BC Fugitive Emission Management Program Effectiveness Assessment

Final Report

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1 Executive Summary

Oil and gas sector methane regulations were introduced in British Columbia in December, 2018 through amendments to the Drilling and Production Regulation (DPR) under the *Oil and Gas Activities Act*. The leak detection and repair (LDAR) provisions contained within section 41.1 of the DPR came into force on January 1, 2020. The DPR prescribes methane leak detection survey methods and frequencies that vary from one to three times per calendar year based on factors such as facility type, well production zone, operating status, and the presence or absence of controlled and uncontrolled production storage tanks. Additionally, leak repair timing requirements of not more than 30 days are set forth, with the exception of leaks at facilities that must shut down to complete the repairs, in which case the repairs may wait until the next facility turnaround to complete (DPR section 41.1(5)).

In May 2021, the BC Oil and Gas Commission (Commission) collected calendar year-2020 LDAR data from permit holders. The data was reviewed by the Commission at a high level for potential errors and omissions and permit holders were provided with the opportunity to make corrections and submit missing data. In January 2022 the final calendar year-2020 dataset was provided to St. Francis University (StFX) by the Commission to analyze on behalf of the Methane Emissions Research Collaborative (MERC) to meet the following objectives:

- assess the effectiveness of optical gas imagining (OGI) based comprehensive LDAR surveys and audial-visual-olfactory (AVO) and soap solution bubble test-based screening surveys at reducing fugitive methane emissions;
- evaluate the cost efficiency, of OGI-based comprehensive LDAR survey methods; and
- evaluate the cost efficiency of AVO and soap solution bubble test-based screening survey methods, collectively.

1.1 Key Findings

1.1.1 Data Quality Issues

Some of the primary data quality issues encountered during the StFX review include the following:

- a lack of data uniformity;
- missing and/or incomplete information;
- recorded leak measurements outside of the recommended device leak rate ranges of manufacturers;
- a high degree of inconsistency between permit holders;

- divergent leak rate profiles associated with estimated leak rate data compared to measured leak rate data; and
- divergent leak rate profiles associated with internal LDAR surveys (i.e., completed by permit holder staff) compared to external LDAR surveys (i.e., completed by third-party service providers).

A considerable amount of data was categorized as *Other* (5-15%) in multiple categories including component type, repair applied, repair delay, and process block. Furthermore, it was not possible to describe and quantify non-leaking observations because information on non-leaking observations was not collected by the Commission and could not therefore be provided to the research team (e.g., no description of the component or process block was provided when no leak was detected). Consequently, a significant amount of needed information was unavailable for analysis. *It is important for the future, that permit holders include all the information requested by the Commission so that the full dataset can be used in subsequent analysis. Moreover, in addition to the data the Commission is already collecting and publishing, we recommend the Commission begin also collecting and publishing non-leaking observations to generate population-based emissions factors for use in future methane modeling.*

As a result of the significant difference in leak rate profiles between internal LDAR surveys and those completed by third-party service professionals, *we recommend the verification of internal surveys by independent accredited third-parties, that they undergo regular audits by the Commission, and that measurement technicians have an instrumentation-based red seal or similar designation to improve the quality of leak rate measurements.* One permit holder who completed internal surveys and used quantitative OGI (QOGI) noted that it was unable to complete QOGI quantification training due to the COVID-19 pandemic and resultant restrictions imposed by government. Their lack of training could have materially affected the representativeness of the measurements they recorded. Furthermore, the data collected is not only based on the first year of implementation of the methane regulations, which by itself would be expected to present challenges for all involved, it was also collected during a pandemic year creating additional challenges for the field-based activities of both permit holders and third-party service providers.

1.1.8 Data Collection and Submission

The availability of reliable and accurate data is essential to inform policy and regulation. Our analysis would not have been possible without the data the Commission collected and made available. Still, however, the data collected for the 2020 calendar year was not sufficient to meet the complete needs of our analysis and gaps remain. *In addition to the data already collected by the Commission, we recommend collecting data for non-leaking observations and that each permit holder tag and report on a statistically valid number of components (leaking and non-leaking) to monitor them across surveys for leaks and leak reoccurrence (surveys 1 to 3).*

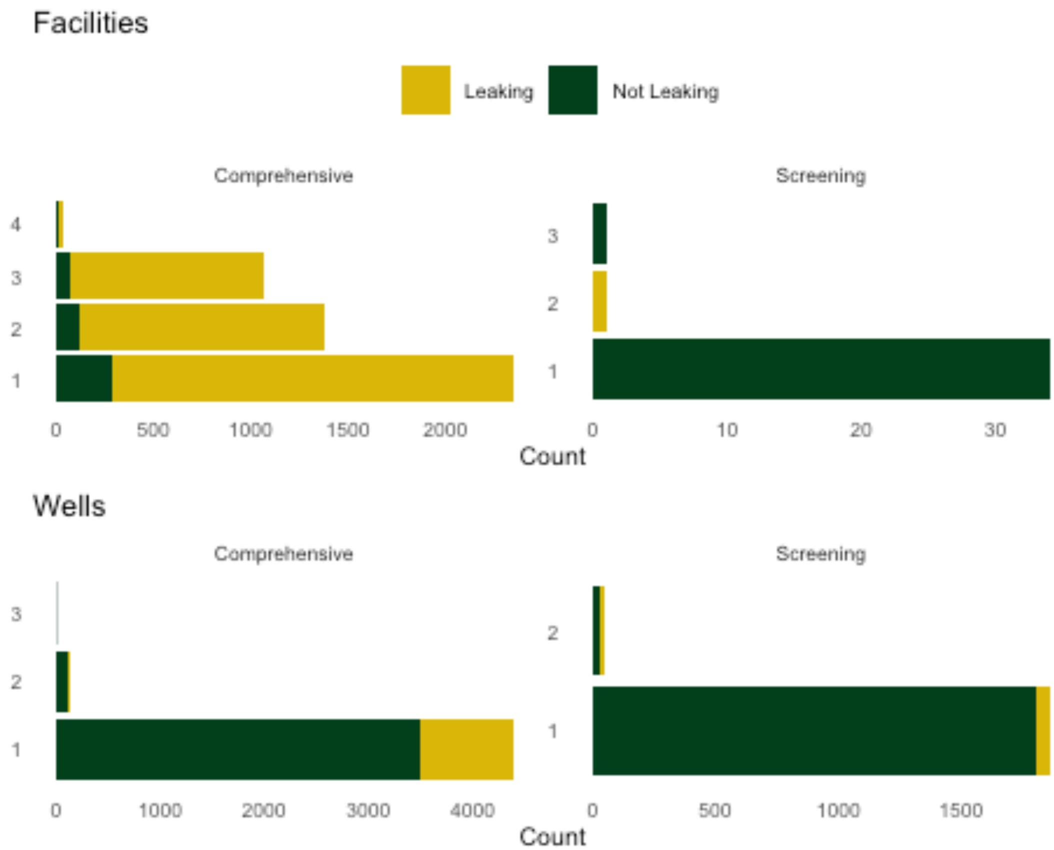
We also recommend the inclusion of the complete list of data currently in guidance in regulation so that all data submission is required and not optional (DPR section 41.1(7)). Moreover, we recommend including a submission deadline in regulation (e.g. March 31st each year) (DPR section 41.1(7)). Furthermore, the Commission should update and maintain its records with respect to facility status (e.g., active vs suspended) for all facilities and begin requiring all facilities and wells to submit a report each year indicating how many days in the reporting year it operated, even if it did not operate.

1.1.2 Non-Compliance

A significant number of facilities did not comply with the minimum number and type of LDAR surveys required in the 2020 calendar year. Assuming all active facilities were operating (n=1,276), it is estimated that only 28% of facilities met the minimum regulatory requirements for number and type of LDAR surveys completed. However, among the operating facilities (n=588) listed in the published LDAR dataset which includes all facilities for which at least one LDAR survey report was submitted to the Commission, 62% met the minimum regulatory requirements for number and type of LDAR surveys completed. Similarly, not all wells that produced for more than 90 days in 2020 were surveyed. We estimate a 62% compliance rate for well LDAR surveys in 2020. Furthermore, many repairs took longer than 30 days to complete and were not noted as needing to wait until turnaround. The estimated compliance rate with respect to completing leak repairs within the timeframe required by regulation, and accounting for turnaround considerations, was 60% for both facilities and wells. Compliance rates were the single largest determinant of regulatory effectiveness. *We strongly recommend that the regulator take immediate steps to significantly improve compliance rates.*

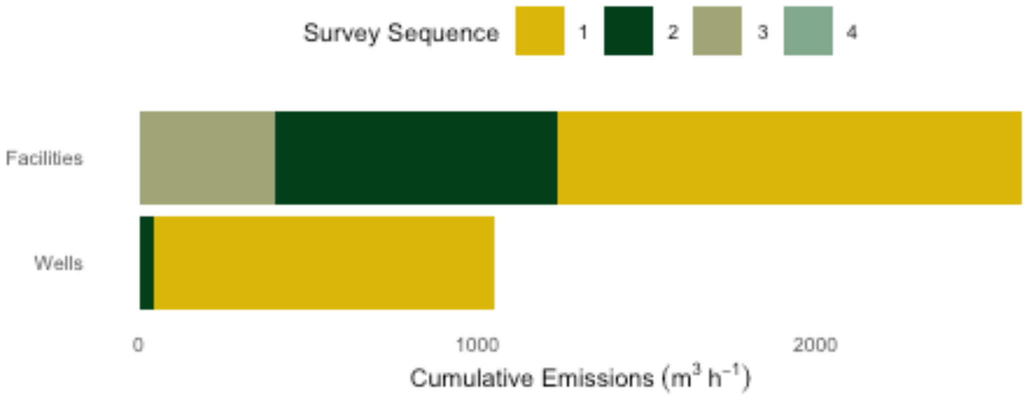
1.1.3 Comprehensive vs. Screening Surveys

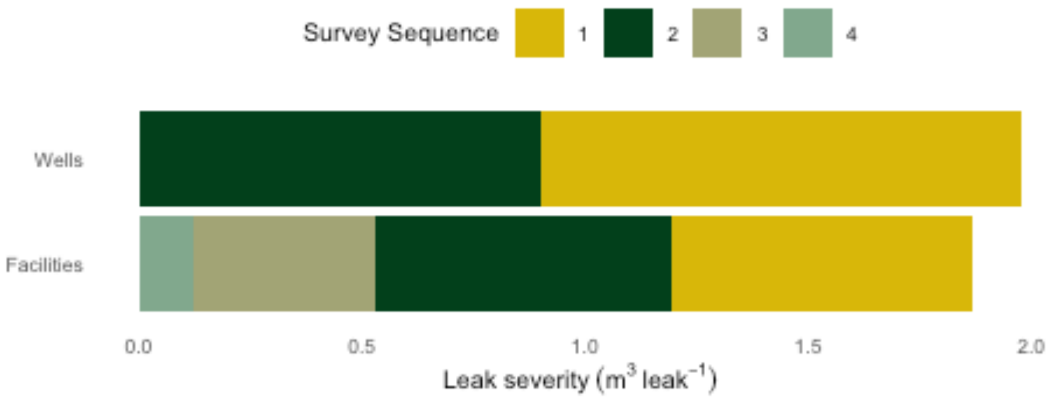
Using only data from surveys at wells for a valid comparison, the data showed that comprehensive surveys are roughly **7x more effective** at detecting leaks compared to screening surveys. From a cost perspective, screening surveys were also inefficient in terms of cost per leak identified. *We recommend eliminating screening surveys in regulation and replacing them with comprehensive surveys because the data shows that screening surveys are ineffective and inefficient compared to comprehensive surveys.*



1.1.4 Regulatory Effectiveness Across the Surveys Sequence

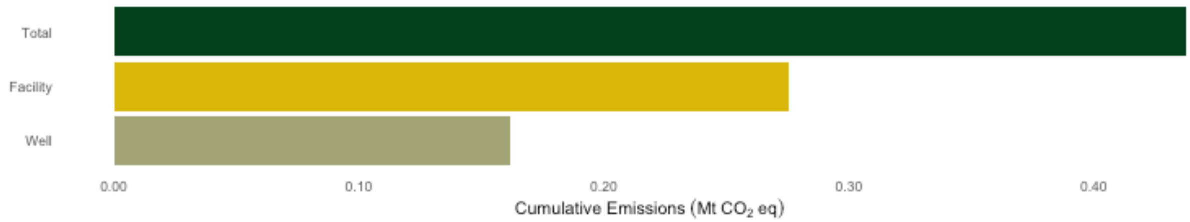
For facilities cumulatively, compared to the first survey in the year, 40% and 70% lower methane emissions were detected for the second and third surveys in the year, respectively (see first plot, below, showing methane in $m^3 h^{-1}$). However, many permit holders completed fewer than the full number of surveys required, and the lower level of compliance drives the apparent appearance of reduction where none exists. In reality, leak severity and incidence changed very little across surveys throughout the year. If we look at per-leak severity (second figure), there is only a very small reduction. We also did not see a significant change in leak detection incidence per surveyed facility or well (see Figure 4.10 of the full report). However, if we compensate for non-compliance, and concentrate on facilities visited three times (n = 210), the results showed, despite a leak detection rate relatively constant, a decrease in cumulative leak rates. So, when done properly, LDAR comprehensive surveys are effective at reducing methane emissions. Twenty-five of the sites surveyed contributed to 90% of total emissions, mainly driven by a few permit holders.





1.1.5 The effect of repair timelines

The estimated methane emissions that would have occurred had no repairs been completed were 0.43 Mt CO_2 eq (GWP = 25, CH_4 density at 15°C, 1 ATM = 0.678 kg/m^3) as shown in the figure below. Some repairs did however, occur, and that decreased estimated leaked methane to 0.26 MT CO_2e eq. Had all repairs been completed within 30 days it is expected that an additional 0.06 MTCO_2e of leaked methane would have been avoided. It is important to note that this analysis includes only detected leaks. It does not account for leaks that were not detected or repaired because required surveys were not completed. The fraction of leaks repaired in a timeframe that met the regulatory expectation (30 days) was 60% (582/970) and 43% (1862/4320) for wells and facilities, respectively. It's important to remember that there is an exception for repairs that require facility shutdowns (DPR section 41.1(5)(b)). Around 24% (126/528) of facilities were noted as waiting until the next shutdown to repair their leaks. We recommend matching the federal requirement that, "the next planned shutdown must be scheduled not later than the date on which the estimated volume of hydrocarbon gas, expressed in standard m^3, that, beginning from the day on which the leak is detected, would if no repairs are made be emitted from the leaking equipment component in question and from all other equipment components that are also leaking as of that day is equal to the volume of hydrocarbon gas, expressed in standard m^3, that would be emitted due to purging of hydrocarbon gas from equipment components in order to carry out the repair" (ECCC, 2018, section 32).



1.1.6 Cost

Detection costs ranged from $50 to $16,000 per leak. Costs per leak were always lower than $1,000 for permit holders who found more than 50 leaks (larger permit holders), with a mean of roughly $300/leak detected. If the average leak size is roughly 0.5 m^3 h^{-1}, the cost of *detecting* a leak that could otherwise pre-regulation persist for more than a year is therefore about half as much as the market value for the same gas ($0.17 in AB Feb 2022 per m^3 x 0.5 m^3 h^{-1} * 8760 h yr^{-1}). The cost of *repair* will vary widely, but we could not access repair cost information. While comprehensive surveys were more expensive than screening surveys, they could be surprisingly cost-efficient at detecting leaks, especially when multiple leaks were detected at a site. Screening surveys were relatively low cost individually, but since few leaks were detected screening survey cost is relatively high per cubic meter of methane detected. The best way to ensure cost efficiency is to ensure that surveys (in whatever form) detect as many leaks as possible by applying tools that are more effective than AVO and soap solution bubble tests, repair timeframes are expedited and by carefully planning LDAR survey logistics. Lastly, it's worth noting that permit holders experience costs differently based on their size, location, asset portfolio, and leaking components found. We did not have sufficient information to examine all of the factors, necessary for a more complete understanding of regulatory compliance costs.

1.1.7 Overall Takeaways

Overall, although comprehensive surveys were effective at detecting leaks and overall leak count decreased through the year, gains made by compliant permit holders were significantly eroded by those who were non-compliant. Thus, compliance was the biggest factor in determining overall regulatory effectiveness. This is followed by the ineffectiveness of screening surveys resulting in false negatives. Screening surveys should be eliminated from the regulation in favor of comprehensive surveys. Data issues were prevalent, which eroded comparability and greatly increased the challenges involved in analyzing these datasets, and which could pose issues for the regulator in future years when attempting to document change over time.

2 Introduction

Oil and gas sector methane regulations were introduced in British Columbia in December, 2018 through amendments to the Drilling and Production Regulation (DPR) under the *Oil and Gas Activities Act*. The leak detection and repair (LDAR) provisions contained within section 41.1 of the DPR came into force on January 1, 2020. The DPR prescribes methane leak detection survey methods and frequencies that vary from one to three times per calendar year based on factors such as facility type, well production zone, operating status, and the presence or absence of controlled and uncontrolled production storage tanks. Additionally, leak repair timing requirements of not more than 30 days are set forth, with the exception of leaks at facilities that must shut down to complete the repairs, in which case the repairs may wait until the next facility turnaround to complete (DPR section 41.1(5)).

All comprehensive surveys completed in the 2020 calendar year, the first year of implementation of the regulations, used handheld optical gas imaging (OGI) and no comprehensive surveys were completed using United States Environmental Protection Agency (US EPA) Method 21. Almost all screening surveys completed in 2020 used audial-visual-olfactory (AVO) methods; however, some soap solution bubble test screening surveys were also completed.

In May 2021, the BC Oil and Gas Commission (Commission) collected calendar year-2020 LDAR data from permit holders. The data was reviewed by the Commission at a high level for potential errors and omissions and permit holders were provided with the opportunity to make corrections and submit missing data. In January 2022 the final calendar year-2020 dataset was provided to St. Francis Xavier University (StFX) by the Commission to analyze on behalf of the Methane Emissions Research Collaborative (MERC) to meet the following objectives:

- assess the effectiveness of OGI-based comprehensive LDAR surveys and AVO and soap solution bubble test-based screening surveys at reducing fugitive methane emissions;
- evaluate the cost efficiency, of optical gas imaging-based comprehensive LDAR survey methods; and
- evaluate the cost efficiency of AVO and soap solution bubble test-based screening survey methods, collectively.

3 Materials and Methods

3.1 Measurements

The DPR allows for the use of two different comprehensive survey methods: US EPA Method 21(DPR section 41.1(1)(a)) and handheld OGI (DPR section 41.1(1)(b)). Likewise, the DPR allows for two different screening survey methods: soap solution bubble test (DPR section 41.1(1)(a)) and the senses of hearing, sight and smell, also known as AVO (DPR section 41.1(1)(b)). When detected the DPR requires leaks to be measured (DPR section 41.1(7)); however, exceptions to protect worker safety and accommodate for technological and access limitations are specified in guidance and therefore, in practice, not all leaks are measured (BC Oil and Gas Commission, 2019). When leaks were measured in 2020, they were measured using either quantitative optical gas imaging (QOGI) or with a Hi-Flow Sampler. When they were not measured leak rates were estimate using emission factors or engineering estimates (BC Oil and Gas Commission, 2022a, 2022b).

3.2 LDAR Data

The data collected in 2020 included roughly 70% and 45% of the total operating wells and facilities in the British Columbia, respectively, assuming that all active facilities were operating (Table 1; BC Oil and Gas Commission. 2022a, 2022b). Fifty-six permit holders in total submitted data and much of the data submitted was not required by the DPR but was only requested in guidance. Indeed, the regulation has no requirements within it for any data submission and only requires the maintenance of a few records (DPR section 41.1(7)). Additionally, some permit holders completed LDAR surveys over and above the minimum required by the DPR. For example, a fourth comprehensive survey was performed at some facilities and second and third comprehensive surveys were done at a few wells. High level data quality control (e.g., duplication, etc.) was performed by the Commission. All permit holder names are anonymized in this report and all the results and conclusions in this report are based on the data that were submitted. Non-methane leaks might be present in these datasets. Thus, for all calculations, leaks were assumed to be 100% methane, given no other information was provided. A Global Warning Potential (GWP) multiplication factor of 25 was used for CO_2 equivalent calculations.

Table 1: Summary statistics for leaks ($m^3\ h^{-1}$) for facilities and wells.

Infrastructure type	Unique ID Surveyed	Total Active	Percent Surveyed (%)	Number of leaks	Sum of leaks	Mean	Median	Max
Well	5869	8379	70.0[a]	979	1052	1.07	0.20	8.4
Facility	588	1276	45.0	4311	2697	0.61	0.16	72.0

[a] Includes wells surveyed with less than 90 operating days in 2020

Some of the results are expressed using boxplots. A boxplot shows the distribution of numerical data and skewness by displaying the data quartiles (or percentiles) and averages. The boxplots show the lower whisker (Q1 - 1.5 x IQR), first quartile (i.e, lower hinge, 25th percentile, or Q1), median (50th percentile), third quartile (i.e., upper hinge, 75th percentile, or Q3), and upper whisker (Q3 + 1.5 x IQR). IQR is the inter-quartile range, or distance between the first and third quartiles. Data beyond the end of the whiskers are called "outlying" points and are plotted individually. If two boxes do not overlap with one another, then there is a difference between the two groups. If the median line of a box lies outside another box entirely, then there is likely to be a difference between the two groups.

3.3 Cost Analysis

Part of the scope of this study is to investigate the costs of regulatory-prescribed LDAR. Cost information was obtained from service providers and included a range of survey costs for different facility and well types, incremental reporting costs, and incremental costs for leaks found and measured (for QOGI versus Hi-Flow Sampler).

Cost information was obtained from service providers with low, average, and high estimates of the cost to conduct and report comprehensive surveys for different facility and well types. For the first part of the analysis, this information was combined with the number of each type of facility/well surveyed to approximate the total costs incurred by permit holders. Next, the facilities and wells were sorted by permit holder. Using the number of leaks reported by each permit holder and the incremental cost to measure a leak, the approximate costs per permit holder were estimated.

Notes:

- Liquefied natural gas (LNG) facilities are excluded from this analysis because they are not subject to the DPR.
- Compressor dehydrators are assumed to have the same survey and reporting costs as compressor stations due to lack of information on compressor dehydrator costs.
- All cost information is from 2020, unless otherwise indicated.
- Tables are left empty where data was unavailable.

4 Results

4.1 Data Quality and Issues

4.1.1 Operating Infrastructures

Not all active facility and well infrastructure was surveyed in 2020. Determining the percentage of operating facilities surveyed was difficult to assess. Only operating infrastructure is subject to LDAR surveys and the facility status information maintained by the Commission does not indicate the operational status of facilities but rather only whether they are active or not, which is not the same thing as operating. That means that the only way to determine if a facility was indeed operating if it is listed as active is to be told its status by the permit holder. Petrinex reporting (not available to the public) under-estimates the number of operating facilities because it is a system focused on volumetric reporting at an aggregated level. Thus, we determined operating facilities and wells in 2020 using datasets provided by the Commission.

4.1.2 Non-Leaking Components

Another challenge was the lack of information for non-leaking components. Leaks were categorized and identified (but leaking components were not identified) but no information was provided about the components that were not leaking. In other words, it was easy to know what was leaking, but we couldn't know what was not leaking. Thus, it was impossible for instance to determine the leaking / not leaking ratio for any of the classifications (e.g. component, process block, etc.) listed in the dataset, or calculate emissions factors. Furthermore, we could not determine if a specific component not leaking in the first or second surveys was leaking in subsequent surveys. It was not possible to identify if new leaks were coming from the same or different components. Future analyses could use the component counts listed per facility type in the Cap-Op Energy (Cap-Op Energy, 2018) and Clearstone (Clearstone Engineering Ltd. and Carleton University, 2018) studies to determine the approximate percentage of leaking components per facility subtype or to compute emissions factors.

4.1.3 Internal vs External Surveys

The last major issue we encountered is the presence of a significant difference in leak rates between internal and external LDAR surveys, particularly for well infrastructure (Figure 4.1). This remained constant throughout the three comprehensive surveys for facilities (Figure 4.2). Screening and comprehensive surveys were completed internally by operators or externally by third-party service providers. Hi-Flow Samplers were used to quantify emissions only by third-party service providers. Some third-party service providers did use QOGI, emission factors, and engineering estimates as well.

Our results show a significant difference in leak rates for QOGI measurements between internal and external surveys. Figure 4.3 shows for wells and facilities 9x and 1.5x higher leak rates when surveys were performed internally rather than by third-party service providers (no difference between third-party surveyors, see Appendix Figure 1). Also, when looking at the leak rate distribution, we see a strong difference between internal and external LDAR surveys for wells (Figure 4.1). Is it also noteworthy that - for facilities - the leak rates for internal programs seem to hit a cap at 8.4 m^3 $h^{-1}$and above which there are no outliers like there are for third-party surveys. This difference between internal and external surveys could lead to misinterpretation of the data. For example, Figure 4.4 shows leak rates per well component type. The right panel includes observations from internal and third-party surveys, and the results suggest significant differences in leak rates between some of the components. But when the observations from the internal surveys were excluded (left panel) from the analysis, the results show no difference between the mean leak rates because all the error bars overlap so we can't actually discern statistically any source that it is larger than other sources due to the variabilities overlap.

Likewise, the comparison of leak rate distributions between permit holders is also problematic because some exclusively use internal surveys, others only use external surveys, and then some use a combination of both. For facilities, 39 permit holders relied on third-party service providers, while only 5 permit holders completed surveys internally. Eight used both. Similarly, for wells, the majority (26) used external providers, while 9 used their own staff, and only 8 used both internal and external labor.

Due to the contrasting results between internal and external surveys we recommend the verification of internal surveys by independent accredited third-parties, that they undergo regular audits by the Commission, and that measurement technicians have an instrumentation-based red seal or similar designation to improve the quality of leak rate measurements. We assume that third-party service provider measurements are more accurate that those by permit holder staff because of their specialist experience.

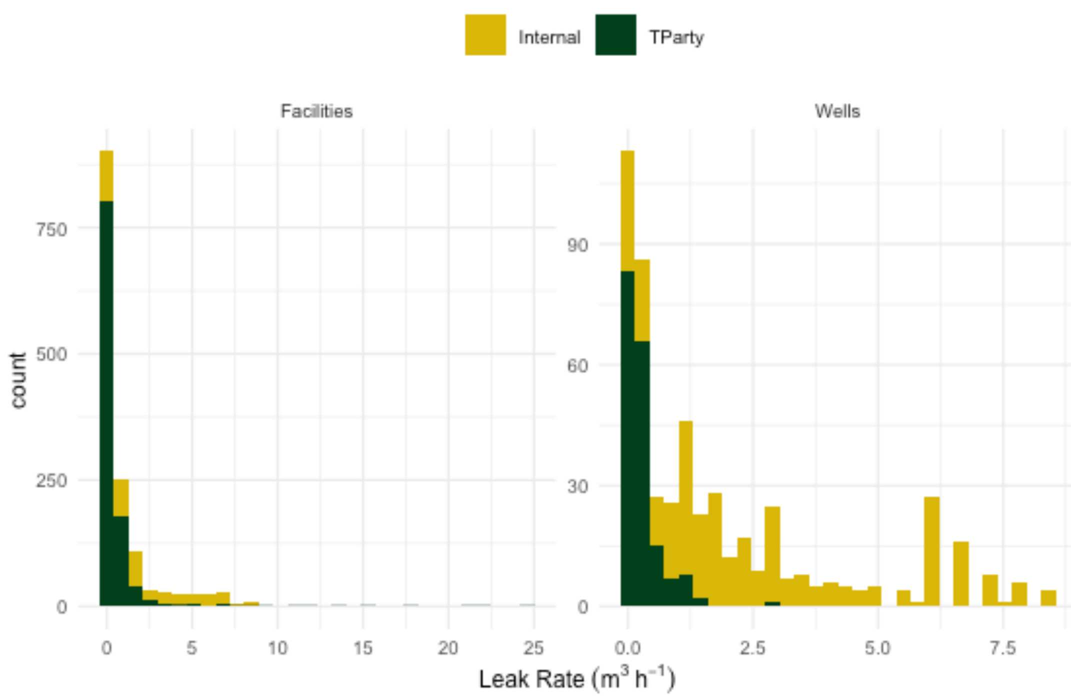


Figure 4.1: Leak rate distribution for internal and third-party service providers (QOGI measurements only) for facility and well infrastructure.

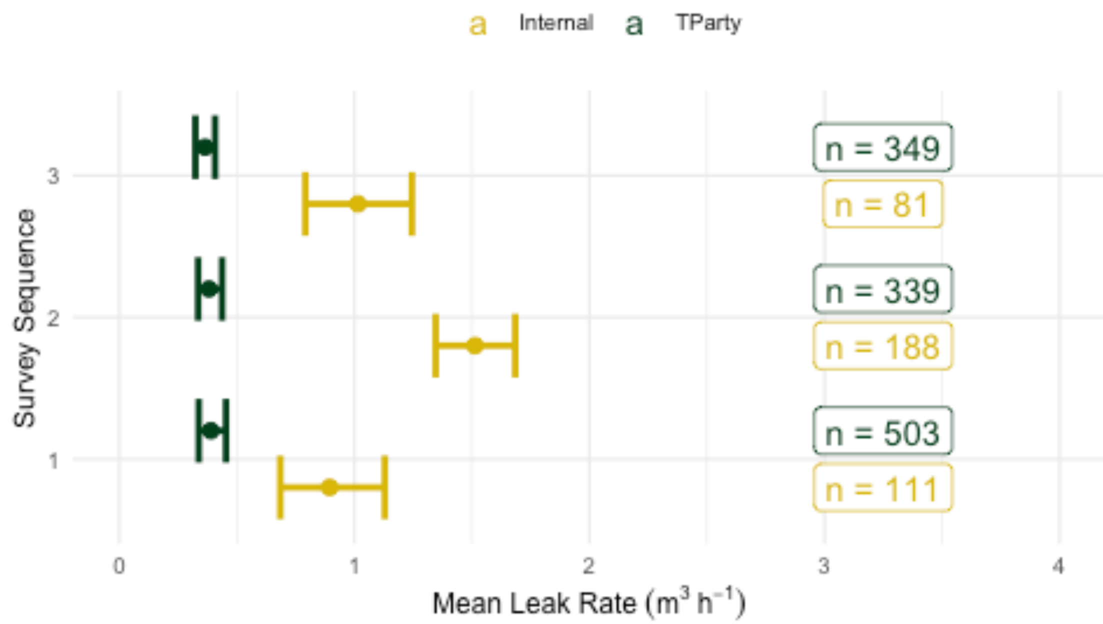


Figure 4.2: Leak rate distribution for internal and third-party service providers (QOGI measurements only) for facilities during the three comprehensive surveys.

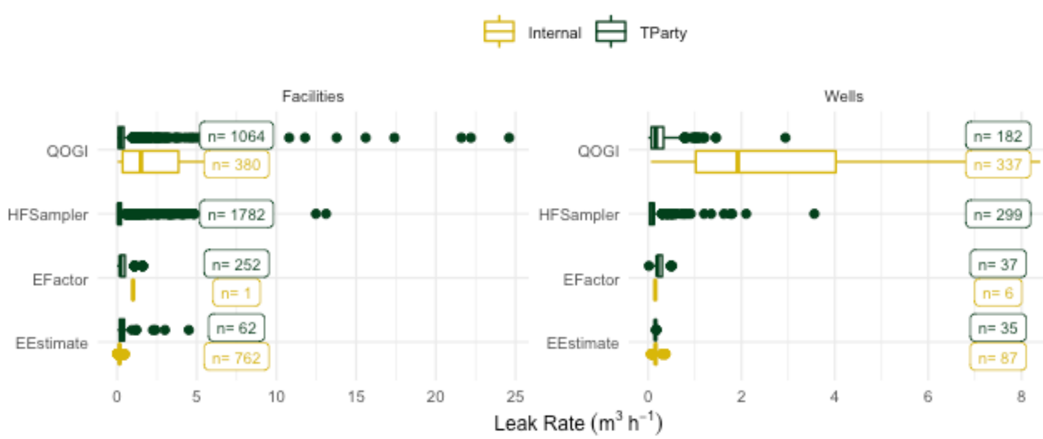


Figure 4.3: Leak rate and number of observations (left panel) for each leak quantification method, per survey type (internal vs third-party service provider) for facility and well infrastructure.

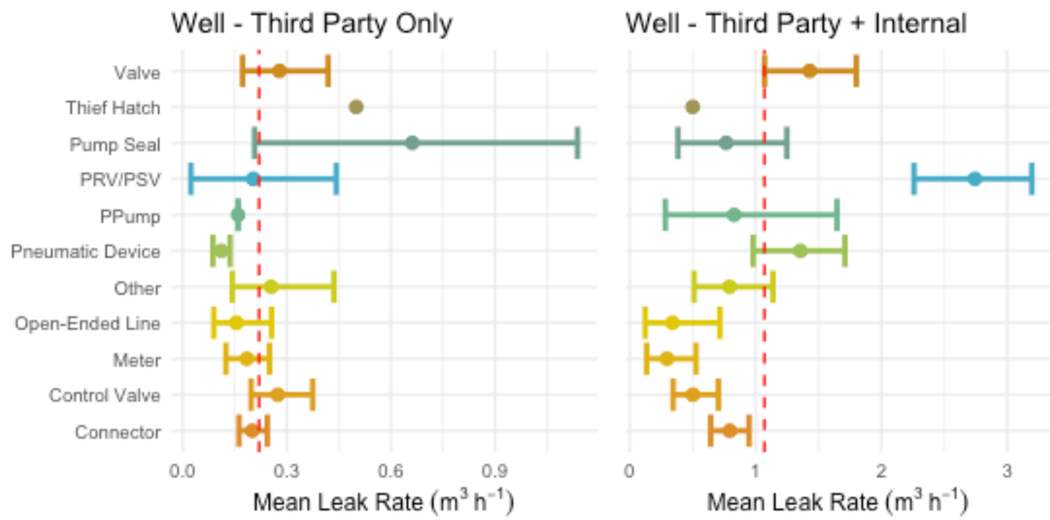


Figure 4.4: Mean leak rate and number of observations with 95% confidence interval per well component type. The red line shows the overall mean leak rate.

4.1.4 Measured vs Estimated Leak Rates

Leak rate quantification was done mostly with QOGI technology or Hi-Flow Samplers, but in some cases, leak rates were estimated instead of measured (EEstimate or EEfactor; Appendix Table 1). More than 75% of the leaks were quantified by measurement, and both measurement and non-measurement-based estimation methods were used to quantify emissions for most leaking components (Figure 4.5). Not only were the distributions different, but the mean leak rate was consistently and significantly higher for QOGI than for estimated data (see example for facilities: Figure 4.6). Thus, for emission quantification estimated data should be removed from the analysis for more accurate emission estimates. Excluding almost 25% of the data leads to under-estimation of cumulative emissions.

It is also problematic to compare emission estimates or emission reductions between permit holders. For example, Figure 4.7 shows the top four permit holders in terms of total number of leaks reported. All four permit holders exhibit different leak rate distributions. Permit holder A only recorded estimated measurements (EEstimate), permit holder B only reported measured leak rates (QOGI), permit holder C reported both measured (QOGI) and estimated (EFactor) leak rates, while the last permit holder reported four leak quantification types (EFactor, HFSampler, Other, QOGI). How then can we compare these four permit holders, especially when one has only estimated leak rates and another has leak rates that might have been incorrectly measured? For the facility surveys, 21 permit holders used both estimated and measured data, 21 used only measured data, and 4 permit holders limited their emissions quantification to estimated data. While for well surveys, only 4 permit holders used both estimated and measured data, 19 used only measured data, and 6 permit holders used estimated data for their emissions quantification methods.

For a more in-depth analysis, we would use the measured data to create emission factors and extrapolate emissions from non-quantified leaks and recreate the inventory using component counts from studies such Cap-Energy (Cap-Op Energy, 2018) and Clearstone (Clearstone Engineering Ltd. and Carleton University, 2018).

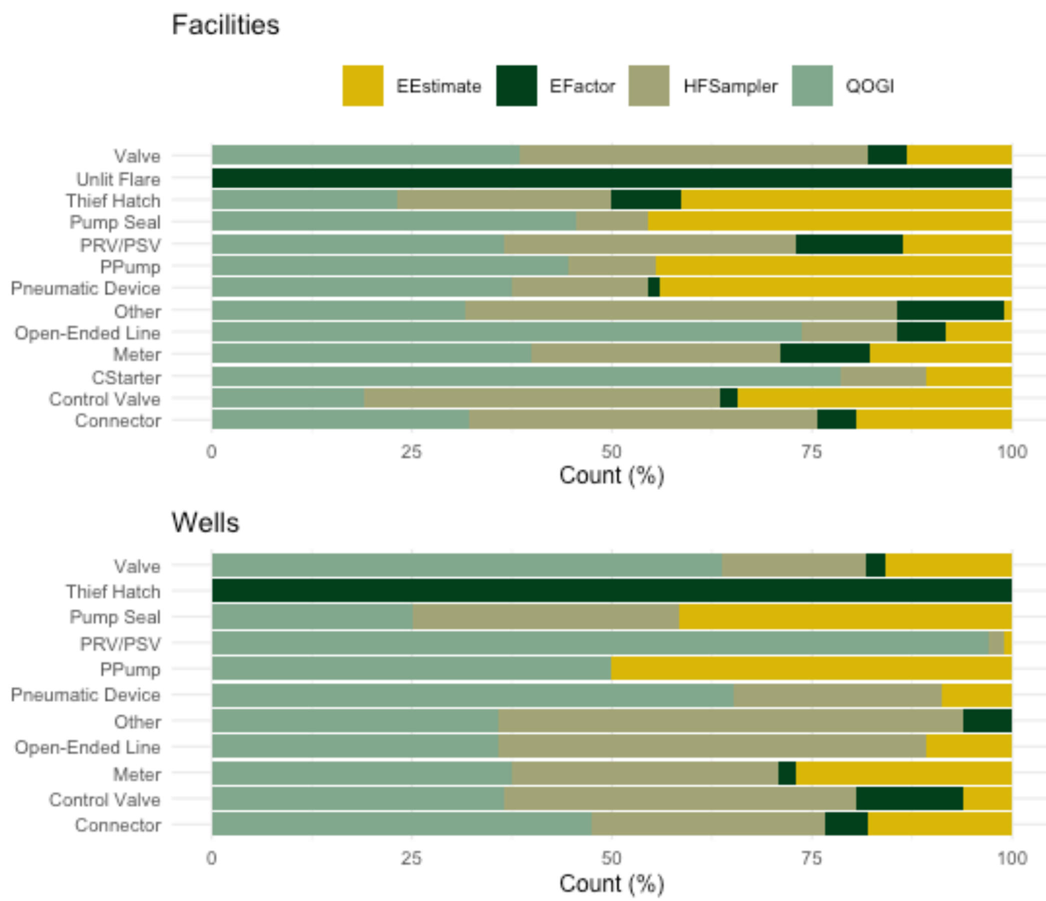


Figure 4.5: Leak quantification method distributions by leaking component.

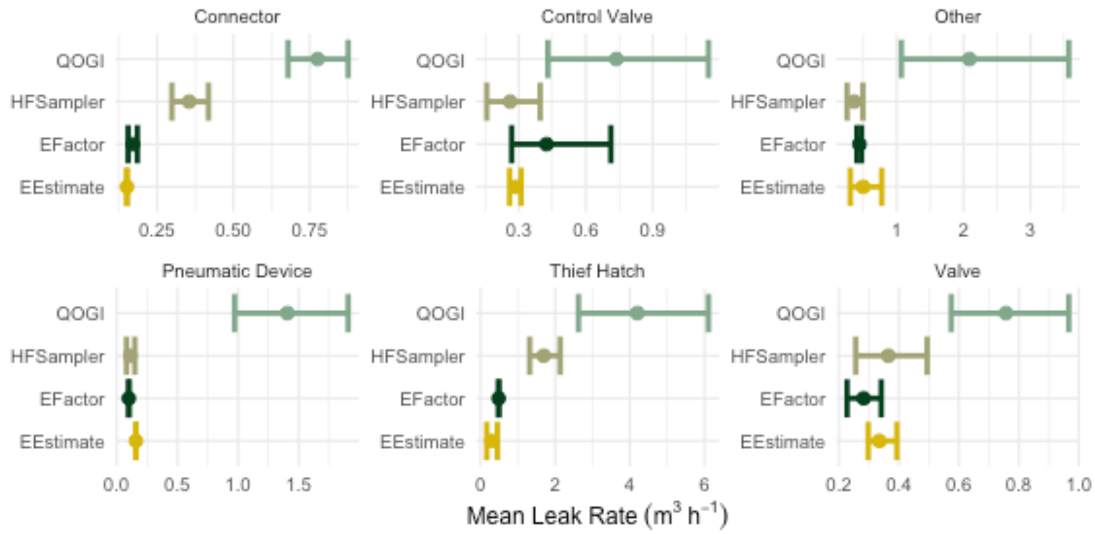


Figure 4.6: Mean leak rate for each emission quantification method for the top six facility leaking components.

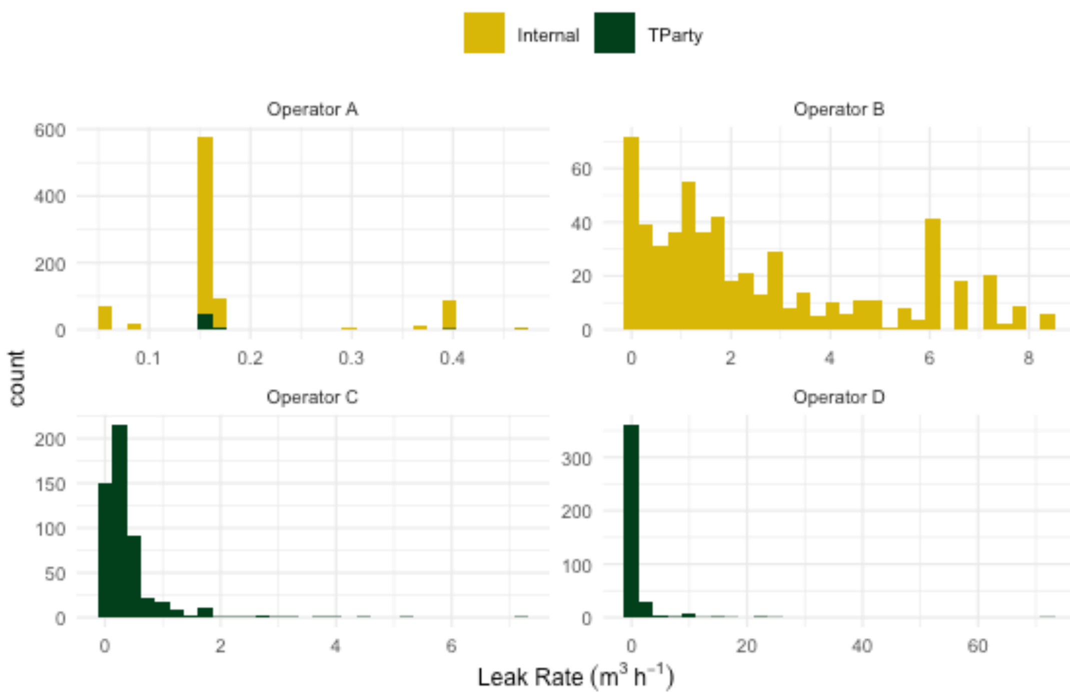


Figure 4.7: Leak rate distribution for the top four permit holders in terms of number of leaks reported. Well and facility infrastructure observations are both included.

4.1.5 Emission Quantification Outside the Limits

Based on the *Fugitive Emissions Management Guideline* published by the Commission (VERSION 1.0: July 2019), it is expected that leaks between 0.018 $m^3 h^{-1}$ and 18 $m^3 h^{-1}$ can be measured using QOGI (FAQ: Providence Photonics QL320 and QOGI). For the Hi-Flow Sampler, the recommended limits are between 0.085 $m^3 h^{-1}$ and 13.6 $m^3 h^{-1}$ (Section 8.5.2.3 Update of Equipment, Component and Fugitive Emission Factors for Alberta Upstream Oil and Gas, Alberta Energy Regulator, June 10, 2018). We expect that leaks will occur that exceed or fall underneath these recommended limits, and we understand that leaks that are higher or lower than these recommended limits should be quantified in some other way.

4.1.5.1 QOGI

One thousand nine hundred and sixty-three leaks were quantified with QOGI (~37 percent of the total leaks detected). Four measurements (0.2%) above the manufacturer recommended upper limit were submitted by permit holders. Sixty-three measurements (3%) below the lower limit were also reported.

4.1.5.2 Hi-Flow Sampler

Two thousand and eighty-four leaks were quantified with a Hi-Flow Sampler (~39% of the total). No measurements above the manufacturer recommended upper limit were reported by permit holders and 767 (36%) below the lower limit were reported.

4.1.6 Missing Information

A considerable number of leaking observations were categorized as *Other* (5-50%) in multiple categories (e.g., component type, repair applied, repair delay, process block, etc.). For example, 15% of the facility leaks (count) were categorized as *Other* under process block. These 15% of leaks with no process block description contributed to 20% of the total facility emissions. For the wells, it was more than *50%* of the emissions that were labelled as *Other* under process block. It was better for components, but still 8% and 13% of the leaks reported for facility and well infrastructure were categorized as *Other* under the leaking component category, respectively. Thus, a lot of the emissions are unattributed.

4.1.7 Differentiating *good data* from *bad* data?

The results show high inconsistencies between operators. The data are a mix of leak quantification methods, and also a combination of data collected internally or by third-service providers.

Visual inspection of the distribution curve is a good indicator of data quality (Figure 4.8). We know from the literature that heavy-tailed emission distributions are commonly observed across oil and gas facilities (see Brandt et al., 2016; Cap-Op Energy, 2018; Clearstone Engineering Ltd. and Carleton University, 2018; Pacsi et al., 2019; Ravikumar et al., 2020; Wang et al., 2021).

Skewness is a measure of symmetry, or more precisely, the lack of symmetry. A distribution, or dataset, is symmetric if it looks the same to the left and right of the center point. Kurtosis is a measure of whether the data are heavy-tailed or light-tailed relative to a normal distribution. That is, datasets with high kurtosis tend to have heavy tails, or outliers. Data sets with low kurtosis tend to have light tails, or lack of outliers. Table 2 shows respectively for facility and well infrastructure the skewness and kurtosis of each leak quantification method. The results show significant differences between the distributions. QOGI and Hi-Flow Sampler measurements from third-party service providers show a severe lack of symmetry and heavy-tailed distributions compared to EFactor, or EEstimate distributions which are average values and not reflective of any individual leak. When comparing internal and external surveys we also see that the skewness and kurtosis numbers of QOGI measurements are very different. Some internal surveys lacked heavy tail statistics, which makes them suspect.

Table 2: Skewness and kurtosis for each leak quantification method and survey type for well and facility infrastructure. EE = engineer estimate; EF = emission factor; HFS = Hi-Flow Sampler.

		Internal			External			
Infrastructure Type	Characteristic	EE	EF	QOGI	EE	EF	HFS	QOGI
Well	Skewness	1.56	NA	0.83	1.87	1.21	10.35	3.36
	Kurtosis	5.90	NA	2.54	5.15	4.04	134.96	20.58
Facility	Skewness	1.61	NA	1.01	3.56	2.07	5.69	17.77
	Kurtosis	4.82	NA	2.85	16.61	7.71	43.87	414.52

Distribution curves with a kurtosis close to 3 and skewness around 1 have a distribution like a normal distribution. In contrast, distribution curves with high kurtosis (> 3) and high skewness (> 1) show characteristics of a distribution often observed across oil and gas infrastructure. In our results, Hi-Flow Sampler distribution curves are good examples of heavy-tailed distributions (very high kurtosis and skewness), while EEstimate, EFactor, QOGI (Internal) kurtosis and skewness values do not conform to our general expectations for oil and gas sites. Although we could defensibly select data for analysis using skewness and kurtosis limits, we did not apply these measures in our study; however, we were able to develop statistics in this study that could be applied in future studies to filter and flag measurements.

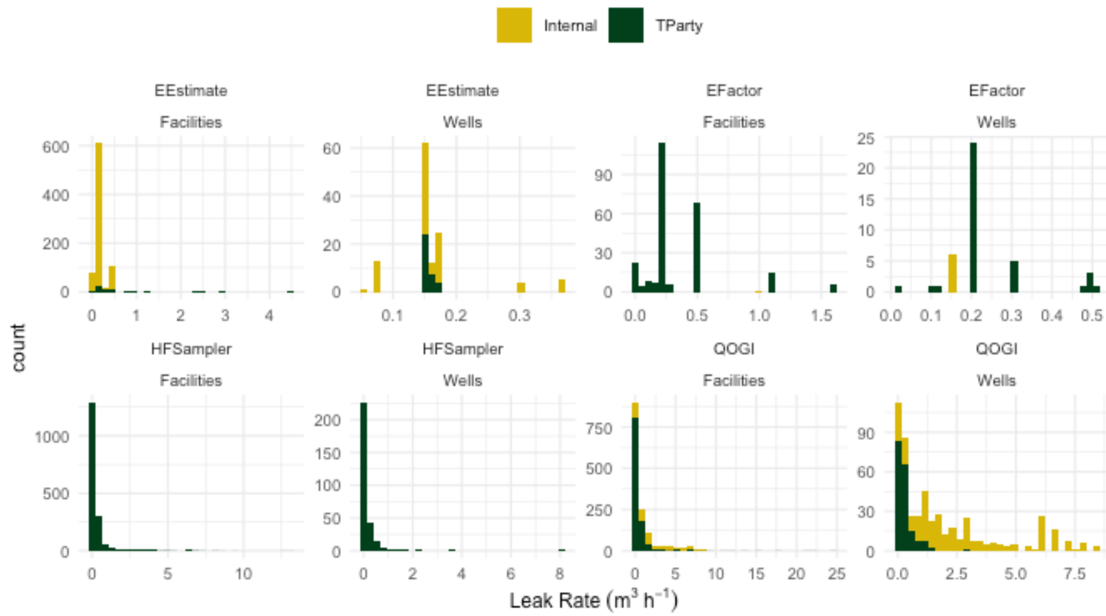


Figure 4.8: Distribution curve for each leak quantification method for facility and well infrastructure.

4.2 Emission Reduction Effectiveness

Screening surveys were very ineffective at finding leaks compared to comprehensive surveys (Figure 4.10). Screening surveys had a detection rate of less than 5% for wells and facilities. Although, fewer than 100 screening measurements were done for facilities compared to 5,000 measurements for comprehensive surveys, which makes this a poor comparison. On the other hand, the order of magnitude was similar for well screening and comprehensive surveys. And the results showed that comprehensive surveys are roughly *7x more effective* at detecting leaks. Leaks were detected at 20% of comprehensive surveys at wells. However, leaks were only detected at 3% of screening surveys at wells. The results suggest that had comprehensive surveys been completed in place of screening surveys at these wells more leaks would have been detected.

4.2.1 Comprehensive Surveys

One comprehensive survey per year is required if a well has a production storage tank, or if it is producing from an unconventional zone listed in Schedule 2 of the DPR, otherwise, one screening survey is required (DPR section 41.1(3)). Approximately 20% of the first comprehensive surveys completed in the year at wells detected at least one leak. When looking at the second comprehensive survey in the year at wells this number decreases to 14%

For facilities, at least one leak was detected at 60% of the comprehensive surveys completed. This varies from 48% for first comprehensive survey of the year to 70% for the third comprehensive survey of the year. And 90% of the facility observations *submitted* were leaks, and this ratio stayed relatively constant through survey 2 and 3 as well (Figure 4.10). However, the number of leaks decreased from 2,050 for survey 1 and to 989 for survey 3. Similarly, emissions also dropped in rough proportion to the survey number, by 30% from survey 2 (1,039 $m^3 h^{-1}$) to survey 1 (702 $m^3 h^{-1}$) and from an additional 60% from survey 2 to survey 3 (275 $m^3 h^{-1}$) (Figure 4.13). To compensate for non-compliance, when we concentrated on facilities visited three times (n = 210), the results showed, despite a leak detection rate relatively constant (Figure 4.11), a decrease in cumulative leak rates (Figure 4.12). So, when done properly, LDAR comprehensive surveys are effective at reducing methane emissions.

4.2.2 Where are the emissions coming from?

The sum of emissions detected were roughly 2x higher for facilities than wells (Figure 4.13). We grouped emitting components to the site level using site mapping provided by the Commission. Twenty-five of the sites surveyed contributed to 90% of total emissions, mainly driven by a few permit holders (Figure 4.9).

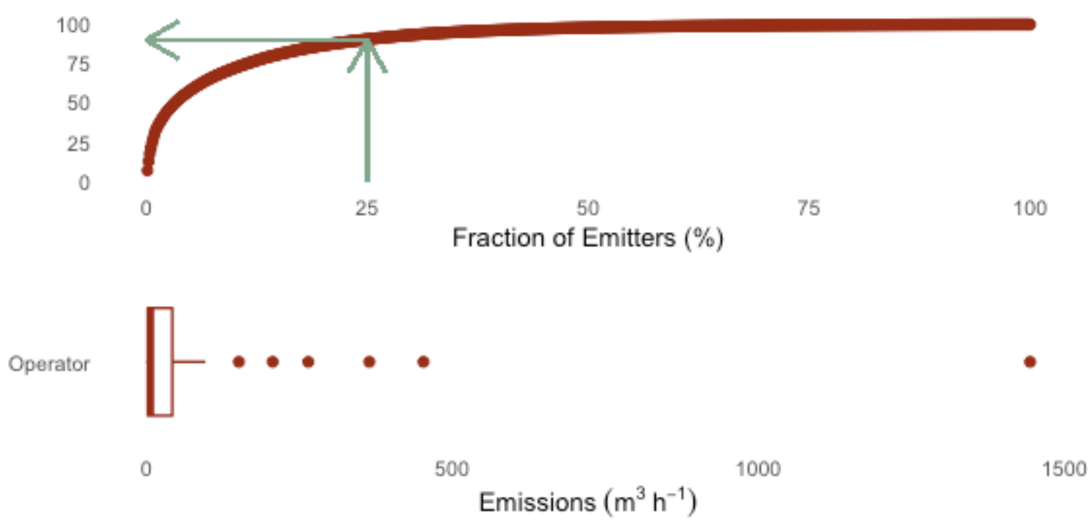


Figure 4.9: Cumulative distribution of emissions as a function of rank-ordered cumulative number of emitters (top) and site-level emissions by permit holder (bottom). Bottom panel, each point corresponds to a permit holder.

4.2.2.1 Overview

First, as expected, most methane emissions at facilities came from gas facilities (Figure 4.14). Gas plants (56%), compressor dehydrators (25%), and compressor stations (10%) were collectively responsible for ~*90%* of the emissions detected at facilities (Figure 4.15).

Second, the majority (65%) of detected well emissions came from unconventional wells (DPR Schedule 2 wells) (Figure 4.16). Looking at the leak severity in terms of emission rates, the results show for the first survey in the year leaks detected by comprehensive surveys were almost 7x more severe than those detected as part of screening surveys (Figure 4.17). Unconventional wells require comprehensive surveys whereas conventional wells (not included in DPR Schedule 2) do not, unless they have a production storage tank present.

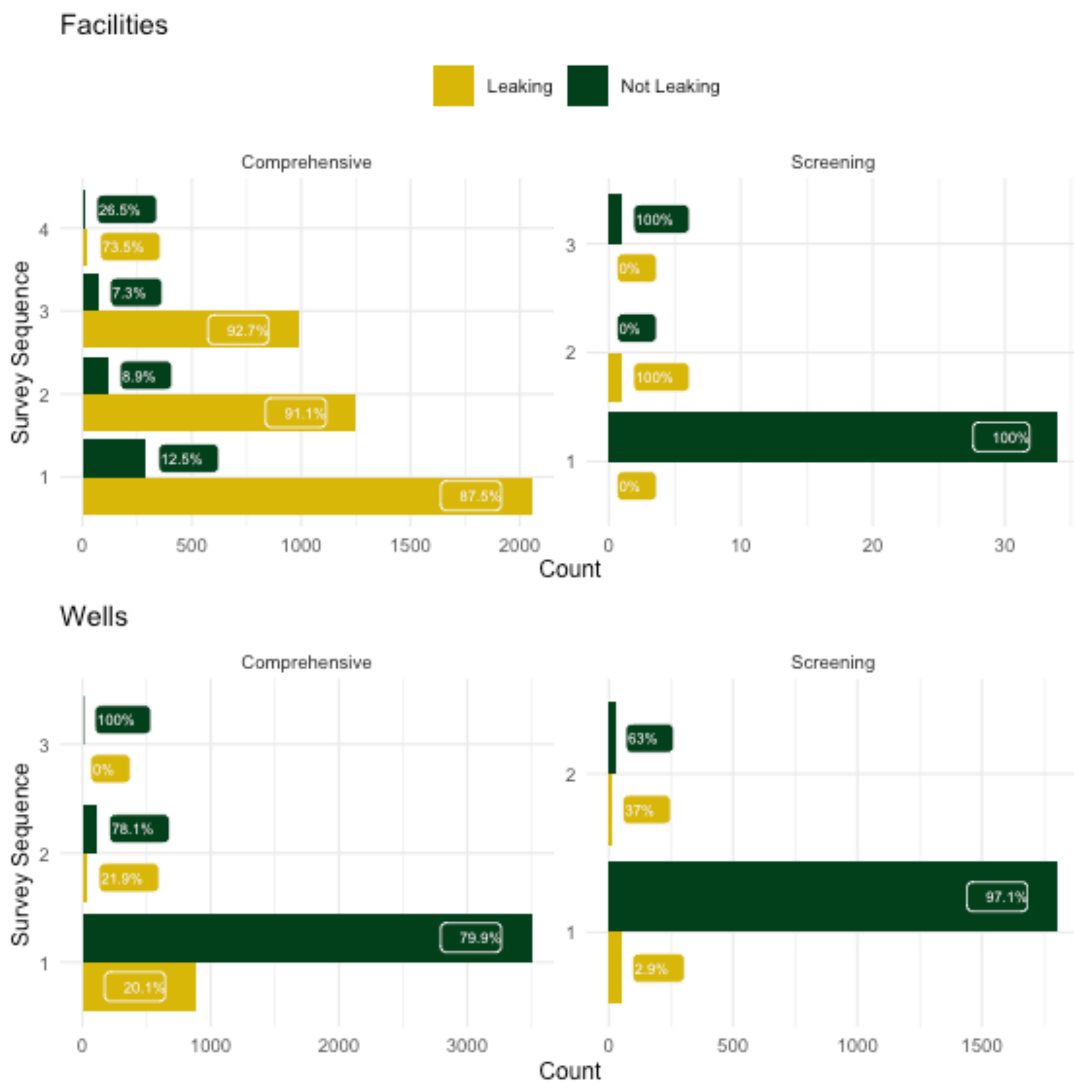


Figure 4.10: Number of leaking and non-leaking observations from facility and well infrastructure. Numbers on the bars are expressed in percentage.

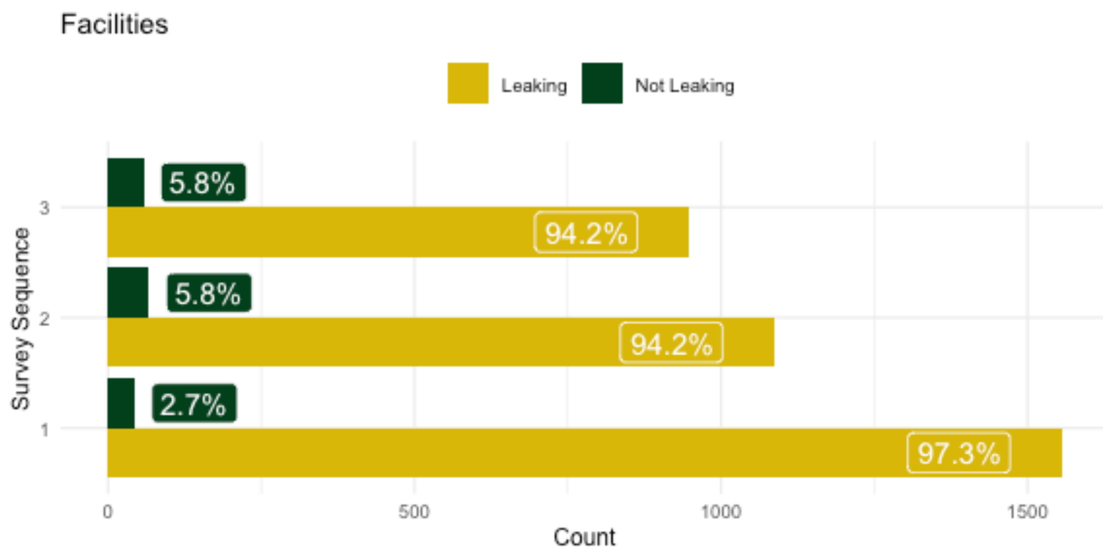


Figure 4.11: Number of leaking and non-leaking observations from facility infrastructure visited three times (n = 210). Numbers on the bars are expressed in percentage.

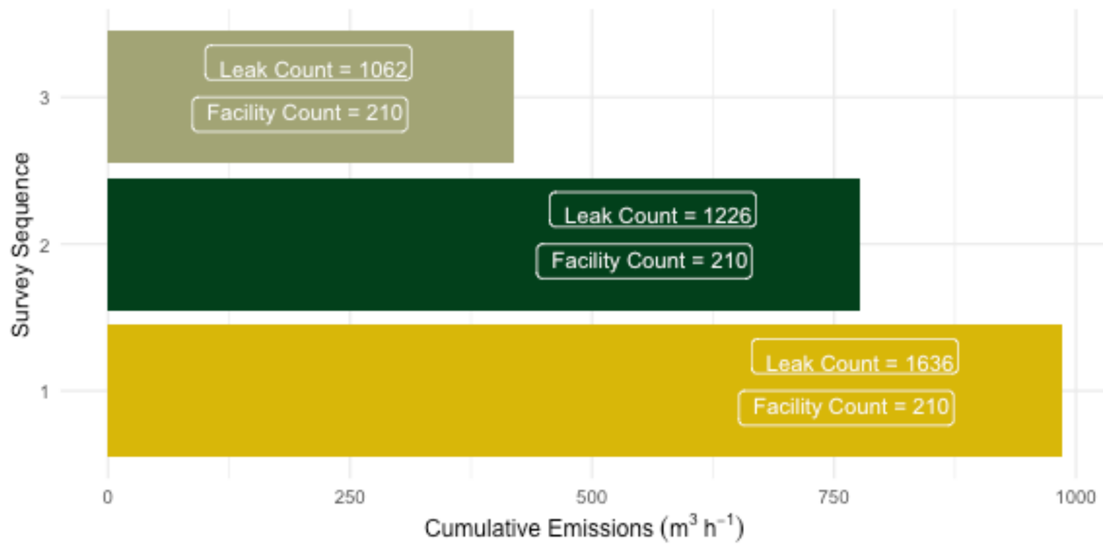


Figure 4.12: Cumulative emissions for facilities (n = 210) with three comprehensive surveys.

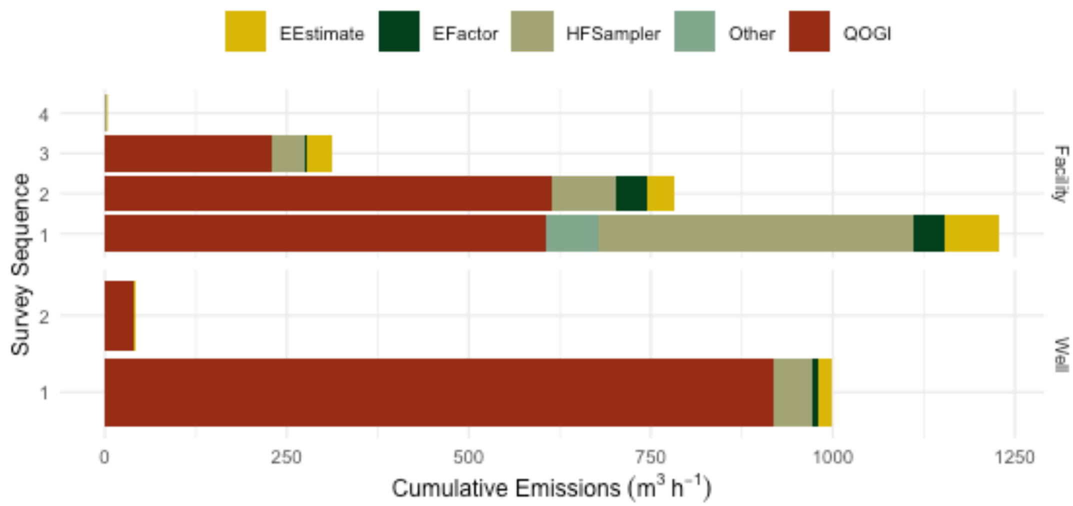


Figure 4.13: Cumulative emissions per survey for well and facility infrastructure. Measured (QOGI and HF Sampler) and estimated (EEfactor and EEstimate) leak rates are included.

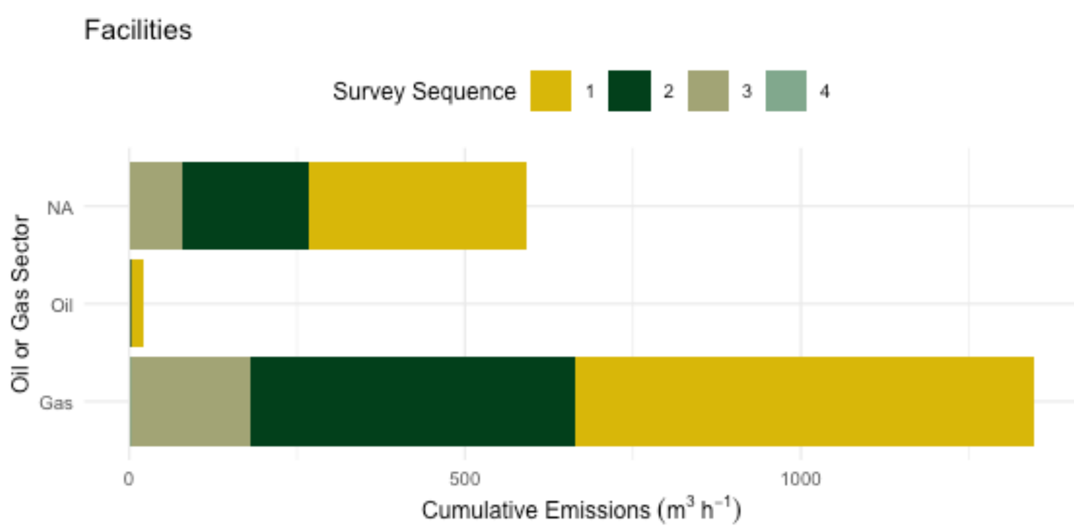


Figure 4.14: Cumulative emissions for oil (Oil Battery) and gas (Gas Battery, Gas Plant) sectors (QOGI + HF Sampler only).

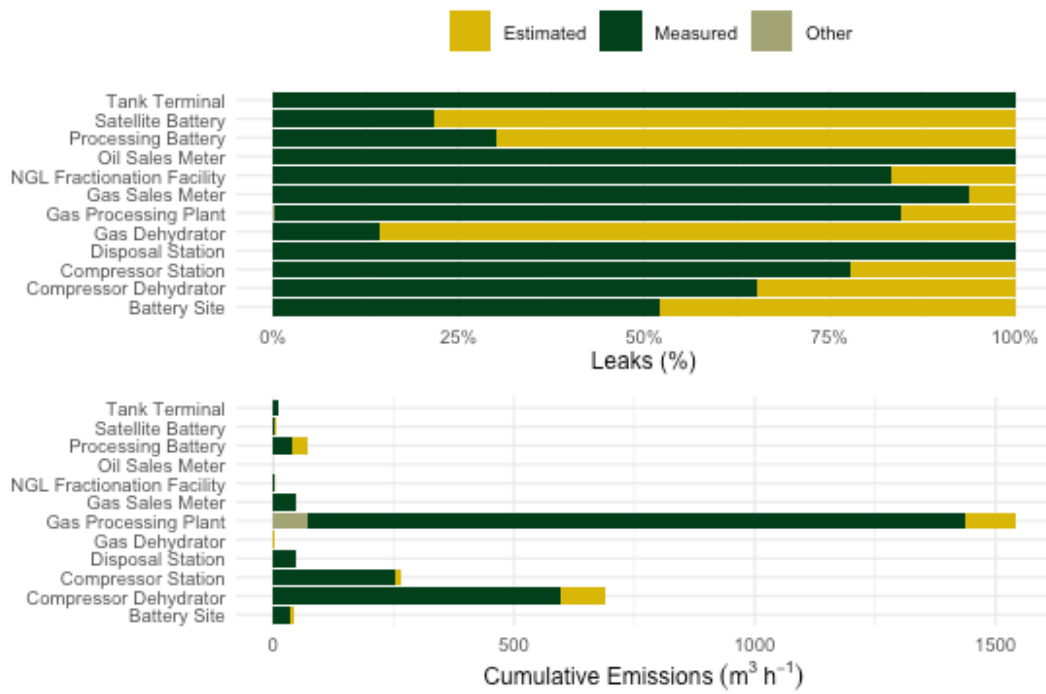


Figure 4.15: Percentage and cumulative emissions for measured and estimated data by facility type.

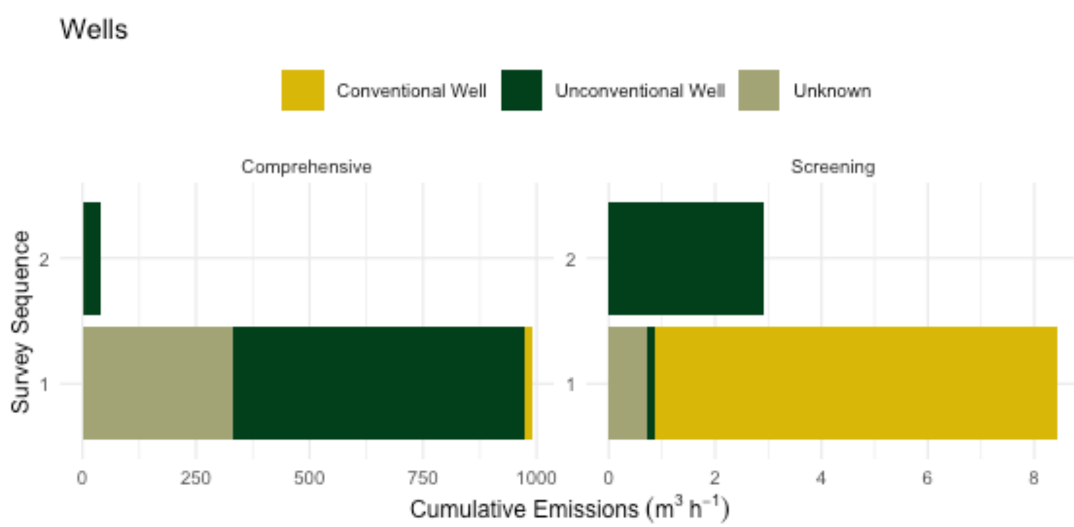


Figure 4.16: Emissions from unconventional and conventional wells.

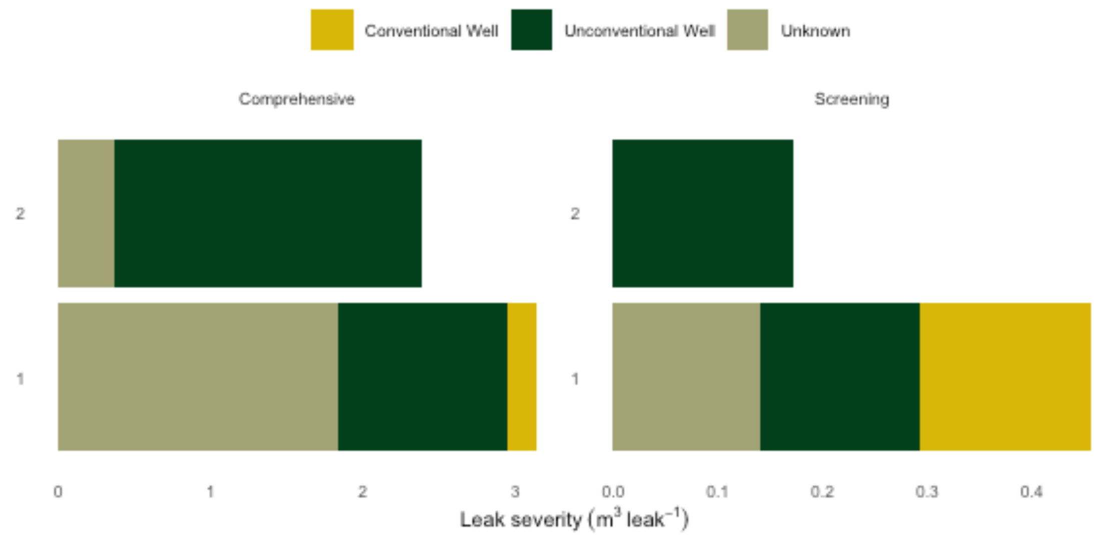


Figure 4.17: Leak severity for unconventional and conventional wells.

4.2.2.2 Components and Process Blocks

More than 60% of leaks came from three component types (Connector, Valve, and Other) (see Figure 4.18). Figure 4.18 also shows the cumulative emissions (measured and estimated data included) per well component (right panel). The component type pressure relief valve/pressure safety valve (PRV/PSV) is higher in this ranking due mostly to higher leak rates measured by one permit holder (internal survey).

Seventy-five percent of the emissions came from two categories under process block (see Figure 4.19). *Other* was the main category with 53% of the emissions. Wellhead came in second with 21% of the emissions.

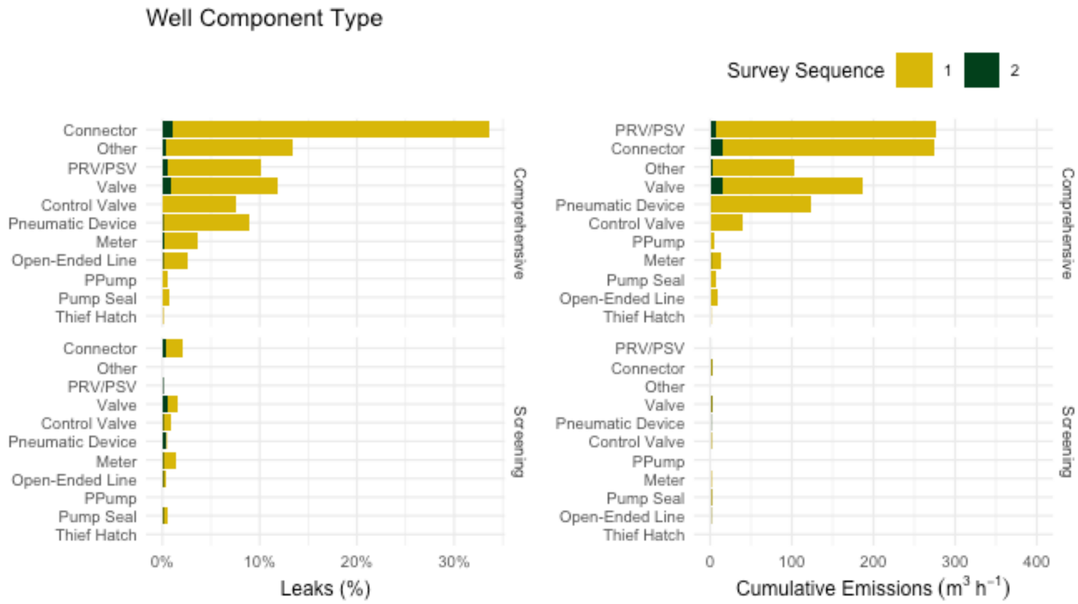


Figure 4.18: Percentage of leaks and cumulative emissions per well component type, survey type, and survey sequence.

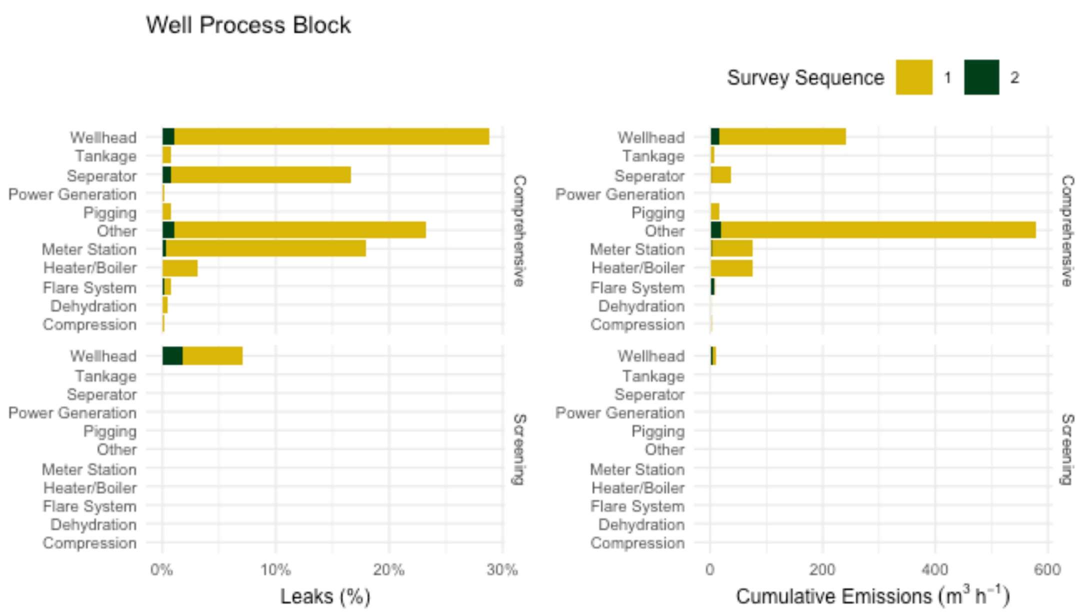


Figure 4.19: Percentage of leaks and cumulative emissions per well process block, survey type, and survey sequence.

Fifty-five percent of all the facility leaks came from connectors (Figure 4.20). Figure 4.20 shows that the thief hatch component type was much more important when looking at the total sum of the emissions (measured and estimated data included; right panel). One permit holder was responsible for the increase as a result of five very high leak rates (i.e, 24.6, 22.2, 21.6, 15.6, 11.8 $m^3\ h^{-1}$) from one gas plant. The surveys were not done internally, but by a third-party service provider. In terms of percentage and total emissions, compression, tankage, and other lead for facilities under process block (Figure 4.21).

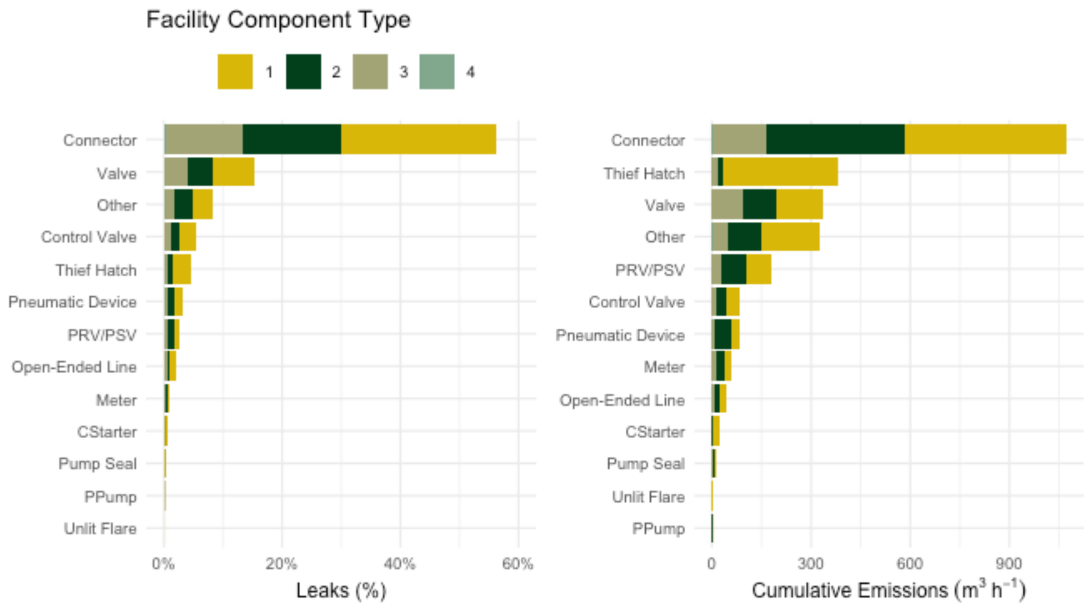


Figure 4.20: Leak percentage and total emissions per facility component type, survey type (only comprehensive displayed), and survey sequence.

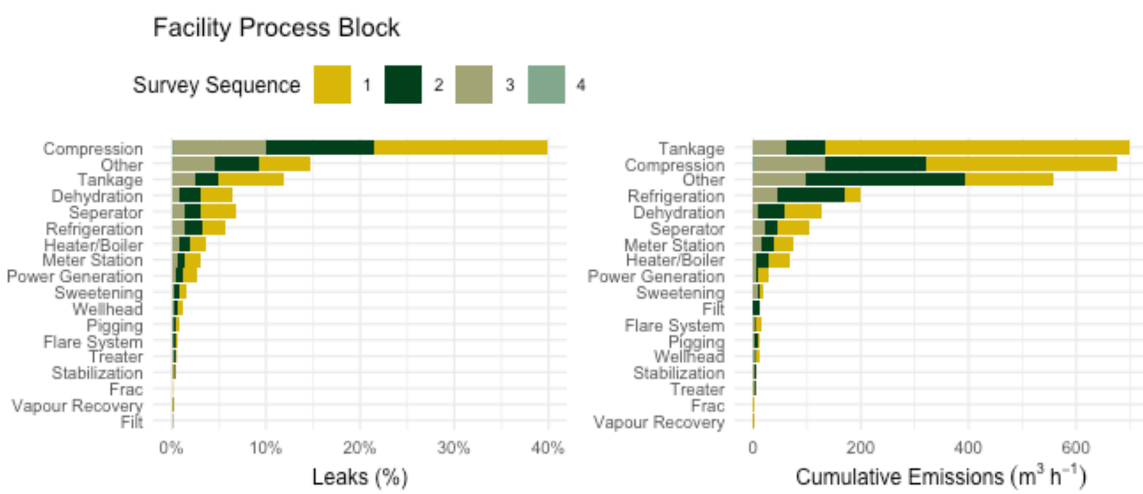


Figure 4.21: Leak percentage and total emissions per facility process block, survey type (only comprehensive survey displayed), and survey sequence.

4.2.3 The effect of repair timelines

According to sections 41.1 (5)(a) and (6) of the DPR, if a leak is detected at a well or a facility, the permit holder who operates the well or facility must repair the leak within 30 days of detection. Based on our analysis of the regulatory data, this rule was not met the majority of the time. The fraction of leak repairs that met the regulatory requirement (30 days) is 63% for wells. Including observations with no repair dates, that percentage is lowered to 60%. However, half of the leaks were repaired in less than 13 days (Figure 4.22). Similarly, the average time to repair leaks at facilities is also more than 30 days, with a mean of 65 days, and a median repair time of 30 days. The percentage of leaks repaired in less than 30 days is 50%, and this decreases to 43% when leaks with no repair dates are included.

Close to 800 leaks at wells and facilities combined, had no repair dates (*not repaired* thereafter). For the wells, all the leaks with no repair dates were under 2 $m^3\ h^{-1}$ with an average of 0.16 $m^3\ h^{-1}$. For facilities, the mean leak rate with no repair dates scheduled was less than 0.6 $m^3\ h^{-1}$, with some of the leaks showing high values (max. 22.2 $m^3\ h^{-1}$ for a thief hatch).

Cumulative emissions (sum of leaks) repaired in less than or in more than 30 days were similar for facilities; however, for wells significantly more leaks were repaired in less than 30 days than in more than 30 days (Figure 4.23). Unfortunately, a large portion of the emissions have Other or missing information for reasons to delay. The bulk of the leaks not repaired were associated with connectors and thief hatches.

The estimated methane emissions that would have occurred had no repairs been completed were 0.43 Mt CO_2 eq (GWP = 25, CH_4 density at 15^oC, 1 ATM = 0.678 kg/m^3) as shown in the Figure 4.24. Some repairs did however, occur, and that decreased estimated leaked methane in 2020 to 0.26 MT CO_2e eq. Had all repairs been completed within 30 days it is expected that an additional 0.06 MTCO_2e of leaked methane would have been avoided. It is important to note that this analysis includes only detected leaks. It does not account for leaks that were not detected or repaired because required surveys were not completed.

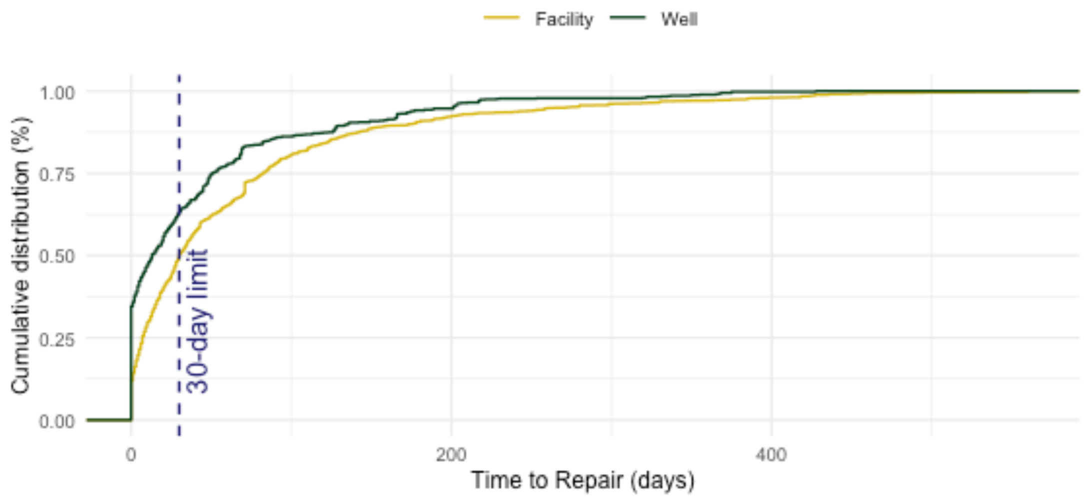


Figure 4.22: Cumulative distribution of time to repair leaking components.

Generally, larger leaks were prioritized and repaired faster than smaller leaks. We acknowledge that larger leaks should be prioritized, but *we also need to keep in mind that small leaks not getting fixed can become as important as larger leaks getting fixed faster*.

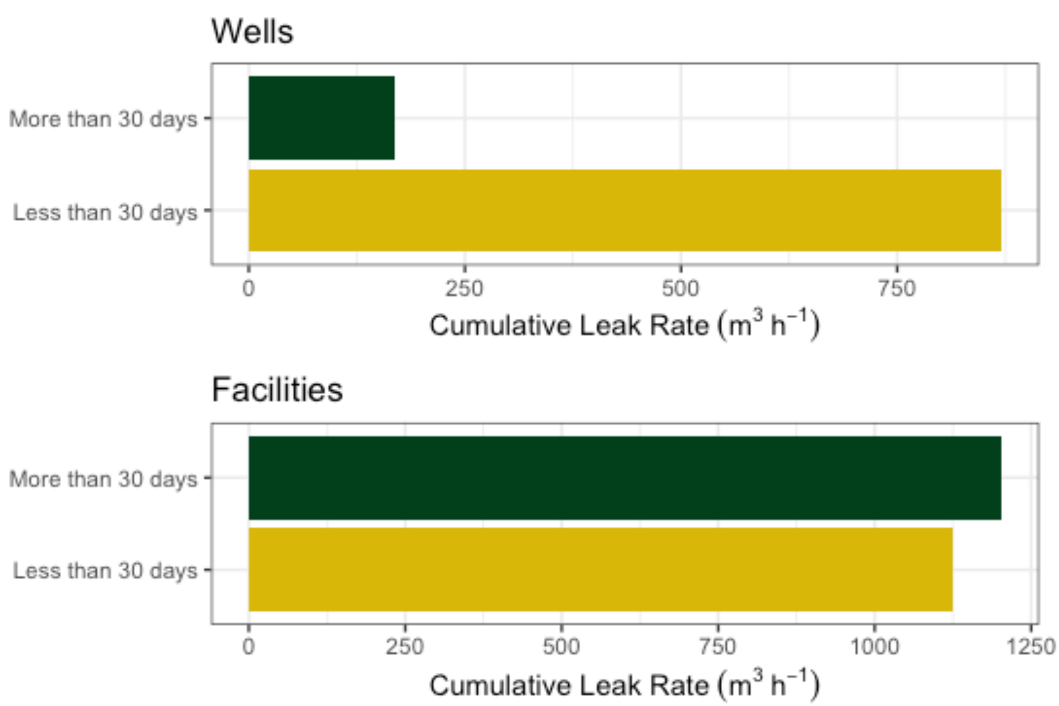


Figure 4.23: Cumulative emissions for leaks detected and repaired before or after 30 days.

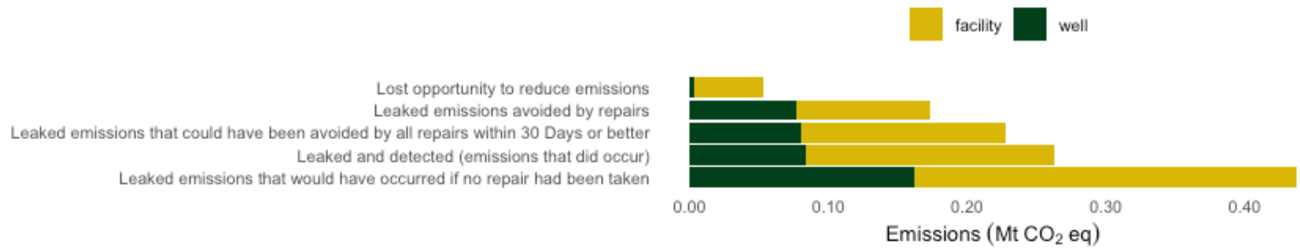


Figure 4.24: Summary of leaked methane emissions scenarios for facilities and wells.

4.3 Comparison with Other Canadian Studies

Leak rates in this study (estimated + measured = 0.61 m^3 h^{-1} (facility); 1.07 (well) m^3 h^{-1}; measured only = 0.72 m^3 h^{-1} (facility); 1.32 (well) m^3 h^{-1}) were comparable to *leak rates* (excluding venting) published in recent articles. In Red Deer Alberta average leak rates of 1.76 m^3 h^{-1} and 0.73 m^3 h^{-1} were measured for 2018 and 2019 respectively (Wang et al., 2021). While, for the Montney basin in North-Western Alberta an average leak rate of 0.35 m^3 h^{-1} was reported (Ravikumar et al., 2020).

4.4 Comprehensive Survey and Reporting Costs

4.4.1 Costs for Facilities

4.4.1.1 Individual Facility Costs by Facility Type

As described in the methodology, our cost estimates are derived from third-party service provider information, and the actual costs borne by individual permit holders will vary.

The DPR requires that gas processing plants, compressor stations, compressor dehydrators, multi-well batteries, and single-well batteries with a controlled storage tank that operate all year must be surveyed three times in the year. Injection and disposal facilities, and single-well batteries without a controlled storage tank that operate all year must be surveyed once a year.

For single-well batteries, the cost estimate range is large ($681.50-$2,044.50). The lowest possible cost occurs when a site is surveyed once a year, and the highest is when a site is surveyed three times. Table 3 presents an estimate of the costs incurred by a facility to comply with regulations. Note that these costs do not include additional costs incurred from quantifying and repairing leaks that are found.

Table 3: Annual Survey and Reporting Costs Per Survey

	Low	Average	High
Facilities requiring three comprehensive surveys per year			
Gas Processing Plant	$4,665	$9,165	$11,842
Compressor Dehydrator	$2,554	$5,481	
Compressor Station	$2,554	$5,481	
Multi-well Battery		$3,639	$4,389
Single-well battery with controlled storage tank[1]	$2,045		
Facilities requiring one comprehensive survey per year			
Injection Station		$1,200	
Single-well battery without controlled storage tank[1]	$682		

[1]This number was taken from the 2021 cost information, and only a low-end cost was provided.

4.4.1.2 Cost to Industry by Facility Type

Table 4 shows the costs from Table 3 multiplied by the number of each type of facility surveyed to demonstrate the full magnitude of the costs incurred by industry. Considering the cost in terms of $/$m^3$ h^{-1} changes the relative cost efficiency of leak detection. For example, since gas processing plants are larger emitters, their cost in $/$m^3$ h^{-1} is relatively lower when compared with a smaller emitter such as a multi-well battery ($190/$m^3$ h^{-1} versus $3,065/$m^3$ h^{-1}).

4.4.2 Costs for Wells

4.4.2.1 Individual Well Costs by Well Type

Wells with a production storage tank or that produce from an unconventional zone (DPR Schedule 2 well) must be surveyed once a year. 0therwise, they only need one screening per year (DPR section 41.1(3)). For this section, we assume that all wells are comprehensively surveyed once a year. However, there are wells that only require screenings, so this estimate is on the high end.

Similar to facilities, Table 5 presents the costs incurred by well permit holders to conduct one comprehensive survey and report per year. Again, this does not include the cost of leak quantification and repair. The following was assumed for well costs: $250 for the well pad and $125 per well on the pad. This also covers travel subsistence.

Table 4: Annual Cost to Industry for Survey and Reporting of Facilities.

Facility Type	Low	Average	High	Count	Average ($\$/m^3\ h^{-1}$)
Facilities requiring one comprehensive survey per year					
Injection Station	NA	$36,000	NA	30	$793
Single-well battery without controlled storage tank	$12,948	NA	NA	19	$289
Facilities requiring three comprehensive surveys per year					
Gas Processing Plant	$149,280	$293,280	$378,936	32	$190
Compressor Dehydrator	$76,606	$164,430	NA	30	$238
Compressor Station	$74,053	$158,949	NA	29	$598
Multi-well Battery	NA	$138,282	$166,782	38	$3,065
Single-well battery with controlled storage tank	$38,846	NA	NA	19	$861

4.4.2.2 Cost to Industry by Well Type

Table 6 shows the costs in Table 3 multiplied by the number of wells to provide an idea of the total costs incurred by industry.

4.4.3 Approximate Costs by Permit Holder

In addition to considering costs in terms of facility and well type, we analyze how permit holders are affected by the cost of regulations.

Assumptions in this section:

- All single well batteries, injection stations, and wells receive one comprehensive survey a year
- Gas processing plants, compressor stations, compressor dehydrators, and multi-well batteries receive three comprehensive surveys a year

- Facilities that could not be associated with a specific permit holder (4 single well batteries and 12 multi-well batteries) were excluded from analysis
- Leaks can either be measured using QOGI ($75/leak) or Hi-Flow ($25/leak)

Table 5: Annual Survey and Reporting Costs Per Well

Well Type	Low	Average	High
Single wellsite	NA	$260	$610
Three well pad	$476	$515	NA
Eight well pad	$718	$1,152	NA
Twenty well pad	$852	$2,680	NA

As the number of leaks increases, the costs incurred by permit holders increase. Permit holders with more leaks incur higher costs since there is an incremental cost to measure each leak. Figure 4.25 compares the number of leaks reported by the permit holder to their annual survey and reporting costs. Permit holders that reported no leaks are not included.

Table 6: Annual Cost to Industry for Survey and Reporting of Wells

Well Type	Low	Average	High	Count
Single wellsite	NA	$13,780	$32,330	53
Three well pad	$19,525	$21,115	NA	41
Eight well pad	$15,070	$24,192	NA	21
Twenty well pad	$4,261	$13,400	NA	5

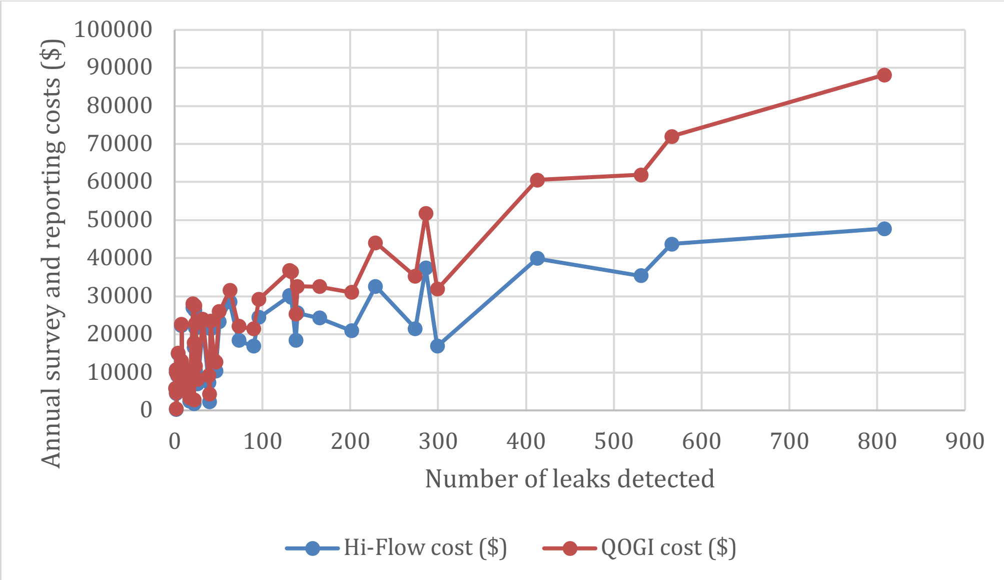


Figure 4.25. Approximate permit holder costs by number of leaks.

While permit holders with a higher number of leaks have higher costs, when no leaks are reported, the permit holder still incurs significant costs from the survey itself. Figure 4.26 displays the range of costs for permit holders who reported no leaks ($260-$22,054). It also highlights that cost vary significantly by permit holder depending on the type and number of facilities and wells surveyed by each permit holder.

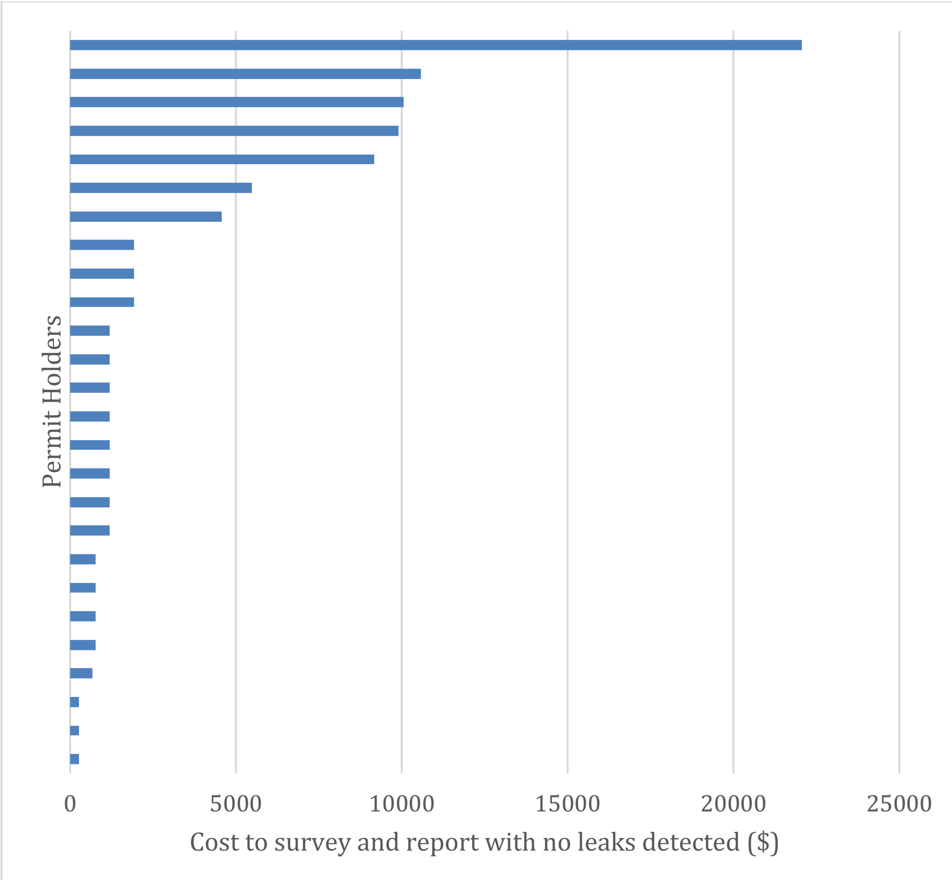


Figure 4.26: Costs for permit holders with no leaks detected.

4.4.4 Cost Efficiency of Comprehensive Screenings

The cost efficiency of comprehensive surveys is determined by comparing the leakage detected to the cost of conducting the survey. Figure 4.27 below provides a rough estimation of the average cost per leak detected by operator. Since the incremental cost to measure a leak is much smaller than the cost for the survey, the more leaks detected by a survey, the more cost-effective the survey is. So, to ensure that surveys are cost-efficient, it is critical to locate, detect, and quantify all leaks at the site. Otherwise, the permit holder incurs significant costs with no benefit. For example, when less than 50 leaks were detected by a permit holder in their overall 2020 program, the costs range from approximately $100/leak-$6,000/leak (Figure 4.27) and for permit holders with more than 50 leaks detected in their overall 2020 program, costs ranged from about $100/leak-$500/leak (Figure 4.28).

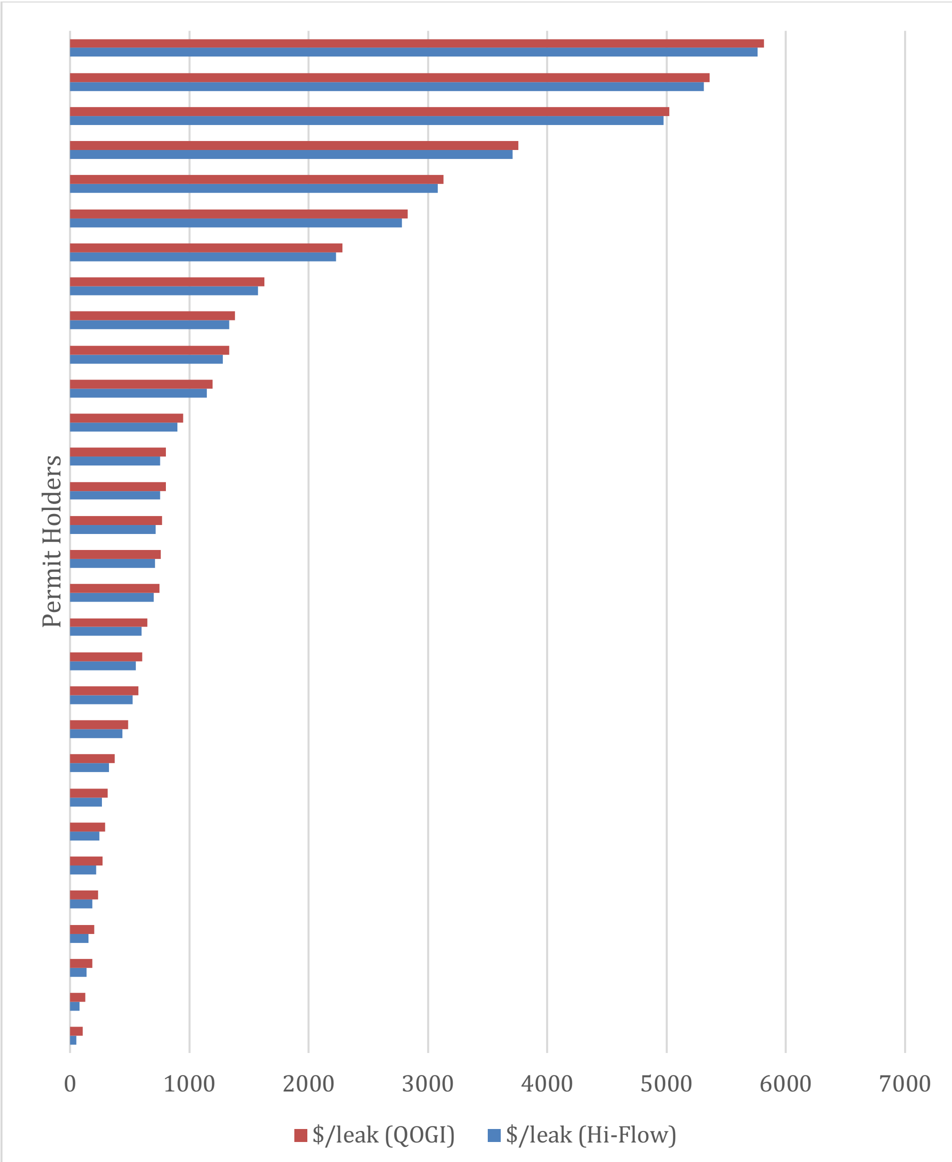


Figure 4.27: Cost per leak detected for permit holders with < 50 leaks reported.

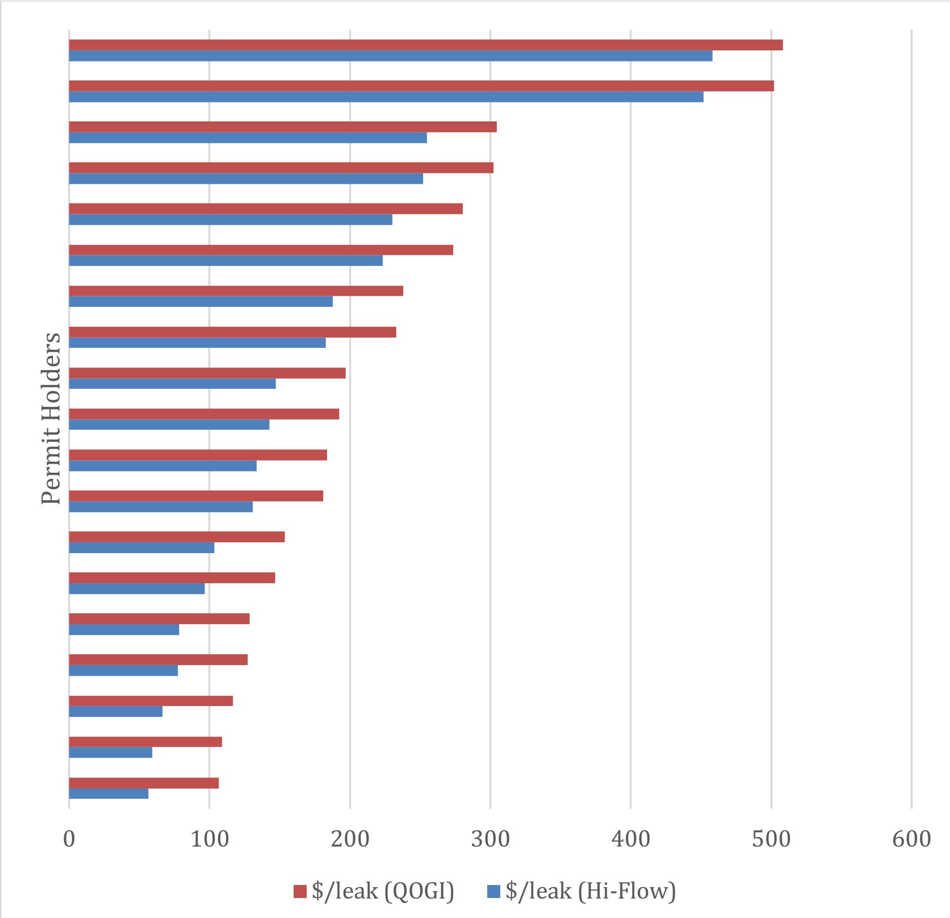


Figure 4.28: Cost per leak detected for permit holders > 50 leaks reported.

4.5 Cost and Cost Efficiency of Screenings

An estimate for the annual cost of screenings can be determined by approximating the cost of the screening as the travel costs to the site ($250) and multiplying this by the number of screenings conducted in a year. According to DPR section 41.1(3)(b), wells that do not have a production storage tank and are not producing in an unconventional zone need one screening per year. Oil and gas sales meters must also have one screening per year as per DPR section 41.1(2)(c). There were 1,905 screening surveys conducted at wells and facilities in 2020. Despite screenings being less expensive than comprehensive surveys, they are not cost-effective. Of all the screenings conducted, only 72 leaks were detected, which is a cost per leak of approximately $6,615/leak, which is less cost-efficient than comprehensive surveys.

4.6 Cost - Further Analysis

This cost analysis was conducted with a limited amount of cost information. For a more complete and accurate model, the following factors should be considered.

4.6.1 Factors that Influence Survey Costs

We assume in our model that all facilities and wells of the same type incur the same survey costs. However, there is variation in survey costs due to factors such as facility size and complexity. Similarly, there is variation in well costs based on the number of wells per pad and the configuration. Wet metering and the presence of group versus individual separators influence costs. Additionally, sites with no gas driven pneumatics are faster to survey, as there are fewer potential points of failure to inspect. Another important factor is the location of the site. Remote sites may see higher costs due to increased travel time. Finally, who conducts the surveys (internal or external parties) could affect costs.

As a result, factors such as the size, complexity, type of equipment, location, and surveyors should all be considered when estimating costs as they affect the degree in which different permit holders are affected by the regulations.

4.6.2 Future Costs

When modelling the costs of regulation over time, fluctuations must be considered. In this case, future costs are expected to decrease for several reasons. First, it is expected that there will be more competition between third-party contractors resulting in a decrease in survey costs. Second, over time it is expected that there will be less leaks that must be reported, measured, and repaired. Third, there will be fewer gas driven pneumatic devices and pumps which means there will be less potential for leaks at facilities and wells that would otherwise have had them.

5 Acknowledgements

We thank the BC Oil and Gas Commission (BCOGC), BC Oil and Gas Methane Emissions Research Collaborative (BC MERC), BC Oil and Gas Research and Innovation Society (BC OGRIS), the Ministry of Energy, Mines and Low Carbon Innovation, and the Pembina Institute.

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7 Appendix

Appendix Table 1: Number of observations (%) per survey type and quantified methods. NaN indicates no observations or no measurements.

Characteristic	AVO	Bubble	OGI	QOGI
Wells				
EEstimate	64 (91)	0 (NA)	58 (14)	0 (0)
EFactor	6 (8.6)	0 (NA)	37 (9.1)	0 (0)
HFSampler	0 (0)	0 (NA)	266 (66)	33 (6.5)
QOGI	0 (0)	0 (NA)	44 (11)	475 (94)
(NA)	1,788	46	1,682	1,940
Facilities				
EEstimate	1 (100)	825 (28)	0 (0)	
EFactor	0 (0)	235 (7.9)	22 (1.7)	
HFSampler	0 (0)	1,783 (60)	2 (0.2)	
Other	0 (0)	0 (0)	8 (0.6)	
QOGI	0 (0)	148 (4.9)	1,296 (98)	
(NA)	35	450	52	

Appendix Table 2: Number of leaks per well and facility components. Includes measured and estimated data.

Characteristic	Facilities	Wells
Leaking Component, n (%)		
Connector	2,429 (56)	350 (36)
Control Valve	230 (5.3)	82 (8.3)
CStarter	28 (0.6)	0 (0)
Meter	45 (1.0)	48 (4.9)
Open-Ended Line	84 (1.9)	28 (2.8)
Other	356 (8.3)	131 (13)
Pneumatic Device	136 (3.2)	92 (9.4)
PPump	9 (0.2)	6 (0.6)
PRV/PSV	118 (2.7)	101 (10)
Pump Seal	11 (0.3)	12 (1.2)
Thief Hatch	202 (4.7)	1 (0.1)
Unlit Flare	1 (<0.1)	0 (0)
Valve	662 (15)	132 (13)

Appendix Table 3: Mean and median leak rates ($m^3\ h^{-1}$) for facility and well leaking components. Includes measured and estimated data.

Component	Facility			Well		
	Mean	Median	Emissions	Mean	Median	Emissions
Connector	0.44	0.15		0.79	0.15	
Control Valve	0.36	0.17	83.64	0.50	0.17	41.13
CStarter	0.82	0.18	22.89	NA	NA	NA
Meter	1.34	0.29	60.08	0.30	0.10	14.20
Open-Ended Line	0.55	0.36	45.91	0.34	0.10	9.51
Other	0.92	0.21	328.43	0.79	0.10	103.89
Pneumatic Device	0.62	0.16	84.09	1.36	0.30	124.70
PPump	0.19	0.16	1.68	0.83	0.53	4.98
PRV/PSV	1.54	0.87	182.03	2.74	1.80	
Pump Seal	1.21	0.37	13.26	0.77	0.37	9.19
Thief Hatch	1.88	0.48	380.62	0.50	0.50	0.50
Unlit Flare	1.60	1.60	1.60	NA	NA	NA
Valve	0.51	0.20	335.68	1.43	0.30	

Appendix Table 4: Number of leaks per well and facility process blocks. Includes measured and estimated data.

Characteristic	Facilities	Wells
Process Block, n (%)		
Compression	1,722 (40)	2 (0.2)
Dehydration	275 (6.4)	4 (0.4)
Filt	3 (<0.1)	0 (0)
Flare System	29 (0.7)	7 (0.7)
Frac	3 (<0.1)	0 (0)
Heater/Boiler	153 (3.5)	31 (3.2)
Meter Station	131 (3.0)	177 (18)
Other	633 (15)	229 (23)
Pigging	36 (0.8)	7 (0.7)
Power Generation	120 (2.8)	1 (0.1)
Refrigeration	243 (5.6)	0 (0)
Seperator	291 (6.8)	164 (17)
Stabilization	18 (0.4)	0 (0)
Sweetening	66 (1.5)	0 (0)
Tankage	509 (12)	8 (0.8)
Treater	19 (0.4)	0 (0)
Vapour Recovery	7 (0.2)	0 (0)
Wellhead	53 (1.2)	353 (36)

Appendix Table 5: Mean and median leak rates ($m^3\ h^{-1}$) for facility and well process blocks. Includes measured and estimated data.

Process Block	Facility			Well		
	Mean	Median	Emissions	Mean	Median	Emissions
Compression	0.39	0.15	676.08	0.58	0.58	1.16
Dehydration	0.47	0.16	128.53	0.10	0.06	0.38
Filt	3.62	2.94	10.86	NA	NA	NA
Flare System	0.54	0.15	15.61	1.02	0.16	7.14
Frac	0.16	0.15	0.48	NA	NA	NA
Heater/Boiler	0.45	0.15	68.48	2.42	2.28	74.94
Meter Station	0.57	0.15	74.19	0.43	0.10	76.23
Other	0.88	0.17	558.81	2.53	1.68	580.20
Pigging	0.29	0.10	10.51	2.46	2.70	17.25
Power Generation	0.24	0.15	28.87	0.03	0.03	0.03
Refrigeration	0.82	0.10	198.09	NA	NA	NA
Separator	0.36	0.15	103.92	0.22	0.14	35.98
Stabilization	0.24	0.08	4.38	NA	NA	NA
Sweetening	0.29	0.15	19.19	NA	NA	NA
Tankage	1.37	0.38	699.45	0.79	0.18	6.33
Treater	0.22	0.15	4.16	NA	NA	NA
Vapour Recovery	0.15	0.15	1.07	NA	NA	NA
Wellhead	0.20	0.10	10.58	0.71	0.16	252.11

Appendix Table 6: Number of leaks per well and facility with H_2S. Includes measured and estimated data.

	H_2S indicator	Count
Facilities	No	4001
Facilities	Yes	310
Wells	No	9
Wells	Yes	42

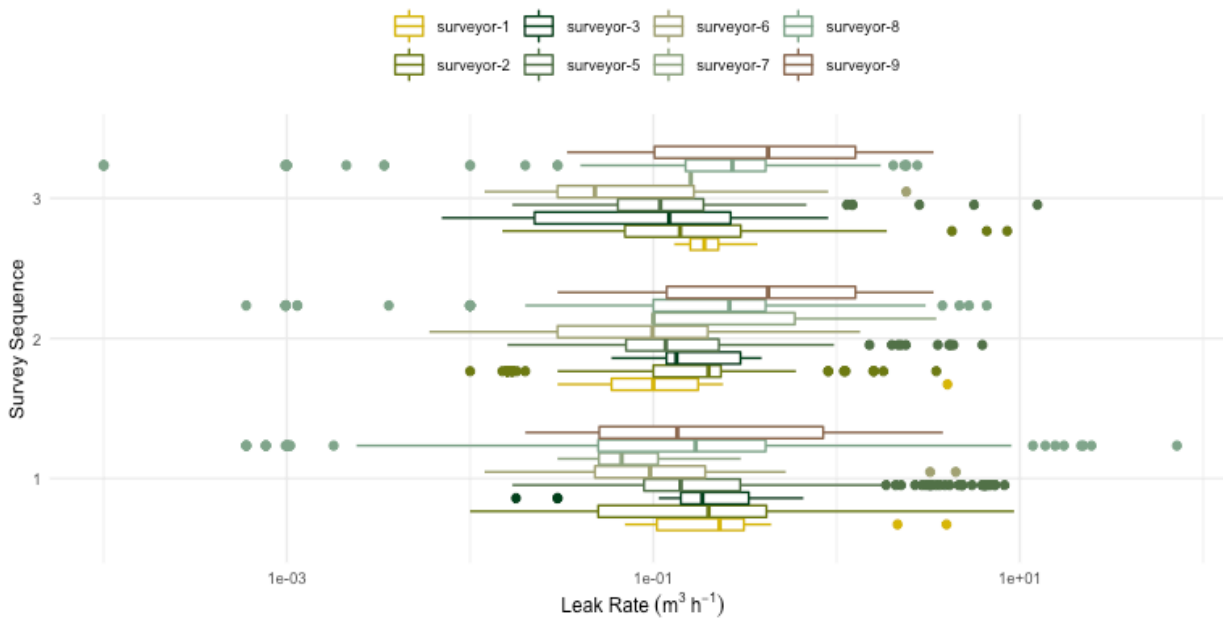
Appendix Table 7: Number of leaks per well and facility inside buildings. Includes measured and estimated data.

Infrastructure Type	Leak Building Indicator	Count
Facilities	No	2062
Facilities	Yes	2249
Wells	No	419
Wells	Yes	564

Appendix Table 8: Mean and median leak rates (m^{-3} h^{-1}) by permit holder. Includes measured and estimated data. All permit holder names were anonymized.

Operator	Mean_Facilities	Mean_Wells	Median_Facilities	Median_Wells	Emissions_Facilities	Emissions_Wells
allpowerful_norwaylobster	0.04	0.03	0.04	0.03	0.04	0.03
anecdotal_belugawhale	0.35	0.23	0.3	0.2	4.5	2.1
arrogant_atlanticbluetang	0.15		0.07		7.11	
atrophic_koi	0.24		0.25		1.68	
autographical_hatchetfish	0.27	0.22	0.1	0.1	28.54	6.92
baleful_gharial	0.7	0.13	0.2	0.04	23.73	0.67
cannibalistic_agama	0.44		0.31		6.97	
canophilic_antelope	0.37	0.21	0.2	0.15	83.2	13.26
carnivoral_bobolink	0.54		0.14		161.6	
cellular_irrawaddydolphin	0.09		0.09		0.09	
cleanlimbed_asianpiedstarling	1	0.3	1	0.3	1	0.3
clinophilic_meadowhawk	1.19		0.36		9.51	
considerate_ermine	0.28	0.5	0.11	0.5	19.57	0.99
defamatory_bedlingtonterrier	0.38		0.13		103.41	
depletive_tick	2.36		1.46		51.85	
dramatisable_jerboa	0.25	0.2	0.05	0.07	6.01	7.77
enchanting_godwit	0.15		0.1		1.06	
famous_chamois	0.25	0.07	0.19	0.08	3.74	0.37
feminine_iguana	0.49	0.41	0.21	0.1	49.23	13.11
fermentable_cougar	1.1		0.15		8.76	
flamboyant_avians		0.12		0.12		0.12
generic_tapeworm	0.07		0.04		1.74	
genetic_quinquespinosus	2.49		0.47		9.96	
goosepimply_irukandjijellyfish	0.37	0.31	0.2	0.1	39.47	10.34
gravelly_gordonsetter	2.21		1.51		364.46	
hedonistic_rockrat		0.12		0.12		0.25
humanoid_glowworm	0.36	0.26	0.31	0.24	3.56	3.42
insulaphilic_cricket		0.39		0.37		2.73
locustal_hornshark		0.15		0.05		2.53
lying_bull	0.19	0.17	0.15	0.17	6.06	0.35
macroscopic_dolphin	0.41	0.29	0.24	0.2	181.66	26.83
marine_quadrisectus	0.18	0.16	0.15	0.15	134.23	19.23

metempsychosic_toucan	0.19		0.07		42.75	
obtuse_snoutbutterfly	0.38	0.31	0.15	0.2	5.34	2.2
pearl_baleenwhale	0.54		0.1		4.32	
poorly_ringworm	0.33		0.15		29.29	
pseudoeconomical_narwhale	0.44		0.11		88.48	
sardonic_kouprey	0.31		0.2		15.95	
scheelite_arrowcrab	0.59		0.18		13.52	
semiacidulated_brownbear	1.1		0.85		44.19	
semiintelligent_ibex	0.31	0.06	0.29	0.06	2.46	0.06
sugared_harrierhawk	0.42	0.15	0.32	0.15	10.02	0.91
thoroughbred_pintail	0.21	0.06	0.1	0.06	8.3	0.12
threpterophilic_polyp	2.3	2.71	1.32	1.92	527.49	913.41
tinfoil_snowdog	0		0		0	
troglodytic_agama	0.18	0.14	0.16	0.05	5.5	2.14
unadored_chrysomelid	0.09		0.09		0.18	
usable_hectorsdolphin	1.15	0.36	0.21	0.23	447.4	8.72
utilizable_ragfish	0.14	0.07	0.1	0.03	6.53	3.6
vixenly_noctilio	0.67	0.15	0.12	0.08	48.77	8.91
weak_cardinal		0.03		0.02		0.38



Appendix Figure 1: Leak rate for third-party service providers. Log scale for better visualization.