EXECUTIVE SUMMARY

This report describes the field campaign conducted at Alberta upstream oil and natural gas (UOG) sites from 14 August to 23 September 2017 and methodology applied to determine average factors and confidence intervals for the following parameters.

- Process equipment count per facility subtype[1] or well status code[2].
- Component count per process equipment unit[3].
- Emission control type per process equipment unit.
- Pneumatic device count per facility subtype or well status code by device and driver types.
- Leak rate per component and service type[4] considering the entire population of components with the potential to leak (i.e., 'population average' factor).
- Leak rate per component and service type considering leaking components only (i.e., 'leaker' factor).

The study was completed under the authority of the Alberta Energy Regulator (AER) and funded by Natural Resources Canada (NRCan) with the objective of improving confidence in methane emissions from Alberta UOG fugitive equipment leaks, pneumatic devices and reciprocating rod-packings. Results are intended for an emission inventory model used to predict equipment/component counts, uncertainties and air emissions associated with UOG facility and well identifiers.

Fugitive equipment leaks and pneumatic venting sources are targeted by this study because they contribute approximately 17 and 23 percent, respectively, of methane emissions in the 2011 national inventory (ECCC, 2014) and are based on uncertain assumptions regarding the population of UOG equipment and components. Moreover, a 2014 leak factor update report published by the Canadian Association of Petroleum Producers (CAPP) recommended equipment and component counts be refined based on field inventories and standardized definitions because of limitations encountered when determining these from measurement schematics, process flow diagrams (PFD) or piping and instrumentation diagrams (P&ID) (CAPP, 2014 sections 4.1.1 and 4.2.1).

1 Facility subtypes are defined in Table 2 of AER Manual 011 (AER, 2016b).
2 Well status codes are defined by the four category types: fluid, mode, type and structure.
3 Process equipment units are defined in Appendix Section 8.4.
4 Component types and service types are defined in Appendix Sections 8.2 and 8.3.

Scope

The scope of this study targets UOG wells, multi-well batteries, and compressor stations belonging to AER facility subtypes contributing the most to UOG methane emission uncertainty. Larger UOG facilities and oil sands operations are specifically excluded from this study because they are often subject to regulated emission quantification, verification and compliance requirements that motivate accurate, complete and consistent methane emission reporting.

The field sampling plan follows the fugitive emission measurement protocol recommended by the Canadian Energy Partnership for Environmental Innovation (CEPEI, 2006) with the optical gas imaging (OGI) method used for leak detection. The field campaign targeted UOG wells, multi-well batteries, and compressor stations belonging to the following UOG industry segments (and AER facility subtypes) contributing the most to UOG methane emission uncertainty. Candidate sample locations were randomly selected from subtype populations with surveys completed at as many sites as budgeted resources allowed.

- Natural Gas Production (subtypes 351, 361, 362, 363, 364, 365, 366, 367, 601, 621 & 622)
- Light and Crude Oil Production (subtypes 311, 321 and 322)
- Cold Heavy Crude Oil Production (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 ES-1.

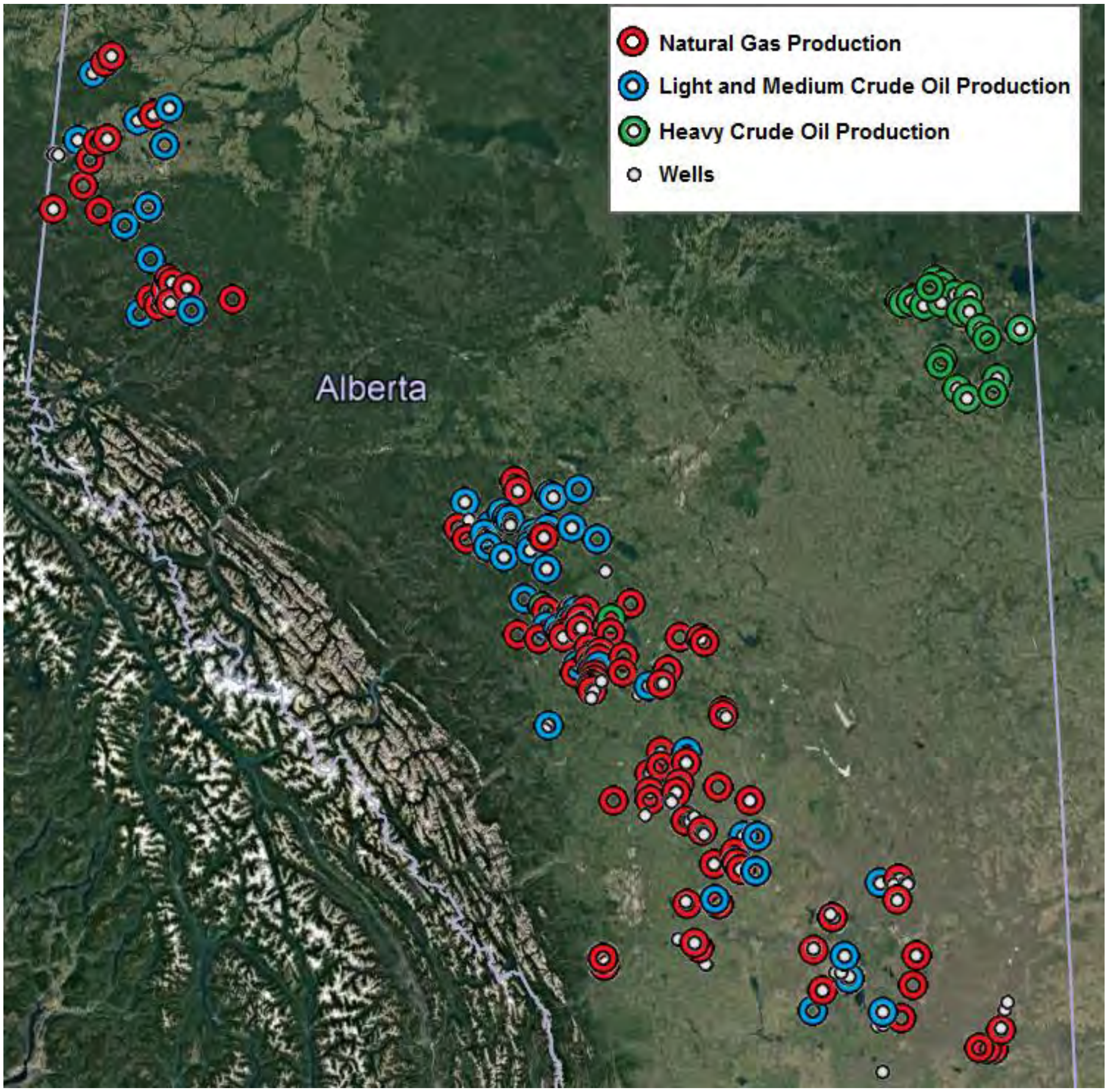

Figure ES-1: Survey locations and facility subtypes for the 2017 measurement campaign.

<u>Data Collection and QA/QC</u>

Field measurements and data collection was led by Greenpath Energy Ltd. (Greenpath). Greenpath technicians were paired with an AER inspector or a Clearstone engineer to enhance field team depth with respect to regulatory inspections and process knowledge. Before beginning the campaign, all field team members attended three days of project-specific desktop and field training. 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. Other quality assurance (QA) measures implemented to ensure reliable field data included:

- Use of leak detection and measurement equipment appropriate for the site conditions and source characteristics encountered at UOG facilities. Equipment is regularly serviced and maintained in accordance with the manufacturer's specifications.

- Field observations were documented in a complete and consistent manner using a software application designed for this project. The application was installed on tablets and pre-populated with site identifiers and standard definitions that enabled selection from drop-down menus (instead of free-form data entry).
- Photos were taken of each site placard (to confirm surveyed locations) and each equipment unit (to confirm the correct equipment type was selected and reasonable component counts were completed).
- Infrared (IR) camera videos were recorded to confirm the component type and leak magnitude.
- Tablet data was uploaded to an online repository at the end of each working day to minimize data loss risk (e.g., due to damaged or lost tablets). Backup archive files were checked at the end of the field campaign to confirm no data leakage occurred.
- Parsing of tablet records into an SQL database was automated to minimize processing time and transcription errors.

The data collected was tested according to the following quality control (QC) procedures:

- Records were reviewed by the field team coordinator on a daily basis to identify and mitigate data collection errors. When observed, problematic records were corrected and communicated to the entire field team to prevent future occurrences.
- The possibility of data leakage between the field tablets and final SQL database was checked by comparing tablet archives to final database records.
- Site placard photos, equipment photos, IR videos and measurement schematics were used during post survey processing to determine the validity of data outliers.
- Various post-processing statistical tests and quality control checks were performed on the data to ensure records are correctly classified and representative of process conditions.
- Raw data records were provided to the operator of each site surveyed. Written feedback regarding data corrections were received from five operators and refinements made to the dataset.

Observational and measurement data are assigned to corresponding AER facility and well identifiers based on measurement schematics provided by subject operators. Field observations are correlated to Facility IDs and UWIs so that the resulting factors are representative and applicable to the AER regulated UOG industry managed with Petrinex data models.

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 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 to yield a final uncertainty in the measurement result. Two types of uncertainties are encountered when measuring variables: systematic (or bias) and random (or precision) uncertainties (Wheeler and Ganji, 2004). Confidence intervals for study results are determined using the bootstrapping method and adopt the IPCC (2000) Good Practice Guidance suggestion to use a 95% confidence level (i.e., the interval that has a 95% probability of containing the unknown true value) and Tier 1 rules for error propagation.

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

Results for Process Equipment and Components

Process equipment and components (greater than 0.5" NPS) in pressurized hydrocarbon service were counted and classified according to standardized definitions presented in Appendix Section 8. Equipment and component schedules are used to estimate the number of potential hydrocarbon vapour leak sources exist in the Alberta UOG industry. Process equipment and components entirely in water, air[5], lubricating oil and non-volatile chemical service were **not** included in the inventory because they are less likely to emit hydrocarbons. Factors representing the average (mean) number of equipment units per facility subtype or well status are calculated by dividing the total equipment count by the total number of sites surveyed for each of the stratums considered. Average counts and confidence intervals are determined for 27 process equipment types observed at 11 facility subtypes and 12 well status codes. Results for facility subtypes are presented in Table 3 of the report body while results for well status codes are in Table 4.

In addition to counting components, the following emission controls were noted by field inspectors when installed on subject process equipment units.

- Gas Conserved – where natural gas is captured and sold, used as fuel, injected into reservoirs for pressure maintenance or other beneficial purpose.
- Gas tied to flare – where natural gas is captured and disposed by thermal oxidization in a flare or incinerator.

5 Pneumatic devices driven by instrument air were inventoried as discussed in Section 3.4. The air compressor and piping were not inventoried.

- Gas tied to scrubber – where natural gas is captured and specific substances of concern (e.g., H_2S or other odourous compounds) are removed via adsorption or catalytic technologies.

Average emission control per subject equipment units are presented in Table ES-1. These results consider the frequency controls are observed and the estimated control efficiency for preventing the release of natural gas to the atmosphere (i.e., how much of the subject gas stream is captured and combusted/conserved over an extended period of time). Because control efficiency assessment was beyond the scope of the 2017 field campaign, a conservative estimate of 95 percent is adopted for conservation and flaring (from CCME, 1995[6]) while scrubbers are assigned 0 control because they prevent very little of subject natural gas streams from being released to atmosphere.

Table ES-1: Average (mean) emission control & confidence interval per equipment unit.

Description of Control	Process Equipment Count	Control Count	Average Control Factor	95% Confidence Interval (%of mean)	
				Lower	Upper
Storage tank tied into flare or conserved	213	46	0.21	28%	31%
Storage tank tied into scrubber	213	3	0.00	-	-
Compressor rod-packing vent tied into flare or conserved	54	7	0.12	65%	72%
Pop tank tied into flare or conserved	20	2	0.10	100%	123%

The average (mean) number of components in hydrocarbon process gas or liquid service per process equipment type is calculated for the following component types. Results with confidence intervals are presented in Table 5 of the report body.

- Reciprocating Compressor Rod-Packing,
- 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).

6 This is the minimum performance required by CCME (1995) for vapour control systems.

A comparison of the 2017 component counts to those derived for the first Canadian UOG "bottom-up" national emission inventory (CAPP, 1992) indicates that the number and diversity of components per equipment type has increased. This is likely driven by increased process measurement/control and liquids-rich gas production introduced over the last 30 years as well as a specific field objective to account for every component in pressurized hydrocarbon service. The 2017 sample plan required inspectors to include all process equipment components plus downstream components until they arrived at the inlet flange of the next process unit. This could include a significant number of components from 'yard piping' that are not physically attached to the process unit but are potential leak sources that need to be accounted. For example, the total average number of components for a separator increased 60 percent and now includes control valve, meter, open-ended line, PSV and regulator counts. These changes are reasonable when considering the 3-phase separator shown in Figure ES-2 and commonly used at liquids-rich gas production sites. In addition to the control valve and senior orifice meter visible in Figure ES-2, this separator also features 1 junior orifice meter, 2 turbine meters, 4 regulators (heater and pneumatic pump fuel supply), 1 PSV, 2 chemical injection pumps and numerous pneumatic instruments.

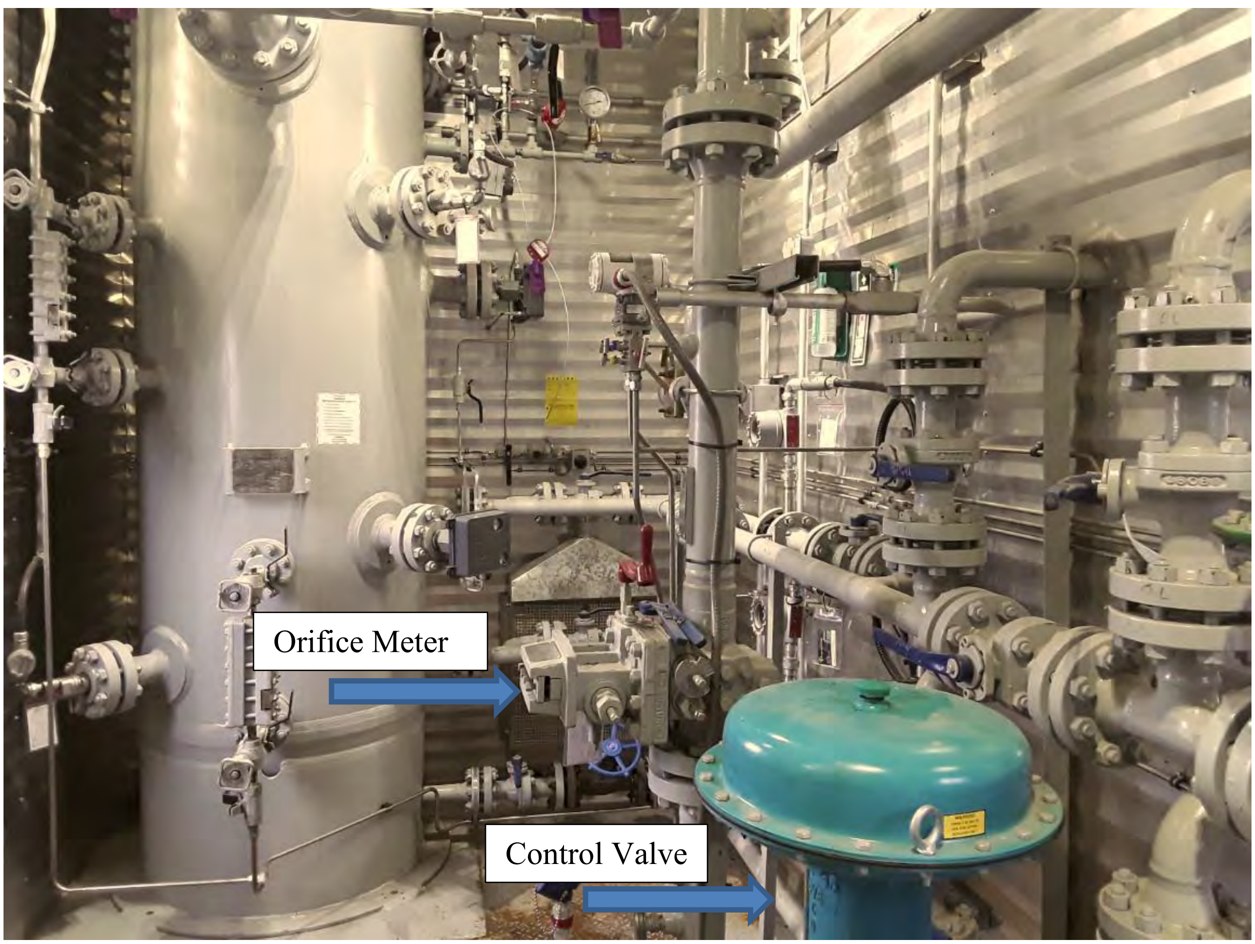

Figure ES-2: Three-Phase vertical separator located at a liquids-rich gas production site.

Results for Pneumatic Devices

Pneumatic devices driven by natural gas, propane, instrument air and electricity were inventoried at each location surveyed in 2017. To increase the sample size, pneumatic inventory data collected in 2016 by Greenpath Energy Ltd. for the AER was considered for this assessment (Greenpath, 2017a). Devices are included in this study when sufficient information was available to assign 2016 records to a Facility ID or UWI (otherwise the data record was discarded). The final dataset includes 1753 devices from the 2017 field campaign plus 1105 devices from the 2016 field campaign.

The average (mean) number of pneumatic devices per facility subtype and well status are presented in the report body Table 7 and Table 8 according to device (e.g., level controllers, positioners, pressure controllers, transducers, chemical pumps and intermittent) and driver type (e.g., instrument air, propane and electric). The factors for natural gas driven devices should be adopted for GHG emission inventory purposes. Factors for propane (relevant to volatile organic compound (VOC) emissions), instrument air and electric driven devices provide some insight into the installation frequency of non-emitting devices. Given the large number of wells and their tendency to rely on natural gas, well-site pneumatics are a noteworthy contributor to total methane emissions in Alberta and deserve careful consideration when developing province-wide emission inventories.

Devices that provide the following control actions are the dominant contributors to pneumatic venting emissions and account for 2,289 of the 2,858 pneumatic devices observed during 2016 and 2017 surveys.

- Level Controller
- Positioner
- Pressure Controller
- Chemical Pump
- Transducer

Figure ES-3 delineates the pneumatic inventory by device type and driver type. The majority of devices are driven by natural gas while approximately 30 percent of devices utilize alternative drivers (instrument air, propane or electricity) that do not directly contribute methane emissions.

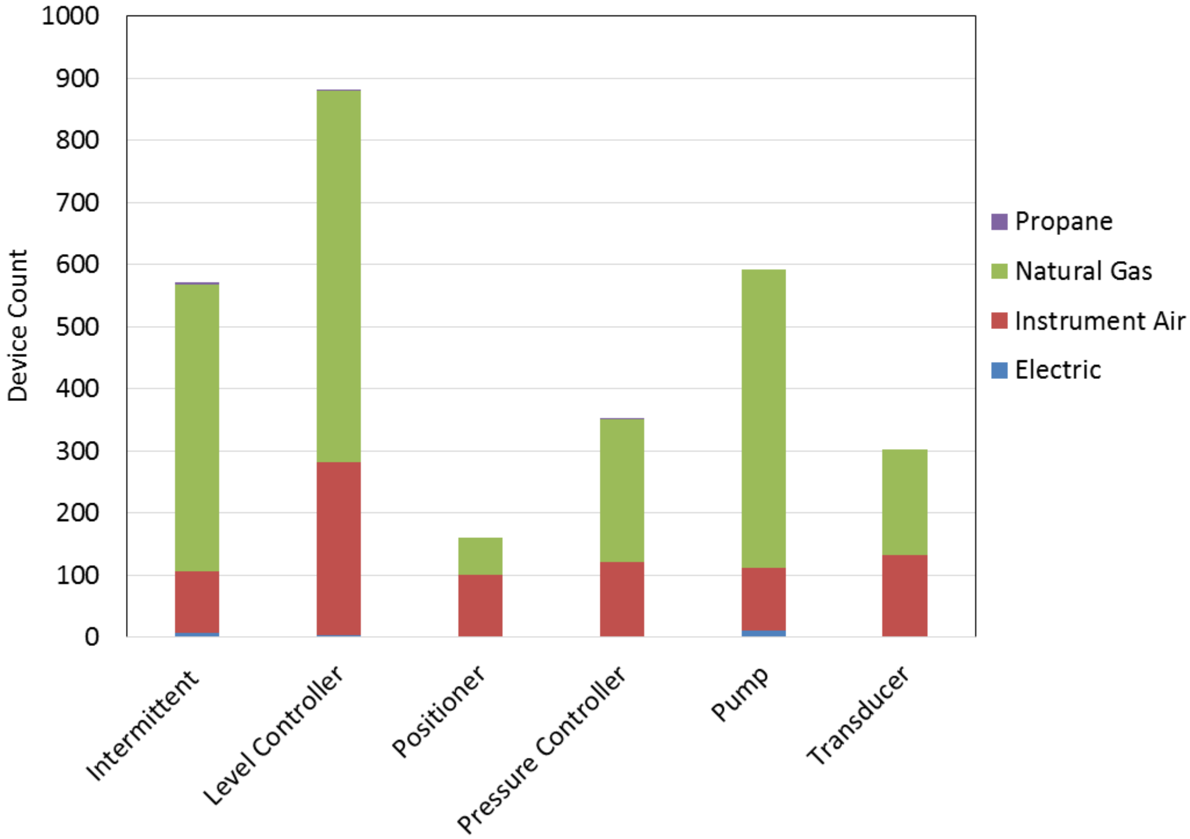

Figure ES-3: Pneumatic counts, by device type and driver type, observed at Alberta UOG facilities and wells during 2016 and 2017 field campaigns.

Devices that provide the following control actions typically vent at rates well below 0.17 m^3 per hour or only during infrequent unloading (de-energizing) events. Therefore, subject models are aggregated and presented as device type "Intermittent" in report tables. This simplifies emission inventory development efforts and is reasonable for devices that contributes very little to total methane emissions.

- High Level Shut Down
- High Pressure Shut Down
- Level Switch
- Plunger Lift Controller
- Pressure Switch
- Temperature Switch

Because pneumatic venting rates were not measured during the 2017 and 2016 field campaigns, other studies are relied on to determine vent rates representative of each device type. Emission factors presented in Table ES-2 are a sample-size weighted average of mean bleed rates from

2013 Prasino and 2018 Spartan (Fisher L2 level controller[7]) studies as well as manufacturer specifications for less common models (Prasino, 2013 and Spartan, 2018). The factor labeled 'generic pneumatic instrument' includes high and low-bleed instruments that continuously vent. The 'generic pneumatic instrument' vent rate of 0.3217 m^3/hr is greater than the 'generic high bleed controller' vent rate published in the Prasino study (0.2605 m^3/hr) largely because of the revised level controller factor published by Spartan (i.e., 0.46 m^3/hr ± 22% versus the Prasino factor of 0.2641 m^3/hr ± 34%) and the large number of level controllers in the study population. Interestingly, the 'generic pneumatic instrument' vent rate is only 9 percent less than the rate applied in the last national inventory (i.e., 0.354 m^3/hr in ECCC, 2014). The same isn't true for chemical pumps, a rate of 0.236 m^3/hr was applied in the last national inventory which is 4 times less than the rate presented in Table ES-2.

Table ES-2: Sample-size weighted average vent rates for pneumatic device types observed during 2016 and 2017 field campaigns.

Device Type	Average Vent Rate (m^3 natural gas/hour)	95% Confidence Interval (% of mean)
Level Controller	0.3508	31.68
Positioner	0.2627	39.02
Pressure Controller	0.3217	35.95
Transducer	0.2335	22.54
Generic Pneumatic Instrument	0.3206	31.53
Chemical Pump	0.9726	13.99

Results for Fugitive Emission Factors

Emission factors for estimating fugitive equipment leaks are normally 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. 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 are determined by summing measured leak rates and dividing by the total number of potential leak sources (i.e., components) for each component/service type of interest. End users multiply population average factors by the entire component population in pressurized hydrocarbon service belonging to the facilities/wells of interest.

7 Further investigation of level controllers was completed by Spartan (with the support of PTAC) because of concerns that the 2013 Prasino study did not adequately capture emission contributions from the transient sate. The mean vent rate from Spartan (0.46 m^3/hr ± 22% based on 72 samples) is used to determine level controller rate in Table 16 instead the Prasino factor (0.2641 m^3/hr ± 34% based on 48 samples).

“Leaker” emission factors are determined in the same manner but the denominator only includes the number of **leaking** components. End users conduct an OGI survey and multiply the number of leaking components by the corresponding component and service type “leaker” factor. Fugitive emissions estimated using this approach should provide better accuracy and identification of high leak-risk components and facilities than population average factors. However, direct measurement of detected leaks is more accurate and provides valuable insight regarding leak magnitude and frequency distributions that are not available from emission factor approaches. For example, Figure ES-4 indicates that a small number of leaks contribute most of the fugitive emissions for a given component population. 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. This result is consistent with other studies and indicates “super-emitters” are present in the 2017 sample population.

Population average emission factor results are presented on a volume and mass basis in Table ES-3 by component and service type. ‘Leaker’ emissions factors for the same stratums are presented in Table ES-4. ‘No-leak’ emission factors are not determined in this study because the High-Flow Sampler method detection limit (MDL) is not sensitive enough to accurately quantify leaks below 10,000 ppmv[8].

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 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.
- Uncertainty that all leaks are detected by the OGI survey method.

Exceptions where 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

8 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.

large no-leak contributions. Whereas, no-leak contributions are not included in 2017 population average factors. Moreover, no-leak contributions should be calculated as a separate category when estimating fugitive emissions. When no-leak emission factors are multiplied by the population of components surveyed in 2017, it's estimated that leakage occurring below OGI and High-Flow MDLs is responsible for approximately 38 percent of total equipment leak emissions.

Comparison of 2017 Leak Results with Historic Fugitive Studies

The implications of 2017 emission factors on total fugitive emissions is estimated by multiplying the component population surveyed in 2017 by population average leak factors from two reference studies: 2014 CAPP *Update of Fugitive Emission Equipment Leak Emission Factors* and 2005 CAPP *National Inventory of GHG, CAC and H_2S Emissions by the Upstream Oil and Gas Industry*. A comparison of results indicates 2017 and 2014 factors generate about the same total fugitive emissions which are approximately 60 percent less than those generated using 2005 factors.

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 is 0.2875 m^3 THC per hour per rod-packing (with lower and 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.

Table ES-3: Population average emission factors for estimating fugitive emissions from Alberta UOG facilities on a volume[a] or mass basis.											
Sector	**Component Type**	**Service**	**Leaker Count**	**Component Count**	**Leak Frequency**	**EF (kg THC /h/source)**	**95% Confidence Limit (% of mean)**		**EF (m^3 THC /h/source)**	**95% Confidence Limit (% of mean)**	
							Lower	**Upper**		**Lower**	**Upper**
All	Compressor Rod-Packing[b,c]	PG		139		0.20622	53%	88%	0.28745	53%	88%
All	Connector	PG	145	137,391	0.11%	0.00014	32%	53%	0.00019	32%	52%
All	Connector	LL	6	45,356	0.01%	0.00001	71%	114%	0.00001	70%	120%
All	Control Valve	PG	16	539	2.97%	0.00487	53%	77%	0.00646	53%	77%
All	Meter	PG	8	531	1.51%	0.00105	47%	73%	0.00145	47%	70%
All	Open-Ended Line	PG	10	144	6.95%	0.06700	91%	219%	0.09249	91%	225%
All	Pressure Relief Valve	PG	7	1,176	0.60%	0.00399	54%	85%	0.00552	53%	79%
All	Pump Seal	PG	6	178	3.37%	0.00761	73%	142%	0.01057	73%	141%
All	Regulator	PG	27	3,067	0.88%	0.00112	60%	99%	0.00122	50%	76%
All	Thief Hatch	PG	6	52	11.46%	0.12870	77%	134%	0.12860	70%	115%
All	Valve	PG	28	20,545	0.14%	0.00044	64%	112%	0.00058	62%	111%
All	Valve	LL	6	8,944	0.07%	0.00015	72%	122%	0.00021	73%	120%
All	SCVF	PG	15	440	3.41%	0.09250	98%	204%	0.12784	98%	196%

[a] Volumes are presented at standard reference conditions of 15ºC and 101.325 kPa.

[b] 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).

[c] Reciprocating Compressor rod-packings vents are typically tied into a common header with measurements conducted on the common vent. Therefore, the actual number of leaking components and leak frequency are not known.

Table ES-4: Leaker emission factors for estimating fugitive emissions from Alberta UOG facilities on a volume[a] or mass basis.									
Sector	**Component Type**	**Service**	**Leaker Count**	**Leaker EF (kg THC/h/source)**	**95% Confidence Limit (% of mean)**		**Leaker EF (sm^3 THC/h/source)**	**95% Confidence Limit (% of mean)**	
					Lower	**Upper**		**Lower**	**Upper**
All	Compressor Rod-Packing[b]	PG	27	1.08150	45%	58%	0.77563	43%	56%
All	Connector	PG	145	0.13281	19%	21%	0.10137	20%	21%
All	Connector	LL	6	0.05906	71%	88%	0.04156	70%	85%
All	Control Valve	PG	16	0.16213	47%	50%	0.12203	48%	52%
All	Meter	PG	8	0.07201	39%	49%	0.05238	40%	50%
All	Open-Ended Line	PG	10	0.98904	90%	195%	0.70729	90%	199%
All	Pressure Relief Valve	PG	7	0.69700	49%	62%	0.50395	49%	63%
All	Pump Seal	PG	6	0.23659	71%	121%	0.16974	71%	125%
All	Regulator	PG	27	0.10275	45%	56%	0.09514	56%	79%
All	Thief Hatch	PG	6	0.81672	67%	83%	0.82401	75%	106%
All	Valve	PG	28	0.31644	58%	90%	0.24356	60%	97%
All	Valve	LL	6	0.23098	72%	107%	0.16929	71%	110%
All	SCVF	PG	15	2.70351	97%	201%	3.74007	97%	189%

[a] Volumes are presented at standard reference conditions of 15ºC and 101.325 kPa.

[b] Because reciprocating compressor rod-packing leakage is routed to common vent lines, the actual number of leakers is not known. The compressor rod-packing 'leaker' factor is calculated on a per vent line basis (**not** per rod-packing basis). Rod-packings are defined as vents in Directive 060 (AER, 2018).

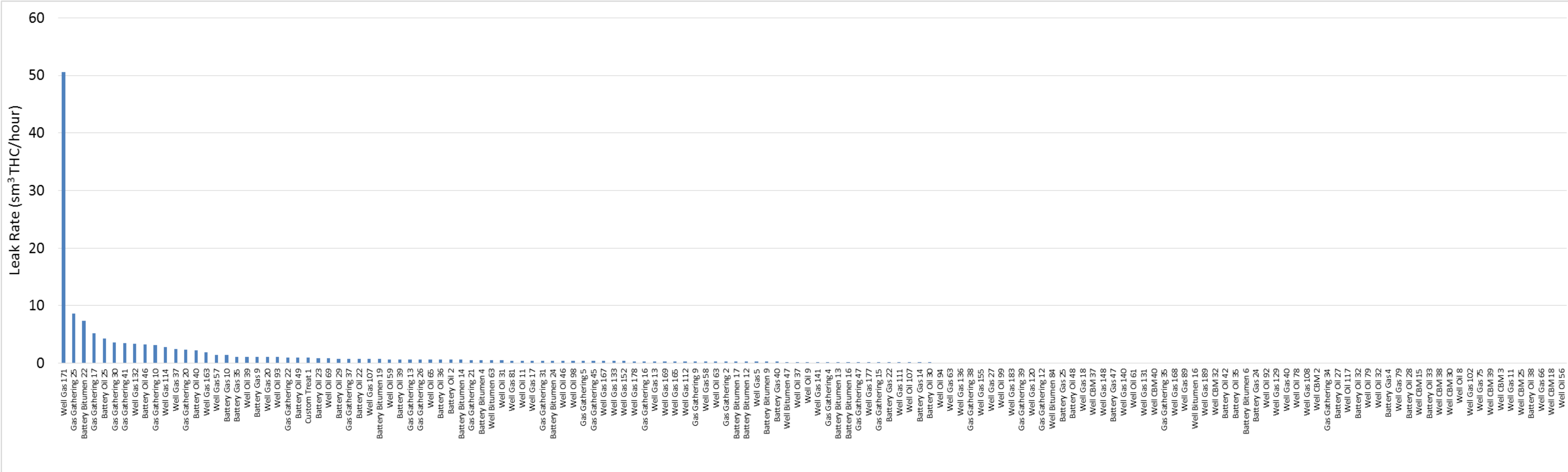

Figure ES-4: Distribution of total leak rate by site observed during the 2017 Alberta field campaign (excluding 195 sites where no leaks were detected).

SCVF Emission Factor

The SCVF component is included in Tables ES-3 and ES-4 to improve emission inventory transparency and highlight the significance of this source. The population average leak factor calculated from 15 leaks detected at the 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.

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 presented in Table 18. All four studies agree that components in heavy oil service have a very small contribution to total UOG fugitive emissions.

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 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 the 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 ES-5. 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.

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 obtained with an IR camera (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 or repair 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. 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.

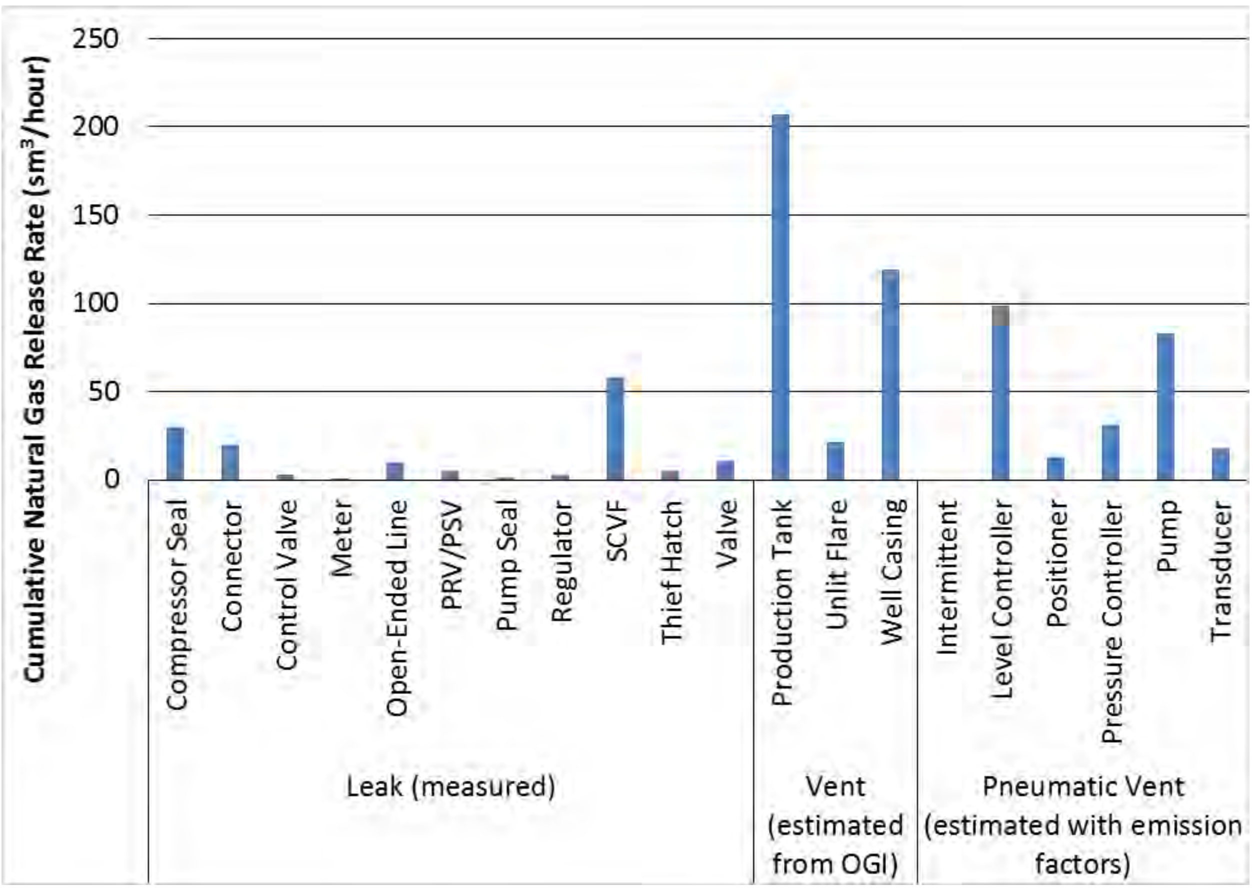

Figure ES-5: Cumulative hourly release rate for emission and source types observed at 333 locations during the 2017 Alberta field campaign.[9]

9 The venting estimates presented in Figure ES-5 have large, undetermined uncertainties and 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.