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BACKGROUND REPORT

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Phase 1 Fugitive Emission Management Program Literature Review and Recommended Field Study

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DISCLAIMER

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EXECUTIVE SUMMARY

This report provides a critical review and summary of key published literature relevant to upstream oil and natural gas (UOG) fugitive emission management practices (FEMP) and their effectiveness. It identifies knowledge gaps and prioritizes field efforts to quantitatively assess effectiveness questions. This study is funded by Alberta Upstream Petroleum Research Fund Program (AUPRF) managed by Petroleum Technology Alliance Canada (PTAC) and directed by the Methane Research Planning Committee (MRPC). The report is prepared by Clearstone Engineering Ltd. with support from Greenpath Energy Inc and Carleton University.

Fugitive emissions from UOG operations has motivated a tremendous number of research initiatives ranging from leak detection and measurement technology development to inventory estimation and regulatory management strategies. Publications that provide the most insight into the effectiveness of FEMP to detect, document, and reduce the risk of small leaks becoming large leaks are summarized in Table ES1. These studies are typically based on field measurements with the leak detection method, number of sites surveyed and key findings summarized in columns 3 to 5 of Table ES1 plus critical observations presented in columns 6 to 11. A critical review of each publication was completed to determine whether it addressed the following FEMP effectiveness knowledge gaps?

- Did the facility maintenance program repair the leaks detected and then confirm component screening concentrations were less than 500 ppmv?
- What was the cost to repair or replace the leaking component documented?
- What was the minimum detection limit of the survey method applied?
- Was a reference method applied to confirm 100% of the leaking components were detected by the primary survey method?
- What impact does survey frequency have on reducing leak magnitude and frequency?
- Was abnormal process venting assessed and distinguished from equipment component leaks?

Four field research priorities are recommended below based on the literature review and analysis of data collected during a 2017 field campaign conducted in Alberta (Clearstone, 2018).

Table ES1: Summary of key publications providing insight on the effectiveness of FEMP.										
Author (year)	**Title**	**Detection Method**	**Number of Sites Surveyed**	**Key Findings**	**Did Publication Evaluate FEMP Effectiveness Knowledge Gaps?**					
					Did maintenance program repair leaks and confirm [screening] < 500 ppmv?	**What was cost to repair leaks?**	**Did survey method detect 100% of leaks?**	**What was the survey minimum detection limit?**	**What impact does survey frequency have on reducing leak magnitude and frequency?**	**Was abnormal process venting assessed (and distinguished from equipment leaks)?**
Allen et al (2013)	Measurements of methane emissions at natural gas production sites in the United States	OGI and tracer test	150 onshore production sites	Measurements indicate that well completion emissions are overestimated in the EPA national emissions inventory, while emissions from pneumatic controllers and equipment leaks are underestimated. Equipment leak emissions are comparable to the EPA estimates.	Not evaluated	Not evaluated	Dual tracer tests completed by Aerodyne used to validate OGI detection and High-Flow measurement.	Leak detection surveys were conducted by infrared cameras in this study. The leak detection threshold for Infrared cameras is stated to be 30 g/hr (0.026 scf/m). Hi-Flow samplers are used for leak measurements. The smallest non-zero leak rate measured was 0.00048 scf/m which is considered as the detection limit.	Not evaluated	Yes, emissions delineated by category. Conclusions focus on comparison of EPA national inventory estimates versus field observations.
Ravikumar, Wang and Brandt (2017)	Are optical gas imaging techniques effective for methane leak detection?	OGI	8 separate studies	Imaging distance plays the most important role in leak detection, and failing to specify maximum imaging distance will lead to inconsistence reported leak rates.	Not evaluated	Not evaluated	Detection efficiency for a given plume under identical conditions decreases with increasing imaging distance. It is found that about 90% of emissions are detected at 10 m distance while only about 40% are detectable at 200 m. Also, increasing temperature difference between the plume and background increases the detection efficiency by enhancing contrast. Consequently, taking leak images from the ground with the sky as the background scene leads to higher contrasts and leak detection efficiency than aerial images looking down. Other factors that improve detection efficiency are (1) low humidity, (2) gas plumes containing hydrocarbons heavier than methane and (3) backgrounds with low emissivity (e.g., metallic surfaces provide better contrast than soils or forest).	Minimum detectable leak rate (MDLR) ranges from ~1 to 20 g/s depending on imaging distance and temperature difference. Recommended that minimum imaging distance be determined based on a desired MDLR.	Not evaluated	Excluded compressor seal vents (implies that large abnormal process vents are not assessed.)

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Omara et al (2016)	Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale Basin	OGI and tracer test	25 sites	(1) The methane emissions distribution was found to be highly skewed. (2) Reported methane emissions for Pennsylvania substantially underestimate measured facility-level CH4 emissions by 10 to 40 times for five UNG sites in this study. (3)Observed methane emissions correlated against production type (conventional vs unconventional), gas production rate, facility age, and maintenance practices. Although some correlation with production is observed, the study does not provide conclusive evidence that methane emissions can be predicted based on a single parameter. It does state facility age is not strong indicator of methane emissions.	Conventional sites that exhibited signs of aging infrastructure and had known maintenance issues were among the highest emitting sites. Well operator practices (e.g., the frequency of well inspection and maintenance) may exert a significant impact on facility-specific CH4 emissions. Component-level screening not completed.	Not evaluated	OGI used to identify methane sources, however, effectiveness of OGI method was not evaluated.	No MDL assertion.	Not evaluated	Yes

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Ravikumar and Brandt (2017)	Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector	NA	multiple publicly-available datasets.	(1) variation in the baseline emissions estimate between facilities leads to large variability in mitigation effectiveness (2) highly heterogeneous leak-sizes found in various empirical surveys strongly affect emissions reduction potential; (3) emissions reductions from OGI-based LDAR programs depend on a variety of facility-related and mitigation-related factors and can range from 15% to over 70%; (4) while implementation costs are 27% lower than EPA estimates, mitigation benefits can vary from one-third to three times EPA estimates; (5) a number of policy options will help reduce uncertainty, while providing significant flexibility to allow mitigation informed by local conditions.	Not evaluated	Study relies on EPA methodology for estimating repair costs (2015 Background Technical Support Document for the proposed NSPS).	OGI effectiveness depends on: (1) viewing distance (declines with increasing distance. Max distance of 5 meters recommended), (2) visual acuity and experience of the operator (demonstrated to impact MDL but difficult to relate back to human characteristics), (3) ambient temperature (very poor detection below 0 Celsius), and (4) wind speed (almost linear decline from best detection @ 1 m/s to half of best @ 9 m/s).	OGI MDL not a study objective.	When max viewing distance is 5 meters, FEAST model predicts 40% (annual survey), 60% (semi-annual survey) and 70% (quarterly survey) methane reduction relative to a baseline 'null-repair' scenario (i.e., periodic repairs by operators as part of 'normal maintenance). Modelling advantage is observing behavior over multi-year periods for different survey frequencies at a much lower cost relative to field observations. However, predicted results are only as good as the underlying assumptions programmed into FEAST. The assumption that 100% of detected leaks are repaired is overly optimistic and likely results in an overstatement of methane reductions. To explore the production sector cases in more detail: a semi-annual LDAR survey only reduces emissions by 37%, 41%, and 48% in the facilities modeled using the Allen (2013), ERG [20], and Kuo [21] distributions, respectively. Mitigation potential drops dramatically and survey frequency becomes less important as viewing distance increases beyond 10 meters.	FEAST designed to model equipment leaks not process vents.

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Ravikumar A P, Wang J, McGuire M, Bell C S, Zimmerle D and Brandt A. (2018)	"Good versus Good Enough?" Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera.	OGI	5 days of testing at METEC	The study provides empirical evidence regarding the probability of leak detection with respect to imaging distance and leak magnitude. It indicates a 90 percent probability of detecting a leak at the EPA minimum detection limit of 30 g CH4/h if the imaging distance is 4 meters. The probability decreases as the OGI camera operator moves away from the source . Moreover, it is predicted that the fraction of leaks detected saturates at median detection limit of ≤ 100 g CH4/h, and any improvement in sensitivity beyond this limit does not improve leak detection. This is because leak-size distribution is highly skewed in natural gas production facilities, where a small number superemitters account for the large fraction of total emissions. These superemitters are easily detectable at lower sensitivities, and increasing sensitivity only results in detecting small leaks that do not contribute significantly in total emissions. The authors conclude that current OGI technology is good enough for detecting leaks as a detection limit of 20 g CH4/h is obtained from an imaging distance of 3 m.	Not evaluated	Not evaluated	The study indicates a 90 percent probability of detecting a leak at the EPA minimum detection limit of 30 g CH4/h if the imaging distance is 4 meters. The probability decreases as the OGI camera operator moves away from the source .	Controlled single blind leak detection tests show that the median detection limit (50% detection likelihood) for FLIR-camera based OGI technology is about 20 g CH4/h at an imaging distance of 6 m, an order of magnitude higher than previously reported estimates of 1.4 g CH4/h.	Not evaluated	Not evaluated
Zavala-Araiza D, Herndon SC, Roscioli JR, Yacovitch TI, Johnson MR, Tyner DR (2017)	Methane emissions from oil and gas production sites in Alberta, Canada	Tracer Dilution and Inverse Plume dispersion	60 sites (25 sites with tracer; 35 with inverse dispersion)	20% of sites responsible for 75% of emissions; Trends similar to other production regions in North America; Statistics analysis suggests superemitters are influencing overall emissions (where emissions at sites are stochastic and therefore not predictable); Loss rates in Red Deer are among the highest of any region measured.	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated
Johnson, M.R., Tyner, D.R., Conley, S., Schwietzke, S, and Zavala-Araiza, D. (2017)	Comparisons of Airborne Measurements and Inventory Estimates of Methane Emissions in the Alberta Upstream Oil and Gas Sector	Aircraft flux (box) method with C2/C1 ratio combined with EDGAR data	Two regions (50x50km and 60x60km) each with ~2700 sites	Actual emissions in Lloydminster 3-5x higher than inventory and 5+ times higher than reported. Casing gas venting (bad GOR measurements) likely the cause. In Red Deer region, 94% of emissions are from sources not currently captured in Petrinex reporting.	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated

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Lyon, D. R., Alvarez, R. A., Zavala-Araiza, D., Brandt, A. R., Jackson, R. B., & Hamburg, S. P. (2016)	Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites	FLIR via helicopter	8220 well pads in 7 U.S. Basins	Overall, 4.0% of sites had large leaks. As many as 14.9% of sites in Bakken had large leaks; Detected leaks were more likely at oil sites than gas sites and more likely at low GOR sites than high GOR sites; Tanks are by far the most common source for large emissions (92% of all leaks were tanks or thief hatches); Newer sites more likely to leak than older sites (contrasts with Atherton et al.); Detailed statistical modelling cannot predict emissions with operating parameters such that sources are stochastic and unpredictable (requiring monitoring to detect)	Not evaluated	Not evaluated	Interesting side note: Test of 19 sites revealed NO CORRELATION between IR camera operator estimates of leaks size and actual leak size; IR camera detection limit (from helicopter) estimated to be 1g/s for wet gas (tanks) and 3 g/s for dry gas (mostly methane) -- this was worse at higher wind speeds	Not evaluated	Not evaluated	Not evaluated
Atherton et al. (2017)	Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia, Canada	Drive-by vehicle survey	~1600 sites	~47% of sites emit above minimum detectable limit (MDL), crudely estimated at 0.59 g/s; Indication of increased emissions at older sites (incl. abandoned wells); extrapolations based on MDL suggest emissions in BC are much higher than government estimates;	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated
Rosciolli et al. (2018)	Characterization of Methane Emissions from Five Cold Heavy Oil Production with Sands (CHOPS) Facilities	Tracer Dilution	5 CHOPS sites	Higher than reported emissions. Dual tracer measurement implicates casing gas venting as main source, but emissions through tanks also important	Not evaluated	Not evaluated	Tracer dilution is the best site quantification method available today	MDL not discussed, but uncertainty of~35% in quantification suggested	Not evaluated	Not evaluated
GreenPath (2017)	Historical Canadian Fugitive Emission Management Program Assessment	OGI	1252 sites	Inconsistent data Inconsistent results in repeat frequencies	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Oscillating leak counts and rates observed for facilities subject to annual OGI inspections	Not evaluated
GreenPath for the AER (2017)	GreenPath 2016 Alberta Fugitive and Vented Emissions Inventory Study	OGI	676 sites	Low leak rate and frequency at well sites and small facilities	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Yes but in-accessible vents not quantified.
US EPA CTG (2016)	Control Techniques Guidelines for the Oil and Natural Gas Industry	OGI/FID	n/a	Assertion on changes in inspection frequency40-60-80. Synthesis of available data. Strongly relies on Carbon Limits 2013	40-60-80 and 46 to 97% effective - relies on model facilities. Overly reliant on CL 2013. 80, 60, 40 not based on previous data. Recommends repair confirmation with days.	estimated	Not evaluated	NSPS defines a leak as 10,000 PPM, NESHAP defines a leak as 500PPM for valves and 1,000 PPM for other sources	Not evaluated	Not evaluated
CCAC - TGD (2017)	Quantification methodology for fugitive emissions	OGI FID Other	n/a	Summary of best practice. Recommends annual surveys. Includes scrubber dump valve leakage as emissions type.	Provides leak common causes. No repair costs. Provides cost estimates for LDAR that are low. Economic decision on	Not evaluated	Not evaluated	10,000 PPM and 100,000 PPM overage	Not evaluated	Not evaluated

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					repairs					
Carbon Limits (2013)	Quantifying Cost-effectiveness of Canadian LDAR	OGI	4293 sites	Provides survey costs that are referenced in other regulatory development pieces. Provides aggregate abatement costs for LDAR by Facility type.	Assumes all leaks fixed. Repair data not verified – likely from CAPP 2007 BMP. Only two LDAR providers. Data set not analyzable. Sites with multiple inspections showed increasing leak rates.	Relies on CAPP BMP values adjusted by service providers	No basis to confirm OGI method detected 100% of leaks.	OGI MDL not a study objective.	Emission reductions of 40 percent are expected for annual survey frequency while further emission reductions of 60 percent can be achieved by surveying two times per year, 70 percent by surveying three times per year, and 80 percent by surveying four times per year. However, these emission reductions are inferred from simple assumptions that leak rate magnitude increases linearly with time and that 100 percent of leaks are detected and repaired.	Not evaluated
Carbon Limits (2017)	Statistical Analysis of leak detection and repair in Canada	OGI	3913 sites	Focuses 2013 data on only Canadian data. Canadian data equivalent to US data for most component types	Same as CL2013	Relies on CAPP BMP values adjusted by service providers	No basis to confirm OGI method detected 100% of leaks.	OGI MDL not a study objective.	Yes, based on sites with more than 1 data point	Not evaluated
Carbon Limits (2018)	Statistical Analysis of Leak Detection And Repair Programs in Europe	FID	415 sites	Time series data on multiple method 21 engagements in T&D	In the data set only 2,000 records have Multiple measurements. Of those 2,000 records, only 60% show that an effective repair was executed.	Not evaluated	FID Based -minimum of 10ppm Maximum of 100,000ppm	<10ppm = background methane	Yes, based on components where concentrations recorded after measurement.	Not evaluated

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Clearstone (2018)	Update of Alberta Upstream Oil and Natural Gas Equipment, Component and Fugitive Emission Factors	OGI	333 sites	The following factors are developed for emission inventory purposes. o Process equipment count per facility subtype or well status code. o Component count per process equipment unit. o Emission control type per process equipment unit. o Natural gas driven pneumatic device count per facility subtype or well status code. o Leak rate per component and service type considering the entire component population surveyed (i.e., ‘average population’ factor). o Leak rate per component and service type considering leaking components only (i.e., ‘leaker’ factor).	Not evaluated	Not evaluated	No basis to confirm OGI method detected 100% of leaks. Uncertainty assessment considers that every 3 of 4 leaks were detected.	OGI MDL not a study objective.	Not evaluated	Yes, qualitative estimates indicate the majority of methane emissions observed during the 2017 field campaign is from venting sources (pneumatics, production tanks, casing vents and unlit flares).

The rationale and objectives for prioritized field research are as follows:

1. <u>Leak Survey Frequency</u>

There is limited empirical basis to quantitatively support the magnitude of emission reductions corresponding to leak detection and repair (LDAR) survey frequency. One study indicates that emission reductions of 40 percent are expected with a survey frequency of once per year, 60 percent at two times per year, 70 percent at three times per year, and 80 percent at four times per year (Carbon Limits, 2014). However, these emission reductions are inferred from simple assumptions that leak rate magnitude increases linearly with time and that 100 percent of leaks are detected and repaired. A simulation study by Ravikumar and Brant (2017) suggests leak rates decrease with LDAR frequency, but also notes that there could be significant variability in the effectiveness of LDAR depending on implementation. Indeed, field conditions often introduce complicating factors that hinder leak detection, control and documentation efforts. Other studies have observed oscillating leak counts and rates for facilities subject to annual inspections (Greenpath, 2017 and Clearstone, 2017) that suggests the following:

- There is uncertainty whether all leaks are detected by the OGI method (which is strongly dependent on standoff distance, technician capability and patience as well as environmental conditions at the time of the survey);
- There is uncertainty whether all leaks are repaired before the next survey (dependent on corporate priorities and maintenance systems);
- The categorization of emission releases as 'leaks' versus 'vents' is vulnerable to subjective decisions by individuals.
- These is uncertainty in measured leak rates.

Thus, there is insufficient and poor confidence in available leak data to establish a baseline or determine fugitive emission reductions achieved by FEMP. This also impedes quantitative cost-benefit assessments.

Central questions remain as to what the benefits of increased LDAR frequency may or may not be, whether LDAR programs have a bottom-line benefit in terms of site-wide emissions reductions, and, closely related to these questions, what is the true cost-benefit of LDAR. Rather than following the modelling approach of Ravikumar and Brant (2017), a more definitive way to address these questions could be to conduct statistically relevant numbers of OGI surveys simultaneous with site-wide emissions measurements. Using the dual-tracer method (e.g. Rosciolli et al, Atmos. Meas. Tech., 2015), total site emissions will be accurately measured concurrent with OGI surveys and repair cost tracking through an LDAR program.

The primary objective of this field study is to conduct dual tracer measurements in parallel with an LDAR program (OGI method) conducted either once per year or three times per year in different samples. Secondary objectives are: to evaluate the effectiveness of OGI in detecting leaks in facilities and operating conditions relevant to Alberta and British Columbia; assess the relevance or lack of relevance of leaks detected by LDAR/OGI in comparison to total site emissions; track feasibility of leak repairs (i.e., screening concentration less than 500 ppm); and collect repair/replacement cost details from operators. This comprehensive project will allow:

i. Quantitative assessment of the effectiveness of LDAR at annual and tri-annual intervals;
ii. Quantitative assessment of the overall effectiveness of LDAR in reducing site-wide emissions (which at many sites are likely to be dominated by venting sources);
iii. Quantitative assessment of the effectiveness of OGI in detecting leaks at facilities and conditions relevant to Alberta and British Columbia; and
iv. Quantitative data with which to define the cost-benefits of LDAR relative to other actions in reducing methane.

2. Abnormal Process Venting

Researchers have observed that a significant portion of methane emissions are from a small number of super-emitting leaks or abnormal process vents (Brandt et al, 2016; Zavala-Araiza et al, 2018). A similar observation was made during 2017 surveys of Alberta UOG sites where the majority of emissions (upwards of 80 percent) are from sources that FEMP typically classify as process vents and **do not trigger remedial action**. The magnitude of gas released from pneumatics, production tanks, heavy oil well casing vents and unlit flares can be under appreciated by operations; difficult to estimate because it's driven by abnormal behavior; and therefore omitted from maintenance programs.

When super-emitting sites are present, different sites may experience abnormal conditions at different points in time (e.g., the same site will not always have the same malfunction, or a process condition could manifest at different sites at varying times). For example, pigging operations that push high vapour-pressure liquids into atmospheric storage tanks may result in rapid flashing losses coinciding with pig deliveries (e.g., daily, weekly or monthly) as was the subject of a recent Environmental Protection Agency (EPA) enforcement settlement (EPA, 2018). The periodic nature of some releases has motivated researchers to assert that mitigating emissions requires frequent monitoring with the time between inspections short enough to minimize the duration of "spatio-temporally dynamic super-emitting sites" (Lyon et al., 2016; Lavoie et al., 2017;

and Zavala-Araiza et al, 2018). However, frequent OGI inspections will not observe short-duration events (unless the IR camera is viewing the source during the event) and, more importantly, existing FEMP will not trigger mitigating actions.

AER draft Directive 060 specifies a site-wide venting limit (500 m^3 per day) with prescriptive requirements for pneumatic devices and heavy oil well casing vents (AER, 2018). Storage tank losses are defined as routine venting subject to site limits. However, the effectiveness of site limits will depend on reliable quantification of storage losses, especially contributions that are difficult to estimate without detailed and site specific data (that may include abnormal behavior). Therefore, this source deserves further attention.

The primary objectives of this field data collection study is to (1) determine the root-cause(s) and (2) recommend basic FEMP checks that identify and mitigate abnormal tank venting. Secondary objectives are to collect process details (i.e., upstream temperature, pressure and product type) and repair/replacement cost details to inform assumptions used in emission inventories and regulatory impact assessments.

3. Fugitive Emission Contributions Below the Leak Definition Thresholds

The ECCC CG2 Section 31 leak definition depends on screening method. A component is leaking if the release (1) consists of at least 500 ppmv hydrocarbons determined by a portable monitor in accordance with M21; or (2) is detected by an eligible OGI instrument (ECCC, 2018). However, the OGI eligibility criteria for maximum viewing distance and minimum detectable release rate are not well defined. This is problematic for consistent implementation by industry as well as determining fugitive emission contributions from components emitting below the regulated leak threshold (i.e., "No-Leak" contribution).

Canadian UOG industry no-leak factors are based on an M21 screening concentration of 10,000 ppmv and measurements completed circa 1990 (CAPP, 1992). No-leak factors are less important for component populations featuring lots of leaks but as fewer leaks are detected, the no-leak contribution to total fugitive emissions become more important. For example, if it's assumed the OGI MDL is equivalent to 10,000 ppmv screening threshold, the no-leak contribution is approximate 38% of total fugitive emissions from the 216,000 components screened in 2017 at 333 Alberta locations (Clearstone, 2018).

Thus, the objective of this field study is to determine the magnitude of no-leak contributions and answer related questions:

- What is the effective field OGI MDL (or no-leak threshold defined on a ppmv and g/s basis) when completed under specified conditions (i.e., viewing distance <5m, wind <5 m/s, ambient temp > 5 C, and zero precipitation)?
- How are no-leak factors impacted by leak definition? Compare no-leak factors determined according to 500 and 10,000 ppmv (Method 21) as well as 30 and 60 g THC per hour (OGI) screening definitions.
- What impact does screening method have on the no-leak contribution to total fugitive emissions?

4. <u>OGI Effectiveness</u>

Section 31 of ECCC methane regulation (CG2) defines a component to be leaking if it is detected by an eligible OGI instrument (ECCC, 2018). This prompts questions regarding the practical effectiveness of an OGI instrument, demonstrated to comply with CG2 Section 30(2)(b), to detect leaks in the field. Given the multitude of challenges introduced by field testing, evaluation of OGI technologies should be completed at the METEC facility (https://energy.colostate.edu/metec/) where single-blind experiments can be conducted.

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AEP	Alberta Environment and Parks
AER	Alberta Energy Regulator
BMP	Best Management Practices
C	Component
CAPP	Canadian Association of Petroleum Producers
CEL	Clearstone Engineering Ltd.
DI&M	Direct Inspection and Maintenance
ECON	Saskatchewan Ministry of Economics
EF	Emission Factor
FG	Fuel Gas
GHG	Greenhouse gas
GM	Gas Migration
GV	Gas/Vapour (process and sales gas)
h	Hour
HL	Heavy Liquid
IPCC	Intergovernmental Panel on Climate Change
IR	Infrared (camera)
kg	Kilogram
LDAR	Leak Detection and Repair
LF	Leak Frequency
LL	Light Liquid
MDL	Minimum Detection Limit
N	Number of components
NIR	National Inventory Report
OGC	British Columbia Oil and Gas Commission
OGI	Optical Gas Imaging
QA	Quality Assurance
QC	Quality Control
SR	Sour
SW	Sweet
THC	Total Hydrocarbon
UNFCCC	United Nations Framework Convention on Climate Change
UOG	Upstream Oil and Gas
US EPA	United States Environmental Protection Agency
VOC	Volatile Organic Compound
VRU	Vapour Recovery Unit

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1 INTRODUCTION

This report provides a critical review and summary of key published literature relevant to upstream oil and natural gas (UOG) fugitive emission management practices (FEMP) and their effectiveness. It identifies knowledge gaps and prioritizes field efforts to quantitatively assess effectiveness questions. This study is funded by Alberta Upstream Petroleum Research Fund Program (AUPRF) managed by Petroleum Technology Alliance Canada (PTAC) and directed by the Methane Research Planning Committee (MRPC). The report is prepared by Clearstone Engineering Ltd. with support from Greenpath Energy Inc and Carleton University.

The literature review is presented in Section 2 with summary of key publications presented in Table 1. Fugitive and venting observations from a 2017 field study of Alberta upstream oil and gas (UOG) facilities are presented in Section 3. The prioritized list of research/data missing from the body of literature is presented in Section 4 with research objectives, field work scope, and study team delineated for each research priority. All references cited herein are listed in Section 5. Standard definitions for terms used throughout this document are presented in Section 6.

1.1 BACKGROUND

Fugitive equipment leaks are defined in Section 6.1.1 as an unintentional loss of process fluid, past a seal, mechanical connection or minor flaw, that can be visualized with an infrared (IR) leak imaging camera (herein referred to as optical gas imaging (OGI) method) or detected by an organic vapour analyzer (with a hydrocarbon concentration screening value greater than 10,000 ppmv) in accordance with U.S. EPA Method 21.

For the Canadian upstream oil and natural gas (UOG) industry, the most up-to-date set of average emission factors are published in CAPP, 2014 and intended to reflect best management practices (BMP) for the management of fugitive emissions (CAPP, 2007). However, the 2014 assessment encountered challenges determining equipment and component counts that impacted the accuracy of emission factor results. The report recommends:

- Process equipment and corresponding component count schedules be developed from a dedicated field inventory campaign.
- The field campaign should establish and utilize standardized definitions for major equipment, component, service and emission types.

Notwithstanding these limitations, engineering judgement was applied to bridge data gaps when sufficient supporting data was available and the resulting emission factors recommended for use for facilities subject to the CAPP BMP.

The BMP identifies key sources UOG fugitive emissions and strategies for achieving cost-effective reductions through the implementation of a Directed Inspection & Maintenance (DI&M) program. The DI&M program enables flexibility regarding target components, screening frequency, measurement and repair through a prioritized decision tree that considers criteria such as health, safety, and environment impact; repair difficulty; repair economics; and the requirement for a facility shutdown.

The CAPP BMP was promulgated through the following regulatory instruments but remains a voluntary initiative for Saskatchewan and other provinces. The BMP succeeded in greater awareness, improved management and has a downward influence on UOG fugitive emissions. However, uncertainty persists regarding the magnitude and most effective approach to managing fugitive emissions.

- Alberta Energy Regulator (AER) Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting.
- British Columbia Oil and Gas Commission (OGC) Flaring and Venting Reduction Guideline.

In general, the studies referenced above indicate fugitive emissions from equipment leaks are due to normal wear and tear, improper or incomplete assembly of components, inadequate material specification, manufacturing defects, damage during installation or use, corrosion, fouling and environmental effects (e.g., vibrations and thermal cycling). The potential for such emissions depends on a variety of factors including the type, style and quality of components, type of service (gas/vapour, light liquid or heavy liquid), age of component, frequency of use, maintenance history, process demands, whether the process fluid is highly toxic or malodorous and operating practices.

Most of the atmospheric emissions from fugitive equipment leaks tend to be from components in natural gas or hydrocarbon vapour service rather than from those in hydrocarbon liquid service[1]. Components in odourized or H_2S service tend to have much lower average fugitive emissions than those in non-odourized or non-toxic service. Components tend to have greater average emissions when subjected to frequent thermal cycling, vibrations or cryogenic service. Different types of components have different leak potentials and repair lives.

1 This reflects the greater difficulty in containing a gas than a liquid (i.e., due to the greater mobility or fluidity of gases), and the general reduced visual indications of gas leaks.

2 LITERATURE REVIEW

Fugitive emissions from oil and gas operations has motivated a tremendous number of research initiatives ranging from leak detection and measurement technology development to inventory estimation and regulatory management strategies. A broad literature review was completed with publication summaries relevant to the Canadian UOG sector delineated according to the following topical categories.

1. leak detection and measurement practices and technologies;
2. strategies for estimating fugitive emissions;
3. field studies and leak behavior observations; and
4. fugitive emission management approaches.

Publications that provide the most insight into the effectiveness of FEMP to detect, document, and reduce the risk of small leaks becoming large leaks are summarized in Table 1. These studies are based on field measurements with the leak detection method, number of sites surveyed and key findings summarized in columns 3 to 5 of Table 1 plus critical observations presented in columns 6 to 11. A critical review of each publication was completed to determine whether it addressed the following FEMP effectiveness knowledge gaps?

- Did the facility maintenance program repair the leaks detected and then confirm component screening concentrations were less than 500 ppmv?
- What was the cost to repair or replace the leaking component documented?
- What was the minimum detection limit of the survey method applied?
- Was a reference method applied to confirm 100% of the leaking components were detected by the primary survey method?
- What impact does survey frequency have on reducing leak magnitude and frequency?
- Was abnormal process venting assessed and distinguished from equipment component leaks?

The prioritized list of research/data missing from the body of literature presented in Section 4 is primarily informed by the Table 1 studies combined with the 2017 field observations described in Section 3.

Table 1: Summary of key publications providing insight on the effectiveness of FEMP.										
Author (year)	**Title**	**Detection Method**	**Number of Sites Surveyed**	**Key Findings**	**Did Publication Evaluate FEMP Effectiveness Knowledge Gaps?**					
					Did maintenance program repair leaks and confirm [screening] < 500 ppmv?	**What was cost to repair leaks?**	**Did survey method detect 100% of leaks?**	**What was the survey minimum detection limit?**	**What impact does survey frequency have on reducing leak magnitude and frequency?**	**Was abnormal process venting assessed (and distinguished from equipment leaks)?**
Allen et al (2013)	Measurements of methane emissions at natural gas production sites in the United States	OGI and tracer test	150 onshore production sites	Measurements indicate that well completion emissions are overestimated in the EPA national emissions inventory, while emissions from pneumatic controllers and equipment leaks are underestimated. Equipment leak emissions are comparable to the EPA estimates.	Not evaluated	Not evaluated	Dual tracer tests completed by Aerodyne used to validate OGI detection and High-Flow measurement.	Leak detection surveys were conducted by infrared cameras in this study. The leak detection threshold for Infrared cameras is stated to be 30 g/hr (0.026 scf/m). Hi-Flow samplers are used for leak measurements. The smallest non-zero leak rate measured was 0.00048 scf/m which is considered as the detection limit.	Not evaluated	Yes, emissions delineated by category. Conclusions focus on comparison of EPA national inventory estimates versus field observations.
Ravikumar, Wang and Brandt (2017)	Are optical gas imaging techniques effective for methane leak detection?	OGI	8 separate studies	Imaging distance plays the most important role in leak detection, and failing to specify maximum imaging distance will lead to inconsistence reported leak rates.	Not evaluated	Not evaluated	Detection efficiency for a given plume under identical conditions decreases with increasing imaging distance. It is found that about 90% of emissions are detected at 10 m distance while only about 40% are detectable at 200 m. Also, increasing temperature difference between the plume and background increases the detection efficiency by enhancing contrast. Consequently, taking leak images from the ground with the sky as the background scene leads to higher contrasts and leak detection efficiency than aerial images looking down. Other factors that improve detection efficiency are (1) low humidity, (2) gas plumes containing hydrocarbons heavier than methane and (3) backgrounds with low emissivity (e.g., metallic surfaces provide better contrast than soils or forest).	Minimum detectable leak rate (MDLR) ranges from ~1 to 20 g/s depending on imaging distance and temperature difference. Recommended that minimum imaging distance be determined based on a desired MDLR.	Not evaluated	Excluded compressor seal vents (implies that large abnormal process vents are not assessed.)

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Omara et al (2016)	Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale Basin	OGI and tracer test	25 sites	(1) The methane emissions distribution was found to be highly skewed. (2) Reported methane emissions for Pennsylvania substantially underestimate measured facility-level CH4 emissions by 10 to 40 times for five UNG sites in this study. (3)Observed methane emissions correlated against production type (conventional vs unconventional), gas production rate, facility age, and maintenance practices. Although some correlation with production is observed, the study does not provide conclusive evidence that methane emissions can be predicted based on a single parameter. It does state facility age is not strong indicator of methane emissions.	Conventional sites that exhibited signs of aging infrastructure and had known maintenance issues were among the highest emitting sites. Well operator practices (e.g., the frequency of well inspection and maintenance) may exert a significant impact on facility-specific CH4 emissions. Component-level screening not completed.	Not evaluated	OGI used to identify methane sources, however, effectiveness of OGI method was not evaluated.	No MDL assertion.	Not evaluated	Yes

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Ravikumar and Brandt (2017)	Designing better methane mitigation policies: the challenge of distributed small sources in the natural gas sector	NA	multiple publicly-available datasets.	(1) variation in the baseline emissions estimate between facilities leads to large variability in mitigation effectiveness (2) highly heterogeneous leak-sizes found in various empirical surveys strongly affect emissions reduction potential; (3) emissions reductions from OGI-based LDAR programs depend on a variety of facility-related and mitigation-related factors and can range from 15% to over 70%; (4) while implementation costs are 27% lower than EPA estimates, mitigation benefits can vary from one-third to three times EPA estimates; (5) a number of policy options will help reduce uncertainty, while providing significant flexibility to allow mitigation informed by local conditions.	Not evaluated	Study relies on EPA methodology for estimating repair costs (2015 Background Technical Support Document for the proposed NSPS).	OGI effectiveness depends on: (1) viewing distance (declines with increasing distance. Max distance of 5 meters recommended), (2) visual acuity and experience of the operator (demonstrated to impact MDL but difficult to relate back to human characteristics), (3) ambient temperature (very poor detection below 0 Celsius), and (4) wind speed (almost linear decline from best detection @ 1 m/s to half of best @ 9 m/s).	OGI MDL not a study objective.	When max viewing distance is 5 meters, FEAST model predicts 40% (annual survey), 60% (semi-annual survey) and 70% (quarterly survey) methane reduction relative to a baseline 'null-repair' scenario (i.e., periodic repairs by operators as part of 'normal maintenance). Modelling advantage is observing behavior over multi-year periods for different survey frequencies at a much lower cost relative to field observations. However, predicted results are only as good as the underlying assumptions programmed into FEAST. The assumption that 100% of detected leaks are repaired is overly optimistic and likely results in an overstatement of methane reductions. To explore the production sector cases in more detail: a semi-annual LDAR survey only reduces emissions by 37%, 41%, and 48% in the facilities modeled using the Allen [22], ERG [20], and Kuo [21] distributions, respectively. Mitigation potential drops dramatically and survey frequency becomes less important as viewing distance increases beyond 10 meters.	FEAST designed to model equipment leaks not process vents.

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Author (year)	Title	Detection Method	Number of Sites Surveyed	Key Findings	Did Publication Evaluate FEMP Effectiveness Knowledge Gaps?					
					Did maintenance program repair leaks and confirm [screening] < 500 ppmv?	What was cost to repair leaks?	Did survey method detect 100% of leaks?	What was the survey minimum detection limit?	What impact does survey frequency have on reducing leak magnitude and frequency?	Was abnormal process venting assessed (and distinguished from equipment leaks)?
Ravikumar A P, Wang J, McGuire M, Bell C S, Zimmerle D and Brandt A. (2018)	"Good versus Good Enough?" Empirical Tests of Methane Leak Detection Sensitivity of a Commercial Infrared Camera.	OGI	5 days of testing at METEC	The study provides empirical evidence regarding the probability of leak detection with respect to imaging distance and leak magnitude. It indicates a 90 percent probability of detecting a leak at the EPA minimum detection limit of 30 g CH4/h if the imaging distance is 4 meters. The probability decreases as the OGI camera operator moves away from the source . Moreover, it is predicted that the fraction of leaks detected saturates at median detection limit of $\leq$ 100 g CH4/h, and any improvement in sensitivity beyond this limit does not improve leak detection. This is because leak-size distribution is highly skewed in natural gas production facilities, where a small number superemitters account for the large fraction of total emissions. These superemitters are easily detectable at lower sensitivities, and increasing sensitivity only results in detecting small leaks that do not contribute significantly in total emissions. The authors conclude that current OGI technology is good enough for detecting leaks as a detection limit of 20 g CH4/h is obtained from an imaging distance of 3 m.	Not evaluated	Not evaluated	The study indicates a 90 percent probability of detecting a leak at the EPA minimum detection limit of 30 g CH4/h if the imaging distance is 4 meters. The probability decreases as the OGI camera operator moves away from the source .	Controlled single blind leak detection tests show that the median detection limit (50% detection likelihood) for FLIR-camera based OGI technology is about 20 g CH4/h at an imaging distance of 6 m, an order of magnitude higher than previously reported estimates of 1.4 g CH4/h.	Not evaluated	Not evaluated
Zavala-Araiza D, Herndon SC, Roscioli JR, Yacovitch TI, Johnson MR, Tyner DR (2017)	Methane emissions from oil and gas production sites in Alberta, Canada	Tracer Dilution and Inverse Plume dispersion	60 sites (25 sites with tracer; 35 with inverse dispersion)	20% of sites responsible for 75% of emissions; Trends similar to other production regions in North America; Statistics analysis suggests superemitters are influencing overall emissions (where emissions at sites are stochastic and therefore not predictable); Loss rates in Red Deer are among the highest of any region measured.	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated

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Johnson, M.R., Tyner, D.R., Conley, S., Schwietzke, S, and Zavala-Araiza, D. (2017)	Comparisons of Airborne Measurements and Inventory Estimates of Methane Emissions in the Alberta Upstream Oil and Gas Sector	Aircraft flux (box) method with C2/C1 ratio combined with EDGAR data	Two regions (50x50km and 60x60km) each with ~2700 sites	Actual emissions in Lloydminster 3-5x higher than inventory and 5+ times higher than reported. Casing gas venting (bad GOR measurements) likely the cause. In Red Deer region, 94% of emissions are from sources not currently captured in Petrinex reporting.	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated
Lyon, D. R., Alvarez, R. A., Zavala-Araiza, D., Brandt, A. R., Jackson, R. B., & Hamburg, S. P. (2016)	Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites	FLIR via helicopter	8220 well pads in 7 U.S. Basins	Overall, 4.0% of sites had large leaks. As many as 14.9% of sites in Bakken had large leaks; Detected leaks were more likely at oil sites than gas sites and more likely at low GOR sites than high GOR sites; Tanks are by far the most common source for large emissions (92% of all leaks were tanks or thief hatches); Newer sites more likely to leak than older sites (contrasts with Atherton et al.); Detailed statistical modelling cannot predict emissions with operating parameters such that sources are stochastic and unpredictable (requiring monitoring to detect)	Not evaluated	Not evaluated	Interesting side note: Test of 19 sites revealed NO CORRELATION between IR camera operator estimates of leaks size and actual leak size; IR camera detection limit (from helicopter) estimated to be 1g/s for wet gas (tanks) and 3 g/s for dry gas (mostly methane) -- this was worse at higher wind speeds	Not evaluated	Not evaluated	Not evaluated
Atherton et al. (2017)	Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia, Canada	Drive-by vehicle survey	~1600 sites	~47% of sites emit above minimum detectable limit (MDL), crudely estimated at 0.59 g/s; Indication of increased emissions at older sites (incl. abandoned wells); extrapolations based on MDL suggest emissions in BC are much higher than government estimates;	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated
Rosciolli et al. (2018)	Characterization of Methane Emissions from Five Cold Heavy Oil Production with Sands (CHOPS) Facilities	Tracer Dilution	5 CHOPS sites	Higher than reported emissions. Dual tracer measurement implicates casing gas venting as main source, but emissions through tanks also important	Not evaluated	Not evaluated	Tracer dilution is the best site quantification method available today	MDL not discussed, but uncertainty of~35% in quantification suggested	Not evaluated	Not evaluated
GreenPath (2017)	Historical Canadian Fugitive Emission Management Program Assessment	OGI	1252 sites	Inconsistent data Inconsistent results in repeat frequencies	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Oscillating leak counts and rates observed for facilities subject to annual OGI inspections	Not evaluated
GreenPath for the AER (2017)	GreenPath 2016 Alberta Fugitive and Vented Emissions Inventory Study	OGI	676 sites	Low leak rate and frequency at well sites and small facilities	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Not evaluated	Yes but in-accessible vents not quantified.

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US EPA CTG (2016)	Control Techniques Guidelines for the Oil and Natural Gas Industry	OGI/FID	n/a	Assertion on changes in inspection frequency40-60-80. Synthesis of available data. Strongly relies on Carbon Limits 2013	40-60-80 and 46 to 97% effective - relies on model facilities. Overly reliant on CL 2013. 80,60,40 not based on previous data. Recommends repair confirmation with days.	estimated	Not evaluated	NSPS defines a leak as 10,000 PPM, NESHAP defines a leak as 500PPM for valves and 1,000 PPM for other sources	Not evaluated	Not evaluated
CCAC - TGD (2017)	Quantification methodology for fugitive emissions	OGI FID Other	n/a	Summary of best practice. Recommends annual surveys. Includes scrubber dump valve leakage as emissions type.	Provides leak common causes. No repair costs. Provides cost estimates for LDAR that are low. Economic decision on repairs	Not evaluated	Not evaluated	10,000 PPM and 100,000 PPM overage	Not evaluated	Not evaluated
Carbon Limits (2013)	Quantifying Cost-effectiveness of Canadian LDAR	OGI	4293 sites	Provides survey costs that are referenced in other regulatory development pieces. Provides aggregate abatement costs for LDAR by Facility type.	Assumes all leaks fixed. Repair data not verified – likely from CAPP 2007 BMP. Only two LDAR providers. Data set not analyzable. Sites with multiple inspections showed increasing leak rates.	Relies on CAPP BMP values adjusted by service providers	No basis to confirm OGI method detected 100% of leaks.	OGI MDL not a study objective.	Emission reductions of 40 percent are expected for annual survey frequency while further emission reductions of 60 percent can be achieved by surveying two times per year, 70 percent by surveying three times per year, and 80 percent by surveying four times per year. However, these emission reductions are inferred from simple assumptions that leak rate magnitude increases linearly with time and that 100 percent of leaks are detected and repaired.	Not evaluated
Carbon Limits (2017)	Statistical Analysis of leak detection and repair in Canada	OGI	3913 sites	Focuses 2013 data on only Canadian data. Canadian data equivalent to US data for most component types	Same as CL2013	Relies on CAPP BMP values adjusted by service providers	No basis to confirm OGI method detected 100% of leaks.	OGI MDL not a study objective.	Yes, based on sites with more than 1 data point	Not evaluated
Carbon Limits (2018)	Statistical Analysis of Leak Detection And Repair Programs in Europe	FID	415 sites	Time series data on multiple method 21 engagements in T&D	In the data set only 2,000 records have Multiple measurements. Of those 2,000 records, only 60% show that an effective repair was executed.	Not evaluated	FID Based -minimum of 10ppm Maximum of 100,000ppm	<10ppm = background methane	Yes, based on components where concentrations recorded after measurement.	Not evaluated

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Clearstone (2018)	Update of Alberta Upstream Oil and Natural Gas Equipment, Component and Fugitive Emission Factors	OGI	333 sites	The following factors are developed for emission inventory purposes. o Process equipment count per facility subtype or well status code. o Component count per process equipment unit. o Emission control type per process equipment unit. o Natural gas driven pneumatic device count per facility subtype or well status code. o Leak rate per component and service type considering the entire component population surveyed (i.e., ‘average population’ factor). o Leak rate per component and service type considering leaking components only (i.e., ‘leaker’ factor).	Not evaluated	Not evaluated	No basis to confirm OGI method detected 100% of leaks. Uncertainty assessment considers that every 3 of 4 leaks were detected.	OGI MDL not a study objective.	Not evaluated	Yes, qualitative estimates indicate the majority of methane emissions observed during the 2017 field campaign is from venting sources (pneumatics, production tanks, casing vents and unlit flares).

2.1 DETECTION AND MEASUREMENT OF FUGITIVE EMISSIONS FROM THE UPSTREAM OIL AND GAS SECTOR

The following studies focus on leak detection and measurement practices and technologies available to the UOG sector. A common objective of these studies is to identify methods for reducing the cost of leak detection and quantification.

2.1.1 US EPA REFERENCE METHOD 21 (US EPA, 1983)

This is the US EPA standard emission measurement test method that is referred to in many of the following literature sources. This method is widely cited in North America and was the original basis for most Leak Detection and Repair (LDAR) or Direct Inspection and Maintenance (DI&M) programs followed by industry since the 1980s. The US EPA develops and maintains standard test methods, which are approved procedures for measuring the presence and concentration of physical and chemical pollutants; evaluating properties, such as toxic properties, of chemical substances; or measuring the effects of substances under various conditions. The methods in the US EPA index are known as US EPA Methods. Method 21 was developed for the measurement of fugitive VOC emissions from process equipment. These sources include, but are not limited to, valves, flanges and other connections, pumps and compressors, pressure relief devices, process drains, open-ended valves, pump and compressor seal system degassing vents, accumulator vessel vents, agitator seals, and access door seals. The method measures VOC concentration of leaking equipment components by using a VOC detector based on one of several technologies, such as catalytic oxidation, flame ionization, infrared absorption, and photoionization. This method is intended to locate and classify leaks only by VOC concentrations as they compare to VOC concentration thresholds established outside of the method in policies established by program authorities. The method cannot be used as a direct measure of mass emission rate from individual sources.

2.1.2 REVIEW AND UPDATE OF METHODS USED FOR AIR EMISSIONS LEAK DETECTION AND QUANTIFICATION (PTAC TEREE 2007)

The goal of this study was to provide industry and government with pertinent information regarding both traditional and emerging methods/technologies for air emissions leak detection and quantification. This work was also intended to support the general guidance for fugitive emissions management at oil and gas facilities provided by CAPP through its BMP document.

The technologies/methods (traditional and emerging) that were reviewed as part of this Project were categorized into 3 separate topic groups:

1. point source leak detection and concentration measurement technologies/methods;

2. point source leak quantification methods; and
3. area source emissions leak detection and quantification technologies/methods.

The first category (point source leak detection and concentration measurement technologies/methods) was further divided into three subgroups. The three subgroups and the technologies listed under each subgroups are as follows:

- close range detection and measurement methods;
  - flame ionization (FI);
  - photoionization (PI);
  - catalytic combustion (CC);
  - solid-state (SS);
  - infrared absorption (IR);
  - tunable diode laser absorption spectroscopy (TDLAS);
  - bubble test;
  - acoustic leak detection.
- remote sensing methods;
  - passive IR gas imaging -thermal imaging;
  - passive IR gas imaging -image multi-spectral sensing;
  - open path - tunable diode laser absorption spectroscopy (TDLAS);
- airborne methods;
  - tunable diode laser absorption spectroscopy (TDLAS);
  - differential absorption LIDAR (airborne DIAL); and
  - passive gas filter correlation radiometry (PGFCR).

The following point source leak quantification methods were reviewed:

- bagging;
- hi-flow sampling;
- rotameters and other flow metering devices; and
- tracer gas detection.

The following area source leak detection and quantification technologies/methods were reviewed:

- light detection and ranging/differential absorption (LIDAR/DIAL);
- AIR detection and ranging (AIRDAR);
- open path tunable diode laser absorption spectroscopy (TDLAS); and
- open path fourier transform infrared (FTIR).

All of these technologies were reviewed in depth, and some of the findings regarding these technologies were summarized in a Microsoft Excel®-based information tool that accompanied the report.

2.1.3 DIAL MEASUREMENTS OF FUGITIVE EMISSIONS FROM NATURAL GAS PLANTS AND THE COMPARISON WITH EMISSION FACTOR ESTIMATES (CHAMBERS, 2006)

This project investigated fugitive emissions at natural gas processing plants in Alberta using two complementary optical measurement methods. At five gas plants, the fugitive emissions of methane and hydrocarbons ethane and larger (C2+ hydrocarbons) were measured and quantified using Differential Absorption Lidar (DIAL). The DIAL was also used to measure emissions from process flares at two of the gas plants. At two of the plants, a gas leak imaging camera was used to locate individual hydrocarbon leaks.

The DIAL measurements were conducted using a mobile DIAL unit operated by Spectrasyne Ltd. This mobile unit was able to easily travel from plant to plant within Alberta to provide emissions measurement services. As shown below, these services were valuable in regards to identifying fugitive emissions not found through other methodologies.

At two gas plants the DIAL measured emissions of methane, VOCs and benzene were compared with values calculated using emission factor methods. Measured emissions of methane and VOCs were four to eight times higher than the emission factor estimates. The largest differences between measured values and estimates were for the flares and storage tanks. DIAL measured values gave a more realistic evaluation of revenue lost as fugitives than the industry accepted estimation methods, leading to an increased incentive to improve leak detection and repair.

2.1.4 US EPA - OIL AND NATURAL GAS SECTOR LEAKS (US EPA 2014)

This document is one of four technical white papers released as elements of President Obama's "Climate Action Plan: a Strategy to Reduce Methane Emissions". The paper focuses on potentially significant sources of methane and volatile organic compounds (VOCs) in the oil and gas sector, covering emissions and mitigation techniques for both pollutants. Leaks are defined as VOC and methane emissions that occur at onshore facilities upstream of the natural gas distribution system (i.e. fugitive emissions). This includes leak emissions from natural gas well pads, oil wells that co-produce natural gas, gathering and boosting stations, gas processing plants, and transmission and storage infrastructure. Potential sources of leak emissions from these sites include agitator seals, compressors seals, connectors, pump diaphragms, flanges, hatches, instruments, meters, open ended lines, pressure relief devices, pump seals, valves, and improperly controlled liquids storage.

The white paper documents the US EPA's understanding of fugitive emissions from UOG facilities, and available mitigation techniques to reduce emissions from these facilities. The final section of the white paper presents a list of charge questions for reviewers to assist the US EPA with obtaining a more comprehensive picture of VOC and methane emissions from leaks and available mitigation techniques.

2.1.5 U.K. ENVIRONMENT AGENCY - MONITORING AND CONTROL OF FUGITIVE METHANE FROM UNCONVENTIONAL GAS OPERATIONS (UK ENVIRONMENT AGENCY 2012)

This general document was commissioned by U.K. Environment to help investigate the potential for fugitive methane to be released from unconventional gas operations (primarily shale gas reserves). As a part of this, U.K. Environment investigated and assessed what monitoring and control elements should be applied to fugitive methane from these operations as part a regime to make unconventional gas extraction more sustainable. The study was made up of the following components:

1) outline of unconventional gas extraction techniques;
2) outline of conventional extraction for comparison with the position for unconventional extraction;
3) survey of the methods available for monitoring methane from each process and position of fugitive release identified in (1);
4) survey of the methods available for controlling fugitive emissions of methane from each process and position identified in (1);
5) case studies to illustrate how monitoring and control methods have been applied to fugitive emissions from unconventional and conventional operations;

6) summary of related issues that may arise during the regulation of fugitive emissions from unconventional operations; and
7) conclusions and recommendations including the identification of best practice for the control of fugitive emissions and recommendations for a cost-effective strategic programme of monitoring and emission estimation

While there is a wealth of information and analysis in the report on control measures, emission estimation techniques, and shale gas practices, a few conclusions derived from the report are of particular importance. First, the use of generic emissions factors to estimate methane emissions from other industries is of questionable value for shale gas. Research published by the US EPA indicates that methane emissions from shale gas well completion may be higher than previously thought.

Second, there is a notable level of discord in the messages from industry, regulators, academics and public sources. The study team's recommendations for the prioritization of future research effort in relation to emissions estimates reflect this deficiency in the core evidence base surrounding this industry.

Finally, while emission factors derived by the American Petroleum Industry are widely used to estimate methane emissions in the oil and gas industry, they are not applicable to the plant and equipment used for shale gas extraction, and may also reflect outdated practices in the shale gas industry. The report advised regulators in the U.K. to avoid relying on these factors and develop emissions estimates from multiple sources whenever possible.

2.1.6 FUGITIVE EMISSIONS MONITORING IN ENI UPSTREAM OIL/GAS TREATMENT PLANTS (ENI 2007)

This document is a presentation developed by Eni Corporation on different calculation approaches and monitoring approaches for fugitive emissions from their upstream oil and gas treatment plants. The presentation concludes that emissions from "well maintained" facilities are generally much lower than emissions calculated on the basis of the U.S. EPA's Method 21. Additionally, the document describes how the costs of these emissions calculation methodologies are very high.

Due to these costs, and the apparent inaccuracy of figures generated through Method 21, Eni was exploring alternative technologies for lower-cost detection of fugitive emissions, such as an infrared gas imaging and quantification camera technology. As this study was completed in 2007, this technology has likely matured and become more acceptable to regulators in the time since. Overall, the most important conclusion to derive from this presentation is that emissions monitoring can be costly, and that businesses/regulators should be researching new technologies that can reduce the burden associated with emissions monitoring/calculation while simultaneously increasing accuracy.

2.1.7 ARE OPTICAL GAS IMAGING TECHNIQUES EFFECTIVE FOR METHANE LEAK DETECTION? (RAVIKUMAR ET AL, 2017)

This work analyzes passive infrared (IR) imaging among optical gas imaging (OGI) techniques which are used for leak detection and repair (LDAR) program mandated by the US EPA since 2012. A mathematical model is developed for the analysis which simulates IR images of controlled methane releases and predicts minimum detection limits. The model is developed using approximately 6400 measured leaks and is able to simulate leaks in typical upstream facilities.

The results show that the detection efficiency for a given plume under identical conditions decreases with increasing imaging distance. It is found that about 90% of emissions are detected at 10 m distance while only about 40% are detectable at 200 m. Thus, short imaging distances are required for effective leak detection.

The results also show that increasing temperature difference between the plume and background ($\Delta T = T_{plume} - T_{background}$) increases the detection efficiency by enhancing the contrast. Consequently, taking leak images from the ground with the sky as the background scene leads to higher contrasts and leak detection efficiency than aerial images looking down. This is because the sky temperature is typically 20 to 50 °C lower than the surface temperature, and choosing the sky as the scene increases the temperature difference and contrast. It is noted that increasing the temperature difference increases detection efficiency. For example, under the conditions of a studied scene, detection efficiency was under 10% when the plume was 10 degrees cooler than the background while it increased to over 60% when the plume was hotter by 20 degrees.

In addition, it is observed that under the same conditions (including temperature difference) increasing scene temperature by 10 degree increments increases detection efficiency by 10% as the temperature changes from 270 K to 310 K. Accordingly, warmer days are preferable for performing leak detection surveys. Humidity, on the other hand, reduces the atmospheric transmission and thus the detection efficiency. Additionally, gas composition affects the detection efficiency since heavier hydrocarbons are more detectable than lighter compounds such as pure methane streams.

Moreover, low emissive scenes such as reflective metallic surfaces provide higher contrast between plume and the scene than low emissive backgrounds such as soil and forests. It is observed that decreasing background emissivity from 0.9 to 0.1 increased detection efficiency from 40% to 70%. This parameter could play an important role when there is no or little temperature difference between the plume and scene. For the extreme cases where the plume temperature is colder than the surrounding temperature, highly emissive scenes provide better contrast and increase the detection efficiency.

It is suggested that an appropriate minimum detectable leak rate (MDLR) could be selected based on the leak-size distributions, and the imaging distance be determined based on the selected MDLR. In this manner, imaging distances may be selected for MDLRs that only target the superemitters. For example, it was observed that conducting leak survey at 10 m imaging distance resulted in a MDLR of about 2 g/s and captured approximately 5% of the leaks which comprised 70% of the volume of the total leaked gas for a selected skewed leak-size distribution.

Overall, the authors concluded that imaging distance plays the most important role in leak detection, and failing to specify maximum imaging distance will lead to inconsistence reported leak rates.

2.2 STRATEGIES FOR ESTIMATING FUGITIVE EMISSIONS FROM THE UPSTREAM OIL AND GAS SECTOR

Publications on different estimation approaches are presented chronologically to demonstrate their refinement over time.

2.2.1 CCME CODE OF PRACTICE FOR FUGITIVE VOCS FROM EQUIPMENT LEAKS (CCME 1993)

The Canadian Council of Ministers of the Environment (CCME) Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks was prepared in 1993 as an initiative of the CCME Management Plan for NOx/VOC. The Code was prepared by a multi-stakeholder task force, consisting of federal, provincial, and regional governments as well as industry and environmental groups.

While the focus was on VOC emissions, fugitive emissions of the GHGs methane and, to a lesser extent, CO_2 are covered in the scope of this Code of Practice. This was the first national document that set guidelines for provincial and regional governments to follow in setting measures to control fugitive VOC emissions. In the Code, environmental considerations have been developed for the measurement and control of VOC emissions from equipment leaks in process operations that use a common set of equipment, including valves, connectors, pumps, compressors, and pressure-relief lines. Practices are included for the application, performance, testing for compliance, record-keeping, and measurement of emissions. These practices are intended to reduce the contribution of fugitive VOC emissions from equipment leaks.

The CCME adopted the stratified emission factors method as the minimum standard for companies to monitor and estimate their fugitive VOC emissions. The stratified emission factors method is a variation on the component screening method that offers improved accuracy because it offers a better characterization of very low leaking fugitive emissions. It uses three stratified emission levels because it splits the “non-leakers” category (i.e. component sources less than 10,000 ppmv) into two sub-categories: emissions < 1,000 ppmv and emissions between 1,000 ppmv and 10,000 ppmv.

The code was originally developed for petroleum refineries and organic chemical plants, but it has application in other industries producing or using volatile organic compound (VOC) streams and applies to upstream oil & gas operations. Starting in the 1990s, all petroleum refining and upstream oil & gas companies would have committed to voluntarily follow the requirements in the Code as part of their environmental and loss control strategies.

2.2.2 PROTOCOL FOR EQUIPMENT LEAK ESTIMATES (US EPA 1995)

This 1995 U.S. EPA document was the first national methodology document that presented standard procedures for estimating fugitive emissions from equipment leaks from four sectors: 1) chemical manufacturing; 2) petroleum refining; 3) petroleum marketing; and upstream oil & gas production. This document was an update to an earlier 1993 EPA equipment leaks protocol document of the same name. During the early-1990’s, the American Petroleum Institute (API) commissioned fugitive hydrocarbon emissions studies of oil and gas production operations, refineries, and marketing terminals. The oil and gas study was jointly commissioned by the Gas Research Institute (GRI); the refinery study was jointly commissioned by the Western States Petroleum Association (WSPA). STAR Environmental collected all data for the oil and gas production studies. Data from the three studies formed the basis for this document and this was augmented by data from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) for the chemical manufacturing sector.

The document outlines four methods of estimating fugitive emissions from equipment leaks in ascending order of preference:

- Approach 1: Average Emission Factor Approach - This approach applies average mass emission rates (in kg/hr/component) to counts of equipment components and other unit-specific data such as: 1) the material stream type each component serves; 2) the Total Organic Compound (TOC) mass concentration in the stream; and 3) the time period (in hours) each component was in that service. The average emission factors were derived from a large number of sampling campaigns and, therefore, are most valid for estimating emissions from a population of equipment. For oil & gas production , average emission factors are presented for valves, pump seals, connectors, flanges, open-ended lines, and others (compressors, pressure-relief valves, vents, and several other components.) in four type of material service (gas, heavy oil, light oil, water/oil).

- Approach 2: Screening Ranges Approach - This approach applies either of two average mass emission rates (in kg/hr/component) to a component based on the result of a screening concentration measurement. The screening method identifies leaks by the concentration of hydrocarbon around the leaking component. Monitoring instruments can include: flame ionization detectors (FIDs), photo ionization detectors (PIDs), non-dispersive infrared detectors (NDIRs), and catalytic combustion detectors (CCDs). In the component screening method, a leak is defined as a fugitive emission having a local concentration of greater than 10,000 ppmv around the leak point. For each component and service, two emission factors are available: one for "non-leaks" (conc. < 10,000 ppmv) and one for "leaks" (conc. > 10,000 ppmv). Average screening mass emission rates are available for the same range of 6 components and 4 services as Approach 1.
- Approach 3: EPA Correlation Approach - This approach offers an additional refinement to estimating emissions from equipment leaks by providing an equation to predict mass emission rate as a function of screening value for a particular equipment type. The EPA Correlation Approach is preferred when actual screening values are available for each component. Correlations can be used to estimate emissions for the entire range of non-zero screening values, from the highest potential screening value to the screening value that represents the minimum detection limit of the monitoring device. This approach involves entering the non-zero, non-pegged screening value into the correlation equation, which predicts the TOC mass emission rate based on the screening value. Default zero emission rates are used for screening values of zero ppmv and pegged emission rates are used when the screening value is beyond the upper limit measured by the portable screening device. Correlation equations, default zero emission rates, and pegged emission rates are available for the same range of 6 components as Approach 1.
- Approach 4: Unit-Specific Correlation Approach - This approach refines the accuracy of Approach 3 by developing a unit-specific correlation between measured mass emission rates (kg/hr/component) and measured screening leak concentrations collected from process unit equipment. The method calls for mass emission rates to be measured by a method of bagging the leaking component to capture the entire leak.

The document also explains two types of fugitive emission measurements:

- Screening Surveys - Guidance is provided on how to set up a screening program, how to perform a screening survey, and how to screen different types of equipment. Requirements are described for the use of a portable monitoring instrument. These requirements are based on the EPA Reference Method 21.
- Leak Rate Measurement - Guidance is provided on how to collect equipment leak rate data (bagging data) by enclosing individual equipment in a "bag" and measuring mass emissions. These data can be used to develop unit-specific leak rate/screening value correlations.

The document explains two approaches to fugitive emission management:

- Leak Detection and Repair (LDAR) Programs.
- Equipment Modifications - such as replacing a standard valve with a sealless type.

2.2.3 PREFERRED AND ALTERNATIVE METHODS FOR ESTIMATING FUGITIVE EMISSIONS FROM EQUIPMENT LEAKS (US EPA 1996a)

This 1996 document from the EPA was published as a chapter in the Emission Inventory Improvement Program (EIIP) documents of 1996. It relies heavily on the EPA Protocol for Equipment Leak Estimates document (described above) from November 1995 and reproduces almost all of its guidance on: 1) the four methods of estimating fugitive emissions from equipment leaks (average EF, screening EF, screening correlation equation, unit-specific correlation); and 2) the two types of fugitive emission measurements (screening and bagging). No guidance is provided on managing fugitive emissions, except for some discussion about how to measure the effectiveness of a Leak Detection and Repair (LDAR) Program.

The document recommends that the EPA correlation equation approach is the preferred method for estimating fugitive emissions when actual screening values are available. This approach involves entering the screening value into the correlation equation, which predicts the mass emission rate based on the screening value. The document reproduces the same correlation equations and average emission factors as cited in the EPA Protocol for Equipment Leak Estimates.

2.2.4 EPA-GRI METHANE EMISSIONS FROM THE NATURAL GAS INDUSTRY - EQUIPMENT LEAKS (US EPA 1996b)

The U.S. EPA and the Gas Research Institute (GRI) cofounded this major 1996 study to quantify methane emissions from U.S. natural gas operations for the 1992 base year. The purpose of this study was to determine the relative global warming impact that U.S. natural gas production had on the natural gas fuel-cycle versus the fuel-cycles of coal and oil. This is the 8th volume in a 15-volume set and it covered Fugitive Emissions from Equipment Leaks exclusively. Other key volumes in the series covered compressor combustion (V11) and the three main sources of vented methane: blow & purge activities (V7), pneumatic devices (V12), and dehydrators (V14). National methane emissions were estimated for six segments of the U.S. natural gas industry:

- Onshore Gas Production;
- Offshore Gas Production;
- Gas Processing;
- Transmission Compressor Stations;
- Gas Storage Facilities; and
- Customer Meter Sets (Gas Distribution).

Industry fugitive emissions were estimated using the average emission factor method, where measured average emission factors were combined with the average number of components per facility and the total count of facilities in each segment. Two estimation methods were combined to quantify average component emission factors for this study: 1) the EPA Correlation Approach; and 2) Direct Measurement using the Hi-Flow™ sampler. The EPA Correlation Approach calculated emission rates from sampled screening concentrations using EPA correlation equations to establish average component emission factors. This approach was applied to Onshore Gas Production (excluding the Atlantic and Great Lakes regions), Offshore Gas Production, and Gas Processing. The second approach was to use the new Hi-Flow™ sampler device (developed by the GRI) to measure mass leak rates directly[2] to establish average component emission factors. This approach was applied to Onshore Gas Production (in the Atlantic and Great Lakes regions), Gas Storage & Transmission facilities, and Customer Meter Sets in the distribution system.

The study estimated total methane emissions from the U.S. natural gas industry of 314 billion standard cubic feet (bscf) (or approximately 6,026 kilotonnes of CH_4) for the data year 1992, which breaks down as shown in Table 2. The data shows that fugitive emissions contributed the largest share of the industry total (61%) and the majority of these fugitives occurred in the storage/transmission and distribution segments. Fugitive methane from production and processing segments, although smaller, were also significant.

Table 2: 1992 methane emissions (kt) from U.S. natural gas industry (US EPA, 1996).

Sector	**Fugitive**	**Vented**	**Combusted**	**Total**	**% Total**
Gas Production	460	1,032	127	**1,619**	27%
Gas Processing	468	98	132	**698**	12%
Gas Storage & Transmission	1,383	634	219	**2,235**	37%
Gas Distribution	1,432	42	0	**1,475**	24%
Total Industry	**3,743**	**1,806**	**477**	**6,026**	**100%**
% of Total	62%	30%	8%	**100%**	

2 The Hi-Flow™ sampler uses a strong vacuum to draw the entire quantity of a hydrocarbon leak through a tube, where the device measures the total gas (air+HC) flow rate and hydrocarbon concentration to calculate the total hydrocarbon mass flow rate.

2.2.5 CAPP 1995 CH4 & VOC EMISSIONS FROM THE UPSTREAM OIL & GAS INDUSTRY (CAPP 1999)

Clearstone conducted this first national inventory study of the upstream oil & gas industry for CAPP in 1999. The study assessed emissions for three GHGs (CO_2, CH_4, and N_2O), three CACs (VOCs, NOx, and CO) and H_2S. Using 1995 as the reference year of the inventory and annual industry activity level data, a trend of inventory data was presented for the years 1990-1996. Environment Canada based its upstream oil & gas GHG estimates for its National Inventory Reports on the data from this report, starting in 1999.

Volume 2 of this study outlined the methodologies used to estimate the national inventory. Fugitive emissions were estimated by the average emission factor method from the U.S. EPA, where average total hydrocarbon emission factors were applied to an inventory of all potential fugitive emission sources (leaking equipment components). The inventory of sources was compiled by applying typical equipment schedules to the total population of process units and major equipment items. Each item was classified by the component type (e.g. valves, connectors) and by type of service. Three sets of average emission factors were used: 1) one set for components at gas production and processing facilities; 2) one set for oil production and transmission facilities; and 3) one set for natural gas transmission facilities, provided by the Canadian Gas Association. No estimates were obtained for the natural gas distribution sector. The oil and gas production emission factors were taken from field studies conducted by Clearstone in the early 1990s and reflect the level of control inherent with the operating and regulatory environment in Canada at the time.

Volume 4 of this study profiles various direct and indirect methods for estimation of fugitive emissions. Indirect methods rely on the use of a theoretical or empirical model to back-calculate a source strength based on pollutant concentrations at a convenient downwind reference point and on appropriate process-activity and/or meteorological data. Direct methods involve the physical measurement of flow rates and pollutant concentrations at the source.

The indirect methods profiled include:

1) **Activity-based emission factors** - a first-pass, highly-uncertain estimate of fugitive emissions based on the activity rate of a process or facility.
2) **Leak-rate factors and correlations** - average emission factors for specific components in specific service based on historical point source leak-sampling campaigns. Three variations of this method, as outlined in the U.S. EPA (1995) reference, are listed in increasing order of accuracy:
    a. Leak/no leak factors;
    b. Stratified emission factors;
    c. leak-rate correlation equations with default zero & pegged emission factors.

3) **Remote sensing** - the use of a portable pollutant monitoring system (e.g. LIDAR, DIAL, FTIR Spectroscopy, UVDOAS, SMUG), meteorological station, an accurate GPS or linear-distance system, and a computerized dispersion-modeling package.
4) **Emission source simulators** - analytic models that utilize rigorous engineering principles and calculation methods to estimate emissions based on the specific physical, operating, and activity parameters of the target source (e.g CHEMDAT8, WATER8, TANKS, E&P-TANK, GRI-GLYCalc).
5) **Plume transect method** - measuring concentration gradients of the target pollutants over the assumed cross-sectional area of the source plume at a convenient downwind location, combined with meteorological data to determine pollutant flux rates across the measurement plane.
6) **Tracer/pollutant ratio technique** - small, carefully metered, amounts of trace gas (e.g. SF6) are released at a steady rate near the source of interest and the crosswind concentration profiles of both the tracer and the target pollutants are then measured at a convenient downwind location. This technique can be combined with remote sensing.

The direct measurement methods profiled included:

1) **Duct or stack flow measurement** - measurement of the contained flow rate or velocity-profile and pollutant concentration in situations where total emissions capture can occur (e.g. ducts, stacks, open-ended lines, capture tubing or piping).
2) **Bagging** - placement of an enclosure or envelope around a target source (typically a leaking component) and passing a measured flow of clean gas (air, inert gas) through the enclosure to sweep the source. The pollutant flow rate is calculated based on its measured steady-state concentration in the chamber and the know sweep gas rate.
3) **Hi-Flow Sampler** - a low-cost, portable vacuum device that uses the same principles of bagging by directly measuring the flow of sweep air that captures the entire leaking pollutant and the hydrocarbon concentration (or differential concentration above background) in the exit air stream.
4) **Isolation Flux Chambers** - Designed for measurement of pollutant fluxes from liquid or solid surfaces, a portable enclosure with a sweep flow of clean air is placed on a selected sample area to capture and isolate pollutant emissions. Flux rate is calculated based on measured sweep air flow, measured outlet pollutant concentration, and footprint surface area.
5) **Portable wind tunnels** - a rectangular chamber similar to an isolation flux chamber, designed with a fan to simulate the flow of natural air over the emitting surface.

2.2.6 IPCC FUGITIVE EMISSIONS FROM OIL AND NATURAL GAS ACTIVITIES (IPPC 2000)

This background paper was written by Clearstone as part of the IPCC Good Practice Guidance sessions held in 2000 in Washington. The paper provides more clarity to IPCC methods for the upstream oil & gas industry originally outlined in the Revised 1996 IPCC Guidelines for National GHG Inventories. The paper identified the following key emission assessment issues and recommended using technical representatives from the industry to help compile bottom-up inventories:

- use of simple production-based emission factors is susceptible to excessive errors;
- use of rigorous bottom-up approaches requires expert knowledge to apply and relies on detailed data which may be difficult and costly to obtain; and
- measurement programs are time consuming and very costly to perform.

The Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC Guidelines) provide a three-tier approach for assessing fugitive emissions from oil and gas activities. These approaches range from the use of simple production-based emission factors and high-level production statistics (i.e., Tier-1) to the use of rigorous estimation techniques involving highly disaggregated activity and data sources (i.e., Tier-3), and could include measurement and monitoring programs. The intent is that countries with significant oil and gas industries would use the more rigorous or refined approaches, and countries with smaller industries and limited resources would use the simplest approach. However, the IPCC Guidelines lack definition and direction in conducting the refined approaches, and the factors available for the simplified approach are in need of further refinement and updating. In addition to that, the established IPCC reporting format contains some deficiencies and should include requirements to provide some general activity summaries and performance indicators to help put the emission results in proper perspective. Accordingly, this paper provides specific recommendations for improvements of the IPCC methodology for oil and gas systems, and generally defines good practice in developing these inventories (including a discussion of key issues, and specific limitations and barriers). Furthermore, it identifies relevant new Tier 1 (activity-based) emission factors and methodological advancements made since the last update of the IPCC Guidelines.

2.2.7 CAPP GUIDE FOR CALCULATING GHG EMISSIONS (CAPP 2003)

This 2003 CAPP document was a comprehensive guidance handbook developed for Canadian oil & gas companies to provide methodologies and emission factors for GHG emission quantification. The guide presents three methods for calculating fugitive GHG emissions:

- A Short Form method using a set of activity-based (Tier 1) emission factors for general scoping estimates;
- A Generic Fitting Count method that uses generic fitting counts for specific equipment/processes, obtained from a 1993 API publication on Fugitive Hydrocarbon

Emissions from Oil and Gas Production Operations combined with average component emission factors published in the CAPP 1999 GHG Inventory; and

- A Detailed method that requires an actual count of facility components combined with average component emission factors published in the CAPP 1999 GHG Inventory.

2.2.8 CAPP 2000 NATIONAL INVENTORY OF GHGS, CACS & H2S FROM OIL & GAS (CAPP 2005)

Clearstone repeated this national inventory study of the upstream oil & gas industry for the CAPP in 2005. The study assessed emissions for three GHGs (CO_2, CH_4, and N_2O), seven CACs (NOx, SOx, VOC, CO, TPM, PM_{10}, and $PM_{2.5}$) and H_2S. Using 2000 as the reference year of the inventory and annual industry activity level data, a trend of inventory data was presented for the years 1990-2000. Environment Canada updated its UOG GHG estimates for its National Inventory Reports on the data from this report, starting for the 2004 data year. For comparable sectors, the Canadian inventory in 2000 was higher than 1995 due to an increase in industry activity. The data suggested that fugitive equipment leaks remained a significant source of methane emissions in the natural gas industry.

Volume 3 of this study outlined the methodologies used to estimate the national GHG inventory. As done with the previous inventory, fugitive emissions were estimated by the average emission factor method. However, the oil and gas production emission factors used in the inventory were developed based on results of field studies conducted by Clearstone over the period 1992 to 2003 for oil and gas facilities in Western Canada. With more recent test data, the average factors used were lower than the average factors used in the 1999 inventory. This reflects the increasing attention to control practices for fugitive emissions that started with the adoption of the CCME Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks.

2.2.9 2006 IPCC GUIDELINES FOR NATIONAL GHG INVENTORIES (IPCC 2006)

The 2006 IPCC Guidelines for National Greenhouse Gas Inventories (2006 Guidelines) were produced at the invitation of the United Nations Framework Convention on Climate Change (UNFCCC) to update the Revised 1996 Guidelines and associated good practice guidance (2000), which provide internationally-agreed methodologies intended for use by countries to estimate greenhouse gas inventories to report to the UNFCCC. Although intended for national jurisdictions, the guidelines can be used for sub-national jurisdictions, such as provinces. Section 4.2 of Volume 2 of the 2006 Guidelines provides guidance on estimating fugitive emissions from oil and natural gas systems. The lead author for this section was David Picard of Clearstone.

The IPCC defines fugitive emissions broadly, meaning all greenhouse gas emissions from oil and gas systems except contributions from fuel combustion. Therefore, the guidance is for quantification of national emission estimates for venting, flaring, and fugitive emissions from equipment leaks. Three methodological tiers are presented for estimating "fugitive" emissions from oil and natural gas systems:

- Tier 1 - The application of appropriate default emission factors to a representative activity parameter (usually throughput) for each applicable segment or subcategory of a country's oil and natural gas industry. Some default Tier 1 average activity-based emission factors are published in various industry sector categories and sub-categories for a source titled "Fugitives," but this source includes fugitive equipment leaks and venting from storage tanks, pneumatic devices, and glycol dehydrators;
- Tier 2 - Tier 2 consists of using Tier 1 equations with country-specific, instead of default, emission factors. The country-specific values may be developed from studies and measurement programs, or be derived by initially applying a Tier 3 approach and then back-calculating Tier 2 emission factors.
- Tier 3 - The application of a rigorous, bottom-up assessment by primary type of source (e.g., venting, flaring, fugitive equipment leaks, evaporation losses and accidental releases) at the individual facility level with appropriate accounting of contributions from temporary and minor field or well-site installations. The Tier 3 guidance states that the type of activity data required for the development of estimates for fugitive equipment leaks includes:

    - a facility inventory, including an assessment of the type and amount of equipment or process units at each facility, and major emission controls (e.g., vapour recovery, waste gas incineration, etc.); and
    - an inventory of wells and minor field installations (e.g., field dehydrators, line heaters, well site metering, etc.).

The 2006 Guidelines do not publish Tier 3 emission factors but instead recommends the use of industry emission factors developed and published by local environmental agencies and industry associations, due to the high level of detail and complexity, the continual updating of emission factors, and the development and penetration of new control technologies and requirements.

2.2.10 API COMPENDIUM 2009 (API 2009)

Initially prepared in 2001 in a pilot test version and 2004 as the first formal version, this 2009 update provides a comprehensive guidance document to estimating GHG emissions for the U.S. oil and natural gas industries, including the downstream petroleum refining industry. The "API Compendium":

- assembles an expansive collection of relevant emission factors and methodologies for estimating GHG emissions, based on currently available public documents;
- outlines detailed procedures for conversions between different measurement unit systems, with particular emphasis on implementation of oil and natural gas industry standards;

- provides descriptions of the multitude of oil and natural gas industry operations—in its various segments—and the associated GHG emissions sources that should be considered; and
- develops emission inventory examples—based on selected facilities from various oil and natural gas industry operations—to demonstrate the broad applicability of the methodologies.

The API Compendium presents the following 3 methods for estimating fugitive emissions in increasing order of accuracy. Emission factors for the natural gas industry are based on the EPA-GRI 1996 study and are converted to CH4 and CO2-specific factors based on average stream composition assumptions.

- Facility-level average emission factors based on type of facility and facility activity level parameters (e.g. throughput);
- Equipment-level average emission factors based on type of equipment and counts of equipment units; and
- Component-level average emission factors based on the count of components in a facility. While the preferred approach is to have actual component counts in a facility, generic equipment counts are provided as an option in Appendix C.

Further information on direct measurement methods for fugitive emissions is summarized in Appendix C of this document. The component-level measurement approaches summarized are three of the four methods first outlined in the 1995 U.S. EPA Protocol for Equipment Leak Estimates:

- Screening Range Factor Approach - the "leak"/"no-leak" approach using U.S. EPA Method 21 to measure leaks (>10,000 ppmv) and non-leaks (<10,000 ppmv) and applying average emission factors;
- Correlation Approach - using U.S. EPA Method 21 to measure the actual concentration of leaking components and applying the correlation equation to estimate mass leak rates for each component.
- Unit-Specific Correlations Approach - applying the same approach as above but conducting unit-specific or site-specific mass flow measurements to derive locally-applicable correlation equations.

2.2.11 EPA GAS INDUSTRY METHANE EMISSION FACTOR IMPROVEMENT STUDY (US EPA 2011)

This 2011 EPA report presented the work performed by the University of Texas and URS Corp., with the goal of updating default methane (CH4) emission factors for selected processes and equipment used in the natural gas industry. The initial impetus of this study was to establish new emission factors that were both statistically superior to the 1996 US EPA and Gas Research Institute (GRI) emissions inventory project (US EPA-GRI, 1996) emission factors, and more relevant than the GRI/EPA factors (by including more recent samples). The default emission factors for various sources were compiled and synthesized for a variety of source categories, and new emission rate measurements were conducted for selected sources where existing data had large uncertainties or were thought to possibly be insufficiently representative of current practices and equipment.

The study focus was high emission rate leaks (fugitive leaks) from transmission, gathering/boosting, and gas processing reciprocating and centrifugal compressor components, including emissions from compressor vents (i.e., blowdown lines and compressor seals). Samples were collected from 66 reciprocating compressors and 18 centrifugal compressors, with a total of 48 reciprocating compressors at transmission compressor stations. Emissions from other fugitive sources such as valves, flanges, and other components were also measured in a few locations.

As found in other similar studies, the largest single emission sources at a compressor station are the compressor blowdown (BD) vent lines and the compressor seal vents.

The new measurements made for this project on fugitive components (i.e., valves, flanges, etc.) produced lower emission factors than the previous GRI/EPA study. This may be due to improved LDAR practices for accessible fugitive components that have been implemented by companies in the past two decades. For centrifugal transmission compressors this project found the average blowdown line emission factors were significantly lower than the GRI/EPA study, but found wet seal degassing vent emissions were much higher. For reciprocating transmission compressors, this project found average blowdown line emission factors that were significantly higher than the GRI/EPA study, and rod packing vent emissions that were also much higher, likely due to continued aging. The study data was not as robust as the earlier EPA-GRI study since fewer sites were sampled. The study concluded that specialized testing methods must be applied to certain compressor leak sources.

2.2.12 CAPP UPDATE OF FUGITIVE EQUIPMENT LEAK EMISSION FACTORS (CAPP 2014)

This CAPP publication from 2014 was prepared by Clearstone to present updated average emission factors for estimating emissions from fugitive equipment leaks at UOG facilities. The previous factors from CAPP (2005) were developed based on measurement results collected from company fugitive emission surveys in the mid 1990s to 2003. The updated factors are reflective of current conditions at UO&G facilities that have implemented DI&M programs in accordance with the CAPP BMP of Fugitive Emissions at Upstream Oil and Gas Facilities (2007) and applicable regulatory requirements.

Eight UO&G companies provided leak survey results for 120 facilities in Alberta and British Columbia. From this data, Clearstone compiled and assessed emission factors for an estimated 276,947 equipment components. The results are averaged across sweet and sour facilities into 20 average emission factors for 8 component types in various process services over two primary categories: oil systems and natural gas systems.

In comparison, the CAPP (2005) factors are based on leak survey results for 251,431 equipment components. A comparison of the two data sets indicates that, overall, the emissions due to fugitive equipment leaks have decreased by 75 percent since the implementation of DI&M programs. Only emission factors for connectors in gas/vapour service at natural gas facilities were unchanged. Emission factors for all other categories with more than 50 leakers showed substantial reductions compared the CAPP (2005) values. These results are a strong indication that DI&M programs and CAPP's BMP for Management of Fugitive Emissions at Upstream Oil and Gas Facilities are effective in controlling fugitive equipment leaks.

2.3 FIELD STUDIES AND LEAK BEHAVIOR OBSERVATIONS

Key field studies investigating the magnitude and characteristics of fugitive emissions from the UOG industry are presented below.

2.3.1 STAR: NEW FIELD STUDY IMPROVES GHG EMISSION FACTORS FOR PETROLEUM INDUSTRY (STAR ENVIRONMENTAL 2010)

STAR Environmental, the same company that measured the average UOG fugitive emission rates in the early 1990s for the EPA (1995) Protocol for Equipment Leak Estimates, presented this paper at a 2010 EPA Emission Inventory conference. The paper stated that new leak quantification data gathered at oil and gas production facilities showed that the average size of leaks decreased significantly over the last 20 years. The most recent study by STAR Environmental found that the population of "Very Large" leaks has decreased significantly. This population reduction is paralleled by a substantial reduction in total fugitive emissions into the atmosphere from the oil and gas industries. The paper does not present any new emission rates.

2.3.2 MEASUREMENTS OF METHANE EMISSIONS AT NATURAL GAS PRODUCTION SITES IN THE UNITED STATES (ALLEN ET AL, 2013)

In this work, methane emissions were directly measured at 190 onshore natural gas sites in the United States which included 150 production sites, 27 well completion flowback events, 9 well unloading events, and 4 workover events that include 489 hydraulically fractured wells in total. The measurements then were compared to the methane emission estimates in the national inventories of GHG emissions for 2011, released by the US EPA in April 2013 (EPA, 2013). The emissions reported in the EPA inventory are mainly based on engineering estimates and average emission factors (EPA, 1996b).

It was observed that the lowest emissions from completion activities were from the wells in which the flowback was sent to a separator immediately at the start of the completion process, and the gas from the separator was sent to sales. On the contrary, the completions with the highest emissions occurred when the flowback was connected to a vented gas or involved considerable flaring.

Overall, the measurements indicated that well completion emissions are overestimated in the EPA national emissions inventory, while emissions from pneumatic controllers and equipment leaks are underestimated. However, the overestimation is partly offset by the underestimation. Additionally, it was noted that equipment leak emissions are comparable to the EPA estimates.

2.3.3 METHANE LEAKS FROM NORTH AMERICAN NATURAL GAS SYSTEMS (BRANDT ET AL, 2014)

This 2014 study was undertaken because natural gas (NG) had been identified as an important "bridge" energy source between coal and renewable sources, and because the climate benefits of NG use could potentially be offset by leakage rates from NG facilities. Additionally, the study states that global methane concentrations in the atmosphere have been on the rise, and that the causes of the phenomenon were poorly understood. Therefore, to improve understanding of leakage rates for policy-makers, investors, and other decision-makers, researchers reviewed 20 years of technical literature on NG emissions in the United States and Canada.

Researchers found that: (i) measurements at all scales show that official inventories consistently underestimate actual CH_4 emissions, with the NG and oil sectors as important contributors; (ii) many independent experiments suggest that a small number of "superemitters" could be responsible for a large fraction of leakage; (iii) recent regional atmospheric studies with very high emissions rates are unlikely to be representative of typical NG system leakage rates; and (iv) assessments using 100-year impact indicators show system-wide leakage is unlikely to be large enough to negate climate benefits of coal-to NG substitution.

The study found that methane emissions estimates based on surface activity data underrepresented actual methane concentrations in the atmosphere for several reasons. First, devices sampled are not likely to be representative of current technologies and practices (i.e. hydraulic fracturing and horizontal drilling). Second, measurements for generating emission factors (EFs) are expensive, which limits sample sizes and representativeness. Many US EPA EFs have wide confidence intervals. There are reasons to suspect sampling bias in EFs, as sampling has occurred at self-selected cooperating facilities. Third, if emissions distributions have "heavy tails" (e.g., more high-emissions sources than would be expected in a normal distribution), small sample sizes are likely to underrepresent high-consequence emissions sources. Studies suggest that emissions are dominated by a small fraction of "super emitter" sources at well sites, gas-processing plants, coproduced liquids storage tanks, transmission compressor stations, and distribution systems. For example, one study measured ~75,000 components and found that 58% of emissions came from 0.06% of possible sources.

The study also examined the implications of their findings on policy and monitoring for the coming years. It found that improved science would aid in generating cost-effective policy responses. Given the cost of direct measurements, emissions inventories will remain useful for tracking trends, highlighting sources with large potential for reductions, and making policy decisions. However, improved inventory validation is crucial to ensure that supplied information is timely and accurate. Device-level measurements can be performed at facilities of a variety of designs, vintages, and management practices to find low-cost mitigation options. These studies must be paired with additional atmospheric science to close the gap between top-down and bottom-up studies

2.3.4 METHANE EMISSIONS FROM CONVENTIONAL AND UNCONVENTIONAL NATURAL GAS PRODUCTION SITES IN THE MARCELLUS SHALE BASIN (OMARA ET AL, 2016)

In this study, facility-level methane emission rates associated with 18 conventional (19 wells) and 17 unconventional (88 wells) natural gas production sites in Marcellus region, US were measured, and the results were compared with the Pennsylvania Department of Environmental Protection (PA DEP) inventory. It was estimated that the total methane emissions from 88500 combined conventional and 3390 unconventional well pads in Pennsylvania and West Virginia were 660 Gg/year and 490 Gg/year respectively. The authors concluded that PA DEP methane emissions inventory considerably underestimated facility level methane emissions for five of the studied unconventional sites by more than 10 to 40 times.

It was found that methane emission rates were highest among the unconventional sites and lowest among the conventional sites at facility level where unconventional sites had approximately 23 times more methane emission rates than conventional sites. Nevertheless, unconventional sites had higher emission rates on a production-normalized basis. The difference in the emission rates are attributed to factors such as natural gas production rate, facility age, the design of the facility including presence of emission captures or control devices, and well operator practices such as the level and frequency of the site inspection and maintenance.

It was observed that methane emission is correlated with total natural gas production; i.e. sites with larger natural gas production had more methane emissions. Conversely, production-normalized emission was inversely correlated with natural gas production. It was also found that the natural gas production rate and methane emissions were negatively correlated with facility age; meaning that newer sites had higher natural gas production and methane emissions. However, the correlation between facility age and the methane emission was proved weak. In addition, it was suggested that avoidable maintenance issues might have a significant contribution in the total methane emissions, and therefore well operator practices such as the frequency of well inspection and maintenance could considerably affect the methane emission rates.

Although some correlation with production is observed, the study does not provide conclusive evidence that methane emissions can be predicted based on a single or small number of parameters. The methane emissions distribution was found to be highly skewed as 17% of conventional natural gas facilities contributed 50% of methane emissions, and 23% of unconventional natural gas facilities accounted for 85% of the total emissions.

2.3.5 TECHNICAL SUPPORT FOR LEAK DETECTION METHODOLOGY REVISIONS AND CONFIDENTIALITY DETERMINATIONS FOR PETROLEUM AND NATURAL GAS SYSTEMS FINAL RULE (EPA, 2016)

An EPA comparison of OGI versus Method 21 based leak factors observed that leaker emission factors determined from more recent OGI study data agreed reasonably well with the leaker emission factors developed from Method 21-based data with a leak screening threshold of 10,000 ppmv (US EPA, 2016). The study also observed that leaker emission factors determined using Method 21 (and a leak threshold of 500 ppmv) are statistically different than OGI-based leaker emission factors. This suggests the OGI method is reasonably equivalent to Method 21 for detecting leaks with a screening concentration greater than 10,000 ppmv but not appropriate for use where the desired screening concentration is 500 ppmv.

2.3.6 METHANE LEAKS FROM NATURAL GAS SYSTEMS FOLLOW EXTREME DISTRIBUTIONS (BRANDT ET AL, 2016)

This study analyzed 15,000 leak measurements from 18 independent studies and observed leaks from natural gas systems follow extreme distributions with the largest 5 percent of leaks ("super-emitters") contributing greater than 50 percent of the total leakage volume. A "5-50" rule of thumb is proposed: for a given source category, the largest 5% of leaks should account for at least 50% of total emissions. Other relevant results:

- Estimating fugitive emissions using a lognormal fit may reasonably predict mean emissions but it systematically underestimates the contribution of super-emitters.
- Determining confidence intervals for equipment leaks based on normal and lognormal distribution assumptions may cause overly narrow and downwardly-biased estimates of uncertainty.
- Determining acceptable sample size for heavy-tailed distributions, typical of leak populations, is more challenging than normally distributed populations. The impact of sample size is investigated via simulation with results showing confidence intervals decreasing as the sample size increases from n = 1 to 1000. Confidence intervals determined assuming a lognormal distribution are consistently understated regardless of

sample size. Although not explicitly stated by the authors, there appears to be limited benefit achieved for the cost of obtaining sample sizes greater than about 300.

- There is a temptation to resolve small sample-size challenges by aggregating measurements from similar sources across multiple studies. However, the statistical validity of grouping different studies was performed using two-sample Kolmogorov-Smirnov (KS) tests and indicates that, despite similar names, components appear to be from different underlying populations. Possible explanations for the KS test failure include differences in component design; FEMP effectiveness by jurisdiction; measurement methods; misclassification of components or the component type definitions incorrectly stratify leak sources (i.e., perhaps component quality is more relevant that component type). KS-test failure also raises concerns about the extrapolation of experimental results from sampled devices to their full populations.

2.3.7 "GOOD VERSUS GOOD ENOUGH?" EMPIRICAL TESTS OF METHANE LEAK DETECTION SENSITIVITY OF A COMMERCIAL INFRARED CAMERA (RAVIKUMAR ET AL, 2018)

This research is completed at the Methane Emission Technology Evaluation Center (METEC brochure attached) where repeatable and quality-assured leaks can be generated so that environmental and operational factors can be isolated and evaluated. Measurements were completed to investigate the ability of an IR camera to detect leaks at known points. The study provides empirical evidence regarding the probability of leak detection with respect to imaging distance and leak magnitude. It indicates a 90 percent probability of detecting a leak at the EPA minimum detection limit of 30 g CH_4/h if the imaging distance is 4 meters. The probability decreases as the OGI camera operator moves away from the source.

In this study, leak detection experiments are divided into two categories of small leaks at short distances (SSD) and large leaks at longer distances (LLD). The SSD experiments were performed at 1.5, 3, and 6 m imaging distances with the leak rates ranging from 3 to 177 g/h (0.2 to 10 scfh), while LLD experiments were conducted at 6, 9, 12, 15 m imaging distances with the leak rates varying from 17 to 332 g/h (1 to 20 scfh).

It is found that the detection limit with 50% detection probability is respectively 3, 6, and 20 g/h at imaging distances of 1.5, 3, and 6 m for SSDs, and 18, 51, 129, and 151 g/h at imaging distances of 6, 9, 12, and 15 m for LLDs. Theses conclusions are made neglecting the effects of weather conditions. It is also shown that typical 90% detection limit at 3 m imaging distance is 20 g CH_4/h which is aligned with U.S. EPA recommendations. Furthermore, it is concluded that an imaging distance between 3 to 6 m is enough to capture leak rates of 30 g/h and above with 90% detection probability.

The experiments were performed with 90% of 5-min average wind speed of less than 4.3 m/s (≈10 mph). Wind speed did not significantly influence leak detection probability function. It is therefore concluded that wind speed below 4.3 m/s is likely acceptable for leak detection surveys.

Moreover, the detection limit is found to increase as the square of imaging distance. This means leak detection becomes more difficult with increasing imaging distance. This is due to the decrease in visible plume size with the square of imaging distance.

This study also investigates the effect of median detection limit -as an indicator of the sensitivity of the detection technology- on emission mitigation programs. Publicly available data from production wellsites, and compressor stations at gathering and boosting, transmission, and storage facilities are used to estimate the fraction of leaks detected as the detection limit changes. FEAST is used to simulate 8 years of semiannual and quarterly leak surveys at production well-pads and compressor stations respectively. It is predicted that the fraction of leaks detected saturates at median detection limit of ≤ 100 g CH_4/h, and any improvement in sensitivity beyond this limit does not improve leak detection. This is because leak-size distribution is highly skewed in natural gas production facilities, where a small number superemitters account for the large fraction of total emissions. These superemitters are easily detectable at lower sensitivities, and increasing sensitivity only results in detecting small leaks that do not contribute significantly in total emissions. The authors conclude that current OGI technology is good enough for detecting leaks as a detection limit of 20 g CH_4/h is obtained from an imaging distance of 3 m. This detection limit is 5 times more sensitive than the saturation detection limit of 100 CH_4/h predicted for semiannual or quarterly LDAR surveys.

2.4 MANAGING FUGITIVE EMISSIONS FROM THE UPSTREAM OIL AND GAS SECTOR

Best management practices and standards relevant to the UOG sector are summarized herein. These are followed by critical studies arguing for the improvement of management practices and fugitive emission reductions.

2.4.1 AER DIRECTIVE 060 - UPSTREAM PETROLEUM INDUSTRY FLARING, INCINERATING, AND VENTING (AER, 2016)

The Alberta Energy Regulator (AER) Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting contains the requirements for flaring, incinerating, and venting in Alberta at all upstream petroleum industry wells, conventional oil & gas facilities, and gas pipelines. While the focus of the Directive is on these combustion and venting emission sources, Section 8.6 - Fugitive Emissions Management contains a requirement for licenses to develop and implement a Leak Detection and Repair program that meets or exceeds the CAPP BMP for

Fugitive Emissions Management. This is the only mandatory regulated requirement for fugitive emissions in Alberta. The requirement is echoed in OGC, 2015a for facilities operating in BC but is not a regulatory requirement in any other Canadian province.

2.4.2 CAPP BEST MANAGEMENT PRACTICE - MANAGEMENT OF FUGITIVE EMISSIONS AT UPSTREAM OIL AND GAS FACILITIES (CAPP 2007)

This 2007 CAPP document lays out the best management practices for the Canadian UOG sector to manage fugitive emissions and meet mandatory requirements stated in AER Directive 060, Section 8.7: "Operators must develop and implement a program to detect and repair leaks." The BMP was developed from multi-stakeholder consultations involving: the Petroleum Technology Alliance of Canada (PTAC); CAPP; the Small Explorers and Producers Association of Canada (SEPAC); Environment Canada (EC); the Alberta Energy Regulator (AER); and the Clean Air Strategic Alliance (CASA). The BMP document:

- identifies the typical key sources of fugitive emissions at UOG facilities,
- presents strategies for achieving cost-effective reductions in these emissions, such as;
    - improved designs;
    - Directed Inspection and Maintenance (DI&M) practices;
    - improved operating practices, and
    - the application of new and retrofit technologies; and
- summarizes key considerations and constraints.

The BMP outlines a three-element Basic Control Strategy for the effective control of fugitive leaks:

1. Application of best available technology and standards - applying proper design and material-selection standards, to follow the manufacturer's specifications for the installation, use and maintenance of components and to implement practicable control technologies (e.g., reduction, recovery and treatment systems).;
2. Implementation of management systems - establishing objective performance targets and implement ongoing monitoring and predictive maintenance programs to ensure that leaks are detected and remain well controlled; and
3. Corporate commitment - a dedicated ongoing commitment, entailing full management support including adequate funding and resource allocation.

A Directed Inspection & Maintenance (DI&M) program is a central recommendation of the management system element that meets Directive 060. The CAPP BMP DI&M program recommends regular screening for leaks, but the emphasis is on maximizing the cost-effectiveness of fugitive emission reductions, while accounting for the unique characteristics and operations of their facility. Repair flexibility is provided for operators through a prioritized decision tree that considers criteria such as health, safety, and environment impact; repair difficulty; repair economics; and the requirement for a facility shutdown. The DI&M guidelines suggested in the BMP include:

- a suggested time limit between leak detection and repair of 45 days;

- increased leak survey frequencies for higher-risk components:
    - every 5 years for quarter-turn ball valves;
    - annually for all other valves, open-ended lines, and emergency vents; and
    - quarterly for compressor and pump seals, blowdown systems, tank hatches, and vapour-recovery unit safety valves.

Appendix 5 of the CAPP BMP also summarizes the following four fugitive emission estimation methods, in increasing order of accuracy. Average emission factors and constants are published for these methods and were derived from fugitive sampling campaigns conducted by Clearstone in the 1990s.

- Leak/No-leak Emission Factors - based on screening surveys using US EPA Method 21;
- Three-stratum Emission Factors - splits "non-leakers" into zero and low leak values;
- Published Leak-Rate Correlations - with parameters based on Canadian industry;
- Unit-Specific Leak-Rate Correlations - operator-developed correlation equations.

Guidelines provided in the CAPP BMP are recommendations only and not enforceable.

2.4.3 AER DRAFT DIRECTIVE PEACE RIVER HYDROCARBON EMISSION CONTROLS (AER 2015)

The AER draft directive, published in Oct. 2015, sets out the Alberta Energy Regulator requirements for addressing odours and emissions generated by heavy oil and bitumen operations in the Peace River area of Alberta. For the Peace River area, mandatory requirements include the elimination of routine and nonroutine venting, reduction in flaring, increasing gas conservation, reducing fugitive emissions, and minimizing odours from truck loading and unloading activities.

Section 5 of the draft directive outlines the requirements to control fugitive emissions including the development of a site Fugitive Emissions Management Program (FEMP). The key elements of the FEMP include:

- More frequent inspections - The required inspection plans include a new initiative - weekly Audio/Visual/Olfactory (VAO) surveys, which require a regular, thorough and documented review of all process operations to identify potential leaking components. Monthly inspections are now required for mandatory components defined as tank-top components, flare igniters, compressor seals, and any high-risk components. The inspection plan now also includes the addition of an independent, annual, third-party survey of all site components.
- Prompt repair of leaks - When leaks are detected, the repair timeframe has been tightened significantly to 1 day for large leaks (>0.2 sm^3/h) and 5 days for smaller leaks (<0.2 sm^3/h); and
- Improved reporting transparency - Documentation of inspection plans, survey details, monthly and annual leak reports, and an annual FEMP Analysis Report.

The requirements in this draft directive are the most stringent elements developed to date in any Canadian oil and gas fugitive emission management initiative. Once the Directive is adopted, companies operating in the Peace River region will likely achieve the lowest fugitive emission rates in Alberta.

2.4.4 CSA Z620.1 STANDARD FOR UOG VENTING AND FUGITIVE EMISSIONS

The Canadian Standards Association (CSA) initiated development of CSA Z620.1 Standard for UOG venting and fugitive emissions in 2013 (CSA, 2015). It will be available to Canadian jurisdictions for discretionary adoption when regulating UOG operations. The standard does not contain any new emission factors or original research. Instead, its objective is to provide the oil and gas industry with minimum requirements and best practices for reduction, or where practicable, elimination of fugitive and venting emissions. It is intended to consolidate provincial directives and guidelines into a single standard for harmonized application across Canada. Moreover, it endeavors to improve monitoring practices by clearly identifying and defining the complete list of fugitive and venting sources. Mandatory LDAR with a prescriptive survey schedule is required for companies that don't have documented DI&M programs in place. Phase I of the standard (Z620.1) is entirely focused on the UOG industry and is scheduled for publication in June 2016. Development of Phase II (Z620.2) is planned to begin in 2017 and will focus on the gas TSD and oil pipeline industries.

2.4.5 US EPA NATURAL GAS STAR PROGRAM (US EPAb)

The US EPA Natural Gas STAR Program is a flexible, voluntary partnership that encourages oil and natural gas companies, both domestically and abroad, to adopt cost-effective technologies and practices that improve operational efficiency and reduce emissions of methane. Since 1993, the Natural Gas STAR program has provided a framework to encourage partner companies to implement methane emissions reducing technologies and practices and document their voluntary emission reduction activities. Through this work, the oil and natural gas industry, in conjunction with Natural Gas STAR, has pioneered some of the most widely–used, innovative technologies and practices that reduce methane emissions.

To control fugitive emissions, the Natural Gas STAR program recommends the implementation of Directed Inspection & Maintenance (DI&M) programs, particularly for gas transmission and distribution systems. DI&M programs are recommended for various components at surface facilities in remote locations, gathering system booster stations, gas processing plants, pipeline compressor stations, and distribution gate stations.

In 2015, to support the U.S. Climate Action Plan and Methane Strategy, the US EPA is developing a new partnership program in the oil and gas sector to build on the success of the Natural Gas STAR program. One of the proposed protocols in their Gas STAR program is an annual and bi-annual inspection frequency for DI&M programs for onshore production and gathering and boosting facilities based on the absolute tonnage of natural gas emissions. This would automatically require very large gas production basins to fall into the bi-annual frequency requirements.

2.4.6 CONTROLLING FUGITIVE METHANE EMISSIONS IN THE OIL AND GAS SECTOR (IIGCC 2012)

This document is a joint statement by the Institutional Investors Group on Climate Change (IIGCC), the Investor Network on Climate Risk (INCR) and the Investors Group on Climate Change (IGCC). It states that the organizations are concerned about climate change, that there are effective steps that can be used to minimize emissions from oil and gas activities, and calls on governments in oil and gas producing nations to consider whether they have effective regulations in place to minimize methane emissions.

According to the organizations that have written the document, burning natural gas, as opposed to coal, can result in 40-50% lower power plant carbon dioxide emissions. However, they are concerned that research that has indicated that increased global warming from high fugitive methane emissions generated along the natural gas value chain may negate some of this benefit, particularly for the first few decades after coal-gas switching. This carries risks for the climate, but also for the industry itself as it threatens to increase public opposition to oil and gas development. The organizations believe that fugitive methane emissions can be substantially avoided using current technologies (2012) at low cost. They cite documentation that indicates many methane leakage control techniques have payback periods of less than three years. (US EPAc)

The organizations that drafted the document issue a "call to companies" and a "call to governments" regarding actions they feel may help to mitigate fugitive emissions from oil and gas facilities. Full descriptions of these "calls" are contained within the document itself, but they can be summarized as follows:

- call to companies:
    - review operational practices and ensure that best management practices are followed;
    - publicly disclose the operational practices of your company to enable a better understanding of current practices/investor oversight;
    - heavy users of natural gas should hold companies upstream (i.e. supplying the gas) accountable to high standards regarding the prevention of fugitive emissions;
- call to governments;
    - review policies to ensure regulations are effective in minimizing methane emissions;
    - as consumers of natural gas, investigate the quantity of methane emissions control demonstrated in regions where gas is supplied from, and discourage the sourcing of natural gas from suppliers that fail to control emissions; and
    - support the global Climate and Clean Air Coalition to Reduce Short Lived Climate Pollutants and the Global Methane Initiative.

Based on these stated goals and information provided by Natural Gas STAR and other experts, investors have prepared a draft disclosure framework for consultation with the industry (available in the "publications" section of their website). (IIGC)

2.4.7 ALBERTA'S UPSTREAM OIL AND GAS ASSETS INVENTORY STUDY – OPPORTUNITIES TO REDUCE GREENHOUSE GAS VENTING AT EXISTING DISTRIBUTED FACILITIES (CAP-OP, 2013)

Although this study does not assess fugitive sources, GHG emissions from UOG venting sources is significant and therefore included in the literature review. In 2013, Petroleum Technology Alliance Canada (PTAC) believed there was an opportunity to reduce emissions associated with these facilities through the use of market ready technologies.

Therefore, PTAC requested that Cap-Op Energy conduct a desktop review of the distributed oil and gas facilities in Alberta, and related methane control and energy efficiency technologies. The review was comprised of three main components: an inventory of distributed oil and gas facilities in Alberta, a subsequent inventory of the typical assets at each facility and a review of the applicable methane control or energy efficiency technologies. The information gained from this three-phase review was used to inform estimations of the potential greenhouse gas reductions possible within the upstream sector in Alberta.

The eight GHG reducing technologies studied in the report include:

- low/no-bleed pneumatic controllers;
- engine fuel management systems (air-fuel ratio systems);
- vent gas capture (SlipStreamTM Technology);
- low/no-bleed pneumatic pumps;
- custom waste heat recovery systems for process heat;
- instrument gas to instrument air for pneumatic technologies;
- well-site vent gas capture; and
- green completions.

The conservative estimate of the stock of GHG emitting equipment that could be retrofitted with the GHG efficient technologies was multiplied by the average GHG emissions reductions offered by each technology. The resulting emissions reductions opportunity was the calculated as 35,300,000 tonnes of CO_2e per year. The full report describes the potential emission reductions associated with each technology, and provides additional information on the technologies and their applicability to Canadian industry.

2.4.8 EMISSION REDUCTION ACTIONS PROGRAM (NAMA) IN NATURAL GAS PROCESSING, TRANSPORT AND DISTRIBUTION SYSTEMS, THROUGH FUGITIVE EMISSION REDUCTION. (CO_2 SOLUTIONS 2013)

This document is an Emission Reduction Action Program (NAMA) published by the United Nations Framework Convention on Climate Change (UNFCCC) for Mexico. It is a description of the NAMA Mexico intends to utilize in order to reduce fugitive emissions from natural gas processing, transport and distribution systems. The activities registered under the NAMA were projected to reduce approximately 3 million tonnes of CO_2 equivalent per year. However, as these changes were meant to help Mexico's systems reach efficiencies that were comparable to the efficiencies already reached in countries like the United States and Canada, it is unlikely that the NAMA has any further guidance to offer Canada's sector regarding the reduction of fugitive emissions.

2.4.9 ECONOMIC ANALYSIS OF METHANE EMISSION REDUCTION OPPORTUNITIES IN THE CANADIAN OIL AND NATURAL GAS INDUSTRIES (ICF INTERNATIONAL 2015)

The Environmental Defense Fund (EDF) commissioned this economic analysis of methane emission reduction opportunities from the Canadian oil and natural gas industries to identify the most cost-effective approaches to reduce these methane emissions. This study is solutions-oriented and builds off a similar study ICF undertook for EDF on oil and gas methane reductions in the United States. (Environmental Defense Fund) This study attempts to project the estimated growth of methane emissions from Canada's oil and gas industry through 2020. It then identifies the largest emitting segments and estimates the magnitude and cost of potential reductions achievable through currently available and applicable technologies and practices. The key conclusions of the study include:

- 35 of the over 175 emission source categories account for over 80% of the 2020 emissions, primarily at existing facilities.
- Methane emissions from oil and gas activities are projected to remain stable from 2013 to 2020 at around 60.2 million tonnes CO_2e (125 Bcf of methane).
- 45% Emissions Reduction with Existing Technologies -This 45% reduction of oil and gas methane is equal to 27 million tonnes CO_2e (56 Bcf of methane) and is achievable with existing technologies and techniques.
- Capital Cost - The initial capital cost of the measures is estimated to be approximately $726.3 million CAD ($581 million USD).
- Largest Abatement Opportunities – In 2020, the Gas Production segment makes up 26.8% of total oil and gas methane emissions, followed by Gathering and Boosting (21.8%) and Oil Production (19.9%). 35 of the over 175 emission source categories13 account for over 80% of the 2020 emissions, primarily at existing facilities. By volume, the top five largest sources of Canadian oil and gas methane emissions are:
  - Stranded gas venting from oil wells – opportunity to reduce emissions by 78% by installing flares.
  - Fugitives from gathering and boosting stations – opportunity to reduce emissions by 60% by implementing leak detection, and repair (LDAR).
  - Chemical injection pumps - opportunity to reduce emissions by 60% by replacing gas-driven pumps with a non-natural gas driven variety.
  - Reciprocating compressor rod packing seals - opportunity to reduce emissions by 22% by replacing rod packing at a higher frequency.
  - Fugitives from centrifugal compressors - opportunity to reduce emissions by 60% by implementing leak detection, and repair (LDAR).
- Provincial Results: Cost Effective Reductions Possible in Alberta and BC – Alberta and British Columbia (Upstream only) make up 58% (32.6 Bcf) and 9% (4.8 Bcf) respectively of

total Canadian oil and gas methane emissions reductions in 2020 and reductions are projected to be achievable in both provinces with existing technologies for less than $0.01/Mcf of gas produced.

- Co-Benefits Exist – Reducing methane emissions will also reduce - at no extra cost - conventional pollutants that can harm public health and the environment.

2.4.10 CLEARING THE AIR: REDUCING UPSTREAM GREENHOUSE GAS EMISSIONS FROM U.S. NATURAL GAS SYSTEMS (WORLD RESOURCES INSTITUTE 2013)

This study focuses primarily on evaluating and reducing upstream methane emissions in the natural gas sector. This has two important implications. First, this paper in no way aims to diminish the urgent need to achieve GHG emissions reductions from other segments of the economy. For example, significant cost-effective opportunities also exist to reduce carbon dioxide emissions from both upstream and downstream stages of the natural gas life cycle, and to reduce methane emissions from coal mines, landfills, and other sources. Longer term, addressing combustion emissions will be increasingly important, whether through carbon capture and storage or by other means.

The study had five major conclusions:

1. Fugitive methane emissions represent a significant source of global warming pollution in the United States.
2. Cutting methane leakage rates from natural gas systems to less than 1% of total production would ensure that the climate impacts of natural gas are lower than coal or diesel fuel over any time horizon. Technologies currently exist to support this goal.
3. Fugitive methane emissions occur at every stage of the natural gas life cycle; however, the total amount of leakage is unclear. More comprehensive and current direct emissions measurements are needed from this regionally diverse and rapidly expanding energy sector.
4. Recent standards from the US EPA will substantially reduce leakage from natural gas systems, but to help slow the rate of global warming and improve air quality, further action by states and EPA should directly address fugitive methane from new and existing wells and equipment.
5. Federal rules building on existing Clean Air Act (CAA) authorities could provide an appropriate framework for reducing upstream methane emissions. This approach accounts for input by affected industries, while allowing flexibility for states to implement rules according to unique local circumstances.

2.4.11 LEAKING PROFITS – THE U.S. OIL AND GAS INDUSTRY CAN REDUCE POLLUTION, CONSERVE RESOURCES, AND MAKE MONEY BY PREVENTING METHANE WASTE (NRDC 2013)

This report focuses on 10 widely applicable methane emission reduction opportunities in the United States UOG industry. The report posits that if these technologies could be used throughout the industry, they would have the potential to reduce U.S. methane emissions by more than 80% of current levels (2012), based on the US EPA estimates, an amount greater than the annual greenhouse gas emissions from 50 coal fired power plants. This methane, if captured and sold, could bring in billions of dollars in revenues while benefiting the environment. A combination of voluntary and mandatory programs implemented by the US EPA and many states has already reduced the industry's U.S. methane emissions by more than 20%. Report authors conclude that given industry practice up to 2012, it appeared that available control technologies, while profitable, did not provide sufficient incentive to drive further voluntary reductions. While voluntary programs resulted in some progress, additional mandatory programs were needed to get closer to the more than 80% methane reduction level that this report demonstrates could be within reach. The 10 technologies that the report investigates are as follows:

1. Green completions to capture oil and gas well emissions.
2. Plunger lift systems or other well deliquification methods to mitigate gas well emissions.
3. Tri-ethylene glycol (TEG) dehydrator emission controls to capture emissions from dehydrators.
4. Desiccant dehydrators to capture emissions from dehydrators.
5. Dry seal systems to reduce emissions from centrifugal compressor seals.
6. Improved compressor maintenance to reduce emissions from reciprocating compressors.
7. Low-bleed or no-bleed pneumatic controllers used to reduce emissions from control devices.
8. Pipeline maintenance and repair to reduce emissions from pipelines.
9. Vapor recovery units used to reduce emissions from storage tanks.
10. Leak monitoring and repair to control fugitive emissions from valves, flanges, seals, connections and other equipment.

2.4.12 EMISSIONS SOURCES AND CONTROL TECHNOLOGIES AFFECTING UPSTREAM AND MIDSTREAM OIL AND GAS (LONDON ET AL. 2013)

This paper describes U.S. regulatory instruments that impact the upstream oil and gas sector. It also provides information on different components in the oil and gas sector that leak methane and other pollutants, and how U.S. regulatory mechanisms interact with these components. It is important to note that as the paper was written in 2013, Part 98, Subpart W is not considered within the text.

Therefore, the document primarily deals with NESHAPs, NSPSs, and the Clean Air Act and how these regulatory tools impact emissions (not fugitive emissions specifically) from the oil and gas sector. This document is primarily written as a compliance aid for operators, fully explaining details regarding how to comply with various U.S. instruments. Therefore, while it does contain interesting information, it is not particularly relevant to this study.

2.4.13 DESIGNING BETTER METHANE MITIGATION POLICIES: THE CHALLENGE OF DISTRIBUTED SMALL SOURCES IN THE NATURAL GAS SECTOR (RAVIKUMAR AND BRANDT, 2017)

This study investigates the effectiveness of US EPA find-all-fix-all policies (EPA, 2016b) which recommend to conducted LDAR surveys using optical gas imaging technologies, by assessing facility- and mitigation-related uncertainties. The authors first developed a mathematical model (FEAST) and analyzed the publicly available emission dataset. Then, they proposed four different policy options to mitigate the emission. The analysis led to the following main conclusions:

Leak-size distributions strongly affect emission mitigation potential as the minimum leak detection limit of OGI technologies are fixed. As a result, leak detection surveys are more effective for the same emissions volume on sites where a small fraction of superemitters contribute significantly to the total emissions.

Variation in emission rates among facilities results in considerable variability in methane reduction effectiveness since OGI techniques only detect the largest leaks. As a result, mitigation percentages of less than 60% are expected for facilities with baseline emissions of lower than about 10 tonnes/year.

Leak detection based on OGI techniques can reduce the emissions by 15% to over 70% depending on the mitigation program and environmental factors. For example, it was observed that 60% emissions reduction was only achievable if the surveys were performed semi-annually at a less than 5m distance from the leak source under the considered conditions. The study asserts OGI effectiveness depends on:

- viewing distance (i.e., declines as distance increases beyond 5 meters),
- visual acuity and experience of the operator,
- ambient temperature (very poor detection below 0^{o} Celsius), and
- wind speed (almost linear decline from best detection @ 1 m/s to half of best @ 9 m/s).

Although implementation costs are fairly constant and about 27% lower than what US EPA estimates, profits from saved gas are as variable as one-third to three times US EPA estimates depending on aforementioned playing factors. For instance, increasing imaging distance significantly decreases the benefits while having higher skewedness in leak-size distribution increases the benefits.

The authors analyzed these observations and proposed the following methane mitigation options:

1. Performance-oriented targets for accelerated emission reductions where mass-based (absolute emissions cap) or rate-based (fraction of system throughput) leakage targets are set.
2. Flexible policy mechanisms to account for regional variation in which emission reduction estimates and mitigation program targets are determined considering regional differences.
3. Technology-agnostic regulations to encourage adoption of the most cost-effective measures; and,
4. Coordination with other greenhouse gas mitigation policies such as Clean Power Plan (EPA, 2015) to reduce unintended spillover effects with the aim to reduce GHG emissions from different sectors of the economy.

3 2017 ALBERTA FIELD OBSERVATIONS

A field equipment inventory and measurement campaign was completed in August and September of 2017 that targeted sites belonging to facility subtypes that contribute the most to uncertainty in the Alberta UOG methane emission inventory. Survey locations were randomly selected from the facility subtype populations belonging to the following UOG industry segments.

- Natural Gas Production (includes subtypes 351, 361, 362, 363, 364, 365, 366, 367, 601, 621, and 622)
- Light and Crude Oil Production (includes subtypes 311, 321, 322, 501, 502 and 508)
- Cold Heavy Crude Oil Production (includes subtypes 331, 341, 342, 343 and 611)

Data collection and leak surveys were completed at 333 locations, operated by 63 different companies, and included 241 production accounting reporting entities and 440 UWIs. This sample data represents the vintage, production characteristics and regulatory oversight corresponding to UOG facilities operating in Alberta during 2017. The geographic distribution of survey locations is illustrated in Figure 1.

Standardized data collection methods and strict definitions for component, equipment, service, emission and facility type are documented in the sampling plan and used by field teams. Field observations and measurements for a location are assigned to corresponding Petrinex[3] facility identifiers (ID) and UWI based on measurement schematics provided by subject operators. Correlating field observations to Facility IDs and UWIs ensures factors are representative of Petrinex site identifiers and enables direct application in emission inventory projects that utilize Petrinex data.

Field teams were instructed to obtain a complete inventory of equipment represented by subject Petrinex Facility IDs and survey at least five wells belonging to each multi-well battery visited. In some cases, all wells are located on the same lease location but in other cases, wells are at multiple off-site locations. Equipment dedicated to the well (e.g., a wellhead) is assigned to the subject UWI whereas equipment servicing multiple wells (e.g., a booster compressor) is assigned to the Facility ID.

3 Petrinex is a joint strategic organization supporting Canada's upstream, midstream and downstream petroleum industry. It delivers efficient, standardized, safe and accurate management of "data of record" information essential to the operation of the petroleum sector.

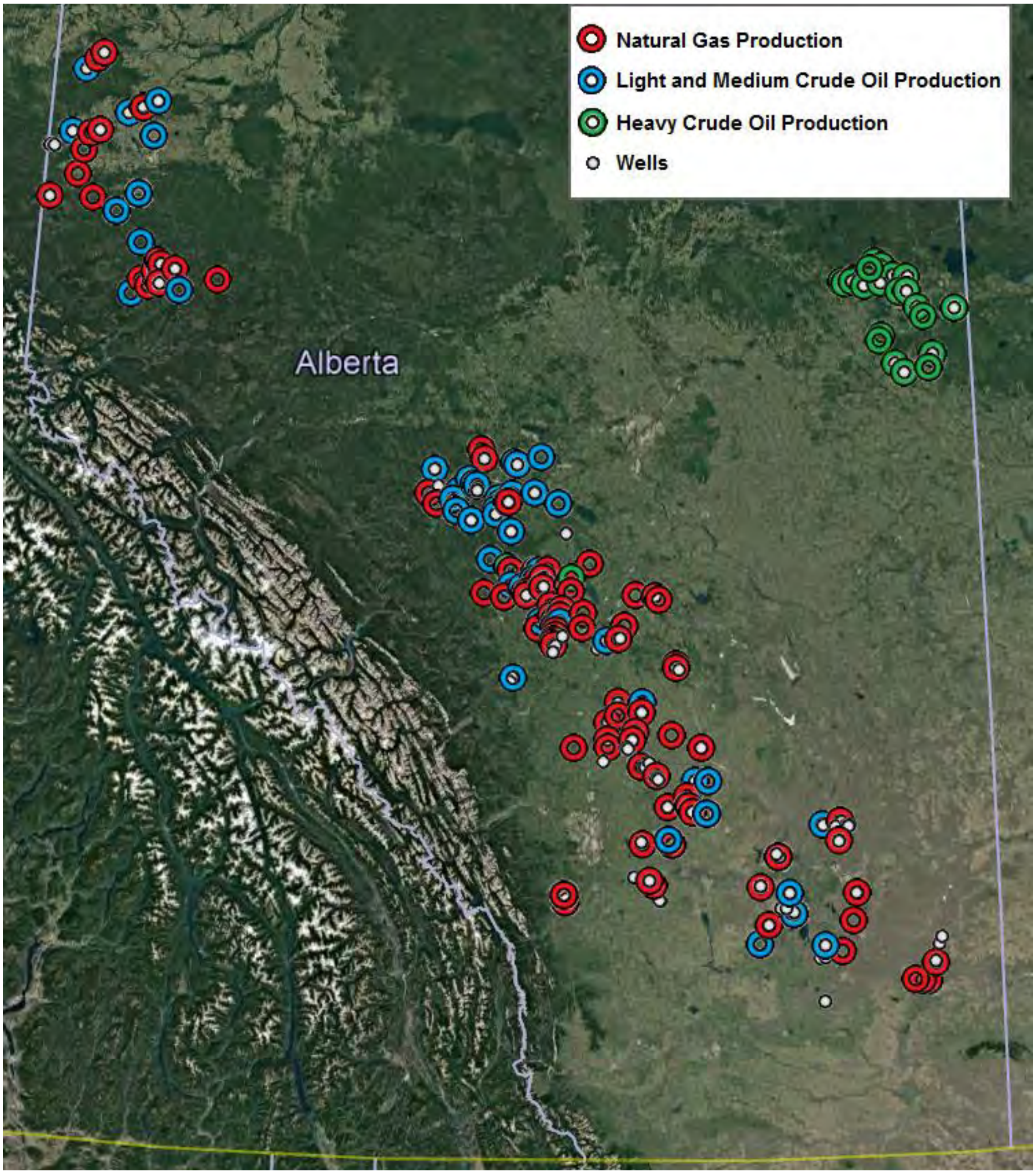

Figure 1: Survey locations and facility subtypes for the 2017 measurement campaign.

Gas analysis were requested from operators for sites with noteworthy equipment leaks[4]. When site-specific analysis are not available, a typical gas composition is used to calculate mass emission rates (Table 26 in Volume 3 of ECCC, 2014).

All volumes are presented on a dry basis at standard reference conditions 101.325 kPa and 15^{o} C. The uncertainty analysis and determination of confidence intervals is presented in Section 3.3.

4 Laboratory analysis reports were requested for the top 20% of leakers for each component and service type.

3.1 COMPONENT COUNTS

Components in pressurized hydrocarbon service, greater than 0.5" nominal pipe size (NPS) and belonging to the process equipment described in Section 6.4 were counted and classified according to the following component types and hydrocarbon service types. More than 216,000 components were counted during the 2017 field campaign. A definition for each component types is presented in Section 6.3 and for each service type in Section 6.2. Average (mean) component counts and confidence intervals (determined according to Section 3.3) for each process equipment type are available in the field study report (Clearstone, 2018).

- Compressor Seals (rod-packings),
- Connector,
- Control Valve,
- Meter,
- Open-Ended Line,
- Pressure Relief Valves and Pressure Safety Valves (PRV/PSV),
- Pump Seal,
- Regulator,
- Thief Hatch,
- Valve, and
- Well Surface Casing Vent (SCVF).

The list of component types is adopted from previous Canadian UOG emission factor publications (CAPP, 2005 and CAPP, 2014) and extended to include meters, thief hatches and SCVF. Meters are included as a convenience to mitigate field component counting effort. The thief hatch and SCVF component types are added because their emission release characteristics are poorly represented by other component types. Historically, thief hatches were counted as a connector while SCVF lines were not considered because they are regulated by AER Interim Directive 2003-01 (or incorrectly counted as open-ended lines[5]). Because the leaker and population leak factors presented below for thief hatches and SCVFs are different than connectors and open-ended lines, separate components types are justifiable.

Subsequent analysis of the data collected observed no statistical difference in leak factors between components in fuel versus process gas service. Therefore, there is little value differentiating between the service types and subject records are assigned to a single service type (process gas). This consolidation is consistent with the methodology used in other fugitive emission factor publications (CAPP, 2014 and EPA, 2016a). Differences are observed between gas and liquid service leak factors so liquid service types are retained.

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5 As defined in Section 6.3.5, open-ended lines feature a closed valve upstream of the open end which is not the case for SCVF lines (unless a valve was installed on the SCVF line and leakage occurred past the closed valve).

3.2 POPULATION AVERAGE LEAK FACTORS

Emission factors for estimating fugitive equipment leaks normally are evaluated by type of component and service category within an industry sector. This allows the factors to be broadly applied within the sector provided component populations are known. The advantage of this level of disaggregation is that it allows facility differences and certain control efforts to be accounted for. A simpler approach which introduces additional uncertainties is to develop factors by type of process unit and area, or by type of facility; however, these higher-level factors are not considered here.

There are two basic types of emission factors that may be used to estimate emissions from fugitive equipment leaks: those that are applied to the results of leak detection or screening programs (e.g., leak/no-leak and stratified emission factors), and those that those that do not require any screening information and are simply applied to an inventory of the potential leak sources (i.e., population average emissions factors). Population average emission factors and 'leaker' emissions factors are determined and available in the field study report (Clearstone, 2018). 'No-leak' emission factors are not determined in this study because the Hi-Flow Sampler minimum detection limit (MDL) is not sensitive enough to accurately quantify leaks below 10,000 ppmv[6]. No-leak factors for the Canadian UOG industry have received little research attention since the early 1990's and available factors (from Table 7 of CAPP, 1992) may not be representative of current component populations. Instead of including no-leak contributions in the population average leak factor (as was the case for factors published in CAPP, 2014, CAPP, 2005 and CAPP, 1992), it's recommended that these factors be applied separately when estimating fugitive emissions so their relative contributions are better understood and to facilitate inclusion of operator estimated fugitives[7] into emission inventories.

The population average emission factor for a given component and service category equals the total hydrocarbon emissions (that satisfy the leak definition presented in Section 6.1.1) divided by the number of potential leak sources (i.e., components).. Unlike other studies that rely on typical component counts (CAPP, 2014 and EPA, 2016a), emission factors are determined using component counts from the same sample population. Moreover, emission contribution from leaks below thresholds stated in Section 6.1.1 (i.e., no-leak factors) are not included in the population average.

3.3 UNCERTAINTY ANALYSIS

It is good practice to evaluate the uncertainties in all measurement results and in the emission calculation parameters derived from these results. Quantification of these uncertainties ultimately

6 Ideally, no-leak emission factors would be developed using an instrument with precision of 1 ppm, MDL of about 2 ppm above background readings and measurement uncertainty of less than ±1% of reading.
7 Pending methane regulations may require operators to report fugitive emissions estimated using leaker factors or by direct measurement. Both cases omit the no-leak contribution.

facilitates the prioritization of efforts to improve the accuracy of emissions inventories developed using these data.

Measurement uncertainty arises from inaccuracy in the measuring equipment, random variation in the quantities measured and approximations in data-reduction relations. These individual uncertainties propagate through the data acquisition and reduction sequences, as described above, to yield a final uncertainty in the measurement result. Elemental uncertainty can arise from errors in calibration, data-acquisition, data-reduction, methodology or other sequences. Two types of uncertainties are encountered when measuring variables: systematic (or bias) and random (or precision) uncertainties (Wheeler and Ganji, 2004). Systematic and random errors are combined using IPCC Tier 1 rules for error propagation (described in Section 7) to determine confidence intervals for the factors presented above.

Random errors are characterized by their lack of repeatability during experimentation and can be described using probability density functions. The probability density function describes the range and relative likelihood of possible values. The shape of the probability density function may be determined empirically from the available measurement data. Confidence limits give the range within which the underlying value of an uncertain quantity is thought to lie for a specified probability. This range is called the confidence interval and is determined using the bootstrapping method described in Section 3.3.3. The IPCC (2000) Good Practice Guidance suggestion to use a 95% confidence interval is adopted for this study (i.e., the interval that has a 95% probability of containing the unknown true value).

Systematic errors do not vary during repeated readings and are usually due to instrument properties or data reduction. The systematic uncertainties for measurement devices and gas analysis presented in Table 3 are considered when calculating leak rate uncertainties. Further discussion of uncertainties introduced by component count and leak detection methods are presented in Section 3.3.1 and 3.3.2.

Table 3: Parameter uncertainties according to measurement device or gas analysis source.

Parameter	**Measurement Device**	**Uncertainty**	**Reference**
Atmospheric Pressure and Temperature	Multifunction digital thermometer and barometer	±10%	Professional judgement
Flow Rate	Anti-Static Measurement Bag	±10%	Heath, 2014
	Hawk PD Meter	±2%	Calscan, 2017
	Hi-Flow Sampler	±10%	Bacharach, 2015
	Technician estimate from IR image	±100%	Professional judgement

Table 3: Parameter uncertainties according to measurement device or gas analysis source.			
Parameter	**Measurement Device**	**Uncertainty**	**Reference**
Leak Detection	IR Camera	On average 3 of every 4 leaks are detected	Professional judgement and Ravikumar et al, 2018
Molecular Weight of Gas Mixture	Site specific gas analysis	±5%	Professional judgement
	Typical gas analysis	±25%	

3.3.1 COMPONENT COUNTING UNCERTAINTY

Of particular influence on overall confidence intervals is the uncertainty inherent to component and pneumatic device counting. Notwithstanding desktop and field training, there is variability and bias introduced by field technicians when interpreting, classifying and counting the tremendous number of components in pressurized hydrocarbon service. To estimate the uncertainty introduced by field technicians, independent surveys were completed on different days by 2 different field teams of the same facility. Results from these surveys provide two overlapping sample counts for 8 distinct component types and 6 different pneumatic devices. Although the surveys covered a variety of equipment, the limited nature of two sample points per component and pneumatic device precludes an empirical estimation of the underlying distribution governing counting errors. Thus, a number of assumptions are required to estimate the uncertainty associated with the potential under or over counting of components and pneumatics. Individual component and pneumatic counts are combined into a single population of counting errors by computing the percent difference of each sample count from their respective sample mean. This normalization step creates a single sample set of 14 representative counting errors based on the assumption that inherent counting errors are independent of the component or pneumatic being counted (e.g. counting connectors carrying process gas is the same as counting connectors in liquid service, is the same as counting level controllers etc.). Under the assumption that these counting errors are normally distributed, the sample standard deviation σ_s could provide a simple point estimation for the spread of population of errors. However, because this survey data is limited in size and is from a single facility it's likely that because of sampling variability the uncertainty bounds defined by $\pm 2\sigma_s$ would not actually encompass 95% of the expected counting errors. To ensure the spread of the uncertainty bounds was sufficiently wide a tolerance interval was used.

A tolerance interval for capturing at least k% of the values in a normal population with a confidence level of 95% has the form $\pm(\text{tolerance critical value}) \cdot \sigma_s$ where the critical values depend on the number of sample points and the desired value of k (typically chosen to be 90, 95, or 99). In the case of the survey data, choosing k = 95 results in a critical value of 3.012 and an overall estimate of the counting uncertainty for components and pneumatics was found to be ±166%.

This random error for component and pneumatic device counts is incorporated into population average count and leak factor uncertainty using IPCC Tier 1 rules for error propagation.

3.3.2 OGI LEAK DETECTION UNCERTAINTY

Considering the recently published empirical correlation between leak rate, viewing distance and detection probability (Figure 3 in Ravikumar et al, 2018) and that most ground-level components are screened at a distance of 1 to 2 meters (Greenpath, 2017b); there is good probability that the IR camera MDL is about 0.015 m^3 CH_4/hr[8] under favourable survey conditions (i.e., warm temperatures with wind speeds less than 4 m/s). However, survey conditions are not always ideal (e.g., wind gusts and rain) and screening distances increase for elevated components like compressor rod-packing vents (perhaps 3 to 6 meters away) and tank thief hatches (perhaps 5 to 20 meters away). Also, the capability and patience of technicians using the IR camera will vary and impact whether a leak is detected or not. Research, supported by the EPA, is underway at the Methane Emissions Test and Evaluation Center (METEC) in Colorado to develop empirical correlations for OGI performance factors (e.g., OGI equipment model, operator group and atmospheric conditions).

In the absence of defensible correlations, it is estimated that the IR camera on average detects 3 of every 4 leaks. Under the assumption that false positives (i.e. detecting a leak from a non-leaking component) do no occur, the actual number of component leaks at a site cannot be less than the leaks observed during an OGI survey. Consequently, the expected number of leaking components was modelled by scaling the observed leak counts by a leak count multiplier equal to 1+X where X is a random variable following a half-normal distribution with a mean of 1/3. This systematic error is incorporated into the population average leak factor uncertainty using IPCC Tier 1 rules for error propagation.

3.3.3 BOOTSTRAPPING METHOD

Bootstrapping is a statistical resampling method which is typically used to estimate population variables/parameters from empirically sampled data (Efron, and Tibshirani, 1993). Bootstrapping as a method is non-parametric and does not rely on common assumptions such as normality, data symmetry or even knowledge of the data's underlying distribution. It is applied by other studies investigating 'heavy-tailed' leak distributions and is shown to increase the width of confidence intervals by increasing the upper bound (Brandt et al, 2016). The one main underlying

8 This equals 10 g CH_4/hr and is also the lowest measurement result obtained when using the High Flow Sampler during 2017. The manufacturer specification for the High Flow is 0.085 m^3/hr and results below this MDL are possible but have greater uncertainty.

assumption behind bootstrapping, for the results to be reliable, is that the sample set is representative of the population.

In its most basic form bootstrapping is easily implemented to estimate the mean and the mean's associated confidence interval. For a sample set of size N, the samples are randomly resampled N-times with replacement to create a new set of observations of equal size. From this new resampled set a statistical parameter, in this case the mean, can be calculated. The procedure of resampling and re-computing a statistic from the original data is repeated over a large number of iterations (e.g. 10000 times) to obtain a distribution of bootstrapped estimates of the mean. An overall estimate and 95% confidence interval of the population mean is then extracted from the bootstrapped distribution.

The above bootstrapping process was directly applied to major equipment counts to obtain mean count estimates with a corresponding 95% confidence interval per well status or facility subtype. By virtue of the bootstrapping process the computed confidence intervals are not necessarily symmetric as would be the case under assumption that counts are normally distributed. For components, pneumatics, and flow rates the sample data was varied normally on each bootstrap resample according to specified counter and measurement device uncertainties.

For components, confidence interval estimates for a mean population leak factor were calculated by a Monte Carlo simulation. For each component type per service, where the leak data permitted, a population leak factor defined by:

$$\frac{\text{\# of component leaks}}{\text{\# of total components}} \cdot \text{Leak factor}$$

was computed 10000 times while randomly varying the number of component leaks as in Section 3.3.2 and varying the total number of components and the leak factor following their respective bootstrapped distributions. Similar to the bootstrapping process above, an overall estimate and 95% confidence interval of the population mean leak factor is then extracted from the resultant Monte Carlo distribution.

3.4 DISCUSSION OF POPULATION AVERAGE LEAK FACTORS

Leak factor results are based on best available OGI survey equipment and technicians currently providing fugitive emission services for the Canadian UOG industry. Notwithstanding this and QAQC efforts, the OGI leak detection and High Flow Sampler measurement methods have limitations that may impact the completeness and accuracy of the subject dataset. Thus, a rigorous quantitative uncertainty analysis endeavors to identify and account for all parameters contributing uncertainty to the final emission factors. 2017 confidence limits are generally greater than historic values primarily because of the following contributions that were acknowledged but underestimated in historic results (CAPP, 2005 and CAPP, 2014).

- Uncertainty in component counts due to field technician variability and bias (discussed in Section 3.3.1).
- Uncertainty in leak frequency due to the OGI survey method (discussed in Section 3.3.2).

Exceptions where the 2017 confidence limits are less than those presented in CAPP, 2014 occur for components with large no-leak contributions (e.g., connectors, PRV, pump seals and valves). The 2014 assessment assigned a very large upper confidence limit to no-leak factors (500 percent) which strongly influences population average confidence limits for components with large no-leak contributions. Whereas, no-leak contributions are not included in 2017 population average factors (and should be calculated as a separate category when estimating fugitive emissions).

Canadian UOG no-leak factors (from Table 7 of CAPP, 1992) are combined with the 2017 population average factors to facilitate an equivalent comparison with historic emission factors. The no-leak contribution to the combined emission factor is very small for compressor seals, control valves, open-ended lines, pressure relief valves and pump seals. However, the no-leak contribution is greater than or approximately equal to the population average for connectors and valves (the components with the largest populations). Thus, 2017 combined leak factors are approximately the same as 2014 factors because they are both strongly influenced by the no-leak contribution. 2005 factors are greater than both 2017 and 2014 for all components (except SCVF) and therefore less influenced by the no-leak contribution.

Other noteworthy observations are discussed in the following subsections.

3.4.1 CONTRIBUTION OF FUGITIVE EMISSIONS NOT DETECTED BY THE IR CAMERA

Multiplying the total population of components screened in 2017 by corresponding no-leak factors equals 94 kg THC per hour while population average factors yields 149 kg THC per hour. Thus, the 1992 vintage no-leak factors are responsible for approximately 38 percent of the total estimated fugitives (for this component population). Considering the significant emission contribution of no-leak factors; the difficulty detecting very small leaks (less than 10,000 ppmv) with an IR Camera; the practicality of repairing very small leaks; and the federal regulatory focus on leak survey frequency, further field studies to validate no-leak factors and their actual contribution to total UOG fugitive emissions should be considered.

3.4.2 DISTRIBUTION OF 2017 LEAKS AND "SUPER-EMITTERS"

As indicated in **Error! Reference source not found.** below, the top 10 sites represent most about 65 percent) of the total leak rate measured during the 2017 campaign with the single largest leak (a SCVF) representing 35 percent of the total leak rate. This is a highly skewed distribution with approximately 16 percent of the leaking components responsible for 80 percent of the total leak rate while the top 5 percent of leaking components are responsible for 64 percent of the total leak rate. This result is consistent with other studies and indicates "super-emitters" are present in the 2017 sample population. For example, a recent analysis of 15,000 leak measurements from 18 independent studies indicates leaks from natural gas systems follow extreme distributions with the largest 5 percent of leaks ("super-emitters") contributing greater than 50 percent of the total leakage volume (Brandt et al, 2016). Skewed distributions are also observed in measurements completed in 2016 at sites near Red Deer, Alberta where high-emitting sites disproportionately account for the majority of emissions. This study indicates 20 percent of sites with highest emissions contribute 74 to 79 percent of the total emissions measured (Zavala-Araiza D. et al, 2018).

Error! Reference source not found. provides some perspective on the relationship between acility production type and leak rate. It indicates that leak rates for 8 of the 11 component categories are greater at oil facilities than gas facilities. This is similar to observations at production sites near Red Deer, Alberta where oil producing sites tended to have higher emissions than sites without oil production (Zavala-Araiza D. et al, 2018).

3.4.3 RECIPROCATING COMPRESSOR ROD-PACKING LEAKAGE RATES EXPECTED BY MANUFACTURERS

The largest manufacturer of reciprocating gas compressors indicates typical leakage rates for packing rings in good condition range from 0.17 m^3 to 0.29 m^3 per hour per rod-packing while the 'alarm' point for scheduling maintenance ranges from 2.9 m^3 to 5.8 m^3 per hour per rod-packing (Ariel, 2018). The probable population average leak rate for rod-packings presented in **Error! Reference source not found.** is 0.2875 m^3 THC per hour per rod-packing (with lower nd upper confidence limits of 0.1361 and 0.5415 m^3 THC per hour). Thus, reciprocating compressors surveyed in 2017 typically vent within manufacturer tolerances for packing rings in good condition. The upper confidence limit is much less than the maintenance alarm threshold of 2.9 m^3 per hour. Only two measurement records were greater than 2.9 m^3 per hour but because rod-packings vent into a common header, it's not known whether the emissions were dominated by one or multiple rod-packings.

Efforts to determine the age of rod-packings and qualify observed emission rates were not successful because maintenance and replacement records were not available from operators or did not provide enough detail to determine rod-packing installation date.

It's speculated that compressor rod-packing population average leak rates published in CAPP, 2014 are understated because of ambiguity in 'leak' versus 'vent' definitions. This study defines leakage from rod-packings as a leak but other programs define it as a vent (e.g., EPA, 2016 and ECCC, 2014)[9]. When "leak data" was provided by industry to complete the CAPP, 2014 emission factor analysis, rod-packing records may have been identified as "vents" by services providers and excluded from the 2014 dataset. Moreover, because 2014 input data was obtained from secondary sources, QAQC testing was limited to the input dataset and not the entire data management system. Thus it was difficult to detect this downward bias.

Similar ambiguity may apply to thief hatch and open-ended line components. Thus, communication of clear and concise definitions to field inspectors and end users is a critical part of fugitive emission assessments.

3.4.4 SCVF EMISSION FACTOR

The SCVF component is included in Figure 2 to improve emission inventory transparency and highlight the significance of this source. The population average leak factor calculated from 15 leaks detected at 440 wells screened in 2017 is 0.0925 kg THC per hour which is only 37 percent less than the factor used to estimate SCVF emissions in the last UOG national inventory (ECCC, 2014). SCVF was the second largest source of methane released by the UOG industry because of the very large number of potential leak sources (i.e., approximately 150,000 wells in Alberta). The refined emission factor and confidence interval decreases SCVF contributions to total methane emissions and uncertainty, however, it is expected to remain one of the top 5 methane emission contributors.

3.4.5 COMPONENTS IN HEAVY LIQUID SERVICE

Also of note is that zero components in heavy liquid service were observed to be leaking. This is consistent with results presented in CAPP, 2014 and CAPP, 1992. Population average leak factors are for components in heavy liquid service are presented in CAPP, 2005 but are at least one order of magnitude less than light liquid no-leak factors. All four studies agree that components in heavy oil service have a very small contribution to total UOG fugitive emissions.

9 Reciprocating compressor rod-packings in good condition are intended to release gas (i.e., a vent) but as they wear, the release rate increases and becomes a leak.

Table 4: Comparison of 2017 and historic population average leak factors (kg THC/h/source) for the Canadian UOG industry.

Sector	Component Type	Service	CAPP (1992) No-Leak EF[b]	2017 Field Measurements			2017 Combined EF	CAPP (2014)				CAPP (2005)			
				EF	95% Confidence Limit (% of mean)			EF	95% Confidence Limit (% of mean)		EF Ratio (2017/2014)	EF	95% Confidence Limit (% of mean)		EF Ratio (2017/2005)
					Lower	Upper			Lower	Upper			Lower	Upper	
Gas	Compressor Rod-Packing[c]	PG	0.00175	0.16736	51%	87%	0.16882	0.04669	41%	44%	3.62	0.71300	36%	36%	0.24
Gas	Connector	PG	0.00061	0.00012	36%	57%	0.00073	0.00082	36%	250%	0.88	0.00082	32%	32%	0.88
Gas	Connector	LL[a]	0.00013	0.00001	71%	114%	0.00014	0.00016	54%	378%	0.86	0.00055	90%	111%	0.25
Gas	Control Valve	PG	0.00023	0.00301	68%	103%	0.00324	0.03992	44%	44%	0.08	0.01620	23%	23%	0.20
Gas	Meter	PG	0.00061	0.00149	52%	80%	0.00209	No emission factor				No emission factor			
Gas	Open-Ended Line	PG	0.00183	0.09630	95%	233%	0.09796	0.04663	42%	45%	2.10	0.46700	62%	161%	0.21
Gas	Pressure Relief Valve	PG[a]	0.00019	0.00399	54%	85%	0.00417	0.00019	55%	420%	21.97	0.01700	98%	98%	0.25
Gas	Pump Seal	PG	0.00023	0.00261	54%	82%	0.00284	0.00291	50%	367%	0.97	0.02320	74%	136%	0.12
Gas	Regulator	PG	0.00061	0.00077	52%	83%	0.00137	0.03844	45%	45%	0.04	0.00811	72%	238%	0.17
Gas	Valve	PG	0.00023	0.00062	66%	119%	0.00085	0.00057	38%	163%	1.50	0.00281	15%	15%	0.30
Gas	Valve	LL[a]	0.00081	0.00015	72%	122%	0.00096	0.00086	55%	442%	1.12	0.00352	19%	19%	0.27
Oil	Compressor Rod-Packing[c]	PG	0.00175	0.76120	92%	257%	0.76226	0.01474	60%	66%	51.71	0.80500	36%	36%	0.95
Oil	Connector	PG	0.00023	0.00019	37%	58%	0.00042	0.00057	27%	96%	0.74	0.00246	15%	15%	0.17
Oil	Connector	LL	0.00013	0.00001	71%	143%	0.00014	0.00013	36%	282%	1.05	0.00019	90%	111%	0.72
Oil	Control Valve	PG	0.00008	0.00962	66%	94%	0.00970	0.09063	87%	87%	0.11	0.01460	21%	21%	0.66
Oil	Meter	PG[a]	0.00061	0.00105	47%	73%	0.00165	No emission factor				No emission factor			
Oil	Open-Ended Line	PG[a]	0.00183	0.06700	91%	219%	0.06870	0.15692	47%	47%	0.44	0.30800	78%	129%	0.22
Oil	Pressure Relief Valve	PG	0.00019	0.00756	55%	87%	0.00775	0.00019	38%	313%	40.79	0.01630	80%	80%	0.48
Oil	Pump Seal	PG[a]	0.00023	0.00761	73%	142%	0.00783	0.00230	38%	294%	3.41	0.02320	74%	136%	0.34
Oil	Regulator	PG	0.00061	0.00154	79%	133%	0.00215	0.52829	38%	38%	0.00	0.00668	72%	238%	0.32
Oil	Thief Hatch	PG	0.00061	0.15852	77%	140%	0.15904	No emission factor				No emission factor			
Oil	Valve	PG	0.00008	0.00009	83%	158%	0.00017	0.00122	44%	48%	0.14	0.00151	79%	79%	0.11
Oil	Valve	LL	0.00058	0.00021	73%	125%	0.00079	0.00058	37%	288%	1.36	0.00121	19%	19%	0.65
All	SCVF	PG	0.00183	0.09250	98%	204%	0.09427	0.1464	Not Available		0.64	0.1464	Not Available		0.64

[a] Insufficient sample size for 2017 to determine confidence limits for this sector, component and service type. Therefore, results presented for 2017 include samples from both oil and gas sectors.

[b] No-leak factors are not available from CAPP, 1992 for Regulator, Meter, SCVF and Thief Hatch components so reasonable analogues are selected.

[c] Reciprocating compressor rod-packing emission factors are calculated on a per rod-packing basis and exclude compressors that are tired into a flare or VRU (because these rod-packings are controlled and have a very low probability of ever leaking to atmosphere). Rod-packings are defined as vents in Directive 060 (AER, 2018).

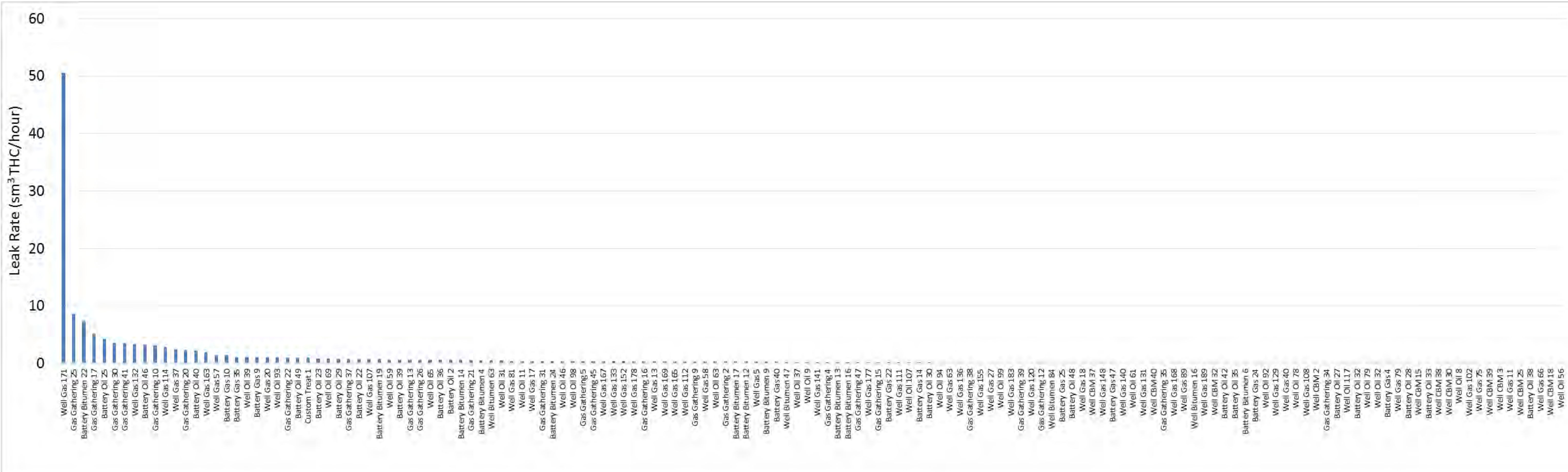

Figure 2: Distribution of total leak rate by site observed during the 2017 Alberta field campaign (excluding 195 sites where no leaks were detected).

3.5 EFFTIVENESS OF FUGITIVE EMISSION MANAGEMENT PROGRAMS

The current AER Directive 060 requires UOG producers to implement a FEMP to detect and repair leaks. The directive does not specify FEMP requirements other than it must meet or exceed the CAPP BMP for Fugitive Emissions Management[10]. The BMP succeeded in greater awareness, improved management and has a downward influence on UOG fugitive emissions as described in Section 3.5.1. However, uncertainty persists regarding the most effective approach for detecting, documenting and reducing the risk of small leaks becoming large leaks. An evaluation of whether the type or frequency of leak detection surveys has an impact on fugitive emission magnitude is presented in Section 3.5.2.

3.5.1 COMPARISON OF 2017 RESULTS WITH HISTORIC FUGITIVE

The 2017 PRV population average leak factor is much greater than the 2014 factor because very few PRV leaks were present in the 2014 dataset so the 2014 PRV factor is dominated by the no-leak contribution. The population average leak factors for regulators and control valves are similar to 2005 factors but much less than 2014 factors because default component populations[11] used in CAPP, 2014 understate counts which has a strong upward bias on the emission factors. These component count limitations were discussed in CAPP, 2014 with recommendations to obtain actual field counts which motivated the current study.

The implications of new emission factors on total fugitive emissions is estimated in Table 5 and calculated by multiplying the 2017 component population by population average leak factors from two other reference studies. However, the differences between 2017 and 2014 emission factors (described above) makes comparison of total fugitive emissions difficult. For example, the total number of regulators and control valves are understated in the CAPP, 2014 dataset so it doesn't matter that the corresponding emission factors are large (if using 2014 component populations). However, multiplying 2014 emission factors for regulators and control valves by corresponding 2017 component populations results in unreasonably large emission estimates. To mitigate this bias, 2014 THC emissions presented in Table 5 are calculated using 2017 analogues for regulator and control valve emission factors.

2017 and 2014 results in Table 5 are about the same and approximately 62 and 61 percent lower than fugitive emissions calculated using 2005 population average leak factors. This observation is similar to the CAPP, 2014 conclusion that fugitive equipment leaks have decreased 75 percent since publication of the CAPP BMP and implementation of DI&M programs.

[10] Modifications to Directive 060 proposed in April 2018 contain specific FEMP requirements, however, they are not finalized before this publication date.
[11] Default component counts are based on inventories published in CAPP, 1992 and are compared to the 2017 counts in **Error! Reference source not found.**.

Table 5: Comparison of fugitive emissions calculated using 2017, 2014 and 2005 population average leak factors and the same component population.					
	2017 (current study)			CAPP (2014)	CAPP (2005)
	Population Average EF	No-Leak EF (CAPP, 1992)	Total	Population Average plus No-Leak EF	Population Average plus No-Leak EF
Total THC Emissions (kg/hr)	149	94	243	245	634
% difference relative to 2005			-62%	-61%	

3.5.2 FEMP STATUS QUESTIONNAIRE DESIGN AND RESULTS

Readers are cautioned that, as indicated by confidence intervals, 2017 sample sizes are small due to the stratification required to answer FEMP effectiveness questions and also subject to limitations described in Section 3.3. Thus, although observations and comments stated below may be plausible they are not statistically defensible.

The impact of leak detection survey type and frequency is evaluated by correlating 2017 data (described in Sections 3.1, 3.2 and 3.3) with the following FEMP status that were implemented at subject locations prior to the 2017 surveys.

1. OGI inspection at least every year.
2. OGI inspection every 2 to 5 years.
3. AVO inspection at least every year (completed as part of a corporately endorsed FEMP).
4. No evidence of prior leak survey.

Population average leak factors and confidence intervals are calculated according to component type (in process gas service) and FEMP status stratums with results presented in Figure 3, Figure 4 and Figure 5 (with error bars representing the 2.5th and 97.5th percentiles). Results are presented on a leak factor basis to enable meaningful comparisons on source-specific and common scales (i.e. component types). Other basis for comparison (e.g., absolute leakage per FEMP status or facility type) are not normalized according to the number of contributing emission sources and therefore can be more influenced by the number of sources within the stratum than the type of stratum being evaluated.

Considering survey frequency research completed by Ravikumar and Brandt (2017) and Carbon Limits (2014) we'd expect to observe declining leak rates as survey frequency increases. This is also implied by survey frequency requirements stated in ECCC Regulations Respecting Reduction in the Release of Methane (i.e., 3 times per year for sites that produce or receive more than 60 $10^3 m^3$ per year as stated in Section 30(3)(b) of ECCC, 2018) and AER's draft Directive 060 (i.e., 3 times per year for sweet gas plants and compressor stations as well as storage tanks tied into VRU or flare as stated in Section 8.10 of AER, 2018). However, at first glance this isn't observed for compressor rod-packing and thief hatch components that have the largest leak rates. For sites in the 2017 data, an initial observation from Figure 3 would indicate that on average the smallest leak rates occured at sites with no evidence of prior leak surveys and increased as OGI screening frequency increased. However, there are a number possible reasons explaining why FEMPs appear to have little impact on rod-packing maintenance practices. Operators typically rely on manufacturer recommended service intervals (3 to 4 years) to maintain and replace rod-packings. Additionally, following the CAPP DI&M decision tree, detecting a large leak rate isn't always sufficient justification for shutting down the equipment for servicing unless the leaking gas was a safety concern (e.g., H_2S release) or there was a risk of mechanical damage to the piston rod or connected components. Moreover, the average population leak rates for each FEMP survey category are well below the fleet average limit of 0.83 m^3 per hour per rod-packing specified in the draft Directive 060 (AER, 2018). Also, only 3 of the 64 compressors surveyed had leak rates within the range that maintenance is recommended by the Ariel Corporation (i.e., 2.9 m^3 to 5.8 m^3 per hour per rod-packing stated in Ariel, 2018). Thus, most rod-packings surveyed appear to be venting within the normal range expected by manufacturers.

Only one thief hatch leak was detected at locations with limited FEMP attention[12] while 5 leaks were detected at locations where OGI is completed annually. While it would appear that OGI screening appears to have little impact on thief hatch leaks this conclusion could be a direct result of the size limitations of the dataset and more importantly that thief hatch emissions were estimated for 5 of the 6 leak detects and not directly measured (because this component is typically difficult to access). Also, in addition to data limitations, it is possible the additional effort required to safely access and repair thief hatches makes them less likely to be repaired. Finally, the screening distance for a 1000 BBL tank (approximately 5.5 meters in height) is typically greater than 7 meters which reduces the probability of detecting a 30 grams CH_4 per hour leak to less than 50 percent (Ravikumar et al, 2018) so thief hatch leaks are simply less likely to be detected.

[12] Gas losses from a thief hatch are only considered a leak when the storage tank is connected to a VRU or flare, making the loss unintentional. During the 2017 surveys, 145 locations were observed to have storage tanks with 18 of these locations featuring tank emission control equipment. Questionnaire results indicate that ten of these 18 locations have no evidence of prior leak surveys while three conduct OGI every 2 to 5 years.

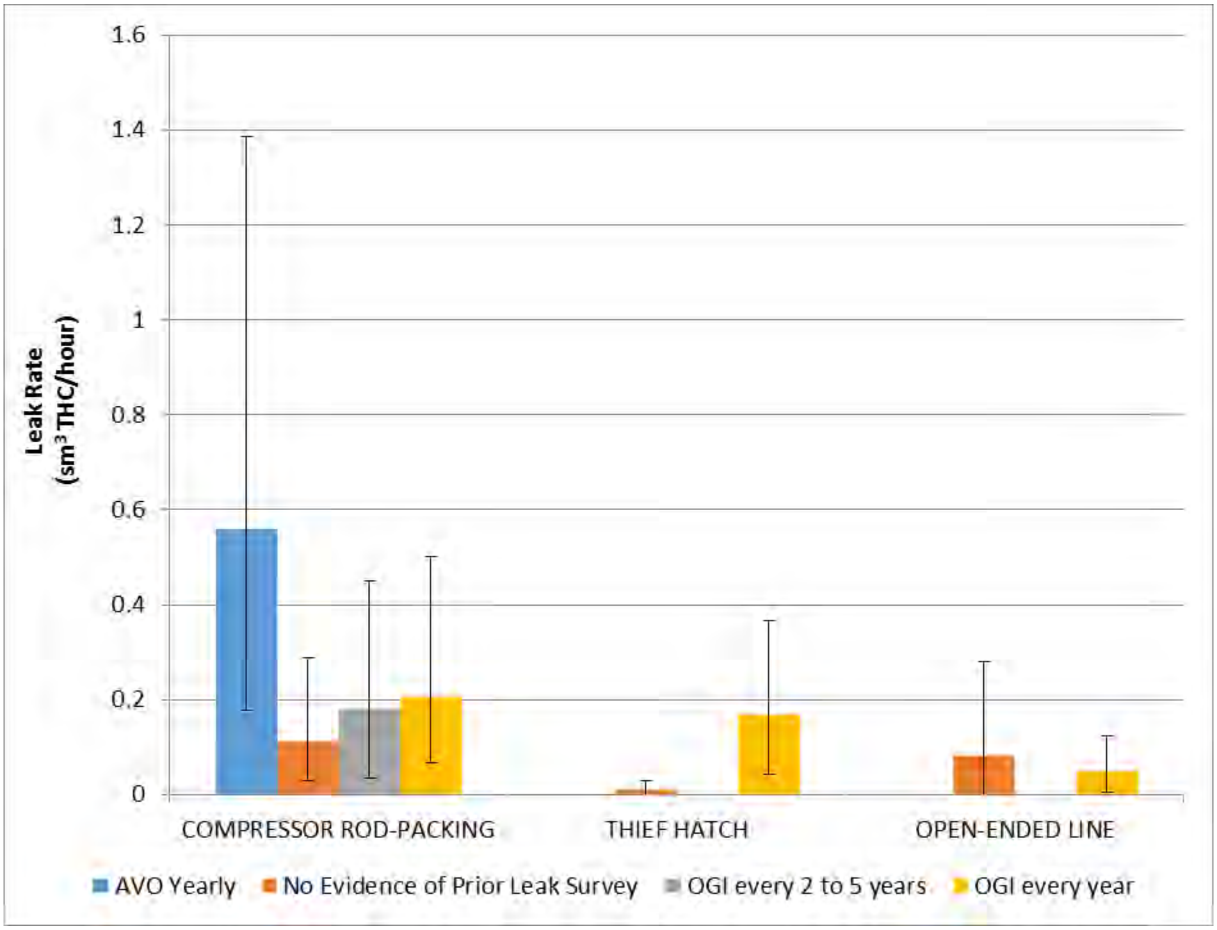

Figure 3: Population average leak rates and confidence intervals (2.5th and 97.5th percentiles) determined according to FEMP status for compressor rod-packing, thief hatch and open-ended line components (in process gas service) measured during 2017 Alberta surveys.

All other components (except meters) generally follow the expected behavior where more frequent surveys correlated with smaller population leak rates. This trend is clear in Figure 3, Figure 4 and Figure 5, if leak rates for "OGI conducted at least once per year" are compared to those with "no evidence of prior leak surveys". Corresponding leak rate reductions range from 30 to 80 percent and indicate annual OGI screening has a beneficial impact on open-ended line, control valve, pump seal, PRV/PSV, valve, regulator and gas service connector components. The benefit of conducting OGI every 2 to 5 years is less compelling.

AVO inspections do not appear to be an effective fugitive emission control method. Population leak rates for rod-packings, control valves and valves are 70 to 80 percent greater at sites that rely solely on AVO inspections to achieve FEMP objectives versus sites that have no evidence of prior leak surveys. Connectors and regulators are the only components where AVO appears to reduce leak rates relative to other methods. This may be due to operator ability to repair these components immediately upon detection for little cost. Whereas repairing rod-packings, control valves and valves may require a work order and become a lower priority after simple cost-benefit review.

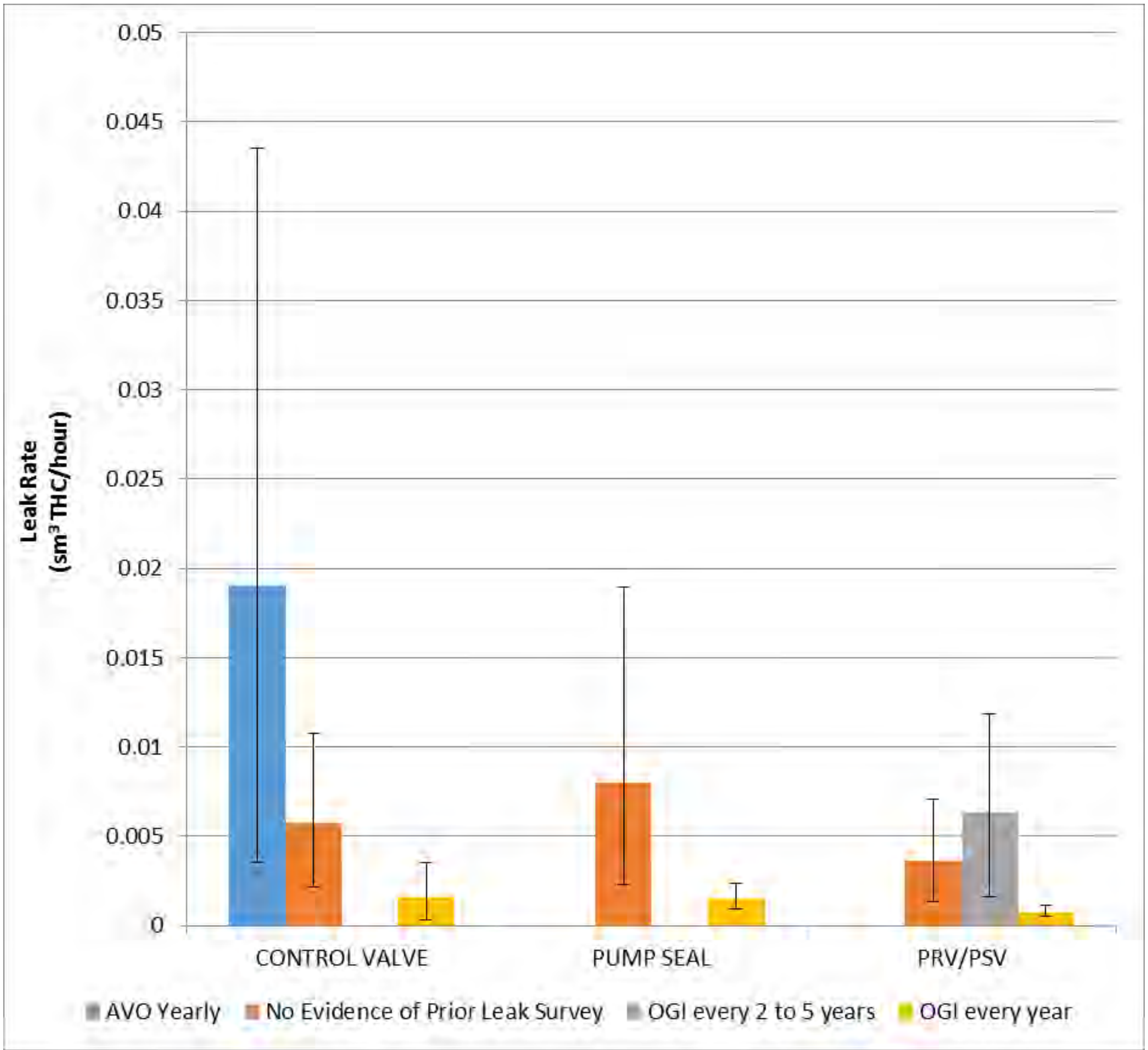

Figure 4: Population average leak rates and confidence intervals (2.5th and 97.5th percentiles) determined according to FEMP status for control valve, pump seal and PRV/PSV components (in process gas service) measured during 2017 Alberta surveys.

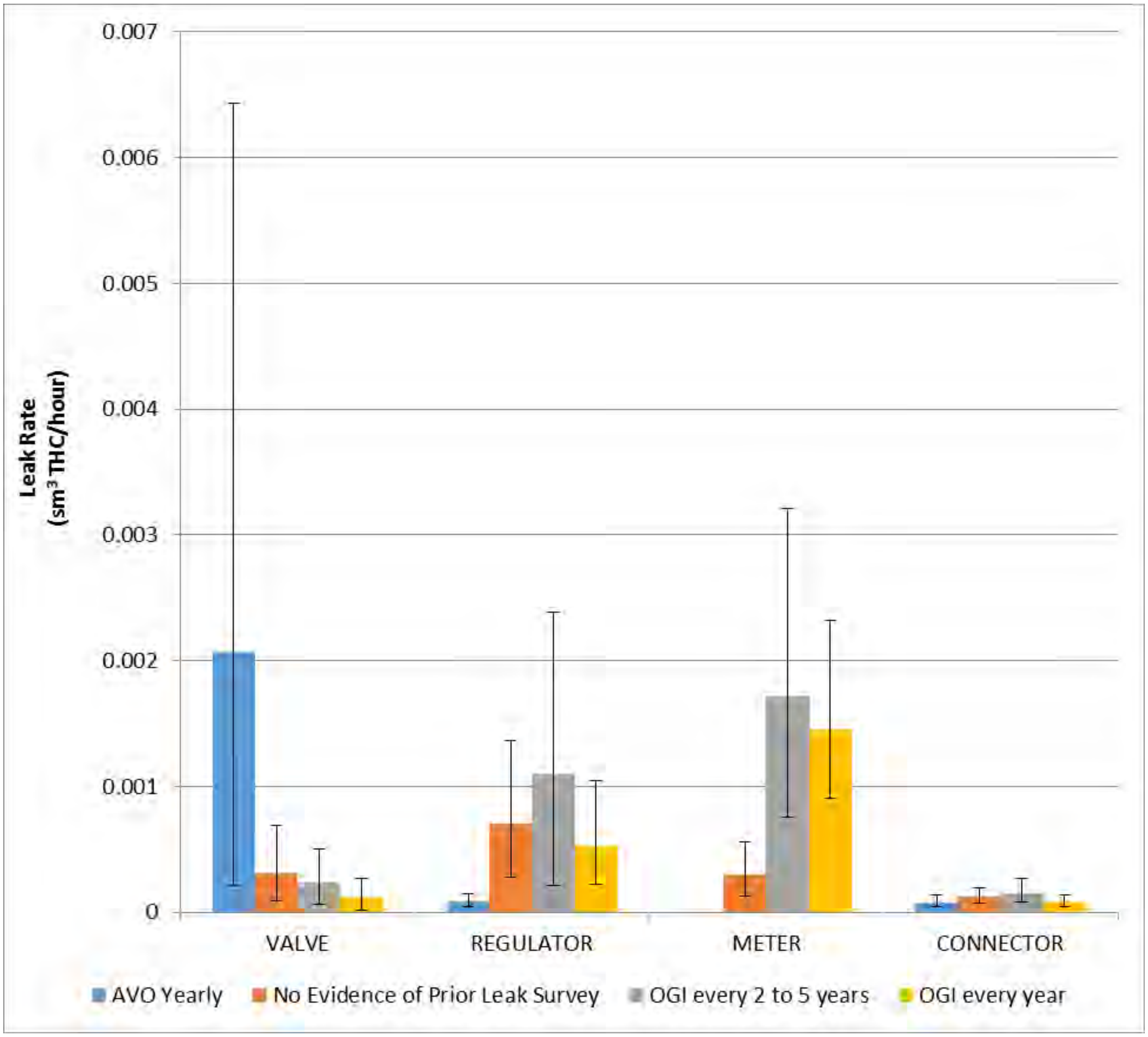

Figure 5: Population average leak rates and confidence intervals (2.5th and 97.5th percentiles) determined according to FEMP status for valve, regulator, meter and connector components (in process gas service) measured during 2017 Alberta surveys.

FEMP status is determined for each location surveyed in 2017 based on operator responses to the questionnaire presented in Section 8. Responses were received by 47 of the 63 subject companies which represents approximately 80% of subject locations. If no response was received, the subject location is assigned to the "No evidence of prior leak survey" stratum (as indicated in the questionnaire covering letter). The four FEMP stratum discussed above reflect the type and frequency of leak detection surveys implemented by respondents. Evidence of OGI surveys being conducted on a monthly or quarterly basis was not observed in the responses.

The questionnaire also asked whether alternative leak detection inspections were implemented for subject locations. Responses included the following and are considered part of baseline operations in which safety inspections, routine AVO inspections and area monitoring are conducted but not as part of a corporately endorsed FEMP.

- The use of 4-head personal monitors to detect and bubble testing to confirm leaks as part of an operator's regular work scope.
- AVO inspections as part of an operator's regular work scope.
- Continuous gas monitoring systems installed in buildings that alarm when hydrocarbon concentrations exceed a percentage of the lower explosive limit (LEL). Although continuous LEL monitoring is primarily intended to prevent combustible gas mixtures it has the co-benefit of detecting large leaks.

3.6 COMPARISON OF VENT AND LEAK EMISSION RATES

In addition to the inventories and leak measurements discussed above, field inspectors recorded venting emission sources observed with the IR camera at the 333 locations surveyed during 2017 and estimated their release magnitude (or measured the release if convenient to do so with the High Flow Sampler). Moreover, pneumatic venting is estimated using average emission factors. Although measurement of venting sources was not a primary objective for this study, available estimates for pneumatic and process vent sources enable a **qualitative** comparison with equipment leaks. Accordingly, the cumulative natural gas release rate is summed for all emission sources observed during the 2017 field campaign and presented by emission and source type in Figure 6. The largest contributors to equipment leaks are SCVF and reciprocating compressor rod-packings that represent approximately 60 percent of the total leak rate.

More importantly, the total leak rate is about 20 percent of the total natural gas released from all sources. Pneumatic devices (approximately 33 percent of the total release), production tanks (approximately 28 percent of the total release), heavy oil well casing vents (approximately 16 percent of the total release) and unlit flares (approximately 3 percent of the total release) are much more important sources natural gas emissions. A similar study of US natural gas production sites observed similar emission distributions where pneumatic and other venting sources contribute upwards of 70 percent while equipment leaks contribute approximately 13 percent of total methane emissions for the industry sector (Allen et al, 2013).

Although direct measurement of vent sources is often difficult to complete with the resources and equipment typically budgeted for leak surveys because of accessibility and process condition challenges (e.g., transient tank top emissions, dehydrator still columns or unlit flares). Qualitative indicators (e.g., the vent is small, large, or very large) may provide useful information to confirm production accounting completeness and improve the identification of cost-effective gas conservation opportunities. This approach may identify venting sources where the release magnitude is not fully appreciated by operators and represents the small number of sources that contribute the majority of methane emissions (discussed in Allen et al, 2013 and Zavala-Araiza D. et al, 2018). For example, a comparison with Petrinex records indicates that approximately 25 percent of Alberta locations observed to be venting in August or September 2017 did not report venting to Petrinex for the corresponding period (which represents about 25 percent of the estimated vent volume in Figure 6) (Petrinex, 2018). Of the 75 percent of locations where venting was observed and reported, the total Petrinex volume is approximately half of the volume estimated with the IR camera. Although the IR Camera estimates are qualitative and not sufficient for production accounting purposes; they can identify process venting sources, provide an indication of abnormal behaviour and trigger root-cause analysis when images indicate a risk of exceeding regulated site venting limits.

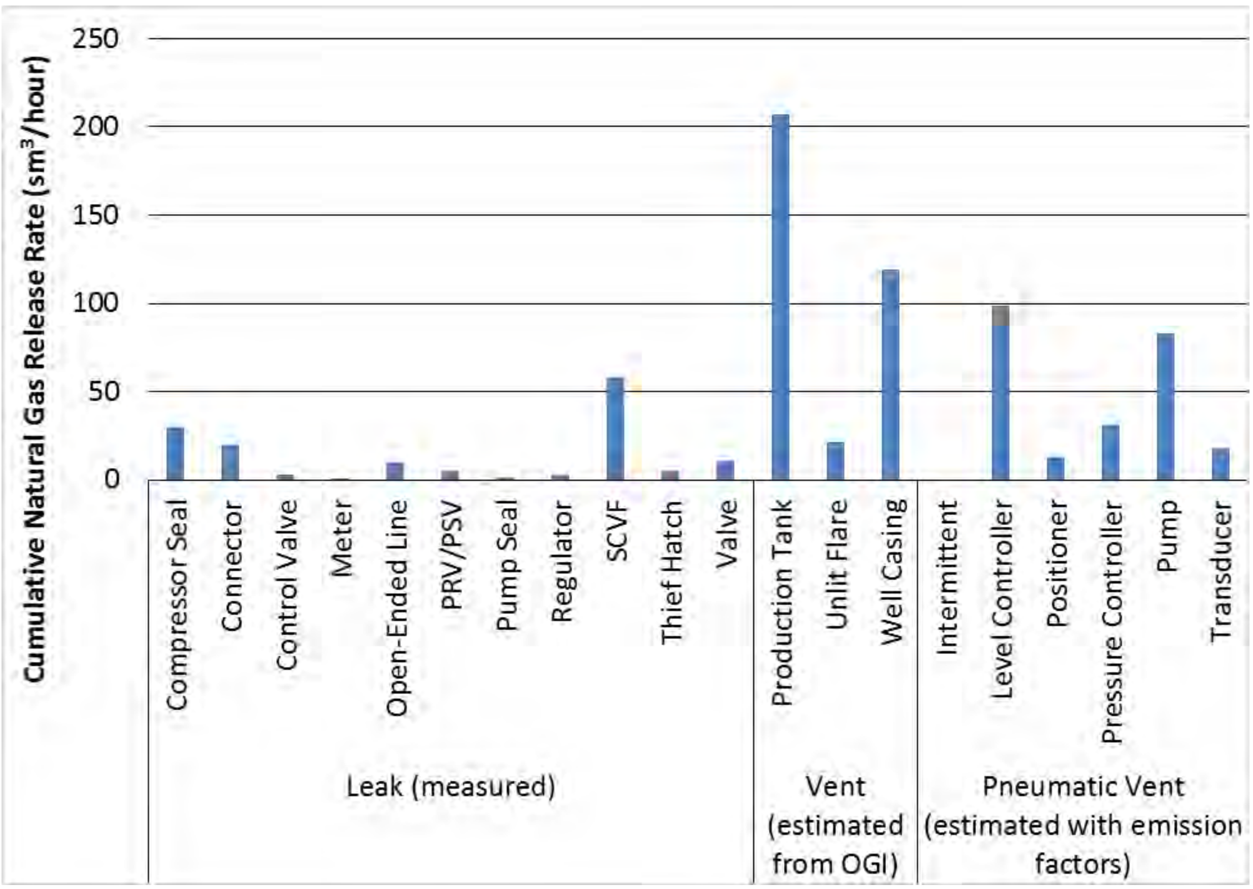

Figure 6: Cumulative hourly release rate for emission and source types observed at 333 locations during the 2017 Alberta field campaign.[13]

13 The venting estimates presented in **Error! Reference source not found.** have large, undetermined uncertainties nd only provide a qualitative perspective on natural gas emission sources. Moreover, pneumatic results assume only half of the inventoried chemical pumps are active because many methanol injections pumps are only active during cold winter months. Also, in addition to flashing, breathing and working losses; production tank emissions may include contributions from well casing vents, leaks past liquid dump valves, unintentional gas flow-through from undersized separators.

4 PRIORITIZED RESEARCH FIELD STUDIES

Four field research priorities are recommended based on the literature review and analysis results presented above. Background details, research objectives, field work scope, and study team are delineated below for each research priority.

4.1 LEAK SURVEY FREQUENCY

4.1.1 BACKGROUND-PROBLEM DESCRIPTION

There is limited empirical basis to quantitatively support the magnitude of emission reductions corresponding to leak detection and repair (LDAR) survey frequency. A study referenced by Environment Canada (ECCC, 2017) and Colorado (2014 Cost-Benefit Analysis Submitted Per § 24-4-103(2.5), C.R.S) regulatory impact assessments indicates that emission reductions of 40 percent are expected with a survey frequency of once per year, 60 percent at two times per year, 70 percent at three times per year, and 80 percent at four times per year (Carbon Limits, 2014). However, these emission reductions are inferred from simple assumptions that leak rate magnitude increases linearly with time and that 100 percent of leaks are detected and repaired. A simulation study by Ravikumar and Brant (2017) suggests leak rates decrease with LDAR frequency, but also notes that there could be significant variability in the effectiveness of LDAR depending on implementation. Indeed, field conditions often introduce complicating factors that hinder leak detection, control and documentation efforts. Other studies have observed oscillating leak counts and rates for facilities subject to annual inspections (Greenpath, 2017 and Clearstone, 2017) that suggests the following:

- There is uncertainty whether all leaks are detected by the OGI method (which is strongly dependent on standoff distance, technician capability and patience as well as environmental conditions at the time of the survey);
- There is uncertainty whether all leaks are repaired before the next survey (dependent on corporate priorities and maintenance systems);
- The categorization of emission releases as 'leaks' versus 'vents' is vulnerable to subjective decisions by individuals.
- These is uncertainty in measured leak rates.

Thus, there is insufficient and poor confidence in available leak data to establish a baseline or determine fugitive emission reductions achieved by FEMP. This also impedes quantitative cost-benefit assessments.

Currently, LDAR cost effectiveness assessments typically omit the actual cost of repair incurred by industry. The cost of leak **detection** programs is generally well understood and included in a number of research publications (Carbon Limits, ICF Methane Cost curve). However, component repair costs are not well understood. For example, repair costs listed in the 2007 CAPP BMP are presented as examples and only intended to clarify payback period calculations. The BMP expectation is that end users determine actual repair or replacement costs given the wide range of repair/replacement complexity and cost variables (e.g., costs incurred for facility downtime, change control management, safe work procedure, etc). In addition there is no reliable data on the percent of leaks detected that are repaired. A study by Carbon Limits in 2018 of European LDAR data suggested that only 60% of components were successfully repaired based on ppm data by component.

4.1.2 RESEARCH OBJECTIVE

Central questions remain as to what the benefits of increased LDAR frequency may or may not be, whether LDAR programs have a bottom-line benefit in terms of site-wide emissions reductions, and, closely related to these questions, what the true cost-benefit of LDAR might be at facilities in Alberta. Rather than following the modelling approach of Ravikumar and Brant (2017), a more definitive way to address these questions could be to conduct statistically relevant numbers of OGI surveys simultaneous with site-wide emissions measurements. Using the dual-tracer method (e.g. Rosciolli et al, Atmos. Meas. Tech., 2015), total site emissions will be accurately measured concurrent with OGI surveys and repair cost tracking through an LDAR program.

Thus, the primary objective of this field study is to conduct dual tracer measurements in parallel with an LDAR program (OGI method) conducted either once per year or three times per year in different samples. Secondary objectives are: to evaluate the effectiveness of OGI in detecting leaks in facilities and operating conditions relevant to Alberta and British Columbia; assess the relevance or lack of relevance of leaks detected by LDAR/OGI in comparison to total site emissions; track feasibility of leak repairs (i.e., screening concentration less than 500 ppm); and collect repair/replacement cost details from operators. This comprehensive project will allow:

1. Quantitative assessment of the effectiveness of LDAR at annual and tri-annual intervals;
2. Quantitative assessment of the overall effectiveness of LDAR in reducing site-wide emissions (which at many sites are likely to be dominated by venting sources);
3. Quantitative assessment of the effectiveness of OGI in detecting leaks at facilities and conditions relevant to Alberta and British Columbia; and
4. Quantitative data with which to define the cost-benefits of LDAR relative to other actions in reducing methane.

4.1.3 SCOPE OF WORK

The scope of work is itemized below:

4.1.3.1 DESKTOP ACTIVITIES PRIOR TO FIELD WORK

1. Identify candidate sample locations that satisfy the following criteria.

- To establish an unbiased baseline, target locations cannot have been subject to an LDAR survey within the last 5 years.
- The target geographic area should not exceed 150 km radius and feature a high density of upstream oil and gas batteries with grid township/range road access. These features will maximize the cost-effectiveness of dual tracer tests completed with the Aerodyne Mobile Laboratory. The farm lands between Grande Prairie, Fairview and Fort St. John provide these features and enable both BC and AB surveys.
- The target sample size is 100 locations which will provide a good representation of the skewed leak distribution based on Phase 1 analysis of recent OGI survey and component count data. This sample size and the quarterly campaigns described below will result in 300 discrete LDAR surveys. Considering the 2017 field observations, it could be expected that the proposed field campaign will detect about 275 leaks and one super-emitter.
- Given that tracer testing is dependent on wind direction and road access, the candidate sample size should be at least 300 locations which provides survey options and minimizes downtime.

2. Engage with the AER and OGC to deputize field technicians. Completion of surveys at 100 locations within the level of effort budgeted in Table 2 is predicated on timely and unconstrained access to facilities which can then be optimally chosen based on wind conditions at the time of the surveys.
3. Contact subject operators to confirm locations that have not undergone LDAR within the last 5 years. A copy of the field sampling plan and repair cost requests will be provided to operators so that they are well informed before the surveys begin.
4. Refine data collection and management software to accommodate specific details collected during this study.

4.1.3.2 LDAR FIELD WORK ACTIVITIES

Field work timing will be coordinated with facility operators to ensure safe and timely access to facilities. The following LDAR field data collection activities will be completed by Greenpath and supported by in-kind AER/BC OGC inspectors (equipped with an IR camera, Calscan PD meter and truck).

5. A one day classroom training session will be completed to review data collection procedures and safety protocols with all field team members.
6. Conduct OGI screening of components in pressurized hydrocarbon service with a FLIR GFx 320 camera. The viewing distance will be between 1 and 6 meters (to ensure greater than 90 percent probability of detecting leaks larger than 60 g CH_4 per hour based on Ravikumar et al, 2018) with maximum wind velocity less than 5 m/s and zero precipitation. Surveys may proceed with ambient temperatures as cold as minus 20 Celsius (to evaluate OGI effectiveness under winter conditions).

7. The following standardized data collection actions will be completed for each leak detected with information recorded on tablets equipped with a custom software application:
    - Measure the leak rate with a high-flow sampler (including compressor-rod-packings) and record the component type, major equipment type, measurement device type, ambient temperature/pressure, description of the emission source and site surface location.
    - Take an IR video recording of the leaking component.
    - Tag the leaking component with a unique leak ID to facilitate data management.
    - Submit a repair work order to the subject operator.
    - Request fuel and process gas analysis for sites with total leak plus vent rate greater than 1 m^3 per hour.
    - Enter these leak details into the Greenpath online fugitive management system.

8. Additional information will be collected to enable post-processing and QAQC activities.
    - Pneumatic venting will also be measured with the high-flow sampler. Vents and open-ended line leaks greater than 1 m^3 per hour will be measured with a Calscan positive displacement meter (to improve accuracy of the largest emitters).
    - Site gate placards (surface location) will be photographed to confirm locations surveyed.
    - Major process equipment in pressurized hydrocarbon service will be inventoried and photographed for each location surveyed to facilitate subsequent data analysis and broader extension of results.
    - GlyCalc files or simulation results for any uncontrolled dehydrators encountered.
9. The leak detection and measurement equipment is serviced and maintained in accordance with the manufacturer's specifications and will be subjected to calibration and functional checks prior to each campaign.
10. A follow-up survey will verify leak repair status by screening subject components with a portable hydrocarbon gas detector (i.e. Bascom-Turner Gas Sentry CGI-211) to confirm hydrocarbon concentration is less than 500 ppm.
11. To facilitate cost-benefit assessment as part of stated project objectives, the leak repair date and the following cost details will be requested from operators and entered into the online fugitive management system.
    - Leak ID and site location.
    - Description of repair or replacement completed or if it was deferred until the next turnaround.
    - Operator time required to complete the repair or replacement (hours).
    - Cost of replacement components ($ CDN).
    - Duration and estimated cost of facility downtime or blowdown caused by the repair.

- Support person(s) position and time required for the repair to be implemented (e.g., root-cause analysis, change control management, safe work procedure development, etc).

4.1.3.3 DUAL TRACER FIELD WORK ACTIVITIES

Reference measurements will be conducted with the Aerodyne Mobile Laboratory using the dual tracer method to quantify site-wide methane emissions and when possible segregate contributions from storage tank(s). Field work timing will be coordinated with facility operators to ensure safe and timely access to facilities.

12. The dual tracer test involves releasing two suitable tracer gases (typically acetylene and nitrous oxide) at a known constant rate into the emissions plume (at or near its origin), and measuring the concentration ratio (on a net-of-background basis) of each emitted substance of interest (i.e., methane) to the tracer gas at a downwind location where the trace gas is well mixed with the plume. The assumption is that the tracer gas goes through the same dilution effects as the emitted substances of interest. Hence, if the tracer-gas release rate and the net downwind concentration ratio are known, then the emission rate of the substance of interest may be determined. A detailed description of the data analysis methods and illustrative examples are provided in Appendix 8.5.2.4 (enclosed). Optimized analysis of data, subject to site-specific conditions, has established the dual trace approach as the best reference standard for emissions measurements.
13. Aerodyne will deploy the acetylene gas canister near storage tanks (or other noteworthy vent if there are no storage tanks) and offset the nitrous oxide gas canister according to wind direction to best facilitate delineation between storage tank and other methane sources.
14. The mobile laboratory will be deployed off-site within approximately 1 km downwind of the target location. Hence, farmland areas with township and range road grids are ideal.
15. To minimize downtime, a second set of tracer canisters will be deployed at the next target location while mobile laboratory measurements are completed at the first location.
16. Data analysis is completed in near real time with results and confidence intervals available to end users in convenient electronic file formats.

4.1.3.4 POST FIELD WORK ACTIVITIES

The primary data analysis activities and outcomes from the first campaign are:

17. Plot the histogram distribution of site-wide methane emissions measured by dual tracer testing at each site. Overlay a second histogram distribution that is discounted by the quantity corresponding to venting sources (i.e., storage losses determined by dual tracer test, pneumatics and compressor rod-packings measured during LDAR surveys, dehydrator emissions estimated by GlyCalc, etc). The second distribution represents equipment leak emissions that could be mitigated by LDAR and is the **baseline** for determining effectiveness of annual and tri-annual survey frequency. The difference

between site-wide emissions and the LDAR baseline distributions represents venting emissions. In addition to this visual illustration, the average emission rates and confidence intervals for the 100 sample locations surveyed are determined using the bootstrapping method. This enables quantification of the relative importance of equipment leaks to overall site emissions.

18. Overlay a third histogram distribution of equipment leaks measured during LDAR surveys. The difference between the second and third distribution represents emissions not detected by OGI method. The difference between average emissions provides a quantitative indicator of OGI effectiveness when completed by a reputable service provider at active production facilities.
19. Assign 50 locations to field survey stratum A, which will be screened at a rate of three times per year using the OGI method, and 50 locations to stratum B which will be screened at a rate of once per year. Once year after the initial surveys and tracer measurements, final set of tracer measurements and OGI surveys will be performed as indicated in the schedule below.

The primary data analysis activities and outcomes after all four campaigns are completed will be to:

20. Determine the average emission rates and confidence intervals for stratum A surveys (50 locations screened at a rate of three-times per year) and stratum B surveys (50 locations screened annually) using the bootstrapping method.
21. The **effectiveness of <u>annual LDAR</u> frequency** to reduce equipment leaks is the relative difference between the average leak rate from campaign #1 (baseline) and average leak rate from campaign #4 determined from tracer testing of stratum B locations. The expected continuing emission rate is represented by the average leak rate observed during the second campaign.
22. The **effectiveness of <u>tri-annual LDAR</u> frequency** to reduce equipment leaks is the relative difference between the average leak rate from campaign #1 (baseline) and average leak rate from campaign #4 determined from tracer testing of stratum A locations. The expected continuing emission rate is represented by the average leak rate observed during the second campaign.
23. Measurement results from campaigns #2, #3 and #4 are added to the histogram distributions described in tasks 17 and 18. The increased sample size will improve confidence in conclusions on the importance of equipment leaks relative to overall site emissions as well as the effectiveness of OGI.
24. Determine the average leak repair cost per (1) component type, (2) avoided leak volume, and (3) avoided methane emissions for each of the cost metrics listed in task #11 above. Moreover, the distribution of repair timing will be plotted for each component type.

The results of the study shall be presented in two stand-alone reports prepared in MS Word format and submitted as Adobe Acrobat pdf files. Executive Summaries of the reports will be written for easy understanding by the public and all detailed technical information shall be presented in the appendices for optimum readability

25. The first study report shall comprise a discussion of the applied methodological approaches and results from the first measurement campaign. This includes quantitative indicators of equipment leaks relative to total site-wide emissions as well as OGI effectiveness to detect leaks.
26. The second study report shall include methodology descriptions and results from all four measurement campaigns. This includes the cost-benefit of repairing leaks; quantitative indicators of the overall and comparative effectiveness annual and tri-annual LDAR surveys relative to baseline emissions plus final conclusions on the importance of equipment leaks and OGI effectiveness. The MRPC will have three weeks to review and comment.
27. Prepare a final report that incorporates MRPC comments.

4.1.4 STUDY TEAM

The study team will comprise key specialists from Clearstone Engineering Ltd, Carleton University, Greenpath Energy Ltd and Aerodyne Research Inc.

4.2 ABNORMAL PROCESS VENTING

4.2.1 BACKGROUND-PROBLEM DESCRIPTION

Researchers have observed that a significant portion of methane emissions are from a small number of super-emitting leaks or abnormal process vents (Brandt et al, 2016; Zavala-Araiza et al, 2018). A similar observation was made during 2017 surveys of Alberta UOG sites where the majority of emissions (upwards of 80 percent) are from sources that FEMP typically classify as process vents **that do not trigger remedial action**. The magnitude of gas released from pneumatics, production tanks, heavy oil well casing vents and unlit flares can be under appreciated by operations; difficult to estimate because it's driven by abnormal behavior; and therefore omitted from maintenance programs.

When super-emitting sites are present, different sites may experience abnormal conditions at different points in time (e.g., the same site will not always have the same malfunction, or a process condition could manifest at different sites at varying times). For example, pigging operations that push high vapour-pressure liquids into atmospheric storage tanks may result in rapid flashing losses coinciding with pig deliveries (e.g., daily, weekly or monthly) as was the subject of a recent Environmental Protection Agency (EPA) enforcement settlement (EPA, 2018). The periodic nature of some releases has motivated researchers to assert that mitigating emissions requires frequent monitoring with the time between inspections short enough to minimize the duration of "spatio-temporally dynamic super-emitting sites" (Lyon et al., 2016; Lavoie et al., 2017; and Zavala-Araiza et al, 2018). However, frequent OGI inspections will not observe short-duration events (unless the IR camera is viewing the source during the event) and, more importantly, existing FEMP will not trigger mitigating actions.

AER draft Directive 060 specifies a site-wide venting limit (500 m^3/day) with prescriptive requirements for pneumatic devices and heavy oil well casing vents (AER, 2018). Storage tank losses are defined as routine venting subject to site limits. However, the effectiveness of site limits will depend on reliable quantification of storage losses, especially contributions that are difficult to estimate without detailed and site specific data (that may include abnormal behavior). Therefore, this source deserves further attention.

4.2.2 RESEARCH OBJECTIVE

The primary objectives of this field data collection study is to (1) determine the root-cause(s) and (2) recommend basic FEMP checks that identify and mitigate abnormal tank venting. Secondary objectives are to collect process details (i.e., upstream temperature, pressure and product type) and repair/replacement cost details to inform assumptions used in emission inventories and regulatory impact assessments.

4.2.3 SCOPE OF WORK

The scope of work is itemized below:

4.2.3.1 DESKTOP ACTIVITIES PRIOR TO FIELD WORK

1) Review IR camera videos and process venting estimates from the 2017 field work (discussed in Section 3.6) to confirm target sites and tanks. The review will endeavor to identify abnormal behaviour such as continuous venting from tanks connected to a single upstream separator (where cyclic venting is expected) or venting from water tanks. A preliminary review of 2017 data indicates that 20 of the 64 tanks observed to be venting in 2017 are responsible for 80 percent of the total gas loss. Thus scheduling and budget estimates below are based on evaluating 20 tanks.
2) Contact subject operators to confirm voluntary participation in this study. To ensure informed consent, the anticipated support required prior, during and after field work as well as co-benefits to the operator will be clearly stated.
3) Using the measurement schematics collected in 2017, identify upstream vessels delivering hydrocarbon liquids to each target storage tank. Request upstream vessel temperature, pressure and product type from subject operators to estimate flashing losses using the Vasquez & Beggs correlation (presented in the 2002 CAPP guide for estimating flaring and venting). This approach is recommended by AER Directive 017 and should provide a reasonable estimate (i.e., normal) for tank venting. Results will be summarized in Table 6 and intended to provide field inspectors with baseline information to compare with field observations and identify any abnormal (or unexpected) behavior.

4.2.3.2 FIELD WORK ACTIVITIES

Field work timing will be coordinated with facility operators to ensure appropriate support personnel are available. The following field data collection activities will be completed by two senior engineers and an AER/ BC OGC inspector (with in-kind IR camera, Calscan PD meter and truck). Both senior engineers will visit the first ten sites but as root-cause trends emerge, only one senior engineer will be required for the remaining 10 sites. Tank top gas flow measurements are not included in the proposed work scope to minimize safety risks.

4) Collect the operating pressure and temperature of each upstream vessel from local analog gauges or from the plant control panel. These can include separators, gas boots, interstage compression scrubbers, treaters and potentially others.
5) Determine the product type, volume and duration between liquid delivery events from each upstream vessel.
6) Record tank top emissions with the IR Camera during ‘normal’ operating conditions.
    a. If IR observations are consistent with expected vent behavior described in Table 6, then there is no abnormal venting behavior.

b. If IR observations are **not** consistent with expected vent behavior (e.g., continuous venting observed when cyclic events expected), then the following checks will be completed to identify the abnormal condition(s).

7) Investigate sources that may be contributing abnormal storage tank emissions. This includes:
   a. Requesting the operator to change process conditions (i.e., stop liquid flows to the target tank) and observe tank top emissions with the IR Camera. If emissions remain the same, process gas is likely passing one of the dump valves.
   b. Acoustical leak detection of dump valves using VPAC unit.
   c. Tracing pipes to identify any process gas sources tied into the storage tank (e.g., well casings tied into storage tanks). Process gas flow rates will be measured using a positive displacement meter if a suitable port and downstream isolation valve are available.
   d. Confirming pipe layout for receiving pigs and corresponding liquids. Obtain typical pigging frequency and liquid volume from operators and ideally record tank top emissions with an IR Camera during a pigging event.
   e. Analyze tank vapours to confirm hydrocarbon content (and that observed plume is not water vapour) using an optical gas chromatograph (Precisive TFS1). This device uses infrared absorption to measure methane, ethane, propane, butanes, pentanes, carbon dioxide and % level H_2S. It is deployed at ground level and connected to a portable battery-powered data capture and display system for real-time trend analysis. Tank vapours are collected with a sample line connected to a GilAir5 pump and extendable pole.

4.2.3.3 POST FIELD WORK ACTIVITIES

8) A description of mitigating actions taken to eliminate abnormal tank venting, time to complete the action and corresponding costs will be requested from facility operators. A standardized form that delineates between capital cost (repair/replacement of components), engineering cost (process modelling, equipment design, etc), administrative cost (change control management, safe work procedure, etc) and lost production time will be used to collect data. The average cost per mitigating action type will be determined and used to support a simple cost-benefit assessment.
9) Upstream process conditions will be compared to those used for national emission inventories. Refinement of inventory pressure and temperature assumptions will be completed if material differences are observed.

The results of the study shall be presented in a stand-alone report prepared in MS Word format and submitted as an Adobe Acrobat pdf file. The study report shall comprise a discussion of the applied methodological approach, any gaps or uncertainty in the presented information; explanation of each root-cause identified; the cost-benefit of mitigating actions; and corresponding refinements to FEMP procedures. The Executive Summary of the report will be written for easy understanding by the public and all detailed technical information shall be presented in the appendices for optimum readability.

4.2.4 STUDY TEAM

The study team will comprise key engineering specialists from Clearstone Engineering Ltd and New Paradigm Engineering Ltd.

Table 6: Upstream vessels and expected tank venting.								
Site Location	**Tank Tag #**	**Upstream Vessels Delivering Liquids to Tank**					**Expected Vent Behavior**	
		Vessel Tag #	**Product Description**	**Temp (°C)**	**Pressure (kPaa)**	**Estimated GOR**	**Magnitude**	**Frequency**
01-01-001-01W4	*T101*	*V101*	*Oil from treater*	*400*	*450*	*5.5*	*Medium*	*continuous*
		V103	*Oil from separator*	*50*	*300*	*0.8*	*Small*	*20 min dump cycle*
	T102	*V102*	*Water from treater*	*400*	*450*	*0*	*zero*	*none*

4.3 ECCC LEAK DEFINITION AND FUGITIVE EMISSION CONTRIBUTIONS BELOW "NO-LEAK" THRESHOLDS

4.3.1 BACKGROUND-PROBLEM DESCRIPTION

The ECCC CG2 Section 31 leak definition depends on screening method. A component is leaking if the release (1) consists of at least 500 ppmv hydrocarbons determined by a portable monitor in accordance with M21 or (2) is detected by an eligible OGI instrument (ECCC, 2018). However, the OGI eligibility criteria for maximum viewing distance and minimum detectable release rate are not well defined. This is problematic for consistent implementation by industry as well as determining fugitive emission contributions from components emitting below the regulated leak threshold (i.e., "No-Leak" contribution).

Canadian UOG industry no-leak factors are based on an M21 screening concentration of 10,000 ppmv and measurements completed circa 1990 (CAPP, 1992). No-leak factors are less important for component populations featuring lots of leaks but as fewer leaks are detected, the no-leak contribution to total fugitive emissions become more important. For example, if it's assumed the OGI MDL is equivalent to 10,000 ppmv screening threshold, the no-leak contribution is approximate 38% of total fugitive emissions from the 216,000 components screened in 2017 at 333 Alberta locations (discussed in Section 3.4.1). Thus, the potential magnitude of no-leak contribution elevates the priority of related questions:

1. What is the effective field OGI MDL (or no-leak threshold defined on a ppmv and g/s basis) when completed under specified conditions (i.e., viewing distance <5m, wind <5 m/s, ambient temp > 5 C, and zero precipitation)?
2. How are no-leak factors impacted by leak definition? Compare no-leak factors determined according to 500 and 10,000 ppmv (Method 21) as well as 30 and 60 g THC per hour (OGI) screening definitions.
3. What impact does screening method have on the no-leak contribution to total fugitive emissions?

4.3.2 RESEARCH OBJECTIVE

1. Conduct OGI inspections under strictly observed field conditions demonstrated to impact detection effectiveness (i.e., improve fidelity wrt training, viewing distance, and acceptable weather conditions). Collect weather data but no leak measurement.
2. Conduct enhanced M21 screening with FID monitor (e.g., ewerin PortaFID with MDL ~2ppm) of same sites the next day to ensure complete detection and establish no-leak contribution. Measure leak rate with enhanced High Flow Sampler (e.g., the High-Flow MDL can be improved by two orders of magnitude by installing a port on the instrument’s inlet sampling line to facilitate independent measurement of the hydrocarbon concentration with an FID).

3. Plot leaks detected by OGI and M21 methods according to their screening concentration (x-axis) and THC release rate (y-axis) as illustrated in Figure 7. Overlay potential leak definition thresholds and determine probability of OGI detecting subject leaks (propose testing no-leak thresholds of 500 and 10,000 ppmv as well as 1, 30 and 60 g THC per hour).
4. Determine "No-Leak" emission factors for each threshold. Calculate corresponding "No-Leak" contribution to total Alberta UOG fugitive emissions using Clearstone inventory database. Quantify impact of OGI eligibility criteria on large population of components.

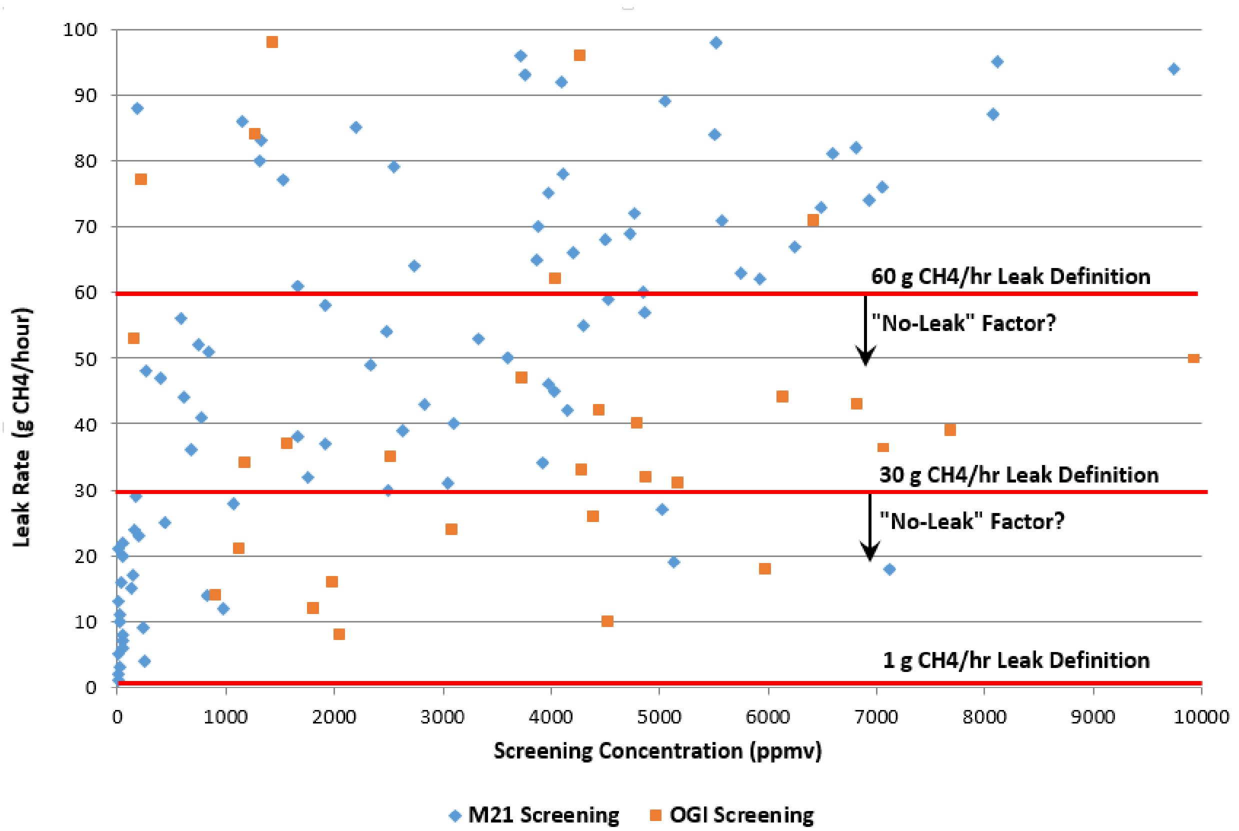

Figure 7: Example data collected using FID enhanced screening and measurement of leaks with potential leak definitions.

4.3.3 SCOPE OF WORK

The MRPC considers this recommendation to be outside the scope of this contract. Therefore, we are not asking for further details on this topic at this time.

4.4 OGI EFFECTIVENESS

4.4.1 BACKGROUND-PROBLEM DESCRIPTION

Section 31 of ECCC methane regulation (CG2) defines a component to be leaking if it is detected by an eligible OGI instrument (ECCC, 2018). This prompts questions regarding the practical effectiveness of an OGI instrument, demonstrated to comply with CG2 Section 30(2)(b), to detect leaks. A recent single-blind study at METEC yielded empirical evidence on the probability of OGI detecting leaks as a function of viewing distance and leak rate (Ravikumar, 2018). Other factors described below can also lower the probability of detection and are the subject of an EPA supported study at METEC.

- Weather (i.e., wind speed, temperature and precipitation/humidity)
- Inaccessible components. These include components hidden from direct line of sight (e.g., under compressor skid grating) or exceed maximum viewing distance (e.g., tank tops).
- OGI technician visual acuity and patience considering campaign schedule demands.

4.4.2 RESEARCH OBJECTIVE

Phase 2 field work conducted at Canadian production sites should **not** focus on OGI effectiveness because total leakage for each site is unknown and the precision of dual tracer tests may not be sufficient to distinguish between leak and vent source contributions. Instead, it's recommended that PTAC participate and support single-blind experiments underway at METEC (https://energy.colostate.edu/metec/).

4.4.3 SCOPE OF WORK

The MRPC will independently evaluate potential collaboration with METEC for OGI performance work.

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