hr) was caused by a process issue. This PC managed back pressure on the low-pressure side of a high-low pressure separator. A suspected process control issue was identified where a bleeding valve upstream of the low-pressure vessel caused the PC to continuously actuate because the low-pressure vessel was continually exceeding the pressure set point of the PC. In this situation, the intermittent PC itself was not malfunctioning.

Auto vs. High Sensitivity Mode

- The initial protocol for the OGI camera included evaluating only auto imaging mode (the less-sensitive mode for the OGI camera used in the study) at 85 PCs that serviced 26 wells at 9 facilities. Later, both high sensitivity mode (HSM) imaging and auto mode (HSM/auto) were used for most of the PC assessments (N= 362 PCs, 22 facilities, and 76 wells).
- The continuous PC emission detection rates for the auto-only versus the HSM/auto subgroups differed significantly. For the auto-only mode subgroup, 1 of 16 continuous PC (6.3%) and 1 of the 69 intermittent PCs (1.4%) exhibited continuous emissions. For the HSM/auto subgroup, 27 of 60 continuous PCs (45%) and 41 of 302 intermittent PCs (13.6%) exhibited continuous emissions.
- OGI camera imaging modes were observed to have a significant effect on emission detectability with HSM mode detection rates being approximately 2 times higher compared to auto mode.

Actuations

- A total of 33 actuation events (AEs) were observed from 22 different PCs in the 447 monitored for this study. Based on observed emissions, only a few percent of intermittent PCs in this basin appear to have actuation frequencies greater than 1/min, with many PCs (e.g. safety category) very infrequently actuating.
- AEs were observed at only 9 of 31 facilities with the top two highest oil producing facilities accounting for 54.5% (12 of 22) of the PCs with actuations. The highest producing facilities had five separate intermittent PCs exhibiting AEs with a total of 13 observed, whereas the second-highest producing facilities had 7 PCs and 8 total AEs. There were a total of six PCs surveyed that had multiple actuations observed during the OGI survey (extended up to 2 min). Three of those PCs were located at the highest producing facility, and one PC with multiple actuations was located at the second, fifth, and sixteenth highest producers.
- The OGI camera survey indicates an expected relationship between normalized oil production and observed actuations. At a high producing facility, the same PC and process will require more actuations than at a lower producing facility. However, PCs with a maintenance issue do not show the same correlation with facility production.
- Estimated actuation volumes ranged from 0.005 to 0.185 scf per actuation event, which indicates that potential emissions from continuous emissions due to a maintenance issue may often be the dominant factor in overall emission rates for infrequently actuating PC populations. At lower producing facilities, the continuous emission component of emissions for intermittent PCs with maintenance issues becomes a more significant factor affecting average PC emissions rates for lower producing facilities.

4.6.4 Conclusions

- Although the findings of this study are representative of the DJ Basin, they are not intended to be representative of PC operating characteristics at a national level and therefore should be used with caution at that scale.
- The observed PCs per well are reasonably consistent with the 2018 data from EPA's Greenhouse Gas Reporting program for the Denver Basin with an average of 3.1 PCs per well and are significantly higher than the national average of 1.6 PCs per well (U.S. EPA 2019c).
- 83% of the PCs surveyed for this study were intermittent PCs, which is consistent with the 91% reported by Allen et al. (2014) for PCs in the Rocky Mountain region.
- The use of an OG camera to profile PC emissions was found to be a helpful approach to inform PC maintenance issues.
- Observing continuous emissions from a PC with an OGI camera on a snap-acting intermittent PC is indicative of emissions beyond the designed shut-off rate and is indicative of a maintenance issue.
- The identification of actuation events for continuous PCs and throttling process control applications was more challenging than those for intermittent PCs in snap acting applications.
- For a low bleed CPC, continuous emissions observed with an OGI camera was not informative to detect a potential maintenance issue unless in the OGI operator's judgment the emission appeared abnormally large compared to typical operation.
- 11.3% of intermittent PCs surveyed were directly observed with OGI to have continuous emissions. Due to an issue with the use of the OGI camera at some sites, this figure probably represents an underestimate of the frequency of continuous

emissions from these controllers. Stovern et al. estimate that the true frequency of continuous emissions in this population was 11.6% to 13.6%. These observations may reflect maintenance issues since these emissions were likely above the designed seepage rate of these intermittent PCs.

- As opposed to intermittent PCs, it is unknown what portion of continuous PCs were experiencing a potential maintenance issue, without measurement. One of the four continuous PCs measured was classified as malfunctioning with a measured emission rate of 9.9 scf/hr, above the 6.0 scf/hr State regulatory limit.
- The type of imaging mode (i.e. auto vs high sensitivity) utilized during the OGI camera survey was observed to significantly affect the detection rate of continuous emissions. The detection rate of continuous emissions using high sensitivity mode was 1.6 and 2.1 times higher than when using auto-mode imaging for intermittent PCs and continuous PCs, respectively. The difference between observation capabilities in high sensitivity vs. auto modes could be used in an inspection approach to approximately separate the PC populations (e.g. minor maintenance issues and significant malfunctions), so that repairs can be prioritized to minimize unnecessary emissions.
- PC actuations from process control-based PCs correlate with facility production. Facilities with lower production will have lower actuation emissions rates among its PC population and continuous emissions from PCs with maintenance issues will therefore be the controlling factor for the average operational PC emission rate. For higher producing facilities that cause PCs to actuate much more frequently, actuations will be a significant contributor to the overall average operational PC emission rate

4.7 Comparison of PCTF Study and EPA/CDPHE Study Findings and Conclusions

The following statements offer key comparisons between the findings and conclusions for the PCTF Study and EPA/CDPHE Study.

4.7.1 Findings

- Both field inspections of PCs were conducted in the DJ Basin during the spring/summer of 2018.
- Both studies focused on identifying improper operation (aka maintenance issues) of PCs using an OGI camera by trained and experienced personnel during facility inspections.
- Facility selection for each of these studies was done randomly for the operators participating in each study.
- Both studies found that the majority of natural gas-driven PCs observed consisted of intermittent PCs (PCTF – 84% vs EPA – 83%)
- The EPA/CDPHE study estimated that 11-14% of the intermittent PCs inspected were not operating properly, while the PCTF study found 5.3% of intermittent PCs were not operating properly.
- The EPA/CDPHE study found that using a camera in high sensitivity mode was more effective in finding smaller emissions from intermittent PCs.
- The EPA/CDPHE study did not evaluate whether continuous PCs were operating properly based on emissions observed with an OGI camera. The PCTF study found 3.4% of continuous PCs were not operating properly. Emissions measurements were performed by EPA/CDPHE on four continuous PCs, finding one of these PCs to have emissions in excess of the 6 scf/hr regulatory limit.
- The EPA/CDPHE study measured 14 intermittent PCs that were observed using an OGI camera to have continuous emissions. Observed emissions rates ranged from 0.1 up to

31.3 scf/hr. The elevated reading of 31.3 scf/hr was attributed to a process issue and not PC improper operation.

A significant contrast between the PCTF study and the EPA/CDPHE study is related to how integrated pilot-actuator devices were classified. Simpson (2014)⁶ defines an *integral* PC as a PC that is built into an end device (i.e. valve) and does not require an external source of gas, nor does it release actuation gas to the atmosphere. Rather, it releases actuation gas into the process downstream. Similarly, Simpson defines a *local* controller is also defined as one built into the end device, but it exhausts gas to the atmosphere to move the process valve toward closed. In contrast, remote pilot controllers are PCs that are not integrated into the end device.

Note that “integral” controllers, as defined by Simpson, would be considered “Self-contained PCs” under Regulation 7. Additionally, note that Stovern et al. refer to both integral and local PCs as “integrated” PCs, and they use the term “no-vent” for PCs that Simpson defines as “integral” – those that release gas into a process downstream. The discussion below uses Simpson’s terminology.

- The EPA/CDPHE study did not include integral devices in their assessment of PCs. EPA stated in its report that integral PCs have the potential to emit natural gas only by diaphragm or connector leaks and that any such leakage should be classified as an LDAR component leak, rather than as a PC that is operating improperly.
- For the PCTF study, integral devices were classified as a type of PC. 59 (8%) of the 740 integral PCs surveyed were determined to be not operating properly, compared to 134 (4.3%) of the 3,098 pilot PCs surveyed. Presumably, these devices were leaking from the diaphragm or connector, as described above.
- Since the PCTF study included integral controllers, while the EPA/CDPHE study did not, and integral controllers were operating improperly at a relatively *high* rate in the PCTF study, this suggests that the inclusion of integral controllers in the PCTF study skewed the improper operation rate slightly higher.
- Regardless if classified as a PC or not, integral controllers are included as a component in a LDAR program for equipment leaks and will therefore be assessed for leakage and repaired as needed to ensure proper operation.

4.7.2 Conclusions

- The Stovern et al. study found that using the high sensitivity mode of the OGI camera resulted in a nearly 2 times higher emission detectability compared to the auto mode. This might explain why Stovern et al found more than twice the percentage of intermittent PCs that were not operating properly compared to the PCTF study (11-14% vs 5%).
- The Stovern et al. study used a set observation time of 60-120 seconds for every PC/PS. The PCTF study did not have this requirement and if the OGI camera operator did not detect emissions within a few seconds, they would move on with the inspection. These varying approaches were utilized because each study had a different objective. The PCTF study set out, in part, to determine the effectiveness of the find and fix program, so inspection protocols were adapted to current industry practices.

⁶ Simpson (2014), *Pneumatic Controllers in Upstream Oil and Gas*. <https://pubs.spe.org/en/ogf/ogf-article-detail/?art=238>.

The longer observation time used by Stovern et al. may also be a contributing factor to the discrepancy between the proper operation rates.

- Both studies concluded that using an OGI camera to profile PC emissions was an effective method to inform possible improper operation of intermittent PCs. However, the use of this method for identifying improper operation of continuous PCs is more challenging, except when the emissions appear to be abnormally large compared to normal operation.

5 Industry Surveys

In order to achieve the goals established by the PCTF for reassessment of the Find and Fix program, additional information needed to be gathered on the effectiveness and costs related to inspection of PCs under the find and fix program and to better understand the use of self-contained and no bleed PCs. A series of questions were developed and incorporated into survey questionnaires that operators were requested to complete. A total of three surveys were developed:

1. The effectiveness and costs of PC inspection techniques
2. The effectiveness and costs of PC repairs
3. The use of self-contained and no bleed PCs.

The surveys were completed in confidence, and then blinded and compiled by API and COGA to address industry anti-trust concerns before being shared with the PCTF in presentations that summarized the survey responses. The first two surveys were to be completed by the nine operators participating in the PCTF study within the ozone NAA. The third survey was distributed to COGA and API members with oil and gas production operations in the state. As described below, the second survey was developed but not completed.

5.1 Effectiveness and Costs of Inspection Techniques (NAA only)

Highlights from the results of survey questions provided to the nine operators participating in the PCTF study on the effectiveness and costs of PC inspection techniques are provided in the following bullets.

- The majority of operators use a combination of employees and contractors to conduct PC inspections. Some operators use employees only.
- The majority of operators use the same party for both LDAR and PC inspections.
- Operators typically conduct LDAR and PC inspections during the same facility visit.
- Operators generally replied that it can be helpful to know in advance whether the PC is an intermittent or low bleed in order to understand if emissions are expected between actuations (low bleed) or not (intermittent).
- Operators also indicated that understanding the process the PC is controlling is beneficial in making a determination whether a PC is operating properly or not.
- For intermittent PCs, operators typically look for continuous emissions between actuations. For continuous bleed PCs, operators typically look for emissions that appear abnormal for that type and application of controller.
- Operators found using OGI camera inspections along with AVO indicators was effective, although OGI cameras are more effective at finding smaller leaks. Soapy water may be used to further pinpoint a leak location.

- AVO indicators such as the presence of liquids at or around/below the vent and whether dependent processes are operating properly can be useful to determine whether a PC is operating properly or not.
- Safety limitations in the use of OGI cameras are largely driven by whether the OGI camera is intrinsically safe or not. An intrinsically safe camera does not pose a potential ignition source and can be used in Class 1 Division 2 areas as defined by OSHA in CFR 1926.449. OGI cameras that are not intrinsically safe may require a hot work permit to be allowed on site at a facility or the camera operator may have to maintain a minimum safe distance from the equipment being observed.
- Responses on the average time to inspect a PC varied depending on the experience of the inspector and included various caveats including weather conditions. The inspection time varies and is dependent on the type of PC and if emissions are observed. If no emissions are observed, then only a few to several seconds is generally sufficient to determine that the controller is operating properly. If emissions are observed, then the time to make this determination is dependent on whether the controller is actuating or not, the type of controller, and the characteristics of emissions observed. It could take up to several minutes to make this determination.
- The costs to conduct PC inspections are variable and likely highly dependent on the size and makeup of facilities of operators and internal programs and processes. Some operators indicated that the incremental equipment costs are not significant since this equipment is required for LDAR inspections. Other operators estimated that incremental annual equipment costs for PC inspections represent a small percent of LDAR related equipment costs. Ultimately, incremental annual equipment costs for PC inspections are dependent on the number of PC inspections performed.

5.2 Effectiveness and Costs of Repairs (NAA only)

Due to the need to focus on regulatory proposals to be considered for the December 2019 AQCC rulemaking, and the willingness of operators to expand the PC “find and fix program” statewide, it was not necessary to complete the planned repair cost survey.

Separately, the PCTF study results indicated that those PCs found to be improperly operating were successfully repaired and the majority of repairs were completed either immediately, the same day of the inspection, or within a few days of the inspection.

Operators seek to repair PCs in order to return them to proper operation since it is in their interest to maintain and optimize production operations. The cost of repairs is considered a normal operation and maintenance cost. The ability to more readily identify PCs that are not operating properly using an OGI camera allows earlier detection of those PCs needing repair that would otherwise eventually fail to control their intended process function and need subsequent repair.

The repair costs range in regard to the extent of the repair. These repairs can range from cleaning the PC of debris or residue that collects over time, replacing worn parts, or replacing the entire controller. Operators stock spare parts, repair kits or extra PCs that are then used to repair or replace the defective PC as a means to promptly make a repair.

The costs of repairs was not considered an impediment to supporting expansion of the PC “find and fix” program from the NAA to statewide during the AQCC December 2019 rulemaking.

5.3 Use of Self-contained and No-Bleed PCs (State-wide survey)

COGA developed and distributed a survey to better understand the use of self-contained and no-bleed PCs. The survey utilized the following definitions in order to establish a common understanding in completing the questions.

- o Instrument air-driven PC: Any PC that uses compressed air as the valve's actuating gas. Known as “no-bleed” under CO Regulation 7.
- o Natural gas-driven PC with exhaust routed to process/sales: Any PC that directs gas to a process or sales line instead of to the atmosphere. Known as “self-contained” under CO Regulation 7.
- o Natural gas-driven PC with exhaust routed to combustion control: Any PC that directs gas to a combustion control device instead of to the atmosphere.
- o Non-pneumatic mechanical controllers: Any controller that uses mechanical force (not a pressurized gas) to trigger actuation.
- o Non-pneumatic electric controllers: Any controller that uses an electrical signal (not a pressurized gas) and motor to trigger actuation.

The survey results are summarized below:

- o 12 Operator Responses for production facilities
 - o 3 Operators in Piceance, 9 in DJ.
 - >5,400 Total Production Facilities: ~4,200 DJ NAA, ~100 DJ AA & ~1,200 Piceance
 - >22,400 total wells: ~15,700 DJ NAA, ~500 DJ AA & ~6,200 Piceance
 - Percentage of facilities where on-site electrical grid power is used:
 - 19% DJ NAA
 - 63% DJ AA
 - 4% Piceance
 - o Operator Responses for compressor stations
 - o 4 Operators in Piceance, 1 in DJ responded.
 - 16 Compressor stations in DJ NAA, 38 in Piceance
 - Percentage of compressor stations where on-site electrical grid power is used:
 - 100% in DJ NAA
 - 76% in Piceance
 - o DJ NAA - 1 operator
 - 16 compressor stations
 - All use instrument air-driven PCs (11 new, 5 retrofitted)
 - o DJ AA - No compressor station operator responded
 - o Piceance Basin - 4 operators responded
 - 38 compressor stations
 - 9 new stations use instrument air-driven PCs
- o Summary of Usage
 - o The majority of PCs in use in Colorado are conventional natural gas-driven PCs
 - o Most of the non-conventional controllers in use in the state are located
 - In the DJ NAA
 - At new facilities receiving production from horizontal wells
 - o The most commonly used non-conventional controllers are air-driven PCs
 - o Other non-conventional controller technologies usually only replace a fraction of the PCs at a site

- o Consideration for Use
 - o Safety
 - Instrument air-driven PCs
 - Some operators expressed concern with facilities using both instrument air-driven and natural gas-driven PCs: potential risk of flammable mixtures or explosion
 - One operator noted that fail-safe close valves need to be used so the site/well can shut-in in case of power loss or air compressor malfunction
 - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
 - The required additional piping/plumbing could significantly complicate work areas
 - There are backpressure issues with remote PCs preventing exhaust vapors from reaching process/sales or combustion control
 - Backpressure can also slow actuation and affect operation
 - Non-pneumatic mechanical controllers
 - Some operators indicated mechanical dumps are more prone to failure due to erosion.
 - One operator noted that mechanical dumps may not have emergency shut down ability.
 - Non-pneumatic electric controllers
 - It was noted electrical controllers may not have a fail-safe capability and do not return to a safe position when power is lost, unlike conventional natural gas-driven PCs. Electric fail safe close valves require programming.
 - Electrical classification determines safe location on site.
 - Overall
 - Non-conventional have a positive impact on safety by reducing the quantity of hydrocarbon vapors in the atmosphere at facilities.
 - o Costs
 - Instrument air-driven PCs
 - New facilities: incremental capital cost of \$70K - \$140K (depending on production/number of wells)
 - o Additional piping, air compressor, supporting infrastructure, grid power/generator.
 - o Use of grid power is critical for most, generators also used by some.
 - o Additional maintenance costs required for air compressor and a desiccant air dryer.
 - o One operator reported reduced maintenance on instrument air-driven PCs themselves.
 - o One operator mentioned a backup instrument gas may be required, increasing costs.
 - Existing facilities: incremental capital cost of \$90K - \$180K (depending on production/number of wells)

- o Several operators reported that, due to declining production, retrofits are not cost effective and have primarily been done under compliance order.
 - o Loss of production for retrofit, in addition to reasons listed above.
 - o Additional incremental cost is on top of the initial cost to run instrument gas line.
 - o One operator reported the need to hydro vacuum instrument air lines before retrofitting
- Natural gas-driven PC with exhaust routed to process/sales
 - Significant cost associated with design of a complex vapor capture system.
 - Cost associated with compression to safely and reliably get emissions into process lines.
 - Additional maintenance on vapor control system (VCS) lines.
- Natural gas-driven PC with exhaust routed to combustion control
 - Cost associated with re-piping equipment. May be do-able for PCs in close proximity to control device, very high cost otherwise.
 - VCS: Additional maintenance on lines and may require updates to the VCS analysis.
 - Some compressor stations are not equipped with ECD: high cost for low reductions.
- Non-pneumatic mechanical controllers
 - Some mechanical dumps usually have lower upfront cost but higher maintenance cost.
 - For retrofits, cost of new controllers when natural gas-driven controllers are already in use.
- Non-pneumatic electrical controllers
 - One operator reported an incremental cost of \$7K - \$10K per well.
 - Controllers have a higher upfront cost and higher maintenance cost.
 - Several operators reported that retrofits are not cost effective.
- o Technical
 - Instrument air-driven PC
 - Sufficient grid power availability (true for new and potential retrofits).
 - Very frequent maintenance on air compressors required to ensure reliability.
 - o One operator noted liquid collection and freezing may require backup compressors.
 - Considerations for power loss:
 - o Some operators do not have back up options and site shuts in.
 - o One operator reported using natural gas powered back up air compressors.
 - o One operator reported using pressurized air bottles.
 - Natural gas-driven PC with exhaust routed to process/sales

- Low pressure and low volume gas needing compression to process/sales.
 - Concerns with vapor collection lines such as air intrusion through components, debris and/or condensate build up, freezing, and backpressure concerns.
 - Not all exhaust from natural gas-driven PCs can be captured.
- Natural gas-driven PCs with exhaust routed to combustion control
 - Low pressure and low volume may make it difficult for gas to reach combustor.
 - One operator mentioned experience indicating back pressure which affects valve actuation and maintaining stable stream to the combustor.
- Non-pneumatic mechanical controllers
 - Generally can only replace a specific type of PC: dump valves/liquid level.
 - Experience shows that mechanical controllers are not as precise or as reliable as natural gas-driven PCs for process control.
- Non-pneumatic electric controllers
 - Need for reliable electrical power (e.g. solar with battery and generator/grid as backup).
 - There are no electric replacement options for some natural gas-driven PCs.
 - There are limitations on where those controllers can be located (e.g. not compressors).
 - Electric fail safe close valves requires programming knowledge.
- o Land/Leasehold
 - Instrument air-driven PCs
 - Ability to bring grid power may be limited: landowner restrictions, BLM land & FS land with approval requirements, remote/mountainous locations.
 - Pad size needs to be sufficient to accommodate air compressor and additional infrastructure in an area that is safe for electrical equipment.
 - o Especially challenging for existing facilities where land has already been reclaimed.
 - Natural gas-driven PC with exhaust routed to process/sales or to combustion control
 - None identified
 - Non-pneumatic mechanical controllers
 - None identified
 - Non-pneumatic electric controllers
 - None identified
- o Other
 - Instrument air-driven PCs
 - Pros:
 - o Instrument air-driven PCs are a proven technology and usually use same/similar PCs.
 - o Instrument air-driven PCs are not subject to the find and fix program.

- o Reg. 7 requires the use of no-bleed (instrument air-driven PCs) at facilities that use grid power.
- Cons:
 - o Grid power availability is utility dependent and can be very complex (permitting and approvals for new lines, proximity to power line does not mean availability).
 - o Electric generators, if used, require permitting through APCD and have extra emissions.
 - o Retrofits are not cost effective and primarily been done under compliance order.
- Natural gas-driven PC with exhaust routed to process/sales
 - Reliability (operation and maintenance very complex). Other options are more desirable.
 - Required by Reg. 7 once grid power is used on site and if technically and economically feasible.
 - Process/sales gas line occasional downtime may require redundancy.
 - Emissions associated with required additional compression.
- Natural gas-driven PC with exhaust routed to combustion control
 - Not considered as no-bleed or self-contained under Reg. 7 definitions.
 - Reliability is a major concern: other options are more desirable.
- Non-pneumatic mechanical controllers
 - None identified
- Non-pneumatic electric controllers
 - One operator reported less maintenance needed for such controllers.
 - Not a proven technology, cannot cover all functions usually covered by natural gas-driven PCs.
 - Use and maintenance requires staff with knowledge related to electrical systems.
- o Survey Takeaways
 - o Fail-safe options a concern for non-natural gas-driven technologies
 - o Instrument air-driven PCs
 - Electrical grid power use is crucial, upfront cost is high
 - Proven technology, familiar make/model of PCs, less training
 - Safety and cost effectiveness concerns for retrofits
 - o Natural gas-driven PCs with exhaust routed to process/sales/control
 - Operationally burdensome, reliability issues
 - Only feasible for a small subset of PCs
 - o Mechanical controllers
 - Can only replace very specific functions (dump valves)
 - Cheaper upfront
 - Reliability and precision concerns
 - o Electrical controllers
 - Require reliable power
 - Require trained staff
 - Only feasible for a small subset of controllers

According to the industry survey on zero-emitting PCs, the practice of capturing gas and routing emissions from a self-contained PC to emission control devices (ECD) is relatively uncommon and is highly dependent upon the distance between the vent port of the PC and the ECD. The PCTF study identified 50 PCs where PC vented emissions were routed to a nearby ECD. All of these PCs that were routed to an ECD were operating properly. The majority of these 50 PCs serviced a level control for a liquid condensate burner knockout pot which was located within a few feet of the ECD. In most cases, these knockout pots are drained by gravity or manually and are not controlled by a PC.

Routing to a process is relatively uncommon due to pressure differences between the vent port and the process. In general, the gas pressure from the vent port is too low to route to a facility process.

The category of no-bleed PCs can be considered a misnomer as all “pneumatic” controllers bleed or vent as part of their normal operation. The term “no-bleed” usually refers to those PCs that use instrument air as a motive force, rather than natural gas. In order to utilize instrument air, an air compressor, desiccants and filters, and pressure regulators are typically installed. The power to operate the air compressor is either provided using an electrical generator that is fueled by natural gas or diesel, or by a connection to an accessible utility line that provides adequate electrical power to the facility. The use of a natural gas or diesel fuel powered generator may result in a net emissions disbenefit in providing instrument air in lieu of natural gas for operating PCs. However, the net emissions benefit or disbenefit would vary on a case-by-case basis.

(Note that low power air compressors designed driving pneumatics using solar-battery systems for electricity,⁷ and hybrid solar-gas powered electric compression systems,⁸ are both available on the market in Canada.)

For new development of multi-well pads, operators pursue commitments from electric utilities to provide a connection and adequate power to a planned facility for electrification of equipment including air compressors for instrument air. A number of factors, many of which are beyond the operator’s control, dictate whether the utility can provide an accessible connection and adequate power when the facility is being constructed. If the utility is not capable of meeting the requested commitment, then the operator will typically either rely on a natural gas or diesel-fired generator to power an air compressor, or utilize natural gas pressure as a conventional power source for PC operation.

5.4 Electrical Infrastructure for Oil and Gas Development

As part of the joint effort with the SHER work group, information was collected from API and COGA operators regarding the availability and planning for the use of electrical power from the grid or the use of natural gas or diesel oil powered generators to provide electrical power at oil and gas production facilities. A presentation was given during the July 12, 2019, SHER meeting which included the following talking points:

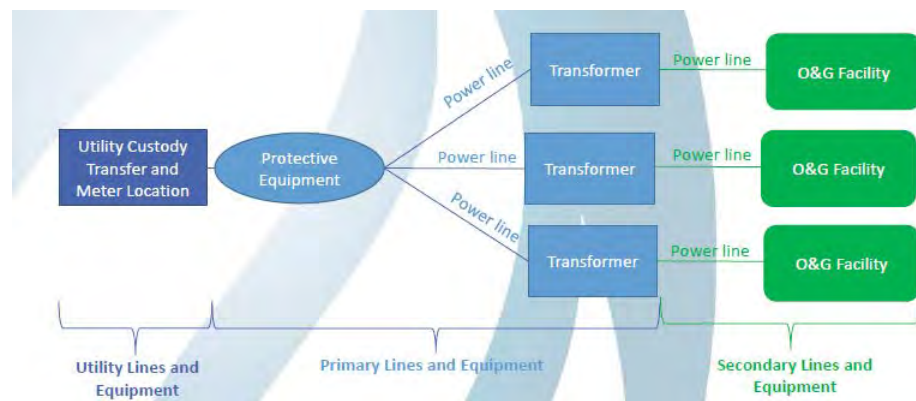
- Urban growth and development is an issue and impacts infrastructure availability

⁷ See <https://lccotechnologies.com/crossfire-compressor.html>.

⁸ See <https://westgentech.com/>.

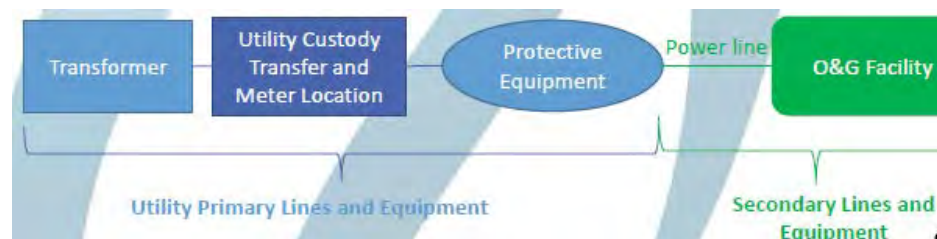
- Federal Lands and The National Environmental Policy Act (NEPA)/ The Federal Land Policy and Management Act (FLPMA) processes in remote areas are also obstacles to the use of electrical grid power
- Colorado has public utilities and cooperatives that provide power:
 - o Each utility has different power drop timelines (1-3 years)
 - o Each utility has different requirements on ownership and installation requirements between primary and secondary power lines and equipment
 - o Primary lines are typically higher voltage lines while secondary lines are supplying power to a location (480-120 volts)
- Primary Meter – primary and secondary lines and equipment after custody transfer are installed, owned, operated and maintained by the company. In this case the O&G Facilities owner.

Figure 7. Primary Meter Ownership



- Secondary Meter –Only secondary lines and equipment after custody transfer are owned, operated and maintained by the O&G Facility owner. Everything upstream of custody transfer is installed, owned and operated by the utility.

Figure 8. Secondary Meter Ownership



- Primary Metering
 - o The company has the staffing and technical ability to install, own, operate and maintain all the electrical equipment
 - o Shorter lead times for power drop because less line and equipment needs to be installed by the utility
 - o Higher costs for companies that only have a few O&G facilities in an area that requires power
 - o Lower cost for companies with many O&G facilities in an area that requires power
 - o Might not be an option because of right-of-way and surface user agreements

- Secondary Metering
 - o Longer lead times for power drop to wait for utility to install primary lines and equipment
 - o Costs may be higher depending on the location and amount of power needed
 - o Some utilities require companies to perform primary metering so this might not be an option
- Challenges include:
 - o Slowdowns from utility companies due to increased residential development
 - o Changes in schedule from drilling permit issuance delays, operator agreement challenges with local governments, or right-of-way changes
 - o Can be limited by proximity and capacity of grid power depending on utility
 - o Power plant expansions dependent on air and other permitting
 - o Cost may be prohibitive for operators in limited development areas
 - o Small operators may not be able to effectively negotiate cost and availability
 - o Contractual third party agreements may limit operator access
 - o Timing often uncertain and power generation needed as backup

6 Good Engineering and Maintenance Practices

In 2017, the AQCC adopted Regulation 7 Part D, Section III.F.1. (formerly Section XVIII.F.1), requiring operators to operate and maintain PCs consistent with manufacturer's specifications, if available, or utilize good engineering and maintenance practices. The SBAP recognizes the need to more fully develop and document those practices, which include but are not necessarily limited to, ensuring proper operation. Data collected by the PCTF can be used to develop and document good engineering and maintenance practices.

Due to the unavailability of documentation from PC manufacturers, there are no widely agreed upon routine or preventive maintenance schedules. Individual operators have developed their own maintenance and operating plans in accordance with industry best practices and Regulation Number 7 requirements. While individual operators may have company-specific protocols for their PC program, all operators are in agreement on some key practices. The use of OGI cameras as the proper inspection tool to identify improperly operating PCs is universally accepted, at this time, by all industry members of the PCTF. However, identification of improper operation from a continuous low-bleed PC may require additional training/experience for the OGI camera operator. The findings above from the survey results on PC inspections also reflect key practices.

There are some barriers to developing prescriptive PC protocols because of the wide variability in how these devices function and the wide variety of designs and specific applications that are employed. More work needs to be done if developing prescriptive maintenance protocols is a goal of the AQCC.

6.1.1 The Environmental Partnership

API established The Environmental Partnership (TEP) in 2017 to "continuously improve the industry's environmental performance by taking action, learning about best practices and technologies, and fostering collaboration in order to responsibly develop our nation's essential natural gas and oil resources." TEP's initial focus is to further reduce the industry's air emissions in continuing to reduce methane, a greenhouse gas, and VOCs, which is one precursor to the formation of ground-level ozone. TEP hosted their first annual conference in

2018 as described in their 2019 Annual Report⁹. The conference focused on PCs and brought together producers, manufacturers, researchers, and regulators to discuss PC technology and how it might be improved.

In addition to periodically checking for proper operation of the controller through AVO and AIMM inspections, operators participating in this study concur with the “Pneumatic Controller Maintenance Work Practices” published by TEP as a wallet card for its members to provide to field personnel responsible for inspecting and maintaining PCs for proper operation of oil and gas production facilities. This wallet card is shown below:



7 Recommendations

The PCTF offers the following recommendations for consideration by the AQCC. Where there was not consensus on specific elements assigned to the PCTF, individual stakeholder positions are presented as such.

7.1 Effectiveness of current program (NAA only)

Pursuant to AQCC Reg 7 CTG rulemaking in November 2017, the PC find and fix program that applied only to the ozone NAA took effect on June 30, 2018, which was during the same summer of the PC field surveys performed for the PCTF study. The PC find and fix program has proven effective as demonstrated in the Division's 2018 LDAR Annual Report¹⁰, which included the results of the PC find and fix program for the NAA, as described below. The AQCC extended the PC find and fix program state-wide effective May 1, 2020, as part of the AQCC SB-181 Reg 7 rulemaking in December 2019.

⁹ See <https://www.api.org/~media/Files/Policy/Environment/TEP/The-Environmental-Partnership-Annual-Report-2019.pdf>

¹⁰ See <https://www.colorado.gov/pacific/cdphe/2018-ldar-annual-reports-regulation-7-section-xii-xvii-and-xviii>

The Division's 2018 LDAR Annual Report (pp. 4-6) summarizes the results of PC inspections performed for the PC find and fix program. Although the report does not break out the number of PC inspections using AIMM at well production facilities that were performed in the NAA in 2018, a total of 4,053 PCs were found to need repair and of these 4,015 (99%) were returned to proper operation. For natural gas compressor stations subject to PC inspections using AIMM in the NAA in 2018, a total of 7 PCs were needed to be repaired and 6 (86%) were returned to proper operation. Upon discovery of an improperly operating PC, repairs must begin no later than five working days and the PC must be returned to proper operation no later than 30 working days. A delay in a repair may be attributed to unavailability of parts, the equipment requires a scheduled shutdown to complete the repair, or other good cause. The Division developed a list of standardized enhanced response actions to repair PCs with input from the oil and gas industry to be used for recordkeeping and annual reporting purposes. These include the following options to return a natural gas-driven PC to proper operation:

1. adjusted/tuned;
2. cleaned/removed debris;
3. tightened;
4. heated/insulated;
5. replaced part(s) of controller;
6. rebuilt controller with repair kit;
7. replaced controller; and
8. other.

Below is Figure 2 from the Division's 2018 LDAR Annual Report that shows the distribution of each type of response action, with a total of 4,060 actions reported. The two most common types of response action were to clean/remove debris, and to rebuild the pneumatic controller with a repair kit.

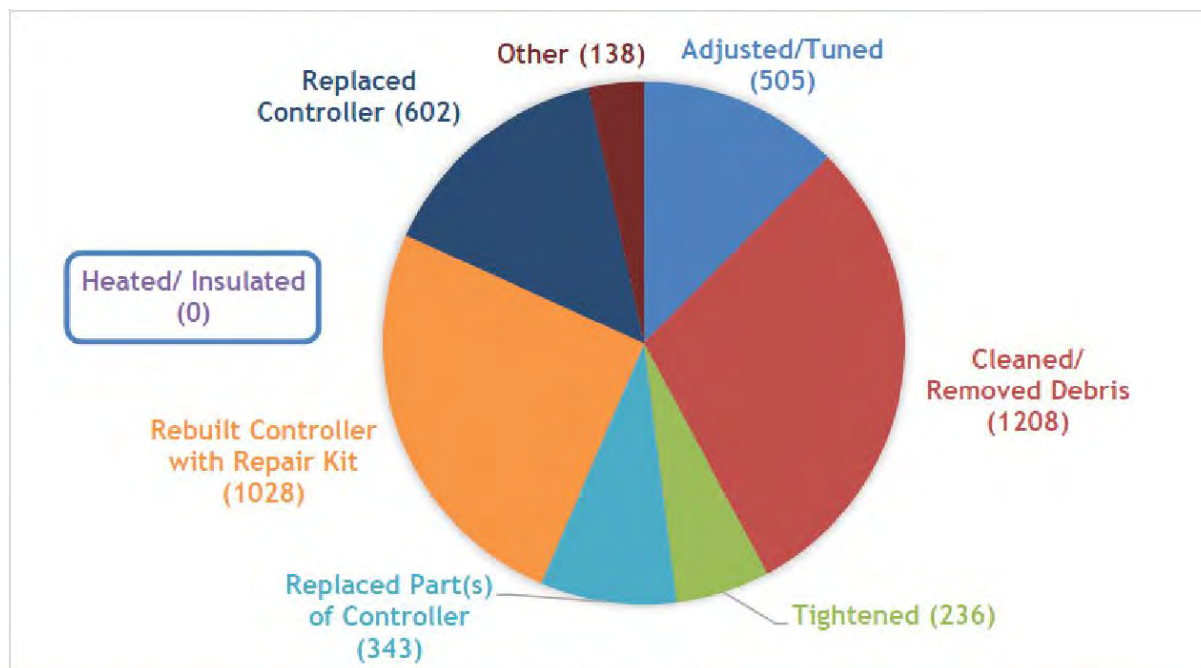


Figure 2: Enhanced response actions taken to return pneumatic controllers to proper operation, by enhanced response action category

Although not specific to natural gas-fired PCs, the Division's 2018 LDAR Annual Report on p.4 indicated that the use of an OGI camera was more effective than AVO observations during facility inspections for emission leaks from components. On page 4, the report states:

"Based on the data reported by owners/operators, more than 90% of leaks were identified through AIMM inspections despite AIMM inspections constituting only 3% of the total number of inspections at WPFs. While AVO inspections are valuable for operations and maintenance purposes, as well as being required by other sections of Regulation No. 7, the data from this year's LDAR annual reporting indicate that AIMM is a more effective monitoring method than AVO for detecting leaks."

Given the results from the 2018 PCTF field inspections, and the 2018 LDAR program and PC find and fix results, the PCTF believes the use of AIMM inspections using an OGI camera is an effective means for identifying both those emissions from PCs that indicate improper operation and from leaky LDAR components.

7.2 Definition Appropriateness

As discussed previously, due to the need to focus on regulatory proposals for consideration during the AQCC December 2019 rulemaking hearing, the PCTF did not complete its evaluation of the appropriateness of the current Reg 7 definitions related to PCs. However, revisions to these definitions will be included in the regulatory proposal specific to the use of no-bleed PCs (aka zero-bleed PCs). Currently, industry is developing a proposal that may be further modified through a future stakeholder and rulemaking process.

Stakeholder meetings will be scheduled and facilitated by the Division staff to review and solicit comments on the no-bleed PC regulatory proposal, which will include the need to make

appropriate revisions to PC-related definitions. As such, for the purposes of completing this report, the PCTF does not recommend making any changes at this time to the definitions for “enhanced response”, “intermittent pneumatic controller”, “no-bleed pneumatic controller”, “self-contained pneumatic controller”, or “pneumatic controller”. Changes to these definitions will be considered separate from this report in vetting the regulatory proposal with stakeholders.

7.3 No-bleed and Self-contained PCs

As defined by Regulation 7 Part D Section III., a no-bleed PC is “any pneumatic controller that is not using hydrocarbon gas as the valve’s actuating gas.” Alternative actuating gases include compressor air or nitrogen, but in practice such PCs in Colorado are mainly compressed air, also known as instrument air. Instrument air systems utilize a skid-mounted compressor and often come with a dryer system to remove moisture from the air prior to compression. Once compressed, the air is routed through the same supply gas system that would otherwise contain pressurized natural gas to actuate the PCs.

As defined in Regulation 7 Part D Section III., a self-contained PC is “a pneumatic controller that releases gas to a process or sales line instead of to the atmosphere.” Such PCs utilize natural gas as the actuating gas, but have minimal emissions to atmosphere because the vent port of the controller is routed back to a process line. Likewise, although not addressed in the current Regulation 7 rule language, emissions from the vent port of the PC can be routed to a control device in some limited applications. As previously mentioned and further discussed below, the use of self-contained PCs is very limited due to technical infeasibility, safety concerns, and cost.

Additionally, mechanical or electric controllers (non-pneumatic) can be used in some very limited applications as described below. These controllers are neither no-bleed or self-contained as defined by Regulation 7 and because they have no emissions, are not subject to the regulatory requirements. However, the PCTF included these controllers in the operator survey so they are also addressed below.

BCPH, DDPHE, and CC4CA Position:

SB181 directed the AQCC to consider a requirement to reduce emissions from pneumatic devices and in 2019 the AQCC directed the PCTF to develop recommendations on the use of zero-bleed pneumatic devices for rulemaking in 2020. Because the PCTF was unable to reach consensus on a recommendation, we believe the AQCC should direct the Division to continue its research and develop a proposal for the planned December 2020 rulemaking. Specifically, the Division should continue to research and put forth recommendations based on the information provided below by Earthjustice and CATF. No-bleed and self-contained PCs are a proven technology that should be implemented in Colorado. Furthermore, the successful implementation of solar-powered PCs in Canada points to the need for serious consideration of this technology in Colorado.

7.3.1 Current applications

As discussed above in Section 5.3, most of the no-bleed PCs in use in Colorado are in the DJ basin NAA and at newer multi-horizontal well pad facilities producing significant volumes of oil and gas. The PC field study also demonstrates that the majority of compressor stations in the NAA are currently operating or under construction to operate on instrument air.

Industry Position:

No-bleed controllers can generally be utilized on any piece of equipment that utilizes a natural gas actuated PC, but as detailed below, technical feasibility, safety concerns, other regulatory requirements, contractual obligations, and cost can all limit the ability of an owner or operator to utilize no-bleed PCs on some or all pieces of equipment at a facility.

Solar-powered PCs have recently been utilized in Alberta, Canada under specific operating conditions for where they are included in the design for a separator equipment package. However, industry believes that the array of solar batteries and battery storage has not yet been fully demonstrated to be sufficient and reliable for the power demands of well pads with multiple horizontal wells that produce significant volumes of oil and gas. As technology advances and costs decrease, the use of solar panels and battery storage to provide electrical power at large oil and gas production facilities may become feasible.

Industry is currently working on a regulatory proposal regarding the use of no-bleed PCs to be considered for a future AQCC rulemaking. This regulatory proposal will build on the work developed for a no-bleed PC emission mitigation strategy proposed under the SHER stakeholder process.

CATF/EJ Position:

Regulations currently in force in Alberta and British Columbia (BC) will significantly limit the use of venting gas-driven PCs moving forward. In BC, new facilities cannot use venting gas-driven PCs after January 1, 2021. Large compressor stations will require retrofit of all venting gas-driven PCs by January 1, 2022.¹¹ In Alberta, no new gas-driven venting PCs can be installed after January 1, 2022 (this regulation was very recently tightened – previously operators were to be allowed to use gas-driven venting controllers for up to 10% of new controllers after January 1, 2022).¹² Both provinces also will subject existing PCs, including intermittent PCs, to various emission limits.

Solar-powered PCs have been utilized for a number of years in Alberta where they are included in the design for separator equipment packages from certain manufacturers. Other operators have utilized similar solar-powered systems in custom configurations (for example to provide more electrical power and storage than is available in standard packages). Solar systems are used on both low-production wellsites and modern, high-production tight/shale wells.

This technology has proven reliable in Alberta north of 55°N latitude, where sunlight on a clear winter day is far weaker than in Colorado, snowfall is higher, winter cloud cover is much more common, and winter temperatures are much lower (affecting battery capacity). In short, CATF and EJ believe that there is no reason that this technology cannot succeed in Colorado.

¹¹ See BC Regulation 282/2010, §52.05.

http://www.bclaws.ca/civix/document/id/regulationbulletin/regulationbulletin/Reg286_2018

¹² See Alberta Energy Regulator (2020), “Directive 060 - Upstream Petroleum Industry Flaring, Incinerating, and Venting,” §8.6.1. https://www.aer.ca/documents/directives/Directive060_2020.pdf

As noted above, there are also air compression systems designed for solar-powered sites on the market.

7.3.2 Effectiveness of devices

Industry Position:

Industry believes that the effectiveness of a no-bleed or self-contained PC is highly dependent on the application of the controller. The scope of the PCTF study did not evaluate the effectiveness of no-bleed PCs so no conclusions can be offered in this report. The consideration of the use of no-bleed PCs is being addressed under a SHER work group regulatory proposal as directed by SB 19-181.

CATF/EJ Position:

CATF and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers;¹³ this approach will be one of the key technologies allowing operators in Alberta and BC to comply with the provincial rules mentioned above.

7.3.3 Costs for new and retrofit facilities

Industry Position:

Based on operator survey results, the cost of instrument air systems (no-bleed pneumatic controllers) is highly variable and significantly higher for retrofits versus new installations.

The cost of self-contained PCs was not able to be ascertained through this study. However, industry has estimated that the cost to design the large and intricate vapor recovery system to capture these small emissions is significant and not cost-effective in most cases.

Likewise, industry estimates that the cost of routing controllers to a combustion device is prohibitively expensive unless the controller is located in close proximity to the control device (e.g. on the inlet to the control device itself).

Mechanical controllers, which can only be used for liquid level control in specific applications, were reported to have low capital costs, but higher maintenance costs than PCs based on operator survey results. Electric controllers were reported to cost significantly more, and also have higher maintenance costs, than PCs.

CATF/EJ Position:

The Conservation Groups' pneumatics proposal from the 2017 oil and gas rulemaking (which was also included as a SHER team proposal) was supported by an Economic Impact Assessment (EIA) documenting the cost-effectiveness of using zero-emitting approaches instead of gas-driven venting controllers. All cost calculations included in the Conservation Group's 2017 EIA include full costs for solar-powered electric systems, including: solar panels, batteries, and control panels and electronics; over-

¹³ See Carbon Limits (2016), *Zero emission technologies for pneumatic controllers in the USA: Applicability and cost effectiveness*. <https://www.catf.us/wp-content/uploads/2019/09/CL2016-ZeroEmitting-Pneumatics-Alts-1Aug2016.pdf>

capacity for solar panels and batteries to ensure power will be available during (for example) extended cloudy periods in winter; electric actuators; installation; and maintenance. Operators report lower maintenance costs with electric systems than gas-driven systems when only wet gas is available to operate PCs, due to deleterious effects of wet gas on some PC components.¹⁴

In the 2017 rulemaking and as part of the SHER team, the Conservation Groups made available spreadsheets listing parameters for calculating cost-effectiveness, such as cost estimates for various components and labor, and engineering design assumptions such as the appropriate oversizing of solar panels and maximum allowable discharge from batteries.

7.3.4 Limitations and Barriers to expanded use

Industry Position:

In addition to cost, industry believes that there are technical, safety, regulatory, and land/leasehold concerns that limit the use of no-bleed and self-contained pneumatic controllers.

In terms of instrument air systems, operators must have sufficient grid or other power to run the instrument air skid and associated equipment. Further, some facilities will not have sufficient area at the facility to install the instrument air skid and associated infrastructure or may have landowner or regulatory restrictions on the grid power right of way or installation of additional equipment at the facility. Additionally, even where some controllers can be converted to instrument air there may be some processes that need to be controlled with natural gas-driven PCs for safety or technical reasons.

The biggest limitations to utilizing self-contained PCs or routing the vent port of the controller to a control device, aside from cost, are related to pressures. If there is not a process that is operating at a relatively low pressure then the pressure released from the vent port will not be sufficient to push the gas into the process line, potentially creating a safety hazard if a safety valve is not able to actuate against the process pressure. Additionally, beyond the cost of the amount of tubing that is required the route emissions from controllers that are located throughout a facility to a process line or control device, the longer that tubing is the more pressure differential (higher than the process or control device backpressure) is required to overcome the backpressure created by the tubing itself.

As mentioned previously, industry claims that mechanical and electric controllers can only be used to control liquid level and can only be used in certain applications (such as liquid level control). Additionally, mechanical controllers have been shown to be less accurate than PCs and electric controllers cannot typically be located on compressors due to vibration and require more technical knowledge to ensure safe application.

CATF/EJ Position:

¹⁴ See Carbon Limits (2016) at p. 15.

As noted above, air compressors designed for solar-powered sites are on the market, as are packages systems that provide compressed air using hybrid electrical systems utilizing solar and batteries for the majority of the power they consume, with a gas-fired generator available as backup for the solar generation and battery. CATF and EJ believe that previous work has documented the general applicability and reliability of solar-powered electric controllers.¹⁵

7.3.5 Opportunities for expanded use

Industry Position:

Given the current state of technology, the use of electric and mechanical controllers is limited due to the limitation outlined in the section above. Industry believes that electric and mechanical controllers have very limited applications and cannot be used in the place of all traditional PCs at a facility. While there are extensive barriers that exist for retro-fitting existing facilities with instrument air, opportunity exists to expand the use of instrument air at new larger horizontal facilities that have sufficient grid power. Many of the land use and spacing limitations can be avoided if these systems are included during the planning phase. Additionally, there is a lower cost associated with installing a new system compared to retrofitting a location.

The ability to be able to plan for and allow utilities to commit to providing access to electrical grid power with sufficient power in advance of constructing new oil and gas production facilities represents a significant opportunity to expand the use of no-bleed PCs.

CATF/EJ Position:

CATF and EJ believe that zero-emitting technology can cost-effectively reduce emissions in Colorado at both new and existing sites. The CATF and EJ recommend that the AQCC consider requiring operators to utilize zero emitting pneumatic controllers statewide at all natural gas compressor stations and all well production facilities with four or more wells producing hydrocarbons so long as it is technically feasible to do so. CATF and EJ have previously offered this proposal in the 2017 oil and gas rulemaking and through the SHER team process. CATF and EJ believe that it is supported by the EIA and supporting spreadsheets, as well as the documented use of zero-emitting technology in Canada and the fact that venting PCs are being phased out for new facilities in British Columbia and Alberta.

8 Acknowledgments

The Division would like to thank all of the members of the PCTF for all of their time and hard work over the last two and a half years. The input from all stakeholders was vital to develop and implement what was the largest study of PCs to date. The information contained in this report is the culmination of thousands of hours of effort. The Division would also like to recognize the high level of engagement, collaboration, and resource expenditure from the industry members on the PCTF.

¹⁵ Carbon Limits (2016).

ECONOMIC IMPACT ANALYSIS (Final Analysis)

Item Title: Regulation Number 7

Meeting Date: December 17-19, 2019

ISSUE

The Air Pollution Control Division (Division) is proposing revisions to the Air Quality Control Commission (AQCC)'s Regulation Number 7 to address Senate Bill 19-181, as well as ozone, streamlining and updating the regulation, and making any necessary typographical, grammatical, and formatting corrections. The Division proposes to include several revisions in Colorado's State Implementation Plan (SIP) as streamlining, clarifications, SIP strengthening, and concerning reasonably available control technology (RACT) provisions for major sources of volatile organic compounds (VOC) and/or nitrogen oxides (NOx).

Two elements of this proposal include recommendations from the Statewide Hydrocarbon Emissions Reduction (SHER) team, formed in response to the Air Quality Control Commission's November 2017 directive to form a stakeholder process to make recommendations on state-wide hydrocarbon emissions reduction strategies for the oil and gas sector. Notably, these SHER team recommendations on addressing emissions from pneumatic controllers and the transmission segment are being made in advance of the January 2020 timeline.

Senate Bill 19-181: Minimizing emissions from the oil and gas sector

During the 2019 legislative session, Colorado's General Assembly adopted revisions to several Colorado Revised Statutes in Senate Bill 19-181 (SB 19-181) (Concerning additional public welfare protections regarding the conduct of oil and gas operations) that include directives for both the Oil and Gas Conservation Commission and the AQCC. This proposed rulemaking focuses on the AQCC directives in § 25-7-109, Colorado Revised Statutes (CRS), which bolster the AQCC's existing authority to "minimize emissions of methane and other hydrocarbons, volatile organic compounds, and oxides of nitrogen" from all the "natural gas supply chain." Further, SB 19-181 identifies specific provisions the AQCC should consider including semi-annual leak detection and repair inspection requirements at well production facilities, transmission pipeline and compressor station inspection requirements, continuous methane emission monitoring requirements, and pneumatic device requirements. This proposed rulemaking addresses many of the specific provisions for consideration, though not continuous methane monitoring, and is expected to

be the first of several rulemakings brought before the AQCC to implement SB 19-181.

Therefore, the Division requests that the AQCC consider proposed revisions to Regulation Number 7 to further minimize emissions from the oil and gas sector. The Division proposes to increase certain leak detection and repair (LDAR) inspection frequencies, expand inspection requirements for pneumatic controllers, revise the thresholds at which a storage tank is subject to control, expand the well emissions best management practices (BMP) requirements, require new storage tanks to use an automatic tank gauging system, require the control of emissions from storage tank unloading, and establish a performance based emission reduction program for the downstream transmission segment. The Division is also proposing annual emissions inventory and reporting requirements for the oil and gas sector.

Ozone reclassification

On May 4, 2016, the U.S. Environmental Protection Agency (EPA) published a final rule that determined that Colorado's Marginal ozone nonattainment area failed to attain the 2008 8-hour Ozone National Ambient Air Quality Standard (NAAQS) of 75 parts per billion (ppb). EPA, therefore, reclassified the Denver Metro North Front Range (DMNFR) to Moderate and required attainment of the NAAQS no later than July 20, 2018. On August 15, 2019, EPA proposed to reclassify the DMNFR to Serious, after 2015-2017 ozone data failed to show attainment, requiring attainment of the 2008 ozone NAAQS no later than July 20, 2021.

Separately, EPA has also designated the DMNFR as Marginal nonattainment for the 2015 ozone NAAQS of 70 ppb, with an attainment date of August 3, 2021.

Colorado must act aggressively to attain both of these standards and submit the necessary revisions to its SIP to address both the Clean Air Act's (CAA) more rigorous Serious ozone nonattainment area requirements, as set forth in CAA §§ 172 and 182(c) and the final SIP Requirements Rule for the 2008 Ozone NAAQS (See 80 Fed. Reg. 12264 (March 6, 2015)). A serious SIP revision must include Reasonably Available Control Technology (RACT) requirements for major sources of VOC and/or NO_x (i.e., sources that emit or have the potential to emit 50 tons per year (tpy) or more) and for each category of VOC sources covered by a Control Technique Guideline (CTG) for which Colorado has sources in the DMNFR.

To address the CAA RACT SIP requirements for Serious nonattainment areas, the Division requests that the AQCC consider proposed revisions to Regulation Number 7 to include RACT requirements in Colorado's ozone SIP for 50 tpy major sources of VOC and/or NO_x including expanding the combustion equipment requirements currently applicable to major sources over 100 tpy

VOC and/or NOx, incorporating specific New Source Performance Standards (NSPS) or National Emission Standards for Hazardous Air Pollutant (NESHAP) requirements, a categorical rule concerning general solvent use, and adopting a requirement that specific sources submit RACT analyses to the Division.

Other revisions

In an effort to improve the organization and thus usability of Regulation Number 7, the Division is proposing to reorganize Regulation Number 7 into five parts. The Division has provided a crosswalk, attached to this proposal packet, to assist in understanding the reorganization.

As a SIP clean-up effort, the Division requests that the AQCC consider proposed revisions to Regulation Number 7, Part B, Sections IV. and VII. and Appendix E to update the gasoline transport truck testing and associated recordkeeping requirements and update and clarify the vapor system requirements.

The Division also proposes clean-up corrections to the requirements for major source combustion equipment adopted in July 2018.

The Division may also make typographical, grammatical, and formatting corrections throughout Regulation Number 7.

The proposed revisions to Regulation Number 7 are SIP revisions, with the exception of revisions to State Only requirements in Part D, Sections II. and III.

REQUIREMENTS FOR ECONOMIC IMPACT ANALYSIS (EIA)

Section 25-7-110.5(4)(a), C.R.S. sets forth the requirements for the initial and final Economic Impact Analysis, as stated below:

Before any permanent rule is proposed pursuant to this section, an initial economic impact analysis shall be conducted in compliance with this subsection (4) of the proposed rule or alternative proposed rules. Such economic impact analysis shall be in writing, developed by the proponent, or the Division in cooperation with the proponent and made available to the public at the time any request for hearing on a proposed rule is heard by the commission. A final economic impact analysis shall be in writing and delivered to the technical secretary and to all parties of record five working days prior to the prehearing conference. If no prehearing conference is scheduled, the economic impact analysis shall be submitted at least ten working days before the date of the rule-making hearing. The proponent of an alternative proposal will provide, in conjunction with the Division, a final economic impact analysis five working days prior to the prehearing conference. The economic impact analyses shall be based upon reasonably available data. Except where

data is not reasonably available, or as otherwise provided in this section, the failure to provide an economic impact analysis of any noticed proposed rule or any alternative proposed rule will preclude such proposed rule or alternative proposed rule from being considered by the Commission. Nothing in this section shall be construed to restrict the Commission's authority to consider alternative proposals and alternative economic impact analyses that have not been submitted prior to the prehearing conference for good cause and so long as parties have adequate time to review them.

Per Section 25-7-110.5(2), CRS, the requirements of Section 25-7-110.5(4) shall not apply to rules which: (1) adopt by reference applicable federal rules; (2) adopt rules to implement prescriptive state statutory requirements where the AQCC is allowed no significant policy-making options; or, (3) adopt rules that have no regulatory impact on any person, facility or activity.

Section 25-7-110.5(4)(c), C.R.S. further provides that:

The proponent and the division shall select one or more of the following economic impact analyses. The commission may ask affected industry to submit information with regard to the cost of compliance with the proposed rule, and, if it is not provided, it shall not be considered reasonably available. The economic impact analysis required by this subsection (4) shall be based upon reasonably available data...

For the purposes of this Initial Economic Analysis the Division has chosen to use the methodology set forth in § 25-7-110.5(4)(c)(I), CRS.

COST-EFFECTIVENESS ANALYSIS

The Division's assessment of the costs and benefits for each of the proposed strategies is set forth below. For each strategy, these assessments identify the cumulative costs for the affected industry, the estimated air pollution reduction, and the projected cost per unit of air pollution reduced. The Division also assessed whether any of the proposed strategies would impose a direct cost on the general public to comply, and determined that based on the available data there will be no direct costs on the general public for any of the proposed requirements. Finally, the Division considered whether there would be any additional costs for the Division to implement the proposed requirements beyond current expenditures and determined that the proposed revisions could be implemented using existing resources.

I. Controls for Petroleum Storage Tanks

Colorado has adopted numerous control requirements to reduce emissions from storage tanks at oil and gas exploration and production and other facilities. The

Division is proposing several new regulatory provisions aimed at reducing VOC, methane, and other hydrocarbon emissions from this category of sources. For the purposes of this analysis the Division assumes that operators will use enclosed flares to control emissions from storage tanks.

A. General Cost Estimates for Flares

In Table 1, the Division has estimated the annualized cost of an enclosed flare, ancillary equipment, pilot fuel, installation along with operation and maintenance based on identified costs from a 2008 oil and gas cost study¹ adjusted for inflation². Based on this information, the estimated annualized cost of a flare control device with auto-igniter³ is about \$6,488.

Table 1: Flare Control Device with Auto Igniter - Annualized Cost Analysis*				
Item	Capital Costs (one time)	Non-Recurring Costs (one time)	O&M Costs (recurring)	Annualized Total Costs
Flare	\$19,245			
Freight/Engineering		\$1,745		
Flare Installation		\$7,393		
Auto Igniter	\$1,745			
Pilot Fuel**			\$642	
Maintenance			\$2,327	
Subtotal Costs	\$20,990	\$9,138	\$2,969	
Annualized Costs***	\$2,909	\$609	\$2,969	\$6,487.7

* All the flare control device costs were escalated by 16.35% to reflect CPI-U increases that have occurred since the 2008 rulemaking.

** Pilot fuel costs based on \$2.85/MMBtu (Henry Hub Spot Price average January - April 2019)

*** Annualized costs are over a 15 year period assuming a 5% rate of return

B. Replace the 90%/70% system-wide condensate storage tank control program in the DMNFR with a discrete threshold-based control requirement for storage tanks ≥ 2 tons per year (tpy) of uncontrolled actual VOC emissions.

Despite significant population growth and increased economic activity, the DMNFR region has seen gradual improvement in ozone levels over the past 20

¹ See "Oil & Gas Emissions Reduction Strategies Cost Analysis and Control Efficiency Determination," Lesair Environmental, Inc., June 2008. Information from this study was previously submitted to the AQCC as part of the 2008 Ozone Action Plan process.

² Inflation adjustment over the period 2008-2018 was estimated at 16.35 % using US Department of Labor CPI-U annual data.

³ Currently all flares in the state are required to have auto-igniters.

years, largely from significant reductions in ozone precursor emissions. However, ozone levels remain above the 2008 and 2015 National Ambient Air Quality Standards (NAAQS) and the DMNFR is facing a pending reclassification to a “Serious” nonattainment area for the 2008 standard. Despite significant decreases in emissions since 2004, presently, condensate tanks remain the largest single source of VOC emissions in the DMNFR. Given the region’s ozone problems, and the administrative complexity of the current regulatory program, the Division proposes to transition from the current system-wide approach of controlling VOC emissions to a more stringent control program requiring control of all storage tanks with uncontrolled actual emissions of greater than or equal to 2 tpy.

Presently, Colorado’s ozone SIP specifies in Section XII.D.2 of Regulation Number 7 that owners and operators of all condensate tanks emitting ≥ 2 tpy meet a 90% system-wide control requirement on a weekly basis during the summer ozone season May 1st through September 30th. During the remainder of the year, operators must meet a 70% control requirement. The regulation provides exemptions from the system-wide control program to small operators with total company-wide emissions under 30 tpy. Operators are required to submit semi-annual reports to the Division detailing the number of tanks, condensate production, the presence of a control device on the individual tank (or tank battery), and the operational status. While many of the condensate tanks in the DMNFR are already controlled pursuant to the existing system-wide control program and a state-wide program requiring controls on storage tanks with uncontrolled actual emissions greater than or equal to 6 tpy, the transition to a 2 tpy tank control threshold will require operators to install additional controls.

1. Condensate Tank Count

All non-exempt operators in the DMNFR are required to submit system-wide control reports to the Division semi-annually. Based on operator reported data for 2017, Table 2 shows there are 5,028 condensate tank batteries⁴ in the DMNFR that are subject to Regulation 7 system-wide requirements. At the proposed tank control threshold of ≥ 2 tpy, there are 65 condensate tanks that do not have emission controls.

Table 2: Condensate Tank Count Based on Reg. 7 System-wide Control Reports			
Tank Battery Size*	Count of NAA Tanks	Count of NAA Tanks w/Controls**	Count of NAA Tanks w/out Controls
≥ 4 tpy	1,812	1,803	9

⁴ In the DMNFR, owners and operators of condensate tanks with total actual uncontrolled VOC emissions less than 30 tpy are exempt from system-wide control requirements and therefore are excluded from the above listed total. Analysis of these currently exempt tanks is addressed below.

≥ 3 tpy to < 4 tpy	285	265	20
≥ 2 tpy to < 3 tpy	409	373	36
Subtotal	2,506	2,441	65

≥ 1 tpy to < 2 tpy	703	571	132
≥ 0 tpy to < 1 tpy	1,219	959	260
= 0 tpy	600	-	-
Subtotal	2,522	1,530	392

Grand Total	5,028	3,971	457

* Tank battery size is based on annual reported uncontrolled VOC emissions

** Tanks with zero emissions do not report whether facility has flare controls.

2. Emission Reductions From Controlling DMNFR Condensate Tank ≥ 2 TPY

Using the Regulation Number 7 system-wide reports for 2017, there are a potential 65 condensate storage tanks without emission controls at the proposed ≥ 2 tpy storage tank control threshold in the DMNFR. The Division assumes that 100 percent of the flash gas in the storage tank is captured and routed to a control device through the implementation of Storage Tank Emissions Management (STEM) system requirements.⁵ As reflected in Table 3, controlling emissions from these tanks will reduce VOC emissions by 188.93 tpy using an assumed 95 percent control device effectiveness⁶.

Table 3: Condensate Tank Emission Reductions			
Tank Battery Size	Count of NAA Tanks w/Controls	Count of NAA Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 4 tpy	1,803	9	40.78
≥ 3 tpy to < 4 tpy	265	20	66.00
≥ 2 tpy to < 3 tpy	373	36	82.15
Total	2,441	65	188.93

3. Cost Effectiveness

Table 4 provides the annualized cumulative cost of installing 65 flare control devices is about \$421,700 dollars with an average cost effectiveness of about \$2,232 per ton of VOC reduced. For the smallest category of tanks (2-3 tpy) the

⁵ See Regulation Number 7, Section XVII.C.2 "Capture and monitoring requirements for storage tanks that are fitted with air pollution control equipment as required by Sections XII.D. or XVII.C.1."

⁶ Generally flares can achieve a destruction efficiency of 98 percent, but the Division assumes 95 percent control to account for some downtime.

incremental cost of controls on 36 tanks is estimated at \$2,843 per ton of VOC reduced.

Table 4: Incremental Control Cost Estimates for Flare Control Devices on Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost ⁷	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs (\$/ton)
≥ 4 tpy	9	\$6,487.7	\$58,389	40.78	\$1,432
≥ 3 tpy to < 4 tpy	20	\$6,487.7	\$129,754	66.00	\$1,966
≥ 2 tpy to < 3 tpy	36	\$6,487.7	\$233,557	82.15	\$2,843
All tanks	65	\$6,487.7	\$421,700	188.93	\$2,232

In order to preserve flexibility in controlling smaller storage tanks that may have very low VOC concentrations that potentially may not be controlled if supplemental firing of natural gas is necessary to control emissions, the Division is proposing to establish in the SIP a control requirement for storage tanks ≥ 4 tpy. At the ≥ 4 tpy threshold, 91.5% control is achieved, thus no SIP backsliding occurs because VOC emission reductions exceed the required 90% system-wide control requirement by 1.5%. The control requirement for storage tanks ≥ 2 tpy but < 4 tpy are proposed as “state-only”.

C. Remove the Part E, Section I.A.7 exemption (associated with the system-wide control program) for owners or operators of condensate tanks with total actual uncontrolled VOC emissions less than 30 tpy.

Regulation Number 7 provides for an exemption from the system-wide control requirement for small condensate tank operators with total VOC emissions less than 30 tpy. Since these operators are exempt from system-wide reporting and Air Pollutant Emissions Notice (APEN) reporting is infrequent, it is difficult to ascertain how many tanks are using the exemption. Based on 2019 COGCC data, there are 67 operators reporting tank operations in Weld County. If the operators reporting to system-wide in Weld County are removed, there are about 46 operators reporting oil production that may have condensate tanks above the proposed 2 tpy VOC emission control threshold that would lose the 30 tpy exemption from control. The 46 operators also include 17 operators that report zero oil production for the first six months of 2019, but who could presumably produce condensate at some point in the future.

The Division assumes that any condensate tanks previously exempted from control would fall into an uncontrolled VOC tank size range between ≥ 2 to < 6

⁷ See Table 1 for estimated annualized cost of flare controls.

tpy because all storage tanks statewide must be controlled if the emissions ≥ 6 tpy. The estimated number of condensate tanks potentially impacted by the proposed ≥ 2 tpy threshold control requirement could be as high as 690 tanks assuming all 46 operators were just below the 30 tpy exemption threshold and all had 15 tanks equal to the 2 tpy threshold. A lower number of tanks potentially impacted by the proposed ≥ 2 tpy threshold control requirement is about 230 tanks assuming all 46 operators were just below the 30 tpy exemption threshold and all had 5 tanks just below the 6 tpy threshold. It is more likely that most operators have a few tanks and some will have no tanks above the ≥ 2 tpy threshold. If the Division assumes that all 46 operators have at least three tanks ≥ 2 tpy, the number of tanks subject to control is estimated at 138 tanks. Operators with condensate tanks below the 2 tpy threshold would not incur any additional control costs.

Although the Division is currently unable to establish the exact number of condensate tanks impacted by the proposal to remove the 30 tpy exemption for condensate tanks, the control costs should be similar to the incremental control cost estimates presented in Table 4. The Division has previously requested more information from operators impacted by the removal of the 30 tpy condensate tank exemption but has yet to receive any such information.

D. Require controls on crude oil and produced water tanks in the DMNFR with uncontrolled actual emissions of 2 tpy VOC or greater.

Currently, in Part D, Section I (formerly Section XII) of Regulation Number 7 only condensate tanks ≥ 2 tpy are subject to the system-wide emission control requirement. Other storage tanks (crude oil and produced water) are subject to controls in Part D, Section II (formerly Section XVII) of Regulation Number 7, and then only if the uncontrolled actual VOC emissions ≥ 6 tpy. Consequently, there are a number of crude oil and produced water tanks over the proposed ≥ 2 tpy threshold that are not currently required by Regulation Number 7 to have controls in the DMNFR.

Based on most recently available Regulation Number 7 APEN reported data (for 2018) on crude oil and produced water tanks, Table 5 shows there are 605 crude oil and water tank batteries⁸ in the DMNFR. At the proposed storage tank control threshold of ≥ 2 tpy, there are 175 tanks that are reported as not having emission controls that will need to install controls.

Table 5: DMNFR Crude Oil & Produced Water Tank Battery Analysis (2018 APEN Data)

Tank Battery Size*	Count of NAA Tanks	Count of NAA Tanks w/Controls**	Count of NAA Tanks w/out Controls

⁸ Crude oil and water tanks are determined by screening by respective source classification codes 404003012 and 4040003015.

≥ 4 tpy	417	371	46
≥ 3 tpy to < 4 tpy	58	25	33
≥ 2 tpy to < 3 tpy	130	34	96
Total	605	430	175

* Tank battery size is based on annual reported uncontrolled VOC emissions

** Tanks with zero emissions do not report whether facility has flare controls.

Table 6 shows the estimated 611.4 tpy VOC emission reduction associated with the proposed control requirements on 175 crude oil and produced water tanks ≥ 2 tpy in the DMNFR.

Table 6: DMNFR Emission Reductions from Crude Oil & Produced Water Tank Controls			
Tank Battery Size	Count of NAA Tanks w/Controls	Count of NAA Tanks w/out Controls	VOC Reduction ⁹ from Added Controls (tpy)
≥ 4 tpy	371	46	269.8
≥ 3 tpy to < 4 tpy	25	33	108.0
≥ 2 tpy to < 3 tpy	34	96	233.6
Total	430	175	611.4

For crude oil and water tanks in the DMNFR, Table 7 provides the estimated annualized cost of installing 175 flare control devices at about \$1.14 million dollars with an average cost effectiveness of about \$1,857 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 96 tanks is estimated at \$2,666 per ton of VOC reduced. Produced water tanks generally have lower hydrocarbon concentrations, which could limit flare control effectiveness and may require supplemental fuel to support effective combustion of the hydrocarbon vapors. The Division requested more information about the level of hydrocarbon concentrations triggering the use of supplemental fuel and quantity of supplemental fuel used but has not yet received such information.

Table 7: DMNFR Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy

⁹ The VOC emission reduction is calculated assuming the use of enclosed flare control operating at 95% control effectiveness.

Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost ¹⁰	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs (\$/ton)
≥ 4 tpy	46	\$6,487.7	\$298,434	269.8	\$1,106
≥ 3 tpy to < 4 tpy	33	\$6,487.7	\$214,094	108.0	\$1,982
≥ 2 tpy to < 3 tpy	96	\$6,487.7	\$622,819	233.6	\$2,666
All tanks	175	\$6,487.7	\$1,135,348	611.4	\$1,857

E. Lower the existing statewide control requirement threshold for condensate, oil and produced water storage tanks from ≥ 6 tpy to ≥ 2 tpy of uncontrolled actual VOC emissions and increase the approved instrument monitoring method (AIMM) inspection frequency from annual to semi-annual for storage tanks with VOC emissions ≥ 6 to ≤ 12.

Based on APEN reports for the most recent complete data year (2018), the Division evaluated the number of condensate, crude oil, and produced water tanks that may need to install controls for areas outside of the DMNFR (referred to herein as the “remainder of the state (ROS)”) including the areas north and east of the DMNFR. The Division acknowledges that the APEN reporting system allows flexibility in reporting (up to every 5 years), which may produce inaccurate counts for each tank battery size tier, particularly if well production has declined since the most recently filed APEN report has occurred. Accordingly, the actual number of tanks without controls evaluated in this proposal may differ from the APEN reported data. The Division requested more information about the number of statewide uncontrolled storage tanks that may impacted by this rulemaking proposal but has yet to receive such information.

Table 8 shows there are about 588 crude oil and produced water tank batteries¹¹ in the ROS. At the proposed storage tank control threshold of ≥ 2 tpy, there are 202 tanks that are reported as not having emission controls.

Table 8: ROS Crude Oil & Produced Water Tank Battery Analysis (2018 APEN Data)			
Tank Battery Size*	Count of ROS Tanks	Count of ROS Tanks w/Controls**	Count of ROS Tanks w/out Controls
≥ 4 tpy	392	320	72
≥ 3 tpy to < 4 tpy	83	33	50

¹⁰ See Table 1 for estimated annualized cost of flare controls.

¹¹ Crude oil and water tanks are determined by screening by respective source classification codes 404003012 and 404003015.

≥ 2 tpy to < 3 tpy	113	33	80
Total	588	386	202

* Tank battery size is based on annual reported uncontrolled VOC emissions

** Tanks with zero emissions do not report whether facility has flare controls.

Table 9 shows the estimated 866.7 tpy VOC emission reduction associated with the proposed control requirements on the 202 crude oil and produced water tanks ≥ 2 tpy in the ROS.

Table 9: ROS Emission Reductions from Crude Oil & Produced Water Tank Controls				
Tank Battery Size	Count of ROS Tanks w/Controls	VOC Reduction from Existing Controls (tpy)	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)
≥ 4 tpy	320	26,905.3	72	506.2
≥ 3 tpy to < 4 tpy	33	197.7	50	167.4
≥ 2 tpy to < 3 tpy	33	110.5	80	193.1
Total	386	27,092.9	202	866.7

For crude oil and water tanks in the ROS, Table 10 provides the estimated annualized cost of installing 202 flare control devices at about \$1.31 million dollars with an average cost effectiveness of about \$1,512 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 80 tanks is estimated at \$2,688 per ton of VOC reduced.

Produced water tanks generally have lower hydrocarbon concentrations, which could limit flare control effectiveness and may require supplemental fuel to support effective combustion of the hydrocarbon vapors. Generally, the firing of supplemental fuel in a flare control device defeats the fundamental purpose of the control device, which is to reduce emissions and not increase them. Accordingly, the Division is proposing to allow operators to submit a technical demonstration showing that supplemental fuel is necessary for safe and effective combustion of the hydrocarbon vapors in situations where a tank has very low hydrocarbon vapor concentrations. The Division requested more information about the safety associated with combusting very low hydrocarbon vapor streams, the hydrocarbon concentration threshold triggering the use of supplemental fuel and quantity of supplemental fuel necessary for safe and effective combustion but has yet to receive such information.

Table 10: ROS Control Cost Estimates for Crude Oil & Produced Water Tanks ≥ 2 tpy

Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost ¹²	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs (\$/ton)
≥ 4 tpy	72	\$6,487.7	\$467,114	506.2	\$923
≥ 3 tpy to < 4 tpy	50	\$6,487.7	\$324,385	167.4	\$1,938
≥ 2 tpy to < 3 tpy	80	\$6,487.7	\$519,016	193.1	\$2,688
All tanks	202	\$6,487.7	\$1,310,515	866.7	\$1,512

In addition to crude oil and produced water tanks, there are about 874 condensate tank batteries¹³ based on 2018 APEN reported data in the ROS. At the proposed storage tank control threshold of ≥ 2 tpy, Table 11 shows there are about 444 tanks that are reported as not having emission controls.

Table 11: ROS Condensate Tank Battery Analysis (2018 APEN Data)

Tank Battery Size*	Count of ROS Tanks	Count of ROS Tanks w/Controls**	Count of ROS Tanks w/out Controls
≥ 4 tpy	522	369	153
≥ 3 tpy to < 4 tpy	140	24	116
≥ 2 tpy to < 3 tpy	212	37	175
Subtotal	874	430	444

* Tank battery size is based on annual reported uncontrolled VOC emissions

** Tanks with zero emissions do not report whether facility has flare controls.

Table 12 shows the estimated 1,715.2 tpy VOC emission reduction associated with the proposed control requirements on the 444 condensate tanks ≥ 2 tpy in the ROS.

Table 12: ROS Emission Reductions from Condensate Tank Controls

Tank Battery Size	Count of ROS Tanks w/Controls	Count of ROS Tanks w/out Controls	VOC Reduction from Added Controls (tpy)

¹² See Table 1 for estimated annualized cost of flare controls.

¹³ Condensate tanks are determined by screening by source classification code 404003011.

≥ 4 tpy	369	153	929.9
≥ 3 tpy to < 4 tpy	24	116	382.3
≥ 2 tpy to < 3 tpy	37	175	403.1
Total	430	444	1,715.2

For condensate tanks in the ROS, Table 13 provides the estimated annualized cost of installing 444 flare control devices at about \$2.88 million dollars with an average cost effectiveness of about \$1,679 per ton of VOC reduced. For the smallest category of tanks (2-3 tons/year) the incremental cost of controls on 175 tanks is estimated at \$2,817 per ton of VOC reduced.

Table 13: ROS Control Cost Estimates for Condensate Tanks ≥ 2 tpy					
Tank Battery Size	Count of Tanks w/out Controls	Each Flare Annualized Cost ¹⁴	Total Annualized Costs	VOC Reduction (tpy)	Average Control Costs (\$/ton)
≥ 4 tpy	152	\$6,487.7	\$992,618	929.9	\$1,068
≥ 3 tpy to < 4 tpy	116	\$6,487.7	\$752,573	382.3	\$1,969
≥ 2 tpy to < 3 tpy	175	\$6,487.7	\$1,135,348	403.1	\$2,817
All tanks	444	\$6,487.7	\$2,880,539	1,715.2	\$1,679

Storage tanks with emissions ≥ 2 and less than 6 tpy will have to conduct AVO and visual inspections every 7 to 31 days. The Division is also proposing to add to the visual inspection requirements inspections of dump valves and liquid knockout vessels. These proposed requirements are based on the storage tank guidelines developed by the Division and industry, and are generally assumed to be conducted by most operators already.

The Division is also proposing semi-annual AIMM inspections of storage tanks with emissions greater than or equal to 2 and less than 6 and to increase the AIMM inspection frequency from annual to semi-annual for storage tanks with emissions greater than or equal to 6 and less than or equal to 12 tpy. These inspections are intended to align with the leak detection and repair (LDAR) inspections, discussed below.

¹⁴ See Table 1 for estimated annualized cost of flare controls.

II. Leak Detection and Repair (LDAR) for well production facilities and natural gas compressor stations

In 2014, the AQCC adopted LDAR requirements for well production facilities and natural gas compressor stations. Recently adopted Colorado Senate Bill 19-181 requires that the AQCC review its rules for oil and gas well production facilities and compressor stations and specifically consider adopting more stringent provisions including increasing the well production facility LDAR inspection frequency to a minimum of semi-annual. In recognition of SB 19-181, the Division is proposing to increase the frequency of AIMM inspections at well production facilities and compressor stations. In addition to proposing semi-annual LDAR inspections, the Division is proposing to require semi-annual AIMM inspections for storage tanks at these facilities so that the inspection schedules for tanks and components continue to align. Since operators will be conducting LDAR inspections at these facilities, the additional cost of an AIMM inspection on the tanks at that facility should be minimal. Accordingly the Division has not separately assessed the costs of increasing the AIMM inspections for storage tanks

Consistent with the 2014 Oil and Gas Rulemaking¹⁵ the Division is using an identical multi-step process to calculate the estimated costs and benefits associated with the proposed leak detection and repair requirements. First, the Division calculated an hourly inspection rate based on the total annual cost for each inspector divided by an assumed 1,880 annual work hours.¹⁶ To calculate the total annual cost for each inspector, the Division included salary and fringe benefits for each inspector, annualized equipment (including an infrared camera) and vehicle costs, and add-ons to account for supervision, overhead, travel, record keeping, and reporting. Based on the assumptions set forth in the Divisions' 2014 Final Economic Impact Analysis, the total annual cost for each inspector is estimated at \$193,629, which equates to an hourly inspection rate of \$103. The Division adjusted the hourly inspection rate by 5.53% to account for cost increases since 2014. The 2019 "In-house" hourly inspection rate rounded to the nearest dollar is \$109.

Table 14: Leak Detection and Repair (LDAR) Inspector - Annualized Cost Analysis

Item	Capital Costs (one time)	Annual Costs	Annualized Total Costs
FLIR Camera	\$122,000		
FLIR Camera Maintenance/Repair		\$7,500	

¹⁵ See the Colorado Department of Public Health and Environment Air Pollution Control Division Final Economic Impact Analysis for proposed revisions to Colorado Air Quality Control Commission Regulation Number 7 (5 CCR 1001-9), dated January 30, 2014.

¹⁶ This assumes a 40 hour work week with ten holidays, two weeks of vacation, and one week of sick leave.

Photo Ionization Detector	\$5,000		
Vehicle (4x4 Truck)	\$22,000		
Inspection Staff		\$75,000	
Supervision (@ 20%)		\$15,000	
Overhead (@10%)		\$7,500	
Travel (@15%)		\$11,250	
Recordkeeping (@10%)		\$7,500	
Reporting (@10%)		\$7,500	
Fringe (@30%)		\$22,500	
Subtotal Costs	\$149,000	\$153,750	
Annualized Costs*	\$39,879	\$153,750	\$193,629

2014 Annualized "In-house" Hourly Rate \$103

2014 Annualized "Contractor" Hourly Rate** \$134

2019 Annualized "In-house" Hourly Rate*** \$109

2019 Annualized "Contractor" Hourly Rate \$142

* Annualized over 5 year period at 6% rate of return

** Contractor rate 30% higher than In-house rate

*** Adjusted by 5.53% to account for inflation since 2014

In the 2014 Oil and Gas Rulemaking, the Division analyzed both "in-house" and "contractor" options for conducting LDAR inspections. The Division recognizes that in-house inspections would be the lowest cost option for larger operators since it would not involve additional profit to be paid to a contractor. However, for smaller companies that cannot fully utilize an IR camera, conducting inspections in-house may not be the most cost effective option. To account for these differences, the Division assumed a 30% profit margin for contractors, which is added to the calculated hourly rate in instances where it appeared that contractors would be used to conduct the inspection (\$142 per hour). Considering the complex mix of large and small oil and gas operations, impacted by this proposal, including some potentially exempted from previous regulatory requirements in the DMNFR, the Division is using the contractor cost option to simplify the analysis. Despite using the higher hourly cost (\$142), the foregoing analysis shows that the proposed increase in inspection frequency and repair is shown to be cost effective.

Second, the Division calculated the average amount of time that it would take to conduct a Method 21 inspection at compressor stations and well production facilities based on the number of components to be inspected and assuming that a component could be inspected every 30 seconds. The proposed rule also

allows owners and operators to use IR cameras either as the sole inspection tool, or as a screening tool to identify potential leaking components followed by a Method 21 inspection. An IR camera inspection or IR Camera/Method 21 hybrid inspection can be conducted more quickly than a Method 21 inspection of each component. While the Division does not currently have actual data regarding how much faster an inspection could be completed using an IR camera, for the purpose of this analysis the Division assumed that an IR camera based inspection would, on average, take 50% of the time required for a Method 21 inspection.¹⁷ In its role as staff to the AQCC, the Division requests additional information on the time and costs associated with conducting IR camera based inspections.

For compressor stations, the Division used APEN reported component counts for the ≤ 12 tpy inspection tier identified in Table 15. Based on these counts, and the inspection times per component discussed above, the Division calculated the following total inspection time per compressor station facility at the ≤ 12 tpy inspection tier:

Table 15: Calculated Inspection Time Compressor Station Leak Inspections			
Component Leak Uncontrolled Actual VOC Emissions	Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
≤ 12 tpy	Rest of State	23.1 hours	11.6 hours

For well production facilities, the Division has limited APEN data on the number of components per facility. Based on this limitation, the Division did not attempt to calculate a separate inspection time for each of the proposed facility tiers, and instead used the overall average component count. Based on the limited available data, however, there does appear to be a distinction between component numbers at well production facilities in the DMNFR and well production facilities in the ROS. Accordingly, the Division calculated separate inspection times for well production facilities by area as set forth in Table 16.

Table 16: Calculated Inspection Times for Well Production Facility Leak Inspections		
Area	Method 21 Inspection	IR Camera/ Hybrid Inspection
DMNFR	12.2 hours	6.1 hours
Remainder of the State	6.8 hours	3.4 hours

¹⁷ Based on the Division's own IR camera inspections, and reports from various parties during the 2014 stakeholder and prehearing process it appears that the Division's assumption may significantly overstate the actual time needed to conduct an IR camera inspection.

In addition to the travel costs that are built into the hourly inspection rate as set forth in Table 16, the Division also assumed an additional three hours in travel time for each inspection in the ROS. This assumption reflects the fact that certain well sites in basins in the ROS area may be remote, requiring additional travel.

Third, the Division calculated the projected inspection costs for both compressor stations and well production facilities. To make this calculation the Division used industry reported APEN emission data to determine the number of facilities that will be subject to semi-annual inspections to determine the total number of inspections for each tier, and multiplied these inspections by the calculated inspection time and projected hourly inspection rate. For both compressor stations and well production facilities the Division assumed that all inspections would be conducted by 3rd party contractors. Since owners and operators of both compressor stations and well production facilities are already subject to recordkeeping and reporting, the Division believes that any additional recordkeeping and reporting costs will be nominal relative to the overall cost of the LDAR program.

In the assessment of repair costs the Division also estimated product savings from conducting leak detection activities. To calculate repair costs, the Division used EPA information regarding leaking component rates, component repair times, and hourly repair rates. Specifically, the Division assumed a \$74.95 hourly rate¹⁸ to repair components, and an average repair time of between 0.17 hours and 16 hours, depending on the both type of component and the complexity of the repair.¹⁹ To calculate the number of leaking components the Division used industry reported component counts and assumed a 1.48% leaking component rate for facilities subject to semi-annual inspections. To calculate the value of the additional product captured, the Division converted the amount of VOC and methane/ethane reduced to thousand cubic feet ("MCF") of natural gas, with a price of \$2.92/MCF. With respect to re-monitoring, the Division determined that because of the small number of components that will require repair and the fact that re-monitoring can be undertaken at the same time as repair, any additional costs associated with re-monitoring are negligible. The subsequent LDAR cost analysis is based on the above methodology.

Since Colorado's leak detection and repair program has been in place for a number of years, some industry stakeholders have questioned if a lower leak frequency or leaking component rate should be used in the LDAR technical analysis. Presently, the Regulation Number 7 LDAR inspection reports show the number of facilities inspected and number of leaks found, but no information

¹⁸ The \$66.24 hourly rate adjusted by 13.15% to account for inflation since 2009

¹⁹ See "Equipment Leak Emission Reduction and Cost Analysis for Well Pads, Gathering and Boosting Stations, and Transmission and Storage Facilities Using Emission and Cost Data From the Uniform Standards," Bradley Nelson and Heather Brown, April 17, 2012; "Analysis of Emissions Reduction Techniques for Equipment Leaks," Cindy Hancy, December 21, 2011.

on the number of components. One important observation from the Regulation Number 7 LDAR inspection reports is that more site visits results in the identification and repair of more leaks. In light of limited data, the Division used EPA data that indicated an annual leak frequency of 1.18%. Since this Regulation Number 7 proposal involves more inspections (i.e. moving from annual LDAR to semi-annual LDAR), the Division is using a scaled semi-annual leak frequency of 1.48%. In response to questions on whether a lower leak rate should be used, the Division evaluated the effect of a lower leak frequency. If the leak frequency is reduced by half (i.e. 0.74%) the total net LDAR cost decreases because the resulting costs of leak detection stay the same but the costs of leak repair go down because fewer leaks are needing to be repaired.

A. Increase the LDAR inspection frequency at well production facilities: from annual to semi-annual for well production facilities in the DMNFR with VOC emissions ≥ 2 tpy to ≤ 6 tpy; from one-time to semi-annual for well production facilities outside the DMNFR with VOC emissions ≥ 2 tpy to ≤ 6 tpy; and from annual to semi-annual for well production facilities outside the DMNFR with actual VOC emissions > 6 tpy to ≤ 12 tpy.

Under Regulation Number 7, LDAR frequency at well production facilities with storage tanks is based on the uncontrolled actual VOC emissions of the largest emitting storage tank at the facility. To calculate the number of facilities that will be subject to additional LDAR inspections at well production facilities the Division used a combination of Regulation Number 7 system-wide operator reported data and 2018 APEN data for storage tanks. Table 17 lists the number of well production facilities throughout the state and the current inspection frequency along with the proposed changes to the inspection frequency for the various facility tiers.

Table 17: Storage Tank Battery Analysis for LDAR at Well Production Facilities				
Uncontrolled VOC at Storage Tank Battery Tier	O & G Basin*	Current Inspection Frequency	Proposed Changes to Inspection Frequency	Total Number of Facilities
> 0 to < 1 tpy	DMNFR	One-time		1,294
≥ 1 to < 2 tpy	DMNFR	Annual		915
≥ 2 to ≤ 6 tpy	DMNFR	Annual	Semi-annual	1,384
> 6 to ≤ 12 tpy	DMNFR	Semi-annual		718

Subtotal:				4,311
> 0 to < 2 tpy	ROS	One-time		466
≥ 2 to < 6 tpy	ROS	One-time	Semi-annual	809
≥ 6 to < 12 tpy	ROS	Annual	Semi-Annual	193
			Subtotal:	1,468
			Total	5,779

* ROS = Remainder of State

In the DMNFR, Regulation Number 7 requires owners and operators of well production facilities with uncontrolled actual VOC emissions >1 tpy to ≤ 6 tpy to conduct an annual LDAR inspection and those > 6 tpy to ≤ 12 tpy to conduct a semi-annual LDAR inspection. For the ROS, owners and operators of well production facilities with emissions > 2 tpy to < 6 tpy must conduct a one-time LDAR inspection and those ≥ 6 tpy to < 12 tpy must conduct an annual LDAR inspection. The LDAR inspection requirement specifies that owners and operators must conduct periodic inspections using EPA Reference Method 21 or IR camera and repair leaks within a prescribed time frame. In Table 18, the Division estimates the increase in inspection frequency at some well production facilities will result in an additional 3,195 inspections at a cost of about \$2.8 million dollars.

Table 18: Well Production Facility Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin*	Number of Facilities	Change in Annual Inspection Frequency	Total Number of New Inspections	Inspection Time Per Inspection (hours)	Total Annual Inspection Cost
Contractor Inspections at \$142/hour						
> 0 to < 1	DMNFR	1,294	0	0	0	-
≥1 to <2 tpy	DMNFR	915				
≥ 2 to < 6	DMNFR	1,384	1	1,384	6.1	\$1,198,821
≥ 6 to < 12	DMNFR	718	0	0	0	
Subtotal:		4,311		1,384		\$1,198,821

Contractor Inspections at \$142/hour						
> 0 to < 2	ROS	466	0	0	0	-
≥ 2 to < 6	ROS	809	2	1,618	6.4**	\$ 1,470,438
≥ 6 to < 12	ROS	193	1	193	6.4**	\$175,398
Subtotal:		1,468		1,811		\$1,645,836
Total (Contractor Inspections):				3,195		\$2,844,657

* ROS = Remainder of State

** ROS inspection time includes additional 3 hours for travel time

Based on the average leak rate, repair time, and hourly repair rate discussed above, the Division calculated that leak repair costs resulting from the proposed new LDAR inspection frequency will total about \$2.2 million dollars as reflected in Table 19.

Table 19: Well Production Facility Leak Repair Costs				
Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Number of Tanks (Facilities)	Total Leak Repair Time per Facility (hours)	Total Annual Repair Cost
> 0 to < 1	DMNFR	1,294		
≥ 1 to < 2 tpy	DMNFR	915		
≥ 2 to < 6	DMNFR	1,384	14.8	\$1,535,216
≥ 6 to < 12	DMNFR	718		
Subtotal:		4,311		\$1,535,216
> 0 to < 2	ROS	466		
≥ 2 to < 6	ROS	809	9.6	\$582,092
≥ 6 to < 12	ROS	193	9.6	\$138,867
Subtotal:		1,468		\$720,959

		Total:	\$2,256,175

In Table 20, the Division estimates the total value of recovered natural gas from the repair of leaks based on the newly required inspections at about \$676,256 dollars.

Table 20: Well Production Facility Recovered Natural Gas Value from Leak Repairs						
Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Number of Facilities	Total Recovered Natural Gas per facility (tons/year)	Value of Natural Gas (\$/MCF)	Conversion Factor (MCF/ton)	Total Annual Value of Recovered Natural Gas
> 0 to < 1	DMNFR	1,294				
≥1 to <2 tpy	DMNFR	915				
≥ 2 to ≤ 6	DMNFR	1,384	1.16	\$2.92	35.8	\$167,826
> 6 to ≤ 12	DMNFR	718				
Subtotal:		4,311				\$167,826
> 0 to < 2	ROS	466				
≥ 2 to < 6	ROS	809	5.74	\$2.92	35.8	\$485,430
≥ 6 to < 12	ROS	193	1.14	\$2.92	35.8	\$23,000
Subtotal:		1,468				508,430
					Total:	\$676,256

Table 21 summarizes the estimated costs from increasing the frequency of LDAR at well production facilities. The overall cost is estimated at about \$4.4 million dollars.

Table 21: Well Production Facility -Net Leak Inspection and Repair Costs					
Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Total Annual Inspection Cost (Contractor)	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
> 0 to < 1	DMNFR				

Table 21: Well Production Facility -Net Leak Inspection and Repair Costs					
Uncontrolled VOC at Storage Tank Battery Tier (tpy)	O&G Basin	Total Annual Inspection Cost (Contractor)	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≥1 to <2 tpy	DMNFR				
≥ 2 to ≤ 6	DMNFR	\$1,198,821	\$1,535,216	\$167,826	\$2,566,211
> 6 to ≤ 12	DMNFR				
Subtotal:		\$1,198,821	\$1,535,216	\$167,826	\$2,566,211
> 0 to < 2	ROS				
≥ 2 to < 6	ROS	\$1,470,438	\$582,092	\$485,430	\$1,567,100
≥ 6 to < 12	ROS	\$175,398	\$138,867	\$23,000	\$291,265
Subtotal:		\$1,645,836	\$720,959	\$508,430	\$1,858,365
Total:		\$2,844,657	\$2,256,175	\$676,256	\$4,424,576

The estimated emission reductions from increasing the frequency of LDAR at well production facilities is about 2,306 tpy of VOC and 4,164 tpy of methane/ethane.

Table 22: Well Production Facility Leak Inspection Emission Reductions						
Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Facilities	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Fugitive VOC Emissions Reduction for each facility (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each facility (tpy)	Total Methane-Ethane Reduction (tpy)
DMNFR						
> 0 to < 1	1,294					
≥1 to <2 tpy	915					
≥ 2 to < 6	1,384	10%	0.46	636.6	0.70	968.8
≥ 6 to < 12	717					

Subtotal:		4,311	636.6			968.8
ROS						
> 0 to < 2	466					
≥ 2 to < 6	809	50%	1.97	1,593.7	3.77	3,049.9
≥ 6 to < 12	193	10%	0.39	75.3	0.75	144.8
Subtotal:		1,468	1,669.0			3,194.7
			Total:		2,305.6	4,163.5

Based on these reductions, Table 23 summarizes the cost effectiveness of conducting ongoing instrument based inspections at well production facilities to be about \$1,919/ton VOC and \$1,063/ton methane/ethane.

Table 23: Well Production Facility Leak Cost-Effectiveness Using IR Camera/Method 21

Uncontrolled VOC at Tank Battery Tier (tpy)	Number of Tanks	Total Net Annual Leak Inspection & Repair Cost	Incremental LDAR Program Reduction % (one-time or annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost (\$/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost (\$/ton)
DMNFR							
> 0 to < 1	1,294						
≥ 1 to < 2 tpy	915						
≥ 2 to ≤ 6	1,384	\$2,566,211	10%	636.6	\$4,031	968.8	\$2,649
> 6 to ≤ 12	718						
Subtotal:	4,311	\$2,566,211		636.6	\$4,031	968.8	\$2,649
ROS							
> 0 to < 2	466						
≥ 2 to < 6	809	\$1,567,100	50%	1,593.7	\$983	3,049.9	\$514
≥ 6 to < 12	193	\$291,265	10%	75.3	\$3,868	144.8	\$2,011
Subtotal:	1,468	\$1,858,365		1,669.0	\$1,113	3,194.7	\$582
	Total:	\$4,424,576		2,305.6	\$1,919	4,163.5	\$1,063

The Division received field gas sample data from the Colorado Oil and Gas Association (COGA) suggesting a lower field gas VOC content for 6 well production facilities (about 7.9%) and 6 compressor stations (about 8.6%). COGA recommended the Division use this data in the final EIA LDAR analysis for the ROS. In the initial EIA, the Division used producer submitted APEN Form 203 data that showed an average 20.3% VOC content (based on 20 samples) for well production facilities and 14.6% VOC content (based on 12 samples) for compressor stations to estimate the ROS facility fugitive emissions.

Unfortunately the Division is unable to use the COGA information because insufficient supporting documentation was provided on the well production facility location, gas sample gathering location, laboratory conducting the analysis and there were only a limited number of samples.

B. Increase the LDAR inspection frequency from annual to semi-annual for compressor stations outside the DMNFR with actual VOC emissions > 0 tpy to ≤ 12 tpy.

For the DMNFR, all compressor stations must conduct quarterly LDAR inspections. Thus, only compressor stations < 12 tpy outside the DMNFR need to increase inspection frequency to semi-annual.

The Division determined there are a total of 238 compressor stations²⁰ in the state based on operator provided LDAR reports, which also include inspection frequency. The estimated number of compressor stations in the ROS is based on subtracting the known number of DMNFR compressors stations²¹ that were identified through Pneumatic Controller Task Force. Based on the estimated compressor station inspection time estimates in Table 17, the Division estimates the total cost of conducting LDAR inspections is about \$141,659 dollars.

Table 24: Compressor Station Leak Inspection Costs Using IR Camera/Method 21 Hybrid

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Change in Annual Inspection Frequency	Time per IR Camera Inspection (hours)	Total Annual Inspection Time (hours)	Total Annual Inspection Cost
≤ 12 tpy	86	1	11.6	997.6	\$141,659
>12 to ≤ 50 tpy	91				
> 50 tpy	11				
Total:	188			997.6	\$141,659

The repair costs associated with these inspections are set forth in Table 25 and fuel savings associated with these repairs are set forth in Table 26.

²⁰ The total number of compressor stations statewide excludes 2 compressor stations in the DMNFR that use compressed air to drive pneumatic devices.

²¹ The total number of compressor stations in the DMNFR NAA is 50, but 2 compressor stations that use compressed air to drive pneumatic devices are excluded.

Table 25: Compressor Station Leak Repair Costs

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Leak Repair Rate (\$/hr)	Total Leak Repair Time per Compressor Station (hours)	Total Annual Repair Cost
≤ 12 tpy	86	\$74.95	32.6	\$210,130
>12 to ≤ 50 tpy	91			
> 50 tpy	11			
Total:	188			\$210,130

Table 26: Compressor Station Recovered Natural Gas Value from Leak Repairs

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Recovered Natural Gas per Compressor Station (tons/year)	Value of Natural Gas (\$/MCF)	Conversion Factor (MCF/ton)	Total Annual Value of Recovered Natural Gas
≤ 12 tpy	86	2.93	\$2.92	35.8	\$26,341
>12 to ≤ 50 tpy	91				
> 50 tpy	11				
Total:	188				\$26,341

The total net costs for compressor station LDAR are set forth in Table 28.

Table 27: Compressor Station Net Leak Inspection and Repair Costs

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Annual Inspection Cost	Total Annual Repair Cost	Total Annual Value of Recovered Natural Gas	Net Annual Leak Inspection and Repair Costs
≤ 12 tpy	86	\$141,659	\$210,130	\$26,341	\$325,448
>12 to ≤ 50 tpy	91				
> 50 tpy	11		-	-	-
Total:		\$141,659	\$210,130	\$26,341	\$325,448

The estimated emission reductions from increasing the frequency of LDAR at compressor stations in the ROS is about 78.3 tpy of VOC and 173.7 tpy of methane/ethane.

Table 28: Compressor Station Leak Inspection Emission Reductions

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Incremental LDAR Program Reduction % (annual to semi-annual)	Fugitive VOC Emissions Reduction for each CS (tpy)	Total VOC Reduction (tpy)	Fugitive Methane-Ethane Emissions for each CS (tpy)	Total Methane-Ethane Reduction (tpy)
≤ 12 tpy	86	10%	0.91	78.30	2.02	173.70
>12 to ≤ 50 tpy	91					
> 50 tpy	11					
Totals:				78.30		173.70

Based on these reductions, Table 29 summarizes the cost effectiveness of conducting ongoing instrument based inspections at compressor stations to be about \$4,156/ton VOC and \$1,874/ton methane/ethane.

Table 29: Compressor Station Leak Cost-Effectiveness Using IR Camera/Method 21

Compressor Station Fugitive VOC Tier (tpy)	Number of ROS Compressor Stations	Total Net Annual Leak Inspection & Repair Cost	Incremental LDAR Program Reduction % (annual to semi-annual)	Total VOC Reduction (tpy)	VOC Control Cost (\$/ton)	Total Methane-Ethane Reduction (tpy)	Methane-Ethane Control Cost (\$/ton)
≤ 12 tpy	86	\$325,448	10%	78.3	\$4,156	173.7	\$1,874
>12 to ≤ 50 tpy	91						
> 50 tpy	11						
Totals:		\$325,448		78.3	\$4,156	173.7	\$1,874

III. Natural gas-driven pneumatic controllers

The Division is proposing to expand the current pneumatic controller inspection and enhanced response program applicable in the DMNFR to owners or operators of natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations statewide. Under the proposed revisions, owners or operators of natural gas-driven pneumatic controllers at well production facilities and natural gas compressor stations in the ROS must inspect their pneumatic controllers for proper operation during their LDAR

approved instrument monitoring method (AIMM) inspections (i.e., with IR camera or EPA Method 21).

The Division estimates there are approximately 2,600 well production facilities and 190 natural gas compressor stations in the ROS that may now have to inspect their pneumatic controllers for proper operation. Based on data collected by the Pneumatic Controller Task Force (PCTF) at two natural gas compressor stations in the DMNFR²², compressor stations have an average of 11 natural gas-driven pneumatic controllers. The PCTF also collected data on the number of natural gas-driven pneumatic controllers at well production facilities²³ and determined averages based on the barrel per day (bbl/day) production of the facility. Well production facilities producing greater than or equal to 250 bbl/day had an average of 98 natural gas-driven pneumatic controllers per facility. Well production facilities producing greater than or equal to 10 bbl/day but less than 250 bbl/day had an average of 34 natural gas-driven pneumatic controllers per facility. Well production facilities producing greater than or equal to zero bbl/day but less than 10 bbl/day had an average of 9 natural gas-driven pneumatic controllers per facility. Looking at the COGCC's 2018 annual production data, the Division estimates that there are 5 facilities in the counties completely outside of the DMNFR with production greater than or equal to 250 bbl/day, 569 facilities with production greater than or equal to 10 bbl/day but less than 250 bbl/day, and 17,061 facilities with production greater than or equal to zero bbl/day but less than 10 bbl/day, resulting in an estimate of 173,385 natural gas-driven pneumatic controllers at well production facilities in counties wholly outside of the DMNFR. This pneumatic controller estimate is based on average estimates of pneumatic controllers at operations in the DMNFR, and developed through the PCTF study. The Division requests that owners or operators of natural gas-driven pneumatic controllers outside of the DMNFR provide data on the number of natural gas-driven pneumatic controllers at their facilities.

The proposed revisions build upon the statewide LDAR program in Regulation Number 7 and the Division assumes that owners or operators will incorporate the pneumatic controller inspections into their well production facility and natural gas compressor station LDAR programs. Therefore, the Division believes that the inspection and recordkeeping costs are likely minimal.

There may also be costs related to activities necessary to return a pneumatic controller to proper operation. In 2017, the Division considered information from pneumatic controller manufacturers about pneumatic controller repair options and potential emission reductions data in EPA's Oil and Gas CTG, NSPS OOOOa TSD, and Natural Gas Star Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry to determine that returning

²² See Division Pneumatic Controller Task Force presentation to the Air Quality Control Commission (February 21, 2019) at <https://drive.google.com/drive/folders/13Wy4shXktxR--UjW6XMbQZm-67bLYGD>.

²³ Id.

pneumatic controllers to proper operation was cost-effective. The PCTF continues to gather data related to the costs of inspections and repair.²⁴ Preliminary data indicates that the incremental labor and material costs, costs above those related to the aligned LDAR inspection, are variable and range from insignificant to \$600 per facility per year. The Division requested that owners or operators of natural gas-driven pneumatic controllers provide Colorado specific cost information concerning the proposed revisions and has not yet received such data.

IV. Storage Tank Automatic Tank Gauging and Truck Loadout

A. Automatic Tank Gauging

The Division is proposing to require the owners or operators of new facilities and certain storage tanks use an automatic tank gauging system to measure and sample (i.e. gauge) the liquid in the storage tank, which will reduce emissions resulting from blowing down the tank and opening the thief hatch to gauge the tank. Based on the Division's permitting inventory, the Division estimates that from 2016 through 2018 an average of 140 well production facilities per year received permits for this process. It is unknown how many new facilities install automatic tank gauging systems either voluntarily or due to permit or other requirements (e.g. compliance orders). Costs related to an automatic tank gauging system may include the gauge, temperature and water level sensors, control panels, transmitters, and management software. The American Petroleum Institute (API) has published the Manual of Petroleum Measurement Standards Chapter 18.2 Custody Transfer of Crude Oil from Lease Tanks Using Alternative Measurement Methods (July 2016), which provides standards for sampling, temperature determination, calculating volume, and quality testing during custody transfer of crude oil from tanks to a transport vehicle without requiring direct access to the tank thief hatch.

An operator could also install a lease automated custody transfer (LACT) unit that provides for the automatic measurement, sampling, and transfer of liquids. LACT units can be used at facilities that unload liquids to a transport truck as well as facilities that transfer liquids directly to a pipeline. In addition to reducing emissions resulting from opening the thief hatch, facilities that use a LACT unit prior to transfer to a pipeline also reduce emissions from vehicle traffic related to storage tank unloading and emissions from decreased flare combustion. For this EIA, the Division has not been able to quantify these co-benefits (i.e. the reduced NOx from vehicle traffic and avoided combustion), and requests information from stakeholders.

The Division has received some limited information from operators currently using an automatic tank gauging system as a result of a compliance order. The

²⁴ The PCTF will make any recommendations on its findings in a report to the Commission, due May 1, 2020.

Division has reviewed cost and emission estimates from these operators, with data varying based on cost and emission calculation methodologies. Estimates of emissions reduced from using an automatic tank gauging system to monitor and sample liquids, thereby eliminating emissions from opening the thief hatch, vary by facility and operation. A tank must be blown-down (i.e., gas is vented) before opening the thief hatch to gauge the tank. Assuming VOC emissions of 0.0011 tons per blow down event (which the Division believes is a low estimate and may vary based on the tank level, pressure, temperature, etc) and 100 blow-down events per year (which again, is a low figure), emission estimates include a 0.28 tpy VOC reduction per tank system by using an automatic tank gauging system. Estimates range from 0 to 4.91 tons of VOC emissions reduced, based on the amount of production loaded out during auto-gauging when thief hatches would otherwise have been open. Estimates range from \$29,180 to \$66,500 per system, reducing emissions by 55.2 tons for all systems installed. Estimates from the use of LACT units (\$350,000 initial and \$800 monthly) or auto-gauging systems (\$17,000 initial and \$100 monthly) range \$2,120 to \$7,094 cost per ton of VOC reduced. Other estimates provided concerning the use of LACT units reflected an average 2.8 tons of VOC reduced from a system costing on average \$1,693,256 and an average 3.46 tons from a system costing an average \$1,265,774. As far as the Division is aware, none of these cost estimates took into account the savings from manual gauging errors.

Equipment costs will likely be less for owners or operators who already use automatic gauging systems at other facilities. In addition, automatic gauging systems and LACT units offer an increased level of accuracy, which will payback over time.²⁵ Emission reductions will depend on how frequently the storage tank is gauged or sampled. There may also be costs due to associated recordkeeping requirements, though the Division's proposal is minimal.

B. Truck Loadout of Hydrocarbon Liquids

The Division is proposing to require owners or operators of hydrocarbon liquid storage tanks with uncontrolled actual VOC emissions greater than or equal to 2 tpy control emissions from the loadout of hydrocarbon liquids from the storage tank into a transport vehicle. Owners or operators must use submerged fill and may use either a vapor collection and return system, air pollution control equipment, or both to control emissions. The Division estimates there are approximately 3,600 storage tanks with emissions greater than or equal to two tpy. The Division also estimates an average of 140 new well production facilities per year, and assumes that all storage tanks will have emissions greater than or equal to two tpy. Based on COGCC's 2018 annual production data (355,697,624 barrels of oil produced) and assuming that all production was loaded to a transport vehicle instead of to a pipeline, the Division estimates

²⁵ See Best Practices for Custody Transfer Using API MPMS 18.2 (October 2017), <https://www.emerson.com/documents/automation/white-paper-best-practices-for-custody-transfer-rosemount-en-1730756.pdf>.

that loadout emissions range from 18,496 to 41,972 tpy (0.104 lb VOC/bbl crude oil loaded and 0.236 lb VOC/bbl condensate loaded²⁶). This is an overestimate as some facilities direct some, if not most, of the product to a pipeline instead of a transport vehicle (although even at those facilities, for example, LACT units can be out of service and operators will need to loadout by truck). In the 2017 oil and gas area source inventory, the Division estimated that emissions from truck loadout of condensate liquid in the DMNFR was 7.5 tons per day (tpd) (2,737 tpy).

Loadout emissions calculations vary based on the hydrocarbon liquid being loaded into the transport vehicle. Using the Division's default emission factor for condensate loadout, the estimated emission reductions anticipated per tank from a 95% loadout control requirement are listed in Table 30 below. Instead of relating loadout emissions to storage tank emissions, Table 30 uses throughput to estimate potential emission reductions. Further, the Division acknowledges that the default emission factors were developed for gasoline transport trucks loading from dedicated loading racks at refineries. Thus, these emissions estimates do not include emission sources such as the blow-down of the tank or from the opening of the thief hatch, and as a result, the loadout emissions may actually be higher.

Table 30: Estimated loadout uncontrolled emissions and potential emission reductions, per tank battery

Storage tank throughput (bbl/yr)	Loadout uncontrolled emissions (tpy)	Loadout emissions controlled at 95% (tpy)	Estimated VOC reduction from loadout control (tpy)
2,000	0.24	0.01	0.22
10,000	1.18	0.06	1.12
20,000	2.36	0.12	2.24
30,000	3.54	0.18	3.36
40,000	4.72	0.24	4.48
50,000	5.90	0.30	5.61

Costs will also vary, depending on facility configuration and control system installed. EPA estimates the cost of purchasing additional connections to route a transport vehicle vent to a useful outlet at \$1,000 (estimated implementation cost) and additional operating costs to connect the lines at \$200 (incremental operating cost).²⁷ EPA also estimates that recovering these vapors can payback in two years depending on the frequency of loading, load volumes, and the

²⁶ See APCD PS Memo 14-02: Oil and Gas Industry Hydrocarbon Liquid Loadout General Permit GP-07 Regulatory Definitions and Permitting Guidance.

²⁷ EPA Natural Gas Star – Recover Gas During Condensate Loading (2011) at <https://www.epa.gov/sites/production/files/2016-06/documents/recyclelinerecovers.pdf>.

value of the gas.²⁸ In most cases, the storage tank will already be controlled as required by the Regulation Number 7 storage tank control programs; therefore, the additional costs to control the transport vehicle emissions may only be related to the installation of vapor return lines to the storage tank such that transport vehicle emissions are then routed to the existing control device. Under the proposed storage tank revisions described above, all storage tanks statewide with uncontrolled actual emission equal to or greater than two tpy must control emissions. However, some operators may choose to install a air pollution control system dedicated to controlling the loadout process, which would have increased costs, though this scenario is not likely for new facilities. The Division is continuing to assess other appropriate applicability thresholds. Lastly, there may be costs associated with the equipment inspection and recordkeeping requirements.

The Division has reviewed cost and emission estimates from several operators, with data varying based on the costs of systems and equipment installed and emission calculations. Estimates provided by operators range from 0.48 to 21.94 tons of VOC emissions reduced, based on the production after the truck loading controls were implemented. Other estimates range from 0.8 to 2.47 tons of VOC emissions reduced, with a loadout system costing \$11,250. Estimates for dedicated air pollution control equipment range from \$48,500 to \$45,000 per loadout control system, with commensurate reduction in loadout emissions of 195 tpy (95% control). Yet other cost estimates range from \$12,200 to \$14,000 per system, with emission reductions of 25.95 tons VOC. And, other estimates from tank loadout controls (\$15,000 each system) range \$7,333 to \$8,420 cost per ton of VOC reduced.

The Division requested that owners or operators of potentially impacted operations provide Colorado specific cost information concerning the proposed revisions. The Division has received some such information from industry and continues to evaluate and discuss both the automatic tank gauging and truck loadout proposed requirements.

Industry provided cost information based on three potential loadout control scenarios: (1) the addition of a vapor line to existing infrastructure without requiring vapor control system upgrades or updates; (2) the addition of a vapor line to existing infrastructure and requiring vapor control system upgrades or updates; and (3) the addition of a dedicated loadout control system. Industry provided a range of costs for each scenario, as listed in the table below. Additionally, industry identified the likely percentage of facilities that would fall under each scenario.

²⁸ Id.

Table 31: Industry provided loadout control system cost estimates

Scenario	Capital cost	Annual maintenance cost	Percentage of facilities
1	\$3,000-\$29,000	\$1,000-\$5,000	50%
2	\$11,000-\$34,000	\$2,800-\$3,600	12%
3	\$21,000-\$83,000	\$1,500-\$8,600	38%

Using the average of the estimated capital and annual costs, amortized over five years, the cost per ton of VOC reduced is listed in the table below. Using the industry cost estimates, the Division believes that controlling loadout emissions is generally cost-effective.

Table 32: Estimated cost per ton to control loadout emissions

Annual throughput (bbl/yr)	2,000	10,000	20,000	30,000	40,000	50,000	
Annual VOC emission reduction (tpy)	0.22	1.12	2.24	3.36	4.48	5.61	
Scenario	Average annual cost	Cost of emission control per ton of VOC reduced per annual throughput category (\$/tpy VOC)					
		2,000	10,000	20,000	30,000	40,000	50,000
1	\$6,200	\$28,182	\$5,536	\$2,768	\$1,845	\$1,384	\$1,105
2	\$7,700	\$35,000	\$6,875	\$3,438	\$2,292	\$1,719	\$1,373
3	\$14,550	\$66,136	\$12,991	\$6,496	\$4,330	\$3,248	\$2,594

The Division continues to evaluate and discuss both the automatic tank gauging and truck loadout proposed requirements.

V. Well Emissions

The Division is proposing to expand the current requirement for owners or operators to use best management practices (BMPs) to minimize emissions associated with well maintenance and liquids unloading to also require operators use BMPs to minimize emissions associated with well plugging activities. During the plugging of a well, emissions may be released from the well to the atmosphere.

According to COGCC data, from 2016 through 2018, an average of 1,854 wells per year were plugged and abandoned. Due to the variability of BMPs that could be employed to minimize emissions, the specific costs and quantity of

emissions that will be reduced by the proposed revision are unknown. Because the proposal only requires use of best management practices, which takes into account the cost of the practices in a given situation, the Division assumes that the proposed strategy will be cost effective.

The Division is also proposing additional recordkeeping and reporting requirements. There is uncertainty around the emissions from these activities as well as when and which BMPs may be used to minimize emissions. There may be additional costs in maintaining records and submitting reports to the Division. The additional records and report will address some of these uncertainties and inform potential, future emission reduction strategies.

The Division requested that owners or operators of potentially impacted oil and gas wells provide Colorado specific cost information concerning the proposed revisions but did not receive such cost information.

VI. Downstream Transmission

The Division is proposing a new performance based program for the downstream transmission segment, as a result of a recommendation from the SHER team. The downstream transmission segment includes pipelines, compressor stations, aboveground and underground storage facilities, and other equipment transporting or storing natural gas downstream of the natural gas processing plant and prior to the natural gas distribution segment. In Colorado, this segment consists of six owners or operators operating 56 facilities and miles of pipelines. Under the proposed program, a Steering Committee will be established to develop a methane emissions intensity target and evaluate progress against this target. Additionally, downstream transmission owners or operators will begin implementing company specific best management practices (BMP) plans in 2021; begin gathering emissions data in 2021, which will be used to establish the segment methane emissions intensity target; and achieve the segment methane emissions intensity target by 2025. Due to the variability of BMPs that could be employed to reduce emissions from these operations, the specific costs and quantity of emissions that will be reduced by the proposed revision are unknown. There will be additional costs associated with participating on the Steering Committee and compiling data through a third party contractor selected and funded by the transmission segment. There will also be costs related to data collection and associated recordkeeping and reporting requirements.

The Division requested that owners or operators of downstream transmission facilities and other SHER team participants provide cost information concerning the proposed revisions but did not receive such cost information. The Division has, however, continued to work with the SHER team participants to finalize the proposed regulatory and statement of basis language.

VII. Oil and Gas Sector - Annual Emissions Inventory

The Division is proposing an annual emissions inventory program for the oil and gas sector. Under the proposed inventory program, owners or operators of oil and gas operations and equipment will collect VOC, NO_x, carbon dioxide (CO), methane, and ethane emissions data and submit an annual report to the Division. These reports may be partially duplicative of current air pollutant emissions notice (APEN) requirements. However, these reports may partially offset future information requests made by the Division to inform emission inventory development for ozone and other modeling efforts and measuring progress against new greenhouse gas reporting requirements of associated with Senate Bill 19-096 and House Bill 19-1261. The Division intends to consider in future rulemakings how to streamline these related reporting regimes. There will be costs related to data collection and associated recordkeeping and reporting requirements.

The Division requested that owners or operators of engines, drilling operations, well production facilities, natural gas compressor stations, and downstream transmission operations provide cost information concerning the proposed revisions but did not receive such cost information. The Division continues, however, to work with stakeholders to draft an appropriate and effective emissions inventory program.

VIII. Serious Area RACT Requirements for Major Sources

The Division expects that EPA will reclassify the DMNFR as a serious ozone nonattainment area in late 2019. As a Serious nonattainment area, Colorado must revise its ozone SIP to include, among other things, provisions that provide for the implementation of RACT for each category of VOC sources covered by a CTG, for which Colorado has sources, and all other major stationary sources of VOC or NO_x located in the DMNFR area. Under a Serious nonattainment area classification, major sources are sources that emit or have the potential to emit greater than or equal to 50 tons per year of NO_x and/or VOC.

The Division analyzed 31 major sources (≥ 50 tpy VOC or NO_x) in the DMNFR. The Division did not analyze oil and gas sources with emissions between 50 and 100 tpy as these sources are subject to the requirements adopted in 2017 that correspond to EPA's Oil and Gas CTG and engine and other combustion equipment requirements in Regulation Number 7. The 31 sources are subject to various and numerous Regulation Number 7 RACT, RACT/beyond RACT/BACT, or NSPS or NESHAP requirements. However, while these requirements are included in federally enforceable permits and NSPS and NESHAP, some of the requirements are not currently included in Colorado's SIP, as is required for a Serious nonattainment area.

Therefore, the Division is proposing to revise Regulation Number 7 to include requirements for general solvent use, to expand the combustion equipment requirements, to incorporate by reference specific NSPS or NESHAP requirements, and to require specific sources to submit a RACT analysis concerning the facility or specific point(s) to the Division.

A. Solvents

The Division is proposing to define RACT on a categorical basis for general solvent use operations. The proposed revisions would broadly apply to sources with a potential to emit 50 tons per year of VOC and whose solvent use emissions trigger permitting thresholds (i.e., 2 tons per year VOC on an uncontrolled actual basis in the ozone nonattainment area, or 5 tons per year in the rest of the state). At these thresholds, new work practice standards apply requiring that containers be covered, proper disposal of solvent waste, and use good air pollution practices (e.g., the use of low/no VOC solvent if possible, using only amounts needed, submerged fill pipes, closed loop systems, maintaining operations to be leak free). Additionally, in the DMNFR, if an applicable source's solvent use operations have 25 tons per year VOC emissions on an uncontrolled actual basis, emissions must be reduced by 90% and additional control requirements, monitoring, performance testing, and recordkeeping requirements for general solvent use operations apply. The Division has identified at least two facilities in the DMNFR that may be subject to this proposal and believes there are likely other sources that may be subject, including marijuana and hemp solvent extraction facilities. There are potential costs related to all of these elements.

The Division requested that owners or operators of equipment or activities that may be subject to these provisions provide cost information concerning the proposed revisions but did not receive such cost information.

B. Combustion Equipment

The Division is proposing to expand the combustion equipment requirements for boilers, turbines, and engines that the AQCC adopted in 2018 for sources with emissions greater than or equal to 100 tpy of NO_x to sources with emissions greater than or equal to 50 tpy of NO_x.

1. Boilers

The categorical RACT requirements for boilers include an emission limit of 0.2 lb/MMBtu, associated monitoring and recordkeeping, and combustion process adjustment (tuning). The Division is proposing to lower the MMBtu/hr applicability for these boilers from 100 MMBtu/hr to 50 MMBtu/hr. The Division is also proposing to require only initial and periodic performance testing for these boilers instead of continuous emission monitoring systems (CEMS).

There are 24 boilers that may be subject to this categorical RACT standard. There are 10 boilers below the heat input applicability threshold of 50 MMBtu/hr that are subject to the combustion process adjustment requirements but not the numerical standard.

There are 14 boilers with a design heat input rating greater than or equal to 50 MMBtu/hr that are potentially subject to the categorical RACT standard. The Division is not proposing to revise the low utilization capacity factor exemption and an owner could maintain the operation of a boiler below the capacity factor, which would exempt the boiler from the numerical standard. Such boilers would then only be subject to minimal recordkeeping requirements. For boilers subject to the numerical limit, the Division is proposing a periodic performance test requirement to ensure compliance with the limit. In developing the monitoring requirements for boilers at sources with NO_x emissions greater than or equal to 100 tpy, the Division estimated that the cost for the installation, operation, and maintenance of a CEMS device range from approximately \$150,000 to \$200,000 (capital cost) and \$26,000 to \$49,000 (annual cost).²⁹ In contrast, for boilers at sources with NO_x emissions greater than or equal to 50 tpy, the Division estimates the cost of a performance test at approximately \$4,000 to \$8,000 per test, depending on the contractor fee schedules and location with response to the source. These tests will be required every two years. Additional costs include costs related to the associated recordkeeping requirements. In addition, these boilers will be subject to period combustion process adjustment requirements.

2. Turbines

The categorical RACT requirements for turbines include compliance with NSPS GG for turbines constructed on or before February 18, 2005, and compliance with NSPS KKKK for turbines constructed after February 18, 2005, as well as associated monitoring and recordkeeping requirements.

There are 8 turbines that may be subject to this categorical RACT standard. The Division believes the direct economic impact to owners or operators of affected turbines to be negligible since these turbines are already required to meet the limits and monitoring requirements of the applicable NSPS provisions.

3. Engines

The categorical RACT requirements for engines include an emission limit of 9.0 g/bhp-hr for compression ignition engines with a maximum design power output greater than or equal to 500 hp. Engines that operator at less than 10% of the capacity factor are exempt from the numerical emission limit.

²⁹ See July 19, 2018, AQCC rulemaking hearing establishing RACT for combustion equipment.

There are 17 engines that may be subject to this categorical RACT standard. As most of these engines are backup or emergency generators, the Division anticipates that the economic impact of the proposal on owners and operators will be negligible since the engines are likely to operator under the capacity factor exemption and therefore be subject to minimal recordkeeping requirements. However, the engines may continue to be subject to the combustion process adjustment requirements, applicable to engines with uncontrolled actual emissions greater than or equal to 5 tpy.

4. Kilns, dryers, furnaces

The categorical RACT requirements for kilns, dryers, and furnaces currently apply to lightweight aggregate kilns and process heaters. Therefore, the Division is proposing to expand the combustion process adjustment requirements to ceramic kilns, dryers, and furnaces.

There are five facilities that may be subject to this proposed requirement, with kilns ranging from 0.9 MMBtu/hr to 10 MMBtu/hr, dryers ranging from 3 MMBtu/hr to 44.1 MMBtu/hr, and furnaces ranging from 17 MMBtu/hr to 32 MMBtu/hr. There may be costs where the owner is not currently conducting a regulatory, voluntary, or manufacturer specified tuning or combustion adjustment due to the time to conduct the adjustment and potential costs of any necessary replacement equipment components.

The Division requested that owners or operators or equipment or activities that may be subject to these provisions provide cost information concerning the proposed revisions but did not receive such cost information. The Division has, however, worked with stakeholders to refine the combustion equipment requirements for ceramic kilns.

C. Incorporation By Reference of NSPS/NESHAP

The Division proposes to include RACT requirements through incorporating by reference certain NSPS and/or NESHAP requirements for specific sources. There may be costs for sources associated with including these RACT requirements in the SIP due to the process and timeframe for a source seeking to amend an EPA approved SIP provision. However, incorporating NSPS or NESHAP requirements for these specific sources does not add additional implementation costs because these requirements are already federally enforceable.

D. Requirements for RACT Analysis Submittal

The Division proposes to require owners or operators of some major sources or specific points at major sources to submit a RACT analysis concerning the facility or specific point(s) to the Division. The proposed revisions may involve

costs related to developing the RACT analyses and potential costs related to resulting emission reduction controls or measures.

The Division requested that owners or operators of potentially subject boilers, turbines, engines, or kilns provide cost information concerning the proposed revisions but did not receive such cost information.

IX. Gasoline transport trucks, testing facilities, terminals, and service stations

The Division is proposing to update and streamline the requirements for gasoline transport truck testing and vapor systems.

The Division processes 2,500 to 3,000 gasoline transport truck vapor integrity certifications per year. These gasoline transport trucks must be vacuum-pressure tested annually. There are seven testing facilities. The Division is proposing to update the vacuum-pressure test in Regulation 7 with the more current EPA Method 27 test method. EPA Method 27 is the required test method in EPA's NSPS and NESHAP for bulk terminals and gasoline dispensing facilities. Under the proposed revisions, the owners or operators of gasoline transport trucks must conduct this annual test using EPA's Method 27 and maintain records associated with the EPA Method 27 test.

There are approximately 40 bulk terminals in the DMNFR, six of which are large volume bulk terminals. Under the proposed revisions, the terminal operators must ensure that the gasoline transport trucks filled at the terminal have been tested annually according to EPA Method 27.

There are approximately 2,200 service stations in the DMNFR. The Division is proposing to clarify that the service stations must ensure that petroleum liquids are transferred using a properly maintained, functioning, and leak-tight vapor system.

The Division's proposed revisions clarify the vapor systems standards and update the test requirements and associated records to align with the current federal standards. Therefore, the Division believes that the cost impacts will be minimal or even reduced due to the removal of the requirement for the Division to provide and gasoline transport truck owners or operators to apply the certification sticker. Further, there may be cost savings in streamlining conflicting requirements in the SIP and associated with EPA's Method 27 and federal rules.

The Division requested that owners or operators of gasoline transport trucks, bulk terminals, or service stations provide Colorado specific cost information concerning the proposed revisions but did not receive such cost information.

SUMMARY AND CONCLUSION

The Division prepared this Final Economic Impact Analysis in accordance with the requirements of §25-7-110.5(4), C.R.S. Specifically, the Division utilized the methodology identified in §25-7-110.5(4)(c)(III), C.R.S.

The Division has determined that there may be costs related to the proposed revisions potentially impacting owner or operators of oil and gas operations including costs related to additional LDAR inspections, responsive actions, recordkeeping, and reporting; costs related to controlling and inspecting additional storage tanks; costs related to inspecting additional pneumatic controllers, as well as associated recordkeeping and reporting; costs related to installing automatic storage tank gauging systems at new facilities; costs related to controlling emissions from storage tank loadout activities; costs related to the use of best management practices to minimize well emissions, and associated recordkeeping and reporting; costs related to the downstream transmission segment performance based program; and costs related to an annual emissions inventory program. Based on the information reasonably available to the Division, the Division projects that the proposal will reduce VOC emissions in Colorado by approximately 5,766 tpy and will result in reductions of methane/ethane by approximately 4,337 per year, with a cost of \$10.5 million/year. The calculated cost per ton of VOC reduced ranges from \$923 to \$4,156 per ton. The overall cost effectiveness for the package is approximately \$1,821 per ton of VOC reduced.

The Division has determined that there may be costs related to the proposed revisions potentially impacting major sources (≥ 50 tpy VOC and/or NO_x) in the DMNFR. There may be economic impacts of the proposed solvent use control and work practices should owners or operators of operations that use solvents have to change work practices or solvent use. There may be economic impacts of the proposed revisions expanding the combustion equipment standards should owners or operators have to conduct additional performance testing, combustion process adjustments, or recordkeeping. The Division has determined there may be costs related to developing RACT analyses for specified major sources. However, the specific potential costs are unknown due to the range of industries impacted and the varied number of emission NO_x and VOC emission points at these major sources.

The Division has also determined that there may be costs related to the proposed revisions potentially impacting gasoline transport trucks, truck testing facilities, terminals, and service stations. However, the proposed revisions update and align with current federal standards; therefore, the Division believes that the costs impact will be minimal or even reduced.

Based on the above analyses, the Division believes the proposed revisions are cost-effective. The Division has provided an estimate of costs based on

reasonably available information and will consider any additional information provided by stakeholders. The Division requested that affected industry or any interested party submit information with regard to the cost of compliance with these proposed rule revisions. Where the Division received such information, the Division continues to evaluate and discuss the proposed requirements.

General Permit 18.1 Template

Equipment leaks from valves, flanges, pressure relief devices, open end valves or lines, pneumatic controllers, pump seals, compressor seals (except seals regulated under 40 CFR 60.5380a or 5385a) in natural gas service

B. Facility-Wide Terms and Conditions

The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
 - a) For the purpose of a permit-to-install document, the facility-wide terms and conditions identified below are federally enforceable with the exception of those listed below which are enforceable under state law only.
 - (1) None
 - b) For the purpose of a permit-to-operate document, the facility-wide terms and conditions identified below are enforceable under state law only with the exception of those listed below which are federally enforceable.
 - (1) None
2. The emissions unit contained in this permit must comply with various federal New Source Performance Standards (NSPS). The complete NSPS requirements may be accessed via the internet from the Electronic Code of Federal Regulations (e-CFR) website <http://www.ecfr.gov> or by contacting the appropriate Ohio EPA District Office or local air agency. The permittee must comply with the applicable requirements of 40 CFR Part 60 Subpart OOOOa as they apply to the emissions source.
3. Records related to this PTIO may be maintained at an off-site location (e.g. regional office), provided they are made accessible when the need arises, otherwise by the next business day upon Ohio EPA request (or made viewable electronically on-site and submitted to Ohio EPA within 24 hours).

C. Emissions Unit Terms and Conditions

Note: The following are the terms and conditions for a General PTIO to be issued to a non-Title V facility

1. Emissions Unit Group: Equipment/Pipeline Leaks, F001

EU ID	Operations, Property and/or Equipment Description
F001	Ancillary equipment ¹ and associated equipment: compressors ² , pumps, piping, pneumatic controllers, inlet separators, gas-water/condensate/oil separators, etc. Equipment/pipeline leaks from valves, flanges, pressure relief devices, open end valves or lines, and pump and compressor seals (except seals regulated under 40 CFR 5380a or 5385a) in natural gas service.

- a) This permit document constitutes a permit-to-install issued in accordance with ORC 3704.03(F) and a permit-to-operate issued in accordance with ORC 3704.03(G).
- (1) For the purpose of a permit-to-install document, the emissions unit terms and conditions in this permit are federally enforceable, with the exception of those listed below, which are enforceable under state law only.
- a. None.
- (2) For the purpose of a permit-to-operate document, the emissions unit terms and conditions in this permit are enforceable under state law only, with the exception of those listed below, which are federally enforceable.
- a. None.
- b) Applicable Emissions Limitations and/or Control Requirements
- (1) The specific operation(s), property, and/or equipment that constitute each emissions unit along with the applicable rules and/or requirements and with the applicable emissions limitations and/or control measures are identified below. Emissions from each unit shall not exceed the listed limitations, and the listed control measures shall be specified in narrative form following the table.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
a.	OAC rule 3745-31-05(A)(3) June 30, 2008	Develop and implement a site-specific leak detection and repair program for ancillary and associated equipment as described in paragraph c)(2). See b)(2)a. below.
b.	40 CFR Part 60 Subpart OOOOa Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and	Every pneumatic controller at a natural gas processing plant must have a natural gas continuous bleed rate of zero. All fugitive emission components must be

¹ "Ancillary Equipment" is defined in 40 CFR Part 63, Subpart HH as "any of the following pieces of equipment: pumps, pressure relief devices, sampling connection systems, open-ended valves, or lines, valves, flanges, or other connectors." The Subpart HH definition is being used for this permit but note that the equipment leak standards found in Subpart HH do not apply for this permit because this permit is for an "area source" and the equipment leak standards do not apply to area sources.

² "Compressor" for the purpose of this permit excludes "Centrifugal compressor" and "Reciprocating compressor" as defined in 40 60.5430a.

	Applicable Rules/Requirements	Applicable Emissions Limitations/Control Measures
	Distribution. 40 CFR 60.5390a(b)(1)	monitored and replaced or repaired according to the provisions of this subpart.
c.	OAC rule 3745-31-05(A)(3)(a)(ii) June 30, 2008	The Best Available Technology (BAT) requirements under OAC rule 3745-31-05(A)(3) do not apply since the calculated annual emissions rate is less than 10 tons/year taking into account the voluntary restrictions from OAC rule 3745-31-05(E). See b)(2)b. below.
d.	OAC 3745-31-05(E)	Emissions of Volatile Organic Compounds (VOC) shall not exceed 10.0 tons per year from fugitive equipment leaks. Develop and implement a site-specific leak detection and repair program for ancillary and associated equipment as described in paragraph c)(2).

(2) Additional Terms and Conditions

- a. This Best Available Technology (BAT) emission limit applies until U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) into the Ohio SIP.
- b. These requirements apply once U.S. EPA approves OAC paragraph 3745-31-05(A)(3)(a)(ii) (the less than 10 tons per year BAT exemption) as part of the Ohio SIP.

c) Operational Restrictions

(1) Ancillary and Associated Equipment Leak Detection and Repair Program

The permittee shall develop and implement a leak detection and repair program designed to monitor and repair leaks from ancillary and associated equipment covered by this permit, including each pump, compressor, pressure relief device, connector, valve, flange, intermittent/snap-action pneumatic controller, vent, cover, any bypass in the closed vent system, and each storage vessel. This program of implementation shall fulfill all requirements of 40 CFR 60.5397a, including the following:

- a. Leaks shall be detected by the use of either a "Forward Looking Infra-Red" (FLIR) camera or an analyzer meeting U.S. EPA Method 21 of 40 CFR Part 60, Appendix A.
- b. The written plan shall include as a minimum all requirements for inventorying and marking affected components, specifying the route to be followed to ensure access or proper viewing angles for affected components, and identification, justification, and special procedures to be followed for any affected sources given designations of "difficult-to-monitor" or "unsafe-to-monitor" as prescribed under sections (d) and (g) and elsewhere as applicable under 40 CFR 60.5397a.

- c. An initial monitoring survey shall be completed by June 3, 2017 or within 60 days of startup of a new compressor station, or each new collection of fugitive emissions components at the new compressor station, and quarterly thereafter, with the surveys being at least 60 days apart.
 - d. The program shall require that the leaking component be repaired or replaced as soon as practicable, but no later than 30 calendar days after the leak is detected, except as provided for in (c)(1)e.
 - e. The program shall allow for the delayed repair of a leaking component following the language found in 40 CFR 60.5397a(h)(2).
 - f. The program shall follow the Monitoring and Record Keeping requirements described in paragraph 1.d) of this permit.
- (2) In the event that a leak or defect is detected in the cover, closed vent system, process equipment, or control device, the permittee shall make a first attempt at repair no later than 5 calendar days after the leak is detected. Repair shall be completed no later than 30 calendar days after the leak is detected as allowed in 40 CFR 60.5416(c)(4). Any delay of repair of a leak or defect shall meet the requirements of 40 CFR 60.5416a(c)(5).

[40 CFR 60.5416a(c)(4) and (5)], [40 CFR 60.5415a(e)(3)], [40 CFR 60.482-9a], and [ORC 3704.03(T)]

d) **Monitoring and/or Recordkeeping Requirements**

- (1) The permittee shall perform an inspection each week that an operator is at the facility and the facility is in operation or is pressurized in any of its components, for indications of releases from the pressure relief valves, and any olfactory, visual or auditory indications of equipment leaks. The positive indication of a release or a leak shall be noted in an operations log, along with the following information:
 - a. the name of the inspector;
 - b. the date and time inspected;
 - c. the identification of the pressure relief valve that released and/or piece of equipment that leaked;
 - d. the estimated or calculated duration of the pressure relief valve release and/or equipment leak and the estimated emission totals; and
 - e. any corrective actions taken to minimize or eliminate the release or leak.
- (2) **Ancillary and Associated Equipment Leak Detection and Repair Program Monitoring and Record Keeping for Programs Utilizing FLIR Cameras**
 - a. Leaks shall be determined by visually observing each ancillary or associated component through the FLIR camera to determine if leaks are visible.
 - b. Intermittent/snap-action controllers showing hydrocarbon emissions shall be scanned repeatedly to determine if emissions occur only during actuation cycles. Otherwise, the controller is determined to be malfunctioning (leaking).

- c. The following information shall be recorded during each leak inspection:
 - i. the date the inspection was conducted;
 - ii. A description of the manufacturer, model number and serial number of the FLIR camera;
 - iii. the name of the employee conducting the leak check;
 - iv. the identification of any component that was determined to be leaking;
 - v. the date the first attempt to repair the component was made;
 - vi. the reason the repair was delayed following the language found in 40 CFR 60.5416(c)(5);
 - vii. the date the component was repaired and determined to no longer be leaking;
 - viii. the total number of components that are leaking; and
 - ix. the percentage of components leaking, determined as the sum of the number of components for which a leak was detected, divided by the total number of ancillary or associated components capable of developing a leak, and multiplied by 100.
- d. The permittee shall maintain written records that demonstrate the FLIR camera is operated and maintained in accordance with the manufacturer's operation and maintenance instructions.
- e. The records from each inspection and the dates each leak is detected and repaired shall be maintained for at least 5 years and shall be made available to the Director or his representative upon oral or written request.

[40 CFR 60.5416a(c)] and [ORC 3704.03(T)]

(3) Ancillary Equipment Leak Detection and Repair Program Monitoring and Record Keeping for Programs Utilizing a Method 21 Analyzer

- a. Leaks shall be measured by utilizing U.S. EPA Method 21 (40 CFR Part 60, Appendix A). All potential leak interfaces shall be traversed as close to the interface as possible. The arithmetic difference between the maximum concentration indicated by the instrument and the background level is to be compared with 500 ppm or 10,000 ppm (as applicable) for determining compliance.
- b. Intermittent/snap-action controllers showing hydrocarbon emissions shall be sampled repeatedly to determine if emissions occur only during actuation cycles. Otherwise, the controller is determined to be malfunctioning (leaking).
- c. A component is considered to be leaking if the instrument reading is equal to or greater than:

pressure relief device in gas/vapor service

500 ppm

pressure relief device in light liquid service	10,000 ppm
pumps in light liquid service	2,000 ppm
compressor	500 ppm
sampling connection system*	*
open ended valves or lines**	**
valves in gas/vapor and light liquid service	500 ppm
closed vent system	500 ppm
connectors in gas/vapor and light liquid service	500 ppm
intermittent snap-action controllers	500 ppm
all other ancillary and associated equipment	10,000 ppm

* must be equipped with a closed-purge, closed-loop, or closed-vent system

** must be equipped with a cap, blind flange, plug, or a second valve

- d. The following information shall be recorded during each leak inspection:
 - i. the date the inspection was conducted;
 - ii. the name of the employee conducting the leak check;
 - iii. the identification of any component that was determined to be leaking (company ID and component type (flange, pump, etc.);
 - iv. the date the first attempt to repair the component was made;
 - v. the reason the repair was delayed following the language found in 40 CFR 60.5416(c)(5);
 - vi. the date the component was repaired and determined to no longer be leaking;
 - vii. the total number of components that are leaking; and
 - viii. the percentage of components leaking, determined as the sum of the number of components for which a leak was detected, divided by the total number of ancillary or associated components capable of developing a leak, and multiplied by 100.
- e. The permittee shall maintain records that demonstrate the Method 21 analyzer is operated and maintained in accordance with the manufacturer's operation and maintenance instructions.
- f. In order to calibrate the analyzer, the following calibration gases shall be used:
 - i. zero air, which consists of less than 10 ppm of hydrocarbon in air; and

- ii. a mixture of air and methane or n-hexane at a concentration of approximately, but less than, 10,000 ppm of methane or n-hexane.
- g. The records from each inspection and the dates each leak is detected and repaired shall be maintained for at least 5 years and shall be made available to the Director or his representative upon oral or written request.

[40 CFR 60.5416a(c)] and [ORC 3704.03(T)]

e) Reporting Requirements

- (1) The permittee shall submit an annual Permit Evaluation Report (PER) to the Ohio EPA District Office or Local Air Agency by the due date identified in the Authorization section of this permit. The permit evaluation report shall cover a reporting period of no more than twelve months for each air contaminant source identified in this permit. It is recommended that the PER be submitted electronically through the Ohio EPA's "e-Business Center: Air Services" although PERs can be submitted via U.S. postal service or can be hand delivered.

[OAC 3745-15-03(B)(2) and (D)]

- (2) Supplement to the PER for the Ancillary Equipment Leak Detection and Repair Program

For each inspection that occurred during the year, the permittee shall submit the following information with the annual PER from data collected by the ancillary equipment leak detection and repair program:
 - a. the date of the inspection;
 - b. the number of components determined to be leaking;
 - c. the company ID and component type (flange, pump, etc.) of each leaking component;
 - d. the total number of components at the site;
 - e. the percent of components determined to be leaking;
 - f. a list of all components that have not been repaired due to a delay of repair and the reason for the delay; and
 - g. a notification indicating if the permittee has changed future inspection frequencies based on the percent of components leaking.

[40 CFR 60.5416a(c)] and [ORC 3704.03(T)]

f) Testing Requirements

Compliance with the Emission Limitations and/or Control Requirements specified in section b) of these terms and conditions shall be determined in accordance with the following methods:

- (1) Emissions Limitation:

Emissions of VOC shall not exceed 10.0 tons per year from fugitive equipment leaks.

Applicable Compliance Method:

The annual VOC limitation is the estimated potential-to-emit based upon the maximum number of components and type of service (gas/vapor and light liquid) expected at this facility. Unless or until more accurate emission factors have been demonstrated or established for the site (e.g. following initial and subsequent monitoring and inspections), the appropriate emissions factors from U.S. EPA's "Protocol for Equipment Leak Emission Estimates," Table 2-4, for Oil and Gas production Operations (EPA-453/R-95-017, November 1995), shall be used to demonstrate compliance with the annual limit, as shown below, with the exception of gas-driven pneumatic controllers, for which emission factors derived from review of recent literature are listed below. The facility's potential emissions from ancillary and associated equipment shall be documented from the summation of the following calculations. Where the maximum mass per cent of VOC and corresponding mean molecular weight (MMW) of the rich gas stream are known, those values may be substituted in the calculations in lieu of 50% and 30.74 lb/lb-mol respectively. (note: where multiplication by % VOC is indicated, it should be understood that multiplication by a decimal fraction is intended, i.e. a divisor of 100 is implicit):

Component Type # of components x emission factor x % VOC* = lb VOC/hr

In Gas/Vapor Service

Number of connectors x 0.000441 lb/hr x 50% VOC = lb VOC/hr

Number of valves x 0.00992 lb/hr x 50% VOC = lb VOC/hr

Number of flanges x 0.00086 lb/hr x 50% VOC = lb VOC/hr

Number of compressor seals** x 0.0194 lb/hr x 50% VOC = lb VOC/hr

(note: the emissions of reciprocating or centrifugal (wet seal or dry seal) compressors, including blowdown and leakage through seals and closed valves, may be subject to capture and control and other permitting requirements appropriate to non-fugitive categories of sources, and may, in that case, not be within the scope of this general permit)

Number of relief valves x 0.01940 lb/hr x 50% VOC = lb VOC/hr

Number of other ancillary and associated units of equipment x 0.01940 lb/hr x 50 % VOC = lb VOC/hr

Number of high bleed (exceeding a 6 scf/hr continuous bleed specification) gas driven pneumatic controllers x (50.8 continuous plus intermittent bleed, scf/hr) x (MMW/379.5 lb/scf) x (17/MMW)^{1/2***} x 50% VOC = lb VOC/hr (note: these are not allowed under this general permit)

Number of low bleed (conforming to 6 scf/hr continuous bleed specification) gas driven pneumatic controllers x (14.89 continuous plus intermittent bleed, scf/hr) x (MMW/379.5 lb/scf) x (17/MMW)^{1/2***} x 50% VOC = lb VOC/hr

Number of zero bleed (i.e., zero continuous bleed, also known as intermittent/snap-action) gas driven pneumatic controllers x (13.5 intermittent bleed, scf/hr) x (MMW/379.5 lb/scf) x (17/MMW)^{1/2***} x 50% VOC*** = lb VOC/hr

In Light Liquid Service

Number of connectors x 0.000463 lb/hr x 100% VOC = lb VOC/hr

Number of_valves x 0.00551 lb/hr x 100% VOC = lb VOC/hr

Number of_flanges x 0.00024 lb/hr x 100% VOC = lb VOC/hr

Number of_pump seals x 0.0287 lb/hr x 100% VOC = lb VOC/hr

Number of relief valves x 0.01653 lb/hr x 100% VOC = lb VOC/hr

The total summation of VOC emissions per hour shall be multiplied by 8760 hours per year and divided by 2000 pounds to calculate the tons of estimated annual fugitive VOC emissions.

Compliance with the ton per year limit shall be determined following the first 12 months of operation.

As an alternative to using the above emission factors to calculate VOC emissions, the permittee may use facility specific VOC information for site specific emission factors.

* The default % VOC for Gas/Vapor service was based on the highest percent VOC in gas analyses submitted by representative facilities.

** This emission factor is intended only for compressors not meeting the definition of "Centrifugal compressor" or "Reciprocating compressor" in 40 CFR part 60, Subpart OOOOa.

*** The conversion of scf/hr to lb/hr is accomplished with the aid of the ideal gas constant 379.5 scf/lb-mol and the assumption that a molecular weight adjustment of $(17/MMW)^{1/2}$ is appropriate to convert emission factors found in the literature (based primarily on lean-gas measurements) to the rich-gas situation of interest. A mean molecular weight of 30.74 may be taken to correspond to VOC mass fraction of 50 percent, in default of more precise information.

g) Miscellaneous Requirements

(1) None.

Closing the gap: Explaining persistent underestimation by US oil and natural gas production-segment methane inventories

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Abstract

Methane (CH₄) emissions from oil and natural gas (O&NG) systems are an important contributor to greenhouse gas emissions. In the United States (US), recent synthesis studies of field measurements of CH₄ emissions at different spatial scales are ~1.5x-2x greater compared to official Environmental Protection Agency (EPA) greenhouse gas inventory (GHGI) estimates. Site-level field studies have isolated the production-segment as the dominant contributor to this divergence. Based on an updated synthesis of measurements from component-level field studies, we develop a new inventory-based model for CH₄ emissions using bootstrap resampling that agrees within error with recent syntheses of site-level field studies and allows for isolation of differences between our inventory and the GHGI at the equipment-level. We find that venting and malfunction-related emissions from tanks and other equipment leaks are the largest contributors to divergence with the GHGI. To further understand this divergence, we decompose GHGI equipment-level emission factors into their underlying component-level data. This decomposition shows that GHGI inventory methods are based on measurements of emission rates that are systematically lower compared with our updated synthesis of more recent measurements. If our proposed method were adopted in the US and other jurisdictions, inventory estimates could become more accurate, helping to guide methane mitigation policy priorities.

Methane (CH_4) is the principle constituent of natural gas and is also a potent greenhouse gas (GHG) [1]. During production of oil and natural gas (O&NG), some processes are designed to vent CH_4 to the air, and CH_4 is also emitted unintentionally via leaks in the system. According to the official United States (US) GHG inventory, CH_4 from O&NG operations are estimated to contribute ~3% of national GHG emissions (with 100 year GWP = 25, [2]). At the international level the contribution is approximately 5% (based on estimates from [3] and [4]). However, the uncertainty in this estimate, data gaps, and inconsistency with alternative approaches suggested a need for further evidence [5]–[8]. To this end, significant research in the past decade has investigated CH_4 emissions from the O&NG system.

The US Environmental Protection Agency (EPA) estimates O&NG CH_4 emissions in an annual Greenhouse Gas Inventory (GHGI) [9]. The GHGI uses a data-rich, “bottom-up” approach to estimate national CH_4 emissions by scaling up CH_4 emissions measurements from activities like well completions and gas handling components like valves or seals. However, a recurrent theme consistently found in the literature is that the GHGI underestimates total US O&NG CH_4 emissions compared to observed values [10]. Brandt et al. [11] summarize the literature, and observe that national-scale estimates from large-scale field studies exceed the GHGI by ~1.5 times. This difference is sometimes referred to as the “top-down/bottom-up” gap [11]–[17], based on the differences in approach between the GHGI and the conflicting studies. “Top-down” studies determine total emissions from multiple sites via measurements from aircraft, satellites, or weather stations (e.g. [14]–[16], [18]–[20]).

Some recent studies have used a meso-scale “site-level” approach which measures CH_4 downwind of facilities (e.g., well-pads) to estimate total emissions of an entire site or facility (e.g. [21]–[24]). A recent synthesis of site-level data by Alvarez et al. [13] finds agreement between site-level results and top-down results, with a best estimate of supply chain emissions (including all equipment from production to distribution) ~1.8 times that of the component-level GHGI [25] (up to ~2.1x in the production-segment).

Most emissions sources in the GHGI are derived using bottom-up methods. The bottom-up approach estimates overall CH_4 emissions by combining counts of individual components (or activities) with emissions per component/activity (the “emission factor”). The bottom-up approach allows for representation of sources at a high resolution, with 67 and 45 separate sources for the O&NG production segments, respectively [25]. Because of this high resolution, the GHGI is useful for development of CH_4 mitigation policies. For example, the Obama administration’s Climate Action Plan developed recommendations using the relative contribution of emissions sources in the GHGI [26]. Also, the bottom-up framework of the GHGI is recommended for reporting national emissions under the United Nations Framework Convention on Climate Change (UNFCCC, [27]), under which participating countries report their inventory of GHG emissions.

This study aims to answer two questions. First, why does the bottom-up EPA GHGI underestimate CH_4 emissions compared to both site-level and large-scale top-down studies? Second, is this underestimation due to an inherent problem with the bottom-up methods used in the GHGI? Previous studies have noted that the underlying data sources of the GHGI were

published in the 1990s and may be outdated [11], [28], [29]. The site-level synthesis study of Alvarez et al. [13] suggested that the divergence is likely due to a systematic bias in the bottom-up methodology that misses “super-emitters”, a finding supported by others (e.g., [11] [30]). Recent work suggests that top-down measurement campaigns are capturing systematically higher emissions during daytime hours from episodic events. However, this may not be true at a national level, as it has been noted that the upward bias of top-down measurements was likely explained by unusually high liquids-unloadings in the Fayetteville shale [13], [31]. Some have attempted to construct alternative inventories (e.g., [13], [32], [33]), however these attempts have not taken full advantage of the robust set of component-level data now available.

In this study, for the first time, we explain with source-level specificity the underestimation of O&NG CH₄ emissions in the GHGI as compared to top-down studies. Our analysis boundary is the O&NG production segment which includes all active, onshore well pads and tank batteries (excluding inactive and offshore wells) and ends prior to centralized gathering and processing facilities (**Figure S1**). We focus on the production segment given its significant emissions (~58% of total supply chain CH₄ emissions in Alvarez et al. [13]) and the large difference between site-level estimates and the GHGI [13] (~70% of difference between Alvarez et al. [13] and the GHGI, **Figure S2**). This study develops and validates approaches that can be applied to other segments in the O&NG supply chain.

Our novel contributions are threefold. First, we construct a bottom-up, O&NG production-segment CH₄ emissions estimation tool based on the most comprehensive public database of component-level activity and emissions measurements yet assembled. Our approach differs from the GHGI in that it applies modern statistical approaches (bootstrap resampling) to allow for inclusion of infrequent, large emitters, thus robustly addressing the issue of super-emitters. Second, we use this tool to produce an inventory of US O&NG production segment CH₄ emissions and compare this with the GHGI and previous site-level results, showing that much of the divergence between different methods at different scales vanishes when we apply our improved dataset and statistical approaches. As mentioned earlier, site-level synthesis studies have been validated against even larger-scale top-down studies, so improved alignment between our method and site-level results suggests much better agreement with top-down results [13], [34]. Third, to isolate specific sources of disagreement between the GHGI and other studies, we reconstruct the GHGI emission factors beginning with the underlying datasets and uncover some possible sources of disagreement between inventory methods and top-down studies. Based on these results, we suggest a strategy for improving the accuracy of the GHGI, and likewise any country using a similar approach in reporting O&NG CH₄ emissions to the UNFCCC.

A new bottom-up approach

Bottom-up approaches extrapolate component or equipment emissions rates to large (e.g., national) scales by multiplying emission factors (emissions per component or equipment per unit time) by activity factors (counts of components per equipment, and equipment per well) (**Figure 1**). Our estimation tool requires two sequential extrapolations, first from the component to the equipment-level, and second from the equipment to the national or regional-level.

The approach utilized in our bottom-up estimation tool begins with a database of component-level direct emissions measurements (e.g., component-level emission factors). We generate component-level emission factor distributions for this study from a literature review building on prior work [11], [30] and adding new publicly available quantified measurements (**Table 1** in Methods). Our resulting tool's database includes ~3200 measurements from 6 studies across a 12-fold component classification scheme (see SI-3.2 for further description of this classification scheme). We applied emission factors as reported in the individual studies, with no modifications beyond unit conversion (noting that there are some differences between studies in High Flow Sampler bias correction for gas concentration and flow rate, which may introduce uncertainty to our results). Data for component counts and fraction of components emitting (the ratio of emitting components to all components counted) was scarce, with only 3 studies containing useful information for both ([35]–[37] for component counts and [35], [36], [38] for fraction of components emitting).

We derive equipment-level emission factors for our tool by random re-sampling (i.e., bootstrapping, with replacement) from our component-level database according to component counts per equipment and fraction of components emitting. Source-specific approaches were required for infrequent events (i.e., completions, workovers, liquids unloadings), methane slip from reciprocating engines, and liquid storage tanks (see SI-3.3).

We then perform a second extrapolation, using our equipment-level emission and activity factors to calculate a 2015 US O&NG production-segment CH₄ emissions estimate. For this step, our tool is integrated into the Oil Production and Greenhouse Gas Emissions Estimator (further description of OPGEE can be found in SI-3.1) and parameterized using 2015 domestic well count and O&NG production data (same dataset as Alvarez et al. [13]). A total of ~1 million wells and associated equipment are partitioned and analyzed across 74 analysis bins (SI-4.1). We performed a Monte Carlo uncertainty analysis repeating the bootstrapping algorithm 100 times across all ~1 million wells (SI-4.4). It is worth mentioning that emission factors are often themselves only measured in a few locations, and thus in our extrapolation we assume applicability to other regions.

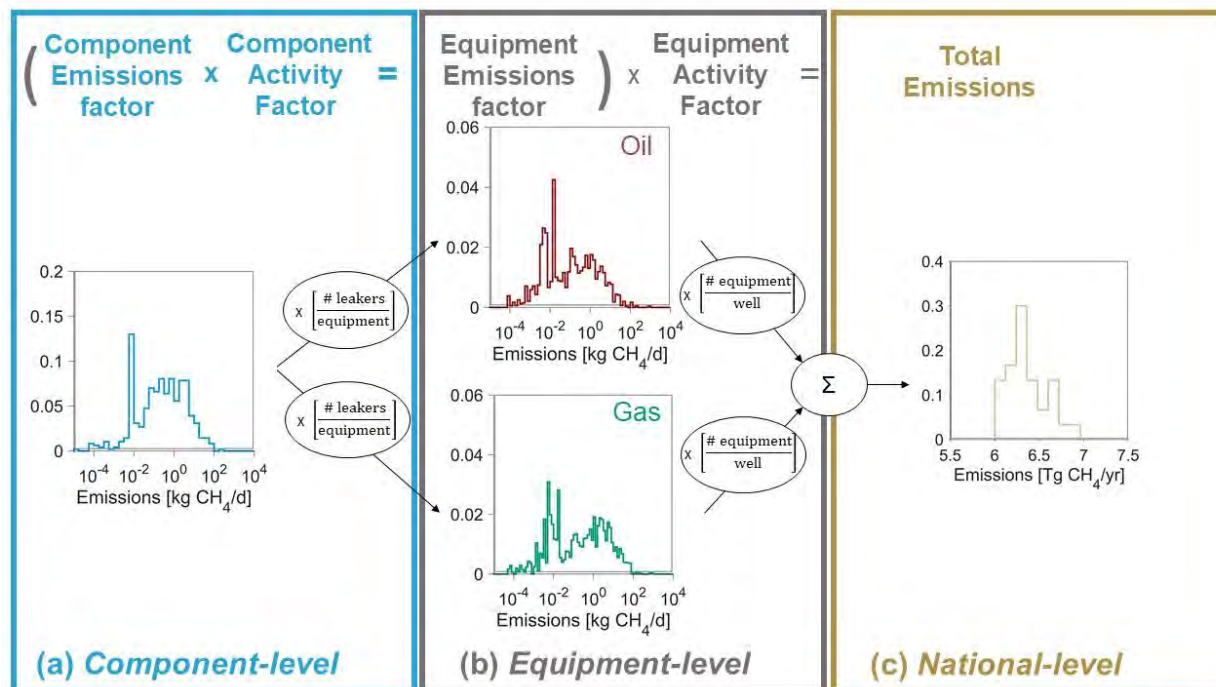


Figure 1: Schematic of this study's bottom-up CH₄ emissions estimation tool which involves multiplication of emission factors (e.g., emissions per valve) by activity factors (e.g., number of valves per wellhead). Two sequential extrapolations are performed using an iterative bootstrapping approach. First, our database of component-level (e.g., valve, connector) emissions measurements (a) is extrapolated using component-level activity factors to generate equipment-level (e.g., wellhead, separator) emission factors (b). Second, these equipment-level emission factor distributions are extrapolated using equipment-level activity factors to generate a 2015 US O&NG production-segment CH₄ emissions estimate. This extrapolation is performed 100 times to generate a distribution of national-level CH₄ emissions (c) and estimate a 95% confidence interval (CI).

Comparison of US production-segment CH₄ emissions with site-level studies and the GHGI

We first compare our resulting US 2015 O&NG production-segment CH₄ emissions estimate with the GHGI's estimate for 2015 produced in their most recent 2020 inventory [25]. We also validate our bottom-up tool by comparing total emissions and emissions distributions with those generated in site-level synthesis studies (total emissions are compared with Alvarez et al. [13], site-level distributions are compared with Omara et al.[34]).

We estimate mean O&NG production-segment CH₄ emissions of 6.3 Tg/yr (5.8-6.9 Tg/yr, at 95% confidence-interval, CI) (Fig. 2a, Note that the CI is relatively narrow given that this only captures uncertainty due to resampling). Our mean, production-normalized emissions rate from the production segment is 1.3% (1.2-1.4% at 95% CI, based on gross NG production of 32 trillion cubic feet and an average CH₄ content of 82% [39], [40]), slightly lower than Alvarez et al.[13], [34], who estimate 1.5% (applying the same denominator as above). Both our bottom-up component-level inventory results and the Alvarez site-level results are approximately 2x those of the GHGI estimate of 3.6 Tg/yr (year 2015 data [25], excludes offshore systems) for the

O&NG production segment. Interestingly, the difference in US production-segment emissions between this study and the GHGI is approximately the same volume as our estimate of contribution from super-emitters (top 5% of emissions events). Given that our results match the Alvarez et al. site-level results, we conclude that the divergence between the GHGI and top-down/site-level studies is not likely to be due to any inherent issue with the bottom-up approach.

Figure 2(b-c) show that site-level distributions developed using our model match empirical distributions from the site-level synthesis study of Omara et al. [34]. To report our results on a basis consistent with site-level studies (recalling that sites can contain more than one well), we cluster equipment-level emissions outputs into production sites (SI-4.3). Several other observations from our simulations are of interest. First, our modeled emissions per site are higher at liquids-rich sites versus gas-rich sites (**Figure S29**), in alignment with recent field measurement campaigns in both Canada and the United States [41], [42]. Second, our model recreates the trend demonstrated by Omara et al. wherein low-producing sites exhibit higher production-normalized emissions rates [34] (**Figure S30**). Finally, the tail of our modeled distribution closely matches the tail of the empirical Omara et al. distribution (**Figure 2b** and **Figure S28**). This is of particular interest, given that recent papers assert the divergence between the GHGI and site-level studies is mostly due to an inability of the bottom-up methods to capture super-emitters [32], [42]. Our results clearly show that a modern dataset with proper bootstrap resampling techniques can recreate observed super-emitters.

Because our approach uses a component-level, bottom-up approach, we can investigate the source of differences with the GHGI. This cannot be done with site-level data. Relative to the GHGI, contributions from equipment leaks in our estimate are larger by ~ 1.3 Tg CH₄ and tank leaks and venting by ~ 2.1 Tg CH₄ (**Figure 3**). Together, these two sources contribute over half of total O&NG production-segment CH₄ emissions. The increase in estimated emissions from equipment leaks compared to the GHGI are due to our updated emission factor; we know that the difference is not due to equipment-level activity factors because ours are nearly identical to the GHGI (see SI-2.3). In the next section we will perform a deeper investigation into both component-level emissions data for equipment leaks and tank modelling as underlying contributors to differences between our results and the GHGI.

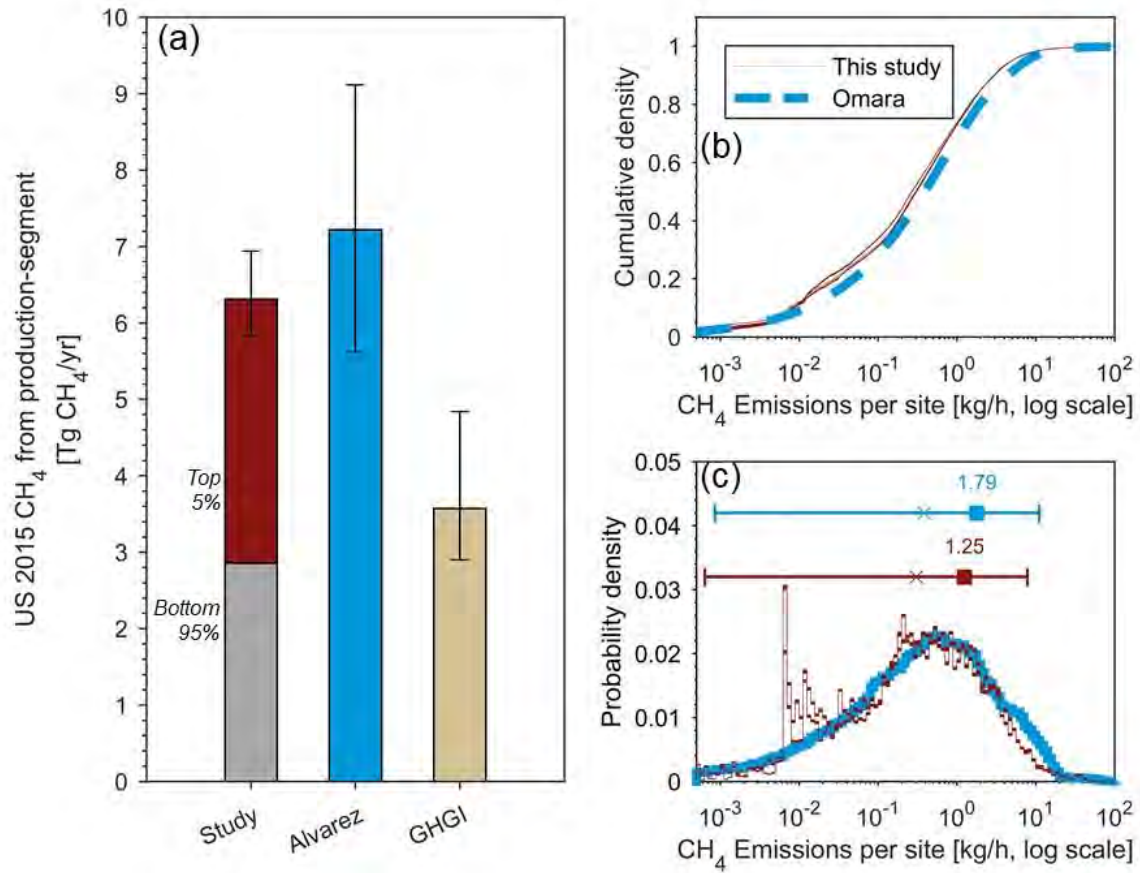


Figure 2: (a) Comparison of this study's aggregate US 2015 CH₄ emissions from O&NG production-segment with site-level results of Alvarez et al. (see Table S3 in [13] minus contributions from offshore platforms and abandoned wells) and the GHGI [25] including fraction estimated from super-emitters (top 5% of sources) and 95% confidence interval. We also compare probability distributions of our component-level simulations (red lines), aggregated into site-level emissions, with site-level results of Omara (blue line): (b) Cumulative distribution plot (CDF) describing the fraction of well-sites with emissions below a given amount, and (c) probability distribution of emissions rate per well-site with the mean (filled square), median (x), and 95% confidence intervals shown above the plots. Results of this study are presented using 100 Monte Carlo simulations. Because of the large number of sampled sites, the Monte Carlo simulations all converge toward the same size distribution in panels (b) and (c).

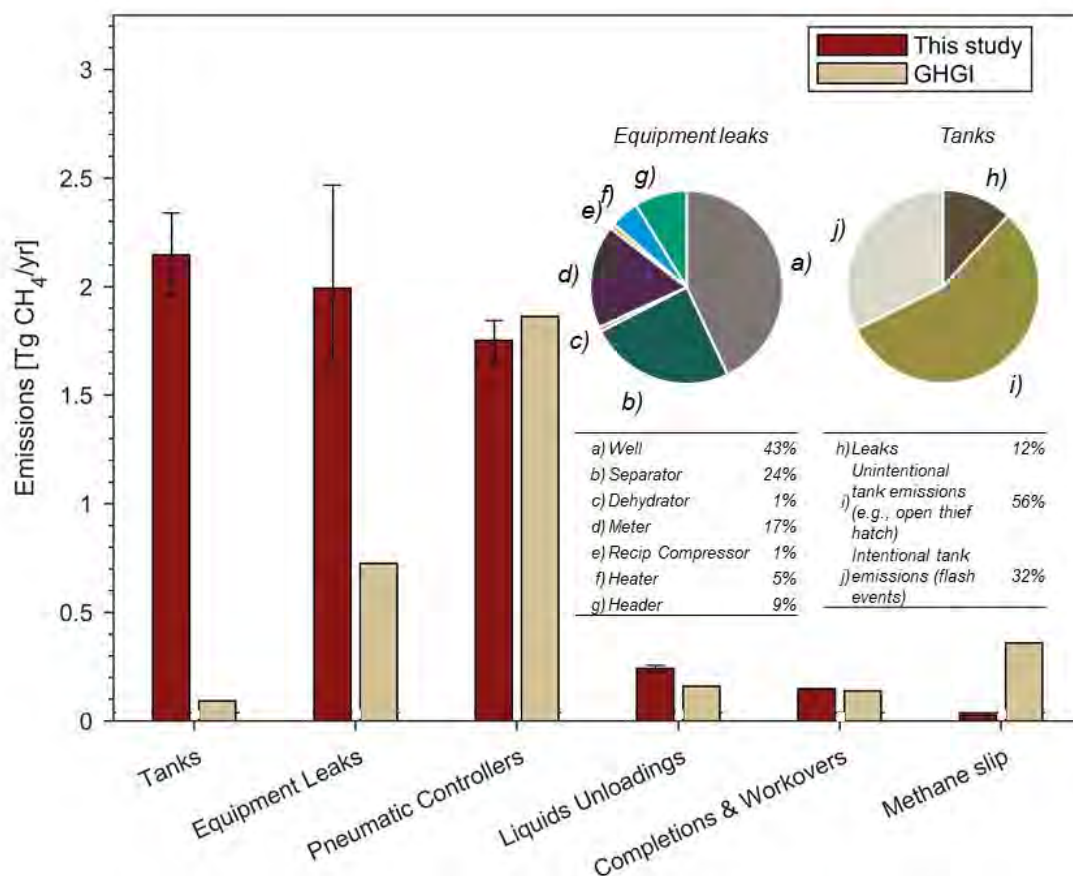


Figure 3: Contributions of emissions sources to our US 2015 O&NG production-segment inventory (and 95% confidence interval) compared with 2020 GHGI [25]. Inset pie charts illustrate individual source-specific contributions of our inventory to equipment leaks (left pie chart) and tanks (right pie chart). Discrepancies with the GHGI are dominated by liquid hydrocarbon tank leaks and venting (“tanks”, ~2.1 Tg/yr CH₄) and equipment leaks (~1.3 Tg/yr CH₄). Details regarding the modelling of tank emissions sources is given in SI-3.3. Results in tabular form are given in Table S2 and Table S3.

Main sources of GHGI underestimation

Given that our new component-level method is validated by the empirical results from site-level field studies, can we explain why the GHGI produces lower O&NG production-segment CH₄ emissions estimates? Results from our modelling (Figure 3), in addition to recent revisions by the GHGI and other analyses (SI- 5.1), suggest that the downward bias of the GHGI is not due to pneumatic controllers, liquids unloadings, or completions and workovers because either the divergence is small or absolute emissions are small, or both. Methane slip in reciprocating engines is higher in the GHGI, although the overall magnitude in difference is small. The combustion emission factor used in the GHGI for methane slip from reciprocating gas engines is based on a 1991 TRANSDAT dataset published by the Gas Research Institute [43]. The difference compared to our study is probably explained by substantial improvement in engine emissions since publication of that report (based on manufacturer reported specifications for

reciprocating gas engines [44]). For these reasons, this paper focuses its analysis of the two largest sources of GHGI underestimation compared to our validated method: equipment leakage and liquid hydrocarbon storage tanks, whose emissions are 1.3 and 2.1 Tg CH₄ lower than our estimates, respectively. See SI-1.1 for definitions of each emissions source.

The GHGI constructs emission factors for equipment-level leaks using an approach very similar to ours, where emission factors of individual components are aggregated according to estimated counts of components per piece of equipment. To explore differences in equipment leak estimates, we decompose equipment-level emission factors into the constituent parts: Component-level emissions data, component counts, and fraction of components emitting (the relationship between these parameters is defined in **Figure 4**).

Reconstructing equipment-level, equipment leakage emission factors from the GHGI is complicated by the fact that the underlying studies from the 1990s [35], [45] are at a more detailed level than the GHGI itself. For example, the underlying data for natural gas system emission factors are subdivided by region (e.g., Western gas versus Eastern gas), and for petroleum systems data are subdivided by product stream (e.g., light oil versus heavy oil). Equipment-level emission factors for gas systems, for example, are a weighted average of both Western emission factors and Eastern emission factors. The GHGI approach to aggregating these factors to overall values for natural gas and petroleum systems is described in SI-5.2.

We demonstrate differences in equipment-level emission factors for equipment leaks via a decomposition into constituent factors for a single example (equipment type and region) – leakage from gas wells in the West (**Figure 4**) – with equipment leaks from all other sources similarly described in the SI (**Figure S18** – **Figure S26**). The difference between our study’s equipment-level equipment leakage emission factor for Western natural gas wells and the GHGI – the difference to be explained by decomposition – is ~5x (3.4 kg/day versus 0.7 kg/day). The underlying factors are plotted in **Figure 4**.

First, we compare component-level emission factors, defined as the average emissions rate of leaking components (**Figure 4a**). (Note that the “average emission rate of leaking components” is not the same as an average emission rate for all components.) For Western gas and petroleum systems in the GHGI, component-level leakage emission factors are constructed using a method referred to by the EPA [46] as the “EPA correlation approach” (defined in detail in SI-5.2.2). In this approach, emission factors are constructed from a dataset of various facilities including oil and gas production sites, refineries, and marketing terminals ($n = 445$, data compiled in the EPA Protocol document [46]). The difference between our study’s component-level emission factors and the GHGI for connectors, valves, and open-ended lines (the components comprising the wells) is ~7x, 6x, and 5x respectively (**Figure 4a**). Note that the decomposition in **Figure 4a** is limited to connectors, valves, and open-ended lines (the three components inventoried by the GHGI) although our inventory also accounts for pressure relief valves, regulators, and other (miscellaneous) components on wells. The fact that GHGI equipment-level emission factors are based upon only three component types (when more component classes exist, according to our database) will contribute to some underestimation.

Figure 4b compares the fraction of components emitting (the ratio of emitting components to all components counted), while **Figure 4c** shows component counts (number of components counted per piece of equipment). These have offsetting effects, where component-level emission factors and component counts contribute to higher emissions in our study versus the GHGI, and fraction of components emitting contributing to lower emissions in our study. The resulting total emissions per well (**Figure 4d**) are the product of these factors, summed across all components.

Similar results are found across all equipment categories compared to the GHGI. In general, in our dataset, component-level emission factors are higher [5x to 46x comparing our emission factors for connectors, valves, and open-ended lines across all GHGI categories, see **Figure S18 – Figure S26**], the fraction of components emitting is lower [1x to 0.05x], and the number of components per piece of equipment is generally, but not always, higher [0.2x to 20x comparing our emission factors for wells, separators, and meters across all GHGI categories, see **Figure S18 – Figure S26**]. Considering the decomposition presented here, along with the rest in the SI (**Figure S18 – Figure S26**, plus some discussion of smaller factors not described here), we can explain much of the overall underestimation of the GHGI compared to our results for the equipment leaks source category.

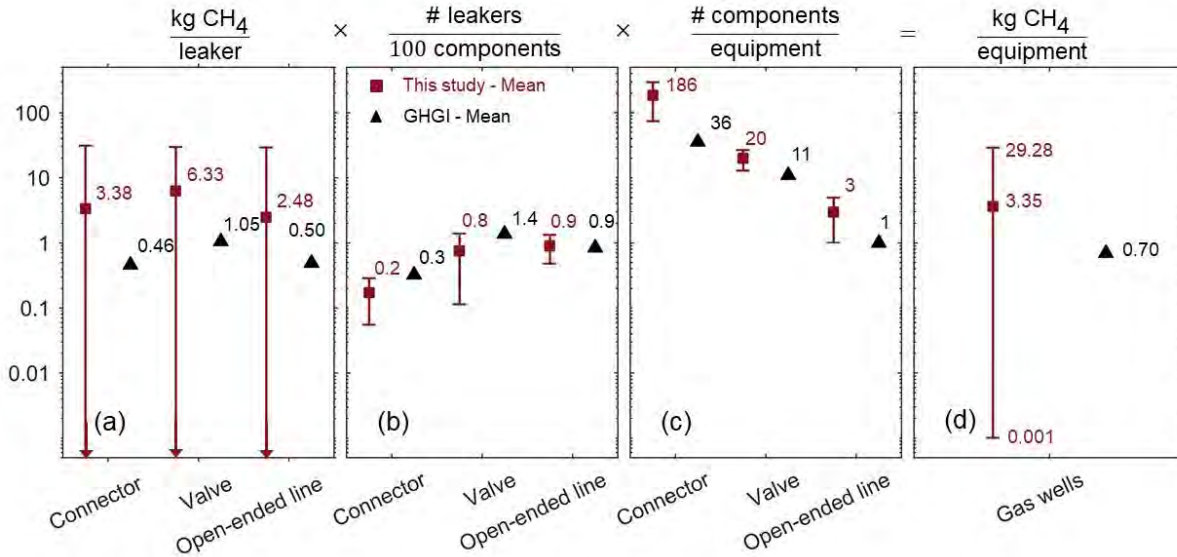


Figure 4: Example decomposition of the equipment-level emission factor for Western US gas wells (Note that units differ for each panel, and also the logarithmic scale meaning that visible differences between points often span orders of magnitude). This study's equipment-level emission factor (d) is decomposed into constituent parts and compared with the GHGI. Constituent parts include: component-level emission factors (a), fraction of components emitting (b), and component counts (c). When multiplied together, these factors have counteracting biases, with component-level emission factors and component counts contributing to higher emissions in our study versus the GHGI, and fraction of components emitting contributing to lower emissions in our study. Note that in actual usage in the GHGI, equipment-level emission factors for gas systems are a weighted average of both Western systems (API 4598, [47]) and Eastern gas systems (Star Environmental, [45]). Here, for illustration purposes, we only show constituent data for Western gas systems; results for Eastern gas system are reported in SI Section 5.2. Further, we also limit this figure to connectors, valve, and open-ended lines (the three components inventoried by the GHGI) although our inventory also accounts for pressure relief valves, regulators, and other (miscellaneous) components on wells.

The second source of significant divergence between this study and the GHGI for US CH₄ emissions in the O&NG production-segment is with emissions from liquid hydrocarbon storage tanks. The EPA GHGI constructs storage tank emissions estimates using Greenhouse Gas Reporting Program (GHGRP) data. The GHGRP is a program which collects emissions data from industrial facilities, where requirements for natural gas and petroleum systems are specified by the Code of Federal Regulations Section 40 Subpart W [48]. Based on GHGRP data for storage tanks (see methods in SI-5.3), we decompose total emissions for the GHGI into tank counts and emission factors allowing us to draw comparisons to results from this study.

Before presenting our decompositions, it is worth noting two key differences in modelling of emissions from liquid hydrocarbon storage tanks between our study and the GHGI (see further description of how our model estimates tank emissions in SI-3.3.2). First, whereas our model is based on direct measurements, the GHGI is based on operator reported simulations from software programs such as API E&P Tank or AspenTech HYSYS [49], [50]. Second, as a consequence of these differing approaches, whereas our emissions are classified based on measurement source (e.g., vent stack, thief hatch, etc.) GHGI emissions are classified according

to the simulated process (e.g., flash emissions). As a consequence of these differences in emissions classification, comparisons between decompositions of our study versus the GHGI will be imperfect.

With this in mind, we define emission factors in our decomposition as the summation of intentional emission factors and unintentional emission factors (**Figure 5**). Here, intentional (flash related) emission factors are based on direct emission measurements at the vent stack for our study, and simulations of uncontrolled and controlled tanks in the GHGI (see details in SI-5.3). Our comparison of unintentional emission factors is less precise. In the GHGI, unintentional emissions are limited to what is reported under “malfunctioning separator dump valves” (although it is unclear if additional unintentional emissions are reported alongside flash emissions in the other tank categories, see SI-5.3). Conversely, unintentional emission factors in our study are based on direct measurements of emissions from open thief hatches, rust-related holes, and malfunctioning pressure-relief valves.

We demonstrate the decomposition in **Figure 5** for petroleum systems (see **Figure S28** in the SI for natural gas systems). Note that flash emissions will only occur at controlled tanks, while unintentional emissions from thief hatches, holes, or pressure-relief valves could occur at either controlled or uncontrolled tanks. **Figure 5** and **Figure S28** demonstrate that, while several factors contribute to differences, difference in emission factors for various unintentional emissions sources are the greatest source of difference between this study and the GHGI. Unintentional emission factors are the product of (i) average emissions rate per event, and (ii) frequency of unintentional emissions events per tank. Both of these values are approximately an order of magnitude higher for our study as compared to the GHGI, contributing to the nearly two orders of magnitude difference in total emissions.

Our findings suggest that both the magnitude and frequency of unintentional emissions sources could contribute to significant underestimation in the GHGI. Due to the limited quantified, component-level data available on tank emissions (based upon safety and accessibility issues) our tank emissions measurements come from a single study in a single geographic area (Eastern Research Group in the Barnett shale,[51]). Therefore, more studies are required to provide a comprehensive view of tank emissions.

However, while quantified emissions data for tank sources are scarce, the *existence* of unintentional emissions from tanks (due to open thief hatches, rust-related holes, pressure-relief valves, etc.) has been corroborated by numerous ground and aerial surveys [42], [52]–[54]. Several of these studies are summarized in **Table S26**. Taken together, these studies provide further evidence that: (i) high emissions events are frequently observed at storage tanks, not just from vents but also at open thief hatches and pressure relief valves, (ii) these high emissions events are common at both controlled tanks and uncontrolled tanks, (iii) the frequency (events/tank) of unintentional emissions events is much higher than the rate suggested by the EPA (2%, see **Figure 5c**) for malfunctioning separator dump valves.

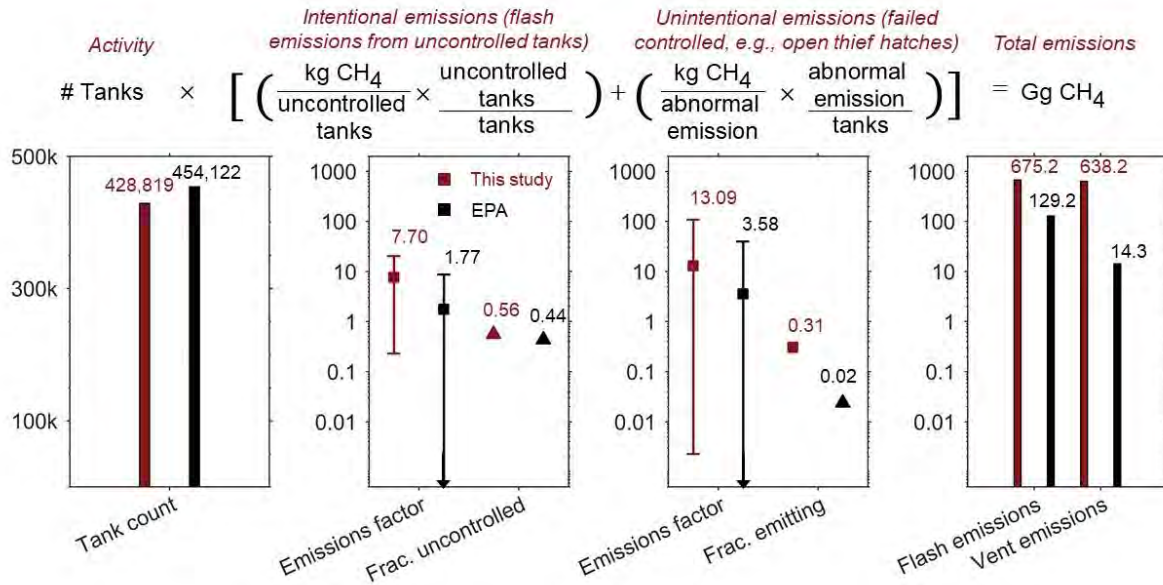


Figure 5: Decomposition of total emissions for oil tanks (far right panel) into constituent parts, with comparison of this study’s dataset to those of the GHGI. From left to right: Total activity, intentional (flash-related) emission factor, unintentional emission factor, and total emissions. Flash and unintentional emission factors are decomposed into emission factors (kg CH₄/ emitting tanks) and control rates (emitting tanks/ total tanks). Note the log scale for the right three panels.

Discussion

Development of accurate inventories at the equipment-level is critical for targeting CH₄ mitigation strategies. US government agencies [26], environmental groups [55], [56], and researchers [57] rely on inventory data for policy design, cost analysis, formulation of leak detection and repair programs, and life-cycle assessment research. However, recent studies have emphasized a ~1.5x-2x divergence between the EPA GHGI estimates of CH₄ emissions from O&NG and those estimated from field measurements at different spatial scales. This suggests an opportunity for improvement in the GHGI approach.

In this study we develop a component-level, bottom-up approach validated by previous site-level estimates of US 2015 CH₄ emissions from the production segment of the O&NG sector. Consistent with site-level findings, our estimate is ~1.8 times that of the GHGI. The strength of our approach is that by developing our estimate using component-level data, we can diagnose at the equipment-level the key sources contributing to the GHGI underestimation. Our detailed decomposition identifies (i) underlying equipment-leak measurements and (ii) neglect of the contribution of unintentional emissions events at tanks (e.g., liquid hydrocarbon tank “thief hatches”) as the most important contributors to the underestimation.

These results demonstrate that the bottom-up methodology is a valid approach to produce accurate emissions estimates and that improvements to inventory methods are possible. We make several recommendations:

- Improvements to equipment leak emission factors can be implemented relatively easily. This study applies a very similar approach to the GHGI, albeit using a more comprehensive set of data on component-level emission factors, fraction of components emitting, and component counts. We can only speculate on why differences exist between our dataset and the GHGI dataset, but based on the fact that our dataset is larger and contains more recent measurements, we suggest that it is likely to be more representative of today's conditions.
- Improvements to crude and condensate storage tank emission factors will be more difficult. Differences between our emissions estimate and the emissions estimate of the GHGI is believed to be largely a result of the GHGI neglecting emissions from failed tank controls (e.g., open thief hatches). Although we attempt to estimate their contribution, and reference supporting site-level surveys, a significant data gap exists in this area.
- Regular efforts to validate equipment-level emission factors by comparing existing or new emission factors with measurements from randomly sampled sources at different spatial scales would also improve accuracy and “build in” to inventory efforts the ability to correct data over time.

The results of this study are also relevant globally. All parties to the UNFCCC submit annual inventories, generated using a bottom-up approach, to report on progress towards GHG targets. The IPCC's Guidance Document on Emission factors outlines three approaches towards producing an inventory, with the simplest approach (Tier 1) based on IPCC default emission factors [27], [58]. Default emission factors for the petroleum and natural gas systems production-segment are based upon the same underlying data sets as the GHGI. This means that, in addition to the US-submitted GHGI, other countries using Tier 1 emission factors will be contributing CH₄ estimates according to data that we have found likely to be underestimating of actual emissions, and thus the recommendations offered herein, if implemented, would improve emissions estimates globally.

Improvements offered in this study are thus potentially directly applicable to the UNFCCC inventory method and any country directly reporting emissions estimates to the UNFCCC. Our study suggests an approach which can be applied to prepare a more accurate inventory.

Methods:

Here, we describe the methodological aspects of each of this study's three key contributions: (i) tool development, (ii) generating a US CH₄ estimate for the O&NG production-segment, and (iii) decomposing GHGI emission factors. Our methods are also described in greater detail in the Supplementary Information (SI). Datasets and code are available in a Github repository:

https://github.com/JSRuthe/O-G_Methane_Supporting_Code

Tool development

Tool structure

The analysis platform for this study is the methane venting and fugitives (VF) subroutine embedded within the Oil and Gas Production Greenhouse Gas Emissions Estimator (OPGEE version 3.0). This subroutine processes equipment-level emissions distributions and well and production values and produces gross emissions estimates.

The following equation describes the methane VF subroutine:

$$Q_{population} = \sum_{i=1}^{n_{field}} \left\{ \sum_{j=1}^{n_{wells,i}} \left[\sum_{k=1}^{n_{equip}} EF_{i,j,k} * af_k \right] \right\}$$

Here, a “field” represents a subpopulation (or bin) of wells that share similar production characteristics (e.g., gas to oil ratio). This binning was necessary because OPGEE generates outputs (carbon intensity or methane leakage rate) on a “field” basis. For each field, i , emissions are calculated well-by-well. For a single well, j , equipment-level emissions are calculated by multiplying a randomly drawn emission factor, $EF_{i,j,k}$ [kg/equipment/day], by its respective activity scaling factor, af_k [# equipment/well]. Because we iterate across wells, there is no need to explicitly multiply the activity scaling factor by well count (see SI section 3.4). Emissions are calculated across all equipment classes, k .

Database on component level studies

Our equipment-level emission factors are generated with a component-level measurement database. We conducted a detailed literature review to inform the database for this study. This review built on prior work done for Brandt et al. [11], [30] and adds new publicly available component-level measurements. Studies were reviewed for information regarding: (i) data on quantified emissions volumes per emitting component or source, (ii) activity counts for numbers of components per piece of equipment or per site, and (iii) data on fraction of components found to be emitting in a survey.

Quantified emissions data was further filtered for: (i) data collected within the production (upstream) segment, (ii) and data collected in the United States (although we do include some component count and fraction leaking data from Canada, see further details in SI-3.2). A total of 6 studies and ~ 3200 measurements met our inclusion criteria (see Table 1).

To aggregate the data from the various studies, we developed a 12-category component classification and 11-category equipment schemes. For components these include: Threaded connections and flanges, valves, open-ended lines, pressure-relief valves, compressor seals, regulators, pneumatic controllers/ actuators, chemical injection pumps, tank vents, tank thief hatches, tank pressure-relief valves, and other (miscellaneous) components. For equipment these include: Well, header, heater, separator, meter, tanks – leaks, tanks – vents, reciprocating compressor, dehydrator, chemical injection pump, and pneumatic controller/actuator (note that the “tanks – leaks” category tracks all non-vent/hatch emissions on a tank (e.g., connectors, valves, etc.) while the “tank – vent” category tracks all vent/hatch related emissions).

To align the categories of components used by the authors of a study to our common component definitions, we create a set of “correspondence matrices” to perform consistent matrix transformations (see SI-3.2.5).

Table 1: Oil and gas methane emission measurement studies that reported raw data for quantified emissions measurements, fraction of components emitting, and component counts. These studies are a subset of all studies that were examined closely, meeting inclusion criteria described. Detailed summary of each study’s results are reported in SI-6.

Study ID	Location	Number of quantified leaks	Number of components screened	Leak volumes used	Component counts used	Components screened
Allen 2013 [33]	Various	645	NR ¹	Y	N	Various components
Allen 2014 [59]	Various	377	377	Y	N	Pneum. controllers
Bell 2017 [60]	Fayetteville	322	NR	Y	N	Various components
ERG 2011 [38]	Barnett	1949	NR	Y	N	Various components
Thoma 2017 [61]	Uintah	80	80	Y	N	Pneum. controllers
Pasci 2019 [36]	Various	192	54,618	Y	Y	Various components
API 1993 [35]	Various	4794	182,833	N	Y	Various components
Clearstone 2018 ¹ [37]	Canada			N	Y	

NR = not reported

¹Given that leakage data was taken in Canada, we limit usage of this data to component counts

In addition to component-level emissions measurements, we also require component counts and fraction of components emitting. A total of 3 studies contained information on component counts [35]–[37], and we aligned the data into our standard categories. Data on fraction of components emitting was also scarce, with 3 studies containing useful information [35], [36], [51]. The fraction emitting rate is an important parameter in deriving equipment-level emission factors, but varies greatly by study due to (i) differences in screening methods between studies (e.g., Method 21 vs. infrared camera) and (ii) use of different screening sensitivity to assign a component to the emitting state (10 ppmv vs. 10,000 ppmv). Therefore, based on the technologies employed different studies may be sampling different parts of the “true” population emissions distribution. In order to ensure that we are not over or under-sampling a subset of the true distribution, we split our dataset at 10,000 ppmv (see reasons for this threshold in SI-3.2.4). Different quantified emissions bins and fraction emitting values were derived for the two halves.

Equipment-level emission factors

We required a variety of approaches to describe the different sources of emissions. The most common approach taken by this study, utilized for fugitive leaks and most vents, is a “stochastic failure” approach. In the stochastic failure approach we combine component-level emissions data, component counts, and fraction emitting values to produce equipment-level emission factors. These emission factors take the form of distributions which are generated by iteratively resampling our emissions datasets (see SI-3.3.1).

For each equipment category, we iterate across component categories and draw emissions measurements according to a probability specified by the fraction emitting value. Given that we split our dataset at 10,000 ppmv (describing quantified emitters that were missed by optical gas imaging but caught with Method 21 below the threshold, and emitters that were caught with optical gas imaging above the threshold), we develop two sets of emission factors. These two emission factor distributions are superposed to form our best approximation of the true emissions distribution (SI-3.2.4).

We applied separate approaches for flashing emission from tanks, methane slip from reciprocating compressors, and intermittent and startup losses from liquids unloading, completions, and workovers. These approaches are described in SI sections 3.3.2, 3.3.3, and 3.3.4 respectively.

Equipment-level activity factors

In the GHGI, direct equipment counts are not available for every year. As an approximation, the GHGI uses “activity drivers” such as gas production, number of producing wells, or system throughput. Activity drivers are multiplied by a scaling factor (e.g., separators per well) derived from a subsample of the population. For each piece of equipment, we employ well counts as the activity driver. Since the 2018 GHGI, the EPA has calculated activity factors for most equipment using scaling factors based on GHGRP data. Scaling factors based upon reporting year 2015 equipment counts are multiplied by year-specific wellhead counts to calculate year-specific equipment counts [62].

*Extrapolation to US oil and gas wells**Development of representative “fields” for analysis*

In OPGEE, fields are described with over 50 primary input parameters, and numerous secondary parameters. Given that we are restricting our analysis to methane leaks and vents in the upstream sector, however, we only concern ourselves with a handful of inputs: Oil production, well count, gas-to-oil ratio (GOR), and methane mole fraction. The 2015 well count and production data (**Table S31**) were based on the dataset from Alvarez et al. [13], which were originally derived from Enverus and filtered to remove offshore and inactive wells (~6,000).

In order to account for the heterogeneous nature of petroleum and NG systems, the total population was divided into several simulation sub-populations (or “bins”) according to the production GOR (where gas wells have a GOR > 100 mscf/bbl, [63]), gas productivity, and

liquids unloadings method. 60 bins were developed for natural gas systems while 14 bins were developed for petroleum systems (see SI-4.1).

Uncertainty analysis

This study applies the Monte Carlo method to estimate uncertainty. Input parameters – component-level emission factors, component counts, and fraction of components emitting – are assigned distributions, and the range of uncertainty in these distributions is propagated through the model. Therefore, the full range of uncertainty is captured to the extent that these distributions encompass the full set of possible values.

A single OPGEE simulation will produce an estimate of total US CH₄, but it will not output a distribution. We run OPGEE 100 times (100 Monte Carlo iterations), each using a different set of equipment-level emission factor distributions (further description in SI section 4.2.1). In producing variable equipment level emission factor distributions, component counts and fraction of components emitting are approximated as uniform distributions between the maximum and minimum values found in our surveyed studies (see **Table S5** and **Table S6** for component counts and **Table S10** for fraction leaking). Unfortunately, our sparse dataset does not allow us to determine a likely distribution shape for these parameters.

Comparison with the EPA GHGI

Equipment leakage

The construction of equipment-level emission factors in the GHGI is rooted in several studies conducted in the 1990s. We review these studies and trace how emission factors in today's GHGI are derived from these earlier analyses. The modelling approach of the early 1990s studies is closely related to the approach in this paper, in that equipment-level emission factors are calculated from component-level emissions measurements and counts. By gathering the underlying datasets used to construct the GHGI's equipment-level emission factors we can generate component-level distributions for comparison with the distributions of our study.

The GHGI relies on a 1996 report by the Gas Research Institute [[64], henceforth referred to as the “GRI report”] for natural gas systems and a 1996 calculation workbook by the American Petroleum Institute [[65], henceforth referred to as “API 4638”] for petroleum systems. These reports were not measurement campaigns, rather these reports summarized the results of multiple earlier works. The GRI report references API 4589 ([35], sites 9-12) for the Western US natural gas system and Star Environmental [45] for the Eastern US natural gas system. API 4638 references data from API 4598 (sites 1 – 8). Therefore, only two measurement campaigns underlie GHGI equipment leakage: the API 4589 and the Star Environmental datasets.

We first analyze the screening data in API 4598 and Star Environmental and follow the methodologies outlined in SI sections 5.2.2 – 5.2.4. In API 4598, screening concentrations from Appendix C were scanned and tabulated. Unfortunately, it was not possible to re-derive the component-level emission factors in the Star Environmental dataset. This was for two reasons. First, in the Eastern leak quantification data (provided in Appendix F, [45]), information is not provided on components measured. Therefore, quantified emissions cannot be connected to the

screening values contained in Appendix E. Second, the Eastern dataset does not report how they assigned leak volumes to the 81 instrument readings > 10,000 ppmv which were not quantified with the Hi Flow sampler. Therefore, component-by-component distributions can only be generated for API 4598.

After digitization and re-engineering of the GHGI methods, we can compare the distributions of the resulting component-level estimates with our dataset (**Figure 4**, with additional comparisons in SI Section 5.2.5).

Tank emissions

To reconstruct emission factors for crude and condensate storage tanks, we begin by downloading GHGRP data from the “Envirofacts GHG Customized Search” tool [66]. After gathering the data, we divide the dataset by product stream (natural gas, petroleum systems) and tank class. However, before making any comparisons with this study, we need to adjust how emissions-factors are reported by the GHGI. The GHGI reports storage tank emission factors on a throughput-basis (kgCH₄/bbl/year) and our study reports emission factors on a tank basis (kgCH₄/tank/day). Fortunately, in addition to tank throughput, atmospheric storage tank counts per sub-basin are also reported to the GHGRP by tank class.

Emissions-factor distributions (**Figure 5**) are calculated by dividing total emissions by tank count for every sub-basin (or row in the downloaded dataset). See SI Section 5.3 for additional details on this calculation. In SI Section 5.3, we validate this approach by calculating and comparing throughput-basis emission factors with those reported in the GHGI.

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**STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD**

IN THE MATTER OF PROPOSED NEW REGULATION,

20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants

No. EIB 21-27 (R)

DIRECT TESTIMONY OF DAVID LYON

Introduction

Q. Please state your name, place of employment, position and responsibilities.

A. My name is David Lyon. I am a Senior Scientist at Environmental Defense Fund where I work on approaches to measure and reduce oil and gas methane emissions.

Q. Please describe your educational background and general work experience.

A. I have a Ph.D. in Environmental Dynamics from the University of Arkansas and performed my doctoral research on oil and gas methane emissions. I have worked at EDF for 9 years and co-authored over 20 peer-reviewed papers on oil and gas methane. Prior to my position at EDF, I managed the State of Arkansas's air pollution emissions inventory program at the Arkansas Department of Environmental Quality.

My resume is attached as EDF Exhibit B.

Summary of Testimony

Q: Please summarize the testimony you will give.

A: My testimony will describe:

- EDF's research on oil and gas methane emissions over the last decade, a collaborative effort involving more than 140 experts from 40 institutions and 50 companies that

resulted in the publication of over 35 peer-reviewed papers. Additionally, I will describe insights from EDF's ongoing Permian Basin Methane Analysis Project, which uses several technologies to measure oil and gas methane emissions in New Mexico and Texas and rapidly publishes data online to facilitate mitigation.

- How the science supports EDF's proximity based LDAR proposal, EDF's proposal to include gas-powered pneumatic controllers in LDAR and EDF's revisions to the pneumatic controller zero bleed retrofit requirements.

Background

Q: What materials have you reviewed to prepare your testimony?

A: In preparation, I reviewed:

- New Mexico Environment Department's ("NMED's") Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021).
- EDF's proposed revisions to NMED's Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021). Ex. A.
- [*Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 SCI. 186-88 \(2018\)](#). Ex. C.
- [*Permian Methane Analysis Project*, EDF \(interactive website\)](#). Ex. D.
- [*Zhang et al., Quantifying Methane Emissions from the Largest Oil-Producing Basin in the United States from Space*, 6 SCI. ADVANCES, Apr. 22, 2020](#). Ex. E.
- [*Robertson et al., New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54:21 ENVTL. SCI. TECHNOL. 13926-13934 \(2020\)](#). Ex. F.

- [Lyon et al., *Concurrent Variation in Oil and Gas Methane Emissions and Oil Price During the COVID-19 Pandemic*, ATMOS. CHEM. PHYS. DISCUSS \(in review, Dec. 11, 2020\) \(“ACP Paper”\). Ex. G.](#)
- [Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, 8:7 ENVTL. SCI. TECHNOL. LETT. 567-573 \(June 2, 2021\). Ex. H](#)
- [Irakulis-Loitxate et al., *Satellite-Based Survey of Extreme Methane Emissions in the Permian Basin*, 7:27 SCI. ADV. \(June 30, 2021\). Ex. I.](#)
- [Allen et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquid Unloadings*, 49:1 ENVTL. SCI. TECHNOL. 641–648 \(2015\) \(“Allen et al. \(2015\)”\).](#)
- [EPA, *Lessons Learned from Natural Gas Star Partners: Options for Reducing Methane Emissions from Pneumatic Devices in the Natural Gas Industry*, Appendix 1 \(2016\). Ex. K.](#)
- [Allen et al., *Measurements of methane emissions at natural gas production sites in the United States*, 110 PROC. NATL. ACAD. 18,023 \(Oct. 29, 2013\) \(“Allen et al. \(2013\)”\). Ex. L.](#)
- [ERG and Sage Environmental Consulting, LP, *City of Fort Worth Natural Gas Air Quality Study, Final Report* \(July 13, 2011\) \(“Fort Worth Study”\). Ex. M.](#)
- [The Prasino Group, *Determining bleed rates for pneumatic devices in British Columbia; Final Report* 19 \(Dec. 18, 2013\). Ex. N.](#)
- [Rutherford, Jeffrey S. et al., *Closing the Gap: Explaining Persistent Underestimation by US Oil and Natural Gas Production-Segment Methane Inventories*, EARTHARXIV \(in review\). Ex. QQ.](#)

- [Carbon Limits, Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Program Using Infrared Cameras \(Mar. 2015\)](#). Ex. O.

Overview of EDF Studies

Q: Please describe the EDF studies of methane emissions from oil and gas operations you have participated in, including any that took place in New Mexico.

A: I have participated in over 16 studies related to U.S. oil and gas methane emissions, which have resulted in more than 35 peer-reviewed papers using numerous empirical approaches to quantify emissions.

Some of the main findings of our studies are:

- 1) Methane emissions occur across the oil and gas (“O&G”) supply chain, with ~80% from upstream sources including well pads and gathering stations.
- 2) Almost all O&G sources have a highly skewed methane emission rate distribution, with the highest 5 – 10% emitters accounting for about 50% of total emissions in that source category; however, many of these high emitters are episodic and stochastic, so all sites potentially could be a high emitter. Tanks are the most common large emission source – both uncontrolled tanks and malfunctioning controlled tanks. Ex. QQ.
- 3) Traditional inventory methods such as emission factors tend to underestimate emissions substantially, which is primarily due to the difficulty in finding and quantifying high emitting sources. High emitting sources, sometimes referred to as “super-emitters,” are not reflected in emission factors and thus traditional inventories do not reflect emissions from these sources. By contrast, EDF used a

combination of site-level, aerial and component measurements to quantify emissions, allowing accurate assessment of total emissions including super-emitters.

- 4) These studies were synthesized in the peer-reviewed paper Alvarez et al 2018, published in the journal Science, Ex. C. Based on over 400 site-level measurements and validated with aerial atmospheric data, we estimate that U.S. O&G methane emissions in 2015 were 13 million metric tons; this estimate is over 80% higher than EPA's current estimate in their Greenhouse Gas Inventory and equivalent to 2.3% of gas production.

The original 16 EDF O&G methane studies did not include measurements from the Permian Basin, but since 2018 I have been involved in several studies that include measurements from the Permian Basin in New Mexico:

- PermianMAP (EDF project that uses multiple approaches to quantify oil and gas methane emissions in the Permian, then rapidly publishes data online). Our 2020 approaches include aerial and tower-based estimates of regional methane emission trends, systematic aerial quantification of small area methane emissions, ground-based quantification of well site methane and VOC emissions, and helicopter-based OGI surveys of flare performance. Ex. D.
- Zhang et al 2020 (2018/2019 TROPOMI satellite data used to estimate basin-level methane emissions). Ex. E.
- Robertson et al 2020 (summary of 2018, ground-based measurements of well pad methane emissions by U. Wyoming using EPA-developed method (OTM 33A). Ex. F.

- Lyon et al 2021 summarizes trends in total emissions during and after the spring 2020 oil price crash. Ex. G.
- Cusworth et al 2021 uses aerial remote sensing to quantify 1100 large methane sources in the Permian and assess their intermittency. Ex. H.
- Irakulis-Loitxate et al 2021 uses three satellites to identify 37 very large sources in the Permian. Ex. I.

The major findings of the Permian studies are as follows:

- Based on 2018/2019 satellite data, Permian Basin O&G CH₄ emissions were 2.7 MMT (3.7% gas normalized loss rate, 4.1% in Delaware). Ex. E.
- Based on 71 well pad measurements, Robertson et al estimates that NM Permian emissions are 510,000 – 620,000 TPY, 5 – 9 x higher than EPA estimates; it is important to note that this estimate only includes well pad emissions that can be sampled at the ground, excluding emissions from other facility types and elevated sources such as flare stacks. Ex. F.
- Tower and aircraft data were used to track changes in total methane emissions in the core production area of the Delaware sub-basin. In early spring 2020, the loss rate was 3.3%, similar to earlier satellite-based estimates, but in April 2020 when oil price crashed, the loss rate dropped to 1.9%. This drop was temporary and emissions quickly rebounded to pre-crash values after prices recovered. The likely cause of the typical high emission rate is an overcapacity gathering system that leads to high rates of flaring and malfunction-triggered super-emitters. During low oil prices, the decline in well development temporarily relieved this over-capacity and improved emissions performance. Ex. G.

- o The ACP paper includes results from 3 aerial OGI surveys, which found that ~5% of observed flares were unlit and venting, consistent with similar surveys contracted by NMED and EPA. In addition, we found another ~6% of flares with combustion issues such as visible hydrocarbon slip. We estimate that the overall flare combustion efficiency is 93% or lower based on this malfunction rate. More recent OGI surveys suggest that the flare failure rate is even worse for small, intermittent flares. Ex. G.
- In fall 2019, NASA Jet Propulsion Laboratory and University of Arizona scientists surveyed ~15,000 square miles of the Permian with the AVIRIS-NG and GAO aircraft, which can locate and quantify emissions above ~200 tons per year methane. They identified 1100 large sources from well pads, tank batteries, gathering pipelines and compressor stations, and processing plants. Production and gathering sites were responsible for 96% of sources and 88% of emissions, while processing plant sources had larger average emissions. Tanks were a common source of detected emissions, as were flares – both lit and unlit. Large sources were mainly intermittent with an average persistence of 26% of survey flights, which indicates the importance of frequent inspections to find large emitters. Ex. H.
- Data from three satellites, PRISMA, GF5, and ZY1, were collected in 2019 – 2020 and analyzed to detect and quantify very large methane point sources in the Permian (>4,000 TPY). They detected 37% sources that accounted for 31 – 53% of total emissions in the area. Most emissions were from sites developed after

2018 and compressor stations, which supports the theory that an overcapacity gathering system in the Permian causes a high loss rate. Ex. I.

Q: Please describe the EDF studies of methane emissions from oil and gas operations you have participated in, including any that took place in New Mexico.

A: The studies point to the need for frequent if not continuous leak detection using modern and advanced leak detection methods capable of identifying leaks. EDF's revisions to the LDAR requirements in NMAC 20.2.50.116 will reduce emissions of methane, volatile organic compounds (VOCs) and air toxics by ensuring that leaking and improperly operating equipment is detected routinely and repaired. By requiring operators to inspect well sites near occupied areas such as homes, schools and hospitals more frequently than otherwise required by the NMED rule, our proposal will reduce the total amount of harmful pollution emitted from affected well sites because operators will be fixing leaks. In addition, as Dr. Thompson explains, frequent leak detection and repair will minimize exposure to harmful air toxic VOCs to persons living, playing or working nearby affected well sites.

EDF's proposal to require inspections of gas-powered pneumatic controllers in NMAC 20.2.50.122 will reduce excess emissions caused by improperly operating controllers. As our studies have demonstrated continuous bleed and intermittent vent pneumatic controllers can malfunction for a myriad of reasons, venting excess methane, VOCs and air toxics to the atmosphere. Our proposal, which is modeled on requirements adopted in other states including neighboring Colorado, as well as California and Ohio, will reduce emissions from improperly operating pneumatic controllers, thus benefiting the climate, air quality and health of New

Mexico residents, including those living at well sites covered by our proximity based LDAR proposal.

Of course, the best way to reduce pollution from pneumatic controllers is to design the controller not to emit at all. We support NMED's proposal to prohibit venting from new pneumatic controllers and are in agreement that it is reasonable and practicable to retrofit existing gas powered controllers with zero bleed controllers. However, as indicated by our suggestions revisions to the tables in NMAC 20.2.50.122, we believe NMED should move up the retrofit schedule and require a greater number of gas-powered pneumatic controllers to be retrofit. Doing so is consistent with the rule recently adopted by the Colorado Air Quality Control Commission. Increasing the pace and amount of retrofits will result in more near term reductions of VOCs, methane and HAPs. This will hasten the reduction of harmful super emitters from gas powered pneumatic controllers and aid in the state's battle against climate change and poor air quality.

INCLUDE GAS-POWERED PNEUMATIC CONTROLLERS IN LDAR

Q. Please describe EDF's the scientific basis for EDF's proposal that operators inspect gas-powered pneumatic controllers when conducting LDAR.

A. EDF recommends NMED require operators to inspect gas-powered pneumatic controllers at the same time operators go out and check for leaks from other equipment. Several recent studies report that pneumatic controllers often vent more than they are designed to vent.

- **Allen et al. (2015).** As part of this study, an expert group reviewed the behavior of the 40 controllers with the highest vent rates in the study, which were responsible for 81% of the

gas loss from all controllers in the study (377 controllers). The expert group concluded that “many of the devices in the high emitting group were behaving in a manner inconsistent with the manufacturer’s design.” Of the 40 highest venting controllers, 28 were judged to be operating incorrectly due to equipment issues. The study reported that many devices observed to actuate (often referred to as “intermittent-bleed controllers” in the US) also vented continuously. Ex. J.

- **Allen et al. (2013).** As noted above, this study reported that venting rates from low-bleed pneumatic controllers were 270% higher than EPA’s emissions factor for these devices – 5.1 standard cubic feet of gas per hour (scfh). Many low-bleed controllers are specified to vent far less than this: EPA’s Gas Star program has documented many low-bleed controller models with bleed rates of less than 3 scfh, Ex. K, and of course the emissions factor used by EPA for low-bleeds (1.39 scfh), 40 C.F.R. § 98.233(a), implies that many low-bleeds are expected to vent at a very low level. Assuming that some low-bleed controllers are performing as specified, the high emissions rate observed by Allen et al. (2013) implies that many “low-bleed pneumatic controllers” are in fact venting more than the design threshold of 6 scfh for low-bleeds, 40 C.F.R. § 60.5390(c)(1) – or much more than 6 scfh – simply to raise the average venting rate to 5.1 scfh. Ex. L.
- **City of Fort Worth Study.** The Fort Worth Study measured venting rates from 489 intermittent pneumatic controllers, using IR cameras, Method 21, and a HiFlow sampler for quantification, and found that many of these controllers were venting constantly and at very high rates, even though these devices were used to operate separator dump valves and were not designed to vent in between actuations. Ex. M. Average venting rates for the controllers in the Fort Worth Study were at a rate that approaches the average venting

rate of a high-bleed pneumatic controller. According to the study authors, these emissions were frequently due to improperly functioning or failed controllers. Ex. M.

- **British Columbia Study.** The Prasino study of pneumatic controller emissions in British Columbia also noted the potential for maintenance issues to lead to abnormally high bleed rates. Ex. N. Although the researchers did not identify a cause for these unexpectedly high venting rates, the results are consistent with the observation that maintenance and operational issues can lead to high emissions. Ex. N.
- **The Carbon Limits Report.** The Carbon Limits Report confirms that pneumatic controllers often function improperly and vent at excessive rates. Ex. O.

Q: How do the studies support EDF's proposal that operators inspect gas powered pneumatic controller as part of LDAR?

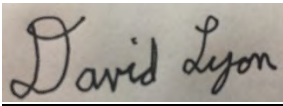
A: EDF's proposal to require inspections of gas-powered pneumatic controllers will reduce excess emissions caused by improperly operating controllers. As our studies have demonstrated continuous bleed and intermittent vent pneumatic controllers can malfunction for a myriad of reasons, venting excess methane, VOCs and air toxics to the atmosphere. Our proposal, which is modeled on requirements adopted in other states including neighboring Colorado, will reduce emissions from improperly operating pneumatic controllers, thus benefiting the climate, air quality and health of new mexico residents, including those living at well sites covered by our proximity based LDAR proposal.

Hasten and Expand Pneumatic Controller Zero Bleed Retrofit Requirements

Q: How do the studies support EDF's proposal that operators inspect gas powered pneumatic controller as part of LDAR?

A: The best way to reduce pollution from pneumatic controllers is to design the controller not to emit at all. We support NMED's proposal to prohibit venting from new pneumatic controllers and are in agreement that it is reasonable and practicable to retrofit existing gas powered controllers with zero bleed controllers. Our proposal increases the pace and amount of retrofits which will result in more near term reductions of VOCs, methane and HAPs. This will hasten the reduction of super emitters from gas powered pneumatic controllers.

This concludes my direct testimony which is true and accurate to the best of my knowledge.



David Lyon

7/28/2021

Date

**STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD**

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF HILLARY HULL

Introduction

Q. Please state your name, place of employment, position and responsibilities.

A. Hillary Hull, Director of Research and Analytics for the Environmental Defense Fund. In my role, I manage development of analytics and policy for EDF's state, federal and international oil and natural gas advocacy efforts, including regulatory advocacy, emissions inventory compilation, data and economic analytics, technical support for rulemaking and regulation, and policy analysis and development.

Q. Please describe your educational background and general work experience.

A. I have a bachelor's degree in Civil Engineering from the University of Texas at Austin and a master's degree in Environmental Engineering with a specialty in Atmosphere and Energy from Stanford University. Prior to working at EDF, I was a Senior Project Engineer for Environmental Resources Management, an environmental consulting firm.

My resume is attached as EDF Exhibit P.

Summary of Testimony

Q: Please summarize the testimony you will give.

A: I will provide a summary of the following:

- EDF's proximity based LDAR proposal.
- EDF's methodology for estimating emissions from oil and gas sources in New Mexico subject to the NMED rules.
- EDF's methodology for estimating the number of wells, and the emissions from such wells, subject to the NMED's proposed LDAR requirements.
- EDF's methodology for identifying wells located within 1,000 ft of Occupied Areas.
- EDF's estimate of the costs and cost effectiveness of our proximity based LDAR proposal.
- EDF's estimate of the demographic impacts of our proximity based LDAR proposal.
- EDF's estimate of the costs and emission reductions of our flowback proposal.

Background

Q: What materials have you reviewed to prepare your testimony?

A: In preparation, I reviewed:

- New Mexico Environment Department's ("NMED's") Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021)
- EDF's proposed revisions to NMED's Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021), EDF Ex. A.
- [*Alvarez et al., Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain*, 361 SCI. 186-88 \(2018\).](#) Ex. C.
- [*Smith et al., Airborne Quantification of Methane Emissions over the Four Corners Region*, 51 ENVTL. SCI. TECHNOL. 5832 \(2017\).](#) Ex. Q.

- [Zhang et al., *Quantifying Methane Emissions from the Largest Oil-Producing Basin in the United States from Space*, 6 SCI. ADVANCES, Apr. 22, 2020.](#) Ex. E.
- [Cusworth et al., *Intermittency of Large Methane Emitters in the Permian Basin*, 8:7 ENVTL. SCI. TECHNOL. LETT. 567-573 \(June 2, 2021\).](#) Ex. H
- [Allen et al., *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Pneumatic Controllers*, 49:1 ENVTL. SCI. TECHNOL. 633 \(Dec. 9, 2014\).](#) Ex. R.
- EDF source-level methane inventory at all well sites in New Mexico for 2019. Ex. S.
- [O&G Emissions Inventory Project: Greater San Juan and Permian Basin, Western Regional Air Partnership \(“WRAP Report”\).](#) Ex. T
- Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities, Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Aug. 2015). Ex. U.
- Colorado Air Quality Control Commission rule, 5 C.C.R., 1001-9, D.9.II.A.16 & E.4 Table 3. Ex. V.
- Datasets and map of wells (within and outside the proposed proximity boundary). Ex. W.
- Proximity Dataset Table. Ex. X.
- [Control Techniques Guidelines for the Oil and Natural Gas Industry Table 9-13, EPA \(Oct. 2016\).](#) Ex. Y.
- Background Technical Support Document, Proposed Reconsideration of the New Source Performance Standards 40 C.F.R. Part 60, subpart OOOOa (Sept. 2018). Ex. Z.
- Analysis of OOOOa Annual Air Emission Reports, MJB&A (Dec. 11, 2018). Ex. AA.

- Cost-Benefit Analysis, Colorado Department of Public Health and Environment (“CDPHE”) (Feb. 7, 2014). Ex. BB.
- California Air Resources Board (“CARB”), Summary of Cost, Emissions, and Cost per Ton using the 20 year and 100 year GWP, respectively (revised Feb. 17, 2017). Ex. CC.
- Data pulled from [American Community Survey Data, United States Census Bureau](#) and [Places:Local Data for Better Health, Centers for Disease Control and Prevention](#). Ex. DD.
- Cost-Benefit Analysis, Regulation 7, CDPHE (Sept. 4, 2020). Ex. CC.

EDF's Proximity Based LDAR proposal

Q: Please summarize the EDF proximity-based leak detection and repair (“LDAR”) proposal and our estimated benefits and costs.

A: EDF proposes that sites subject to NMED's proposal and located within 1,000 ft. of an “Occupied Area” be subject to increased LDAR frequency. Specifically, we propose that sites with the potential to emit zero to 5 tons per year (“tpy”) of volatile organic compounds (“VOC”) be subject to quarterly inspections and that sites with the potential to emit above 5 tpy of VOCs be subject to monthly inspections. The repair, recordkeeping and reporting requirements proposed by NMED would apply. Thus, our proposal only affects the frequency at which operators must inspect well sites subject to NMED's proposal and located within 1,000 ft of Occupied Areas.

Our analysis indicates that EDF’s LDAR proximity proposal will impact 3,365 (7.7%) of the well sites in the state. Our proposal represents an incremental increase in LDAR costs of \$4.8 million (13% higher than the NMED draft) and will increase reductions associated with the

rule by 3,600 tons of VOC at an average cost of \$894 per ton VOC reduced within the proposed 1,000 ft boundary (or \$349 per ton VOC reduced via LDAR statewide).

Overview of EDF Methodology for Identifying Wells and Emissions Covered by the NMED

LDAR Proposal

Q: Please describe the methodology EDF used to estimate emissions from oil and gas sources in New Mexico subject to the NMED rules.

A: We first estimated the methane inventory for each well site in the state and then used those data to develop the associated VOC inventories, as follows:

Well Site methodology: The starting point to analyze the wells subject to the proposed NMED rules and the associated emissions is well-level data downloaded from Enverus/DrillingInfo. We download well-level data for all oil, gas and CBM wells in New Mexico that report production in 2019. These data include API number, latitude/longitude, operator name, and oil and gas yearly production. These wells are mapped in ArcGIS and then clustered into well sites, using an assumed buffer of 50 meters (i.e., all wells within 50 meters belong to the same well site). These well sites are then fed into our synthesis model to estimate methane emissions for each well site.

Methane Emissions Methodology: Production methane emissions are estimated for each well site in New Mexico using two separate methods: total site-level emissions based on direct measurements from previously published studies, and component-level “bottom-up” emissions based on the EPA Greenhouse Gas Reporting Program (“GHGRP”). The difference between these two emissions estimates is attributed to 'abnormal process conditions' (“APCs”), emissions

that are difficult to quantify with bottom-up inventory based approaches. Because these APCs are subject to some uncertainty at a site-level (these emissions estimates will be more robust at a basin level), we complete our analysis both with and without these APC emissions.

Site-level emissions are estimated in the Permian, San Juan, and Raton basins using different methods.

For the San Juan and Raton basins, well site-level emissions are estimated using site-level emissions factors. These emissions factors are calculated using site-based measurements at 433 production sites in six production areas (Barnett Shale, Fayetteville Shale, Marcellus Shale [Southwest PA/WV], Uintah County, Upper Green River Basin, and Weld County). Emissions factors are correlated with yearly site-level natural gas production (from Enverus/DrillingInfo) and used to assign an emission total for all well sites in these basins. Although the underlying data do not include site-level measurements from New Mexico, Ex. C, reports that analogous estimates of San Juan Basin 2015 emissions agree closely with basin-level, aircraft-based measurements from the region, Ex. Q, suggesting that this combined dataset is broadly representative of the region.

Emissions for well sites in the Permian Basin are not calculated with the above method, but are instead calculated using the leak rate measured by satellite in Zhang et al., Ex. E, The calculated leak rate of 3.7% is applied to the gross gas produced at each well site in the Permian for 2019 to calculate the site-level emissions total for each site.

Component-level emissions for each well site are calculated using GHGRP data for 2019. GHGRP reported data are analyzed with a statistical model that uses production data and reported basin-level emissions to estimate county-level emissions for both reporters and non-reporters. For some sources, we use GHGRP activity data and other emissions data to estimate emissions. For example, pneumatic controller emissions are based on adjusted GHGRP controller counts and emission factors from Allen et al. Ex. R. County-level, component-level emissions are then disaggregated down to the well site level using the percentage of production each well site represents in a particular county.

This approach yields a source-level methane inventory at all well sites in New Mexico for 2019. Ex. S. For more details on the methodology, please refer to Alvarez et al. 2018, Ex. C.

VOC Emissions Methodology: In order to analyze the proposed NMED rule, VOC emissions by well site are needed. The site-level, source-specific methane inventory described above is converted to a VOC inventory using basin and source-specific methane-to-VOC ratios from a 2016 WRAP report. When converting site-level methane emissions to VOC emissions, we exclude the APC emissions. The NMED rule is based on potential to emit (“PTE”). Because we cannot directly calculate PTE, we assume that GHGRP-reported “bottom-up” emissions will most closely approximate PTE and we therefore exclude the APC emissions. With this methodology, we create a database of well sites in New Mexico, with latitude/longitude, operator name, and emissions: total VOC “bottom-up” emissions, total methane “bottom-up” emissions, and total methane “site-level” emissions. From this database, we can bucket well sites into the

different LDAR tiers from the NMED proposal and map the well sites as part of our proximity analysis.

Q: Please describe the methodology EDF used to estimate the number of wells covered by the NMED LDAR proposal.

A: The following describes our methodology:

- *Analysis of NMED LDAR Proposal:* Using the VOC bottom-up emission inventory by well site described above, we can analyze the NMED LDAR proposal. Using the VOC bottom-up inventory as a proxy for PTE, we categorize each well site depending on the VOC tier (<2 tpy VOC, between 2 and 5 tpy VOC, and >5 tpy VOC). We sum the methane and VOC emissions covered by the proposal in each tier (using both the bottom-up and site-level methane emissions as lower and upper bounds). We then calculate emissions reductions for equipment leaks in each tier using the assumed reduction percentages of 40%/60%/80% for annual/semiannual/quarterly LDAR respectively. Ex. U. Due to the intermittent nature of APC emissions we estimate LDAR emission reductions for these emissions using data from Cusworth et al., Ex. H. Cusworth et al. used airborne imaging spectrometers to measure CH₄ emissions from production facilities and additionally estimated the persistence of emissions from those sources. Using this data we estimate the likelihood that APC emissions would be detected by LDAR: ~25%/44%/68%/97% for annual/semiannual/quarterly/monthly LDAR, respectively. We assume that 100% of APC emissions that are detected by LDAR are mitigated.

Q: Please describe the methodology EDF used to estimate occupied places.

A: For our proposal we used the same definition for Occupied Areas as the Colorado Air Quality Control Commission, 5 C.C.R. 1001-9:D.II.A.16. Ex. V. Colorado and our current proposal defines an Occupied Area as the following:

- (1) a building or structure designed for use as a place of residency by a person, a family, or families. The term includes manufactured, mobile, and modular homes, except to the extent that any such manufactured, mobile, or modular home is intended for temporary occupancy or for business purposes;
- (2) indoor or outdoor spaces associated with a school that students use commonly as part of their curriculum or extracurricular activities;
- (3) five thousand (5,000) or more square feet of building floor area in commercial facilities that are operating and normally occupied during working hours; and
- (4) an outdoor venue or recreation area, such as a playground, permanent sports field, amphitheater, or other similar place of outdoor public assembly.

Geospatial data was collected from multiple databases in order to create a complete map of Occupied Areas in NM. A table of all used datasets and their sources is provided as Exhibit W. First, we collected all available data relevant to schools and outdoor recreation areas for (1) and (4) above. A complete publicly available dataset of residences in NM was unavailable. In order to identify all buildings designed for residency, we first combined datasets on public housing and multifamily assisted properties from the U.S. Department of Housing and Urban Development (HUD). While not explicitly included in this definition, we believe that hospitals and other health facilities should be considered occupied areas due to both the quantity and the

potentially vulnerable nature of those in residence and thus we included these facilities in our proposal. We also downloaded a land-use and building dataset from OpenStreetMap, which included some structure and building classifications (i.e. residential, schools, etc.) but is incomplete, specifically in rural areas. These datasets were filtered based on building type and/or name. A list of specified keywords can be found in Exhibit X.

The state of NM provides a statewide building footprint dataset and we selected all buildings >5000 square feet for number (3) above, and all buildings between 1,400 and 4,000 square feet as residences. Based on Census Survey data, 85% of new single-family homes built in 2020 in the West (including NM) were between 1,400 and 4,000 square feet. While the average size has increased (~1,600 sq. ft. in the 1970s to ~2,400 sq. ft. in 2020) more than 80% of homes built since 2000 have been between 1,400 and 4,000 square feet. A table outlining the datasets we used for this analysis is included as Exhibit W.

Q: Please describe the methodology EDF used to estimate the emissions from leaks and abnormal operating conditions at wells within 1,000 ft of occupied areas.

A: The datasets outlined above were then combined into an “Occupied Areas” master dataset. We created 1,000 ft buffers around each Occupied Area in ArcGIS, and overlaid these buffers with our 2019 well site dataset. Using this method we identified 3,365 well sites that are within 1,000 ft of an occupied area. In order to estimate emissions from leaks and abnormal process conditions, we relied on the EDF site-level VOC emissions inventories for the sites within 1,000 feet of an occupied area.

Cost Effectiveness of EDF LDAR Proposal

Q: Please describe the expected benefits from EDF's proximity based LDAR proposal

A: Our analysis indicates that EDF's LDAR proximity proposal will impact 3,365 (7.7%) of the sites in the state and will increase reductions at those sites by 73%. Specifically, our proposal will result in an additional 3,600 tons of VOC reductions annually. Co-benefits associated with our proposal include an additional 14,300 tons of methane and 150 tons of hazardous air pollutants.

Q: Please describe EDF's methodology for estimating the costs of our proposal and its cost effectiveness

A: Our proposal represents an incremental increase in LDAR costs of \$4.8 million (13% higher than the NMED draft standard) at a cost of 894/ton of VOC reduced within the proximity boundary. This increases the overall statewide cost-effectiveness of LDAR from \$317 per ton VOC reduced (per the state's proposal) to \$349 per ton VOC reduced (accounting for increased frequency within the proximity boundary). We estimated costs associated with our proposal two ways: (1) using the site-level LDAR costs NMED used in its technical documentation, taken from the EPA Control Technique Guidelines (CTGs), Ex. Y, and (2) using the costs EPA presents in its NSPS TSD, Ex. Z which we then revised to reflect reported data from the NSPS compliance reports submitted by operators to EPA. Ex. AA. Neither source explicitly included monthly LDAR costs, so we scaled the costs for lower frequencies to account for more frequent monthly inspections. We make the assumption that wells performing monthly LDAR are likely to be non-low producing wells since the wells subject to monthly inspections must have a PTE VOC emissions of at least 5 TPY. Using 2020 EPA cost estimates for non-low producing wells

from Ex. AA, we performed a linear regression to estimate an average monthly LDAR cost. We then applied the ratio of cost increase from quarterly to monthly to both the NMED & EDF cost-per-site estimates. Once we identified the sites within the 1,000 foot boundary of occupied areas, we applied the cost figures I've outlined and estimated total and incremental costs associated with our proposal. We then divided that cost by the reductions associated with our proposal and calculated the cost-effectiveness.

Q: Is the EDF proposal based on rules adopted by other jurisdictions?

A: Yes, in 2019 the Colorado AQCC promulgated a rule that requires operators to inspect well sites located within 1,000 feet of occupied areas more frequently than facilities located outside of this radius (Exhibit E). Specifically, the Colorado rule requires operators inspect well sites monthly rather than quarterly, if the well site has actual uncontrolled VOC emissions of 12 tpy or greater. Operators must inspect well sites quarterly, rather than semi-annually, if the well site has actual uncontrolled VOC emissions of between 2 and 12 tpy. Our proposal mirrors Colorado's in that we used the same 1,000 ft radius in which to require more frequent inspections of well sites, the same definition of Occupied Areas, and the same inspection frequencies of quarterly or monthly. Colorado uses a different metric than NMED to bucket well sites for purposes of its LDAR program. For example, the NMED proposal uses potential to emit VOCs whereas Colorado uses actual uncontrolled VOC emissions. Colorado's tiered LDAR program also buckets well sites into different inspection tiers than NMED (e.g., Colorado requires semi-annual inspections for well sites with actual uncontrolled VOCs between 2 and 12 tpy whereas NMED proposes semi-annual inspections for well sites with a PTE of between 2 and 5 tpy of

VOCs). Thus, our proposal differs from Colorado in terms of the metric used to bucket wells into the quarterly or monthly inspection frequencies.

Q: How do the costs, and cost effectiveness of EDF's proposal compare to costs and cost effectiveness prepared by other regulators?

A: The estimated cost-effectiveness of EDF's proposal (which includes both quarterly and monthly inspections implemented at a cost of \$894 per ton of VOC reduced within the 1,000 ft boundary) is lower than quarterly and/or monthly cost-effectiveness figures for regulatory standards in other jurisdictions. Considering quarterly and monthly inspections separately, this comes to \$576 per ton VOC reduced for monthly inspections within the boundary and \$1,351 per ton VOC reduced for quarterly inspections within the boundary. However, EDF estimates that statewide quarterly inspections (including those both within and outside the proposed 1,000-foot proximity boundary) will only cost \$187 per ton VOC reduced overall, and our proposal increases overall statewide LDAR cost-effectiveness from \$317 per ton VOC reduced to \$349 per ton VOC reduced, which is highly cost-effective relative to cost-benefit analyses from other jurisdictions. For example, in its 2014 Cost-Benefit analysis, the Colorado Department of Public Health and Environment (CDPHE) found quarterly inspections at production facilities to be \$1,019 - \$1,268 per ton of VOC reduced and monthly inspections to be \$2,235 - \$2,752 per ton of VOC reduced. Ex. BB. The EPA CTGs estimate that quarterly inspections at well sites cost \$3,453 - \$15,929 per ton VOC reduced without savings and \$2,619-\$15,064 per ton VOC reduced with savings. Ex. Y. Both of these cost-effectiveness calculations are somewhat outdated (the rules were promulgated in 2014 and 2016, respectively), whereas the EDF cost calculation accounts for information taken from more recent compliance reports submitted by

operators to the EPA which reflect real-world inspection metrics. Additionally, the California Air Resources Board (“CARB”) requires quarterly inspections at all well site facilities, a standard which CARB found to be part of a cost-effective methane rule. The CARB cost-effectiveness analysis associated with its rule finds the quarterly LDAR standard would be implemented at a cost of \$575-\$650 per ton of methane. Ex. CC. Using the average methane-to-VOC ratio in New Mexico, this translates to a cost of \$2,300-\$2,600 per ton VOC, which is also higher than EDF’s estimate for the cost per ton associated with our proximity proposal.

Impact of EDF LDAR Proposal on Demographics

Q: Were you able to assess the demographics of impacted populations?

A: Yes, we developed a methodology to estimate the characteristics of populations living within 1,000 ft of affected wellsites. Using the US Census Bureau’s American Community Survey 5-year estimates for 2012-2016 and the Centers for Disease Control 2020 Places dataset, we were able to estimate the populations living within a 1,000 foot radius of the previously identified low production well sites using areal apportionment. This method determines the area encompassed within a 1,000 ft buffer radius of all affected wells, and overlays those buffers onto census tracts to calculate the percentage of each tract comprised of buffers (i.e. the area of each tract within a 1,000 ft of an affected well). The areal apportionment method assumes that populations are spread evenly across a given census tract (excluding water bodies), and thus we are able to estimate the populations at a census tract level of those living within a 1,000 ft of a low production well site. This method is commonly used in published literature utilizing distance-based analysis. While some studies have used finer spatial resolutions such as census block groups, we performed our analysis using census tracts in order to minimize margin of error

in census estimates. Census tracts, and even larger regions such as zip codes, have often been used in similar analyses. Using this tool, we estimate that over 35,000 New Mexicans live within 1,000 ft of a wellsite. Of those, we estimate that over 2,700 are children under the age of 5, more than 4,500 are adults 65 years or older, more than 5,700 are living in poverty, and 19,000 are people of color, including over 5,800 Native Americans. Additionally, those living in close proximity to these well sites have health conditions that could be exacerbated by additional air pollution. These include more than 3,800 adults with asthma, over 2,200 adults with coronary heart disease, almost 2,600 with chronic obstructive pulmonary disease, and more than 1,200 adults who have experienced or are at risk of a stroke. Ex. DD.

EDF Flowback Proposal

EDF used the CDPHE Cost-Benefit analysis for revisions to Regulation 7 from September 2020 to evaluate costs and cost-effectiveness associated with emissions control requirements for flowback vessels and associated equipment. Ex. EE. The CDPHE requirements include using vapor-tight flowback tanks and conducting periodic visual inspections of the flowback tanks and associated equipment. The analysis found that these requirements could be implemented at a cost of \$53.79 per ton methane reduced using the 3-year average for number of completions over 15 years. Using the statewide average methane to VOC ratio for completions, this comes to \$259.48 per ton VOC reduced. As such, EDF finds these measures to be a cost-effective means of mitigating flowback emissions.

This concludes my direct testimony which is true and accurate to the best of my knowledge.

A handwritten signature in cursive script, appearing to read "Hillary Hull", written in black ink.

Hillary Hull

7/28/2021

Date

**STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD**

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF TAMMY THOMPSON

Introduction

Q: Please state your name, place of employment, position and responsibilities.

A. My name is Dr. Tammy Thompson, I am Senior Air Quality Scientist at the Environmental Defense Fund. My job is to guide decision making at EDF based on the science on atmospheric chemistry and physics, air quality modeling, and human health impacts.

Q: Please describe your educational background and general work experience.

A. I have a BS, and a PhD in Chemical Engineering with a focus, and thus an expertise in atmospheric chemistry and physics and air quality modeling. I did my post doctoral research at MIT working on the linkage of climate change and air quality, investigating and modeling how national and sub-national climate policies would impact human health through air quality co-benefits. I worked as a Research Scientist at Colorado State University investigating how emissions from oil and gas production in the US would impact the National Park System. As a scientific consultant, I modeled national human health impacts from oil and gas production emissions and how methane standards would change those human health impacts. I have since worked as a science policy fellow in EPA's Office of Policy evaluating the use of air quality modeling in cost/benefit analysis (of which human health is a key part). My expertise focuses on using modeling tools and input data to estimate ambient concentrations of air pollution species. I

then use existing information about the human health impacts of different species of air pollution recognized by US EPA and WHO to make links to human health outcomes.

My resume is attached as EDF Exhibit FF.

Summary of Testimony

Q: Please summarize the testimony you will give.

A: I will summarize studies that have found that persons living near oil and gas facilities are at greater risk of developing adverse health impacts due to increased exposure to volatile organic compounds that are also classified as hazardous air pollutants. I will also summarize EDF's proposed proximity based LDAR requirement that will reduce volatile organic compounds that contribute to ground-level ozone and reduce exposure to harmful pollutants for persons residing, working or playing within 1,000 ft of oil and gas facilities. Benzene is a well established cause of cancer in humans. Ex. GG. I am not here to convince you that hazardous air pollutants like Benzene, things we KNOW are emitted from oil and gas production wells, cause cancer and other major non-cancerous health impacts. The US EPA and the World Health Organization ("WHO") have made that declaration, and WHO states that there is no safe level of exposure. I am here to convince you that people living near oil and gas sites will breathe in more of these harmful species, and if living within 2000 feet of oil and gas sites, evidence suggests they may breathe enough to statistically increase the likelihood that they will develop cancer or other negative health impacts based on what the US EPA and the WHO know about human health response to these toxic compounds.

In addition, increasing the frequency of well site inspections, and quickly repairing any malfunctioning or leaking equipment (as proposed here) will reduce the emissions of all VOCs from oil and gas operations in New Mexico. The resulting reduction in VOCs will help New Mexico reduce local formation of ozone, and thus stay in attainment of the national ambient air quality standards for ozone, a criteria pollutant that EPA recognizes is dangerous to humans.

Background

Q: What materials have you reviewed in preparation of your testimony?

A: To prepare my testimony I reviewed the following documents:

- New Mexico Environment Department’s (“NMED’s”) Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021)
- EDF’s proposed revisions to NMED’s Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021), EDF Ex. A.
- [Preventing Disease Through Healthy Environments, WHO \(2010\)](#). Ex. GG.
- [National Ambient Air Quality Standards for Ozone, 80 Fed. Reg. 65292, 65322 \(Oct. 26, 2015\)](#). Ex. HH.
- [Final Report: Human Health Risk Assessment for Oil and Gas Operations in Colorado, ICF \(Oct. 17, 2019\) \(submitted to CDPHE\)](#). Ex. II.
- [State of New Mexico Environmental Improvement Board, IN THE MATTER OF PROPOSED NEW REGULATION, 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants No. EIB 21-27 \(R\), Petition for Regulatory Change \(May 6, 2021\)](#). Ex. JJ.

Overview of need for VOC reductions to protect air quality

Q: Please describe the ozone benefits of EDF's Proximity Based LDAR Proposal.

A: One of the clear benefits of EDF's proposal is that it will lead to additional VOC reductions necessary to ensure compliance with the ozone NAAQS. EDF estimates that requiring quarterly, rather than annual or semi-annual inspections at well sites with site wide VOC emissions less than 5 tons per year will result in an additional 2,080 tons of VOC reductions annually. Bumping up the inspection frequency to monthly for those well sites located within 1,000 ft of occupied areas that emit greater than 5 tons per year of VOCs will remove an additional 3600 tons of VOCs from the atmosphere.

VOCs contribute to ground-level ozone. Ground-level ozone is a dangerous air pollutant. Exposure to elevated concentrations of ozone lead to serious, adverse health effects, including asthma, increased emergency room visits, and premature death - impacts that are particularly severe in sensitive populations, like children and the elderly. Ozone also causes direct harm to the environment by impeding plant growth and vitality and decreasing crop yield. Per the NMED's Petition for Regulatory Change, air quality in eight counties in New Mexico is dangerously close to being out of compliance with the federal health-based standards for ozone. Much more must be done to protect healthy air and to protect against air quality degradation in New Mexico. Additional inspections at well sites near occupied areas can help NMED protect air quality.

Overview of Health Studies

Q: Please describe the studies that have examined health impacts to persons living/working/playing near oil and gas facilities.

A: I'm going to talk about a Colorado Department of Public Health and Environment ("CDPHE") study that links air pollution emissions from oil and gas production operations to the potential for serious human health impacts in populations living near well sites. Specifically, I will discuss how to use models to take oil and gas emissions information and estimate what the short term (hourly) and longer term (annual to lifetime) concentrations of VOCs including hazardous air pollutants resulting from those emissions would be within 500 ft, 1000 ft, and 2000 ft of those wells. The purpose is to understand the range of concentrations of air pollutants, including hazardous air pollutants, that people living, playing, and breathing at those distances from these well sites are likely to be exposed to. The particular CDPHE study was done in Colorado using state of the science air pollution plume dispersion modeling. The study looked at three sizes of well sites, and four types of processes on well sites (as different processes have different emissions), including drilling, fracking, flowback, and production. They used a years worth of data on wind direction and speed to capture a range of weather patterns. Ex. II.

The study found the following with respect to elevated lifetime cancer risk:

- Benzene exposures from both production emissions alone, and all activities combined (drilling, fracking, flowback and production), were associated with an increased lifetime risk (above 1 in a million) of leukemia for the average individual at 500 ft.

- Risks in the populations exposed to the highest concentrations only dropped below the 1-in-a-million risk threshold after a distance of 2000 ft.

The study also found non-cancer health risks, including the following:

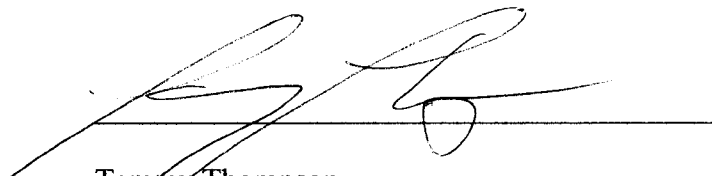
- Benzene and 2-ethyltoluene emissions were found to be higher than considered safe for most simulated populations at 500 feet away after the maximum one hour exposure.
- Exposures of benzene were more than 10 times higher than considered safe for one hour maximum exposure and is a risk for blood disorders. Blood disorders could result in anemia, disturbances in clotting or the ability to fight infections, and could manifest as fatigue, nose bleeds or infections.
- The study also found the potential for neurotoxic effects, such as headaches, blurred vision, dizziness, from combined acute exposures of benzene and 2-ethyltoluene.
- Risks were seen with acute exposure in every age group assessed.
- Exposures and risks during the flowback stage were found to be higher than those from other drilling and fracking activities. Specifically, long term (chronic) exposure to multiple VOCs (n-nonane, benzene, m+p-xylene, and trimethylbenzenes) during prolonged flowback activities, in large well sites resulted in elevated risks for neurotoxicity and blood disorders.

Q: Please describe any policy implications that EDF believes flow from this study.

A: The CDPHE study demonstrates the need for more stringent controls of oil and gas emissions at well sites located near to where people play, work or recreate. Colorado adopted a rule in 2019 that requires operators to inspect well sites located within 1,000 feet of occupied

areas (such as homes, schools and playgrounds) more frequently than would otherwise be required by state rules. This was done in response to a proposal by local communities who were concerned about exposure to harmful air pollutants at nearby well sites. EDF's proposal is modeled on Colorado's rule, and like Colorado's rule, requires operators to inspect well sites located near occupied places wither quarterly or monthly.

This concludes my direct testimony which is true and accurate to the best of my knowledge.



Tammy Thompson

7-28-21
Date

**STATE OF NEW MEXICO
ENVIRONMENTAL IMPROVEMENT BOARD**

IN THE MATTER OF PROPOSED NEW REGULATION,
20.2.50 NMAC-Oil and Gas Sector-Ozone Precursor Pollutants **No. EIB 21-27 (R)**

DIRECT TESTIMONY OF THOMAS ALEXANDER

Introduction

Q: Please state your name, place of employment, position and responsibilities.

A: Tom Alexander. I have been a consultant to EDF for the past 5 years working on: Underground gas storage, flaring, venting, conventional and unconventional regulations (in eastern states mostly). I assisted EDF in their advocacy before the New Mexico Oil Conservation Commission last January when the Commission adopted its flaring and venting rule. I have also assisted EDF in its contributions to the Interstate Oil and Gas Compact Commission and Energy Resources, Research and Technology committee and two American Petroleum Institute work groups on risk management, Health, Safety and Environment, security and training.

Q: Please describe your educational background and general work experience.

A: In total I worked for SWN for 18 years (1998 – 2016) first as a consultant and then as a staff production and completion engineer, team leader for their Fayetteville Shale discovery team and Completion Manager. More recently, from late 2012 to 2016, I served as Vice President of Health, Safety & Environment for SWN. I also worked for SWN's Canadian subsidiary, SWN Resources Canada in New Brunswick, Canada as the General Manager from mid 2010 through most of 2012. Prior to SWN, I worked for New Prospect Company and Revere Corporation in Fort Smith, Arkansas, Habersham Energy Company in Englewood, Colorado, Southwest

Operating, Incorporated and Altair Energy Corporation in Tyler, Texas and Schlumberger Offshore Services in Houston, Texas. From 1975 to 1981, I served in the United States Air Force as a B-52H Navigator and Radar Navigator.

I received a Bachelor of Arts, Psychology from Wake Forest University (1973). I did post-graduate work in chemistry and genetics at Duke University (1973). I received a Master of Science, Mining Engineering (1981) and a Bachelor of Science, Mining Engineering (1981) from South Dakota School of Mines and Technology. I completed the course work for Master of Arts, Environmental Policy and Management at the University of Denver (1994). My resume is attached as EDF Ex. KK.

Summary of Testimony

Q: Please summarize the testimony you will give.

A: In summary, my testimony will reflect the following:

- There are areas for improvement in the NMED proposed rule as indicated by the revisions EDF proposes to the leak detection and repair provisions and pneumatic controller provisions. In addition, EDF proposes two additional provisions, one to require control of emissions during flowback and the second to require the use of auto gauges.
- With respect to EDF's LDAR proposals, I will speak to the reasonableness of EDF's proposal that operators inspect gas-powered pneumatic controllers when conducting leak inspections and the reasonableness of requiring frequent inspections at well sites near homes and other "occupied areas."

- My testimony will also discuss EDF’s proposal that requires operators use vapor tight flowback vessels equipped with a control device, such as a flare, capable of destroying hydrocarbons by at least 95%, and equipped with safety relief systems to control emissions during flowback.
- I will also discuss why New Mexico should follow Colorado’s lead and require a shorter (i.e., four years) timeframe to retrofit existing gas-powered pneumatic controllers to zero bleed devices, and increase the number of pneumatic devices that must be zero bleed.
- Lastly, I will speak to the benefits of requiring operators to use a tank measurement system (i.e., auto gauge) to measure liquid levels in new storage tanks. These four improvements will secure additional reductions of harmful volatile organic compounds, methane and air toxics from oil and gas sources in New Mexico.

Background

Q: What materials have you reviewed to prepare your testimony?

A: In preparation, I reviewed:

- New Mexico Environment Department’s (“NMED’s”) Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021)
- EDF’s proposed revisions to NMED’s Proposed Oil and Gas Sector-Ozone Precursor Pollutants Rule, 20.2.50 NMAC (May 6, 2021), EDF Ex. A.
- Colorado Air Quality Control Commission rule, 5 C.C.R., 1001-9, D. Ex. V.
- [Pneumatic Controller Task Force Report to the Air Quality Control Commission, Colorado Air Pollution Control Division \(“AQCC”\), \(June 1, 2020\).](#) Ex. LL.
- Economic Impact Analysis (Final) for Regulation 7, AQCC (Oct. 4, 2017). Ex. MM.

- Economic Impact Analysis (Final Analysis) for Regulation 7 (Nov. 5, 2019). Ex. NN.
- [California Air Resources Board, Standards for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities, Section 95668\(e\)\(2\).](#) Ex. OO.
- [Ohio General Permit.18.1, C.1.\(d\)\(3\)\(b\).](#) Ex. PP.
- Analysis of OOOOa Annual Air Emission Reports, MJB&A (Dec. 11, 2018). Ex. AA.
- Cost-Benefit Analysis, Regulation 7, CDPHE (Sept. 4, 2020). Ex. CC.

Overview of NMED Rule

Q: What is your overall impression of NMED’s proposed rule?

A: NMED’s proposed rule is very comprehensive in nature (a broad variety of practices and equipment are addressed) and will lead to the elimination of many unnecessary emissions from machinery, equipment and processes at a reasonable cost to operators. In many cases, there will be measurable payouts, but in those cases where payout is difficult to define or may not occur, implementing practices that reduce emissions is simply the right thing to do. The absence of a direct, easily measured economic benefit should not be justification to oppose the adoption of practices that clearly enhance safety and health and protect the environment. Indeed, in many cases there are benefits (e.g., public health, environmental health, social license to operate) outside of the immediately measurable economics for the oil and gas operator.

EDF's Proposal to Include Gas Powered Pneumatic Controllers in LDAR

Q: Can you summarize EDF's proposal to include gas-powered pneumatic controllers in the instrument-based leak detection and repair (LDAR) inspections contained in proposed NMAC 20.2.50.116(C)(3) and (D)?

A: EDF proposes operators inspect gas-powered pneumatic controllers located at wellhead sites, tank battery facilities, gathering and boosting sites, gas processing plants and transmission stations when conducting required EPS method 21 or optical gas imaging inspections in order to identify leaks from improperly operating pneumatic controllers.

Q: Are instrument-based inspections necessary to identify leaks from improperly operating controllers?

A: Yes. Instruments such as OGI cameras and Method 21 devices can reliably detect excess/abnormal emissions from malfunctioning gas-powered pneumatic controllers. NMED's proposal requires operators inspect gas-powered pneumatic controllers for leaks using audio-visual -olfactory (AVO) inspections, but not using instruments. While AVO inspections are better than nothing, instrument assisted inspections are more effective than AVO.

Q: Please describe your experience with LDAR programs that looked for leaks from gas-powered pneumatic controllers.

A: When I was at Southwestern Energy (SWN) the company developed a leak detection program that included gas-powered pneumatic devices. Specifically, during the development of the Fayetteville Shale in Arkansas, SWN took great measures to eliminate leakage, flaring and venting from a variety of what was originally viewed as routine sources, processes and

procedures. In fact, we pioneered the notion AND practice of green completions. With respect to reducing leaks from improperly operating or aging equipment like pneumatic controllers SWN began by studying how much gas is potentially lost from production face (i.e., the perforated well bore interval) to the burner tip. This was borne out of a discussion in the public sphere regarding whether natural gas was as “dirty” or “dirtier” than coal. SWN engaged a research group to help and found that if methane leaked above a certain percentage of production, then the claim could well be true. At SWN we identified that point to be approximately 1% and developed what we initially called the 1% solution which eventually became 1 Future. Armed with this information and a goal to get methane loss below 1% from the production face to burner tip, we sought to identify any and all avenues where leakage occurred. We had discussions with midstream (for the Fayetteville Shale we owned and operated that) and downstream (folks like Kinder-Morgan were involved) and set out to do our part. We purchased 6 OGI cameras (\$100,000 each) and set up a protocol for identifying and fixing leaks at all SWN operated wells and installations. It was very successful. Our overall expenditures were perhaps in the \$1,500,000 range with 5 to 6 dedicated individuals doing the work over a two-year period. We learned a lot about trends, at least in our area of operations, which helped us preclude even having leaks in many cases. In the end we achieved approximately a 0.2% or below emission rate for CH₄.

Our LDAR program helped SWN identify useful information and trends that led to emissions reductions. In particular, we discovered that equipment such as certain gas-powered pneumatic controllers, liquid level controllers and certain liquid unloading procedures fail due to specific reasons. By inspecting our equipment such as gas-powered controllers with OGI

cameras we were able to detect and repair leaks, which helped us reduce methane emissions. In addition, we optimized our operations as we discovered trends that helped us prevent leaks in the future. We developed preventative maintenance procedures that specifically addressed our locations and operations. While each individual installation may not account for a great deal of lost methane, our well count added up to a significant volume. We converted to all low or zero bleed pneumatics. There will be a number of pieces to the pie, such as on the ground LDAR and over flights, process and procedure, equipment and culture. Culture may actually be the most important. Furthermore, on new installations, one can and should incorporate the best available technology and processes into the well design and operation.

In sum, SWN's program demonstrated that leak detection and repair can help identify emissions from malfunctioning equipment including, but not limited to, gas-powered pneumatic controllers.

Q: Are you familiar with other states that have implemented an LDAR program that applies to gas-powered pneumatic controllers?

A: Yes. In preparing my testimony I reviewed Colorado's Pneumatic Controller Inspection and Enhanced Response rule that requires operators inspect for malfunctioning gas-powered pneumatic controllers using an approved instrument monitoring method when conducting LDAR inspections. Ex. LL. I see the Colorado rule as a good example for New Mexico to follow since in my experience inspections of gas-powered pneumatic controllers generates good data on operational practices and reduces emissions.

Q: Did you review the Colorado APCD Pneumatic Controller Task Force Report to the Air Quality Control Commission (“AQCC”)?

A: Yes. I reviewed the Colorado APCD Pneumatic Controller Task Force Report to the Air Quality Control Commission (“AQCC”). Ex. LL. This report contains helpful information that explains why Colorado adopted its pneumatic controller inspection program for sources located in the Denver Metropolitan Ozone Nonattainment Area initially in 2017 and why it chose to expand the program statewide in 2019. In discussing the initial adoption of the rule in 2017, the report notes that “the AQCC recognized that continuous bleed and intermittent pneumatic controllers are designed to have emissions but these emissions can be excessive when the controllers are not operating properly. The AQCC adopted the Find and Fix program to reduce excess emissions from such natural gas-driven pneumatic controllers.” Ex. MM, p. 1.

At the time the AQCC adopted the rule for sources in the Denver Metropolitan Ozone Nonattainment Area it also adopted a reassessment provision. A task force, consisting of representatives from industry, non-governmental environmental organizations and local governments, convened and set out to collect data on the efficacy of the program. Specifically, nine operators of well production facilities and compressor stations in the Denver Julesburg Basin collected data on their inspections of gas-powered pneumatic controllers. All inspections were conducted using OGI. Ex. LL, p. 8. Operators inspected over 3,800 pneumatic controllers. They found that 5% were improperly operating. Ex. LL, p. 11. Of these continuous bleed pneumatic controllers were found to have an improper operation rate of 3.5% while intermittent controllers had a rate of 5.6%. Ex. LL, p. 12. The study revealed a number of reasons for improper operation including corrosion, seal failure and diaphragm failure. Ex. LL, p. 13.

Operators were able to repair 26% of the improperly operating controllers on the spot. Many were made a day later, with an average lag time of 4 days later. The report concluded that:

- an OGI camera can identify improperly operating natural gas-driven pneumatic controllers
- the use of an OGI camera is particularly effective in identifying excess emissions from intermittent PCs
- where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven PCs to the inspections adds minimal incremental inspection costs. Ex. LL.

Based on the information in the PTFR, the Task Force recommended the AQCC expand the program statewide in 2019. Ex. LL, p. 4.

Q: Do you agree with the findings of the Colorado APCD Pneumatic Controller Task Force Report to the Air Quality Control Commission (“AQCC”)?

A: Yes. My experience at SWN confirms the findings in the Pneumatic Controller Task Force Report. Specifically, I agree with the conclusions of the report that:

- an OGI camera can identify improperly operating natural gas-driven pneumatic controllers
- the use of an IR camera is particularly effective in identifying excess emissions from intermittent pneumatic controllers where an existing LDAR program exists for fugitive leaks, adding the inspection of natural gas-driven pneumatic controllers to the inspections adds minimal incremental inspection costs.

Q: Did you review additional documents supporting the Colorado pneumatic controller inspection requirement?

A: I also reviewed the Colorado Economic Impact Analysis (EIA) that accompanied the expansion of the find and fix requirement statewide in 2019. I agree with the Colorado Air Pollution Control Division (APCD) that “the inspection and recordkeeping costs are likely minimal” since operators will incorporate pneumatic controllers into their LDAR programs. Ex. NN, p. 29. The Colorado APCD estimated that costs for returning an improperly operating controller to normal operation would range from “insignificant to \$600 per facility per year.” This is a reasonable estimate in my opinion and well worth the investment in resource capture, safety, health and the environment.

Q: Are you aware of other jurisdictions that require inspections of gas powered pneumatic controllers?

A: Yes. In addition to Colorado, California, Ex. OO and Ohio, Ex. PP require operators inspect gas-powered pneumatic controllers when conducting LDAR. Specifically California requires operators inspect gas-powered continuous and intermittent controllers. Ohio requires operators inspect intermittent controllers when conducting LDAR. These other state requirements demonstrate the reasonableness and feasibility of EDF’s proposal.

EDF's Proximity Based LDAR Proposal

Q: Do you support EDF's proposal to require more frequent inspections at well sites located near people's homes, schools, outdoor venues and workplaces?

A: Yes. SWN's experience with LDAR demonstrates that inspections help to reduce emissions. EDF's proposal requiring more frequent inspections of well sites located near homes, schools and playgrounds and other public places will help reduce emissions at those well sites. I have reviewed EDF's cost effectiveness analysis in support of its proximity based LDAR proposal and I believe the costs associated with its proposal are reasonable.

Flowback Vessels

Q: Please summarize EDF's flowback proposal and provide a brief overview of the completions process.

A: EDF has proposed NMED require operators use vapor tight flowback vessels equipped with control devices to reduce venting during flowback. Before diving into the proposal, a quick primer on completions may be helpful.

After drilling is complete and casing set and cemented, the completion process begins. There are a number of preparatory steps that are not germane to this discussion, so I will begin with the hydraulic stimulation.

Most wells require some sort of reservoir stimulation to produce at attractive economic rates. This often involves the injection of fluids and sand at high rates and pressures to cause complex fractures to be created in the near wellbore region. The overall objective and result is to

greatly increase the area open to flow and keep that area reasonably open (hence the use of sand or proppant) throughout the productive life of the well. Once that injection process is complete, the flow is reversed in order to evacuate the region of as much fluid as possible and have the created fracture close onto the introduced proppant. This phase is termed “flowback.” The initial flowback is often at high and variable rates and pressures but soon settles into a more predictable and declining rate and pressure regime. The phase of more predictable rates and pressures is what we term the separation phase. In this phase, given the more stable and predictable rates and pressures, equipment can be used to collect and process the fluids and gases coming from the well into saleable products.

Following stimulation (and drill-out of plugs if required) operators are able to safely route flowback fluids to enclosed, controlled flowback vessels provided such vessels have pressure relief systems to accommodate any safety issues presented by significant changes in pressure or flow rates. It is feasible and important to route any emissions from a pressure relief system to a flare equipped with an auto-igniter or continuous pilot light to minimize venting and emissions during completions.

Q: Do other states require operators control emissions during flowback as EDF proposes?

A: Yes. EDF’s proposal is modeled on a rule adopted by the Colorado Air Quality Control Commission in 2020. Ex V.

Q: Do you believe EDF's proposal is economically practicable and technically feasible?

A: Yes. I have reviewed EDF's proposal, EDF's analysis of the costs and benefits of its proposal, the Colorado AQCC rule which EDF's proposal is modeled on, and Colorado's Economic Impact Analysis for its rule, Exs. A, AA, EE, and in my opinion, EDF's proposal is economically practicable and technically feasible. First, I agree with the Colorado AQCC finding that vapor-tight flowback tanks are "manufactured, available, and technically feasible for flowback operations." Ex. EE, p. 23. I also agree that steel piping used "to connect all the active flowback vessels to a common manifold for routing vapors to" control devices and liquid knockout vessels are "widely available and technically feasible to install and operate." Ex. EE. Colorado assumed that operators would use temporary flowback tanks. Ex. EE. I agree this is a reasonable assumption. Notably, as Colorado acknowledged, if operators use permanent storage tanks to collect flowback fluids, they will save costs since they will not need to rent temporary flowback vessels.

I have reviewed the Colorado EIA for its proposal and I agree with Colorado's conclusion that its rule is cost effective. To estimate the costs of its rule Colorado assumed that operators require 10 to 15 500 bbl flowback vessels at a multi-well production facility with 10 wells. Colorado estimated the cost of each new storage vessel to be \$30,500. Costs for used tanks, they estimated, at \$19,500 to \$7,000. Colorado assumed a one-time capital cost of \$500 for steel piping, a one-time cost of \$500 to install the steel piping, and operation and maintenance costs of \$500. Colorado assumed a 15-year lifetime for this equipment. Colorado accordingly concluded that the annualized cost per flowback tank would be \$4,830. Assuming an average of 12 flowback tanks, this equates to an annualized cost of \$57,958 per well site.

This is a “worst-case cost effectiveness estimate” because it assumed an operator would use the 12 flowback tanks only once, at one well site. Ex. EE, p. 28. More likely operators would use the same flowback tank at multiple wells for the lifetime of the tanks. CDPHE estimated a 15-year lifetime for flowback tanks which I agree is reasonable.

Using the cost estimates contained in the Colorado EIA EDF analyzed the cost effectiveness of its initial flowback proposal using New Mexico specific completions data. I have reviewed EDF’s cost effectiveness analysis and in my opinion EDF’s analysis demonstrates the cost effectiveness of its proposal.

Zero Bleed Pneumatic Controllers

Q: Please summarize EDF’s revisions to the pneumatic controller retrofit provision?

A: At a high level EDF has proposed to increase the number of gas-powered pneumatic controllers that must be retrofit to zero bleed devices, and shorten the timeframe in which operators must do so. EDF’s proposal is modeled on a rule recently adopted by the Colorado Air Quality Control Commission, which I reviewed in preparing my testimony. In my opinion, EDF’s proposal is economically reasonable and practicable. Gas-powered pneumatic controllers vent methane and other pollutants to the atmosphere by design. As NMED’s proposal demonstrates, technologies exist today to operate pneumatic controllers with zero venting. EDF’s proposal does not require the use of any new types of technologies that could theoretically increase costs. Rather, we simply seek to require operators to retrofit more devices in a more timely manner than NMED has proposed. This is good policy, and will result in a decrease of

emissions from normally functioning pneumatic controllers as well as malfunctioning controllers.

Auto Gauging

Q: Please describe EDF's proposal to require operators use auto gauges on new storage tanks and flowback vessels.

A: EDF proposes operators install auto gauges on new storage tanks and flowback vessels to minimize emissions associated with manual tank gauging and measurement.

Q: Please describe what an automatic tank gauge is.

A: An automatic (tank) gauge is a device that automatically/continuously measures the level of crude oil, LNG and petroleum products (could be for water also) in storage tanks/vessels and raises an alarm when the level goes down or up to threshold limits. It operates electronically and can keep track of tank leakage.

Q: What are the benefits of EDF's proposal?

A: There are multiple benefits to EDF's proposal including:

- Overall safer operations: avoiding the need for workers to open hatches thus exposing them to fumes; eliminating the possible needs for work at heights; reducing the possibilities of ignition/fires/explosions due to the combination of fumes, oxygen and any type of ignition source.
- Operational efficiency: more accurately and timely measurements; easier planning of liquid removal; can run centralized inventory control and disposition; less likelihood of

needing temporary flow interruption; less labor intensive; eliminates sources of operator errors such as leaving thief hatches open.

- Environmental and health advantages: reduce likelihood of spills; reduce pollution from emissions and spills; protect public from poor air quality; protects waterways from spill pollution; less likely to have disastrous impacts from fires and explosions.

Q: Have you reviewed Colorado's Economic Impact Analysis for its tank measurement requirement, and if so, please state your opinion of the analysis.

A: Yes, I have reviewed the Colorado EIA for its tank measurement requirement. In my opinion, the costs estimated are reasonable and appropriate and support NMED including a similar requirement in its rule.

This concludes my direct testimony which is true and accurate to the best of my knowledge.

A handwritten signature in black ink, appearing to read "Tom Alexander", written in a cursive style.

Tom Alexander

A handwritten date in black ink, "7/28/2021", written in a cursive style.

Date