Fugitives in Our Midst

Investigating fugitive emissions from abandoned, suspended and active oil and gas wells in the Montney Basin in northeastern British Columbia

By John H. Werring, M.Sc., R.P. Bio. Senior Science and Policy Advisor,
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Cataloguing data available from Library and Archives Canada
ISBN 978-1-988424-11-8

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ACKNOWLEDGEMENTS

Special thanks go to Mackenzie (Makz) Werring, who provided logistical, tactical and moral support in the field and to the donors who provided financial support for this work.

We would like to acknowledge the contributions of the Flux Lab at St. Francis Xavier University in Antigonish, Nova Scotia, on completion of the first phase of research and publication of an associated peer-reviewed paper (Atherton 2017: www.atmos-chem-phys.net/17/12405/2017/) that provided the impetus for this field study.

We would also like to acknowledge those who peer-reviewed and provided comment on this report, in particular Amin Asadollahi, North American lead for climate mitigation, International Institute for Sustainable Development; Jeffery Young, senior science and policy analyst with the David Suzuki Foundation; and Ian Bruce, director of science and policy at the Foundation.

Editing services were provided by David Suzuki Foundation senior editor Ian Hanington and climate and clean energy communications specialist Emily Fister.

Report Layout and Design by Samantha Matheson.

Cover Photo: Photo of an oil well at an undisclosed location obtained from a Creative Commons web site https://pixabay.com/

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Executive summary

In summer 2015, the David Suzuki Foundation collaborated with St. Francis Xavier University's Flux Lab to examine and detect fugitive gas emissions from upstream oil and gas wells and facilities in an area of unconventional natural gas development in Northeastern British Columbia (the Montney formation, near Fort St. John, B.C.) using sophisticated mobile gas-measuring technology. This study showed that fugitive methane emissions from B.C. oil and gas operations in the Montney region were higher than the fugitive methane emissions estimated and reported on by the B.C. government for the entire province (Atherton et al., 2017), with the Montney region representing only about 55 per cent of total natural gas development.

This study covered over 8,000 kilometres of mobile measurements and showed that approximately 47 per cent of active wells were emitting methane. To support this work and provide an additional estimate of methane emissions, David Suzuki Foundation researchers accessed oil and gas infrastructure along the previously surveyed routes and attempted to directly measure emissions from specific infrastructure in areas where plumes were detected.

Using a simplified screening program, we were able to identify emissions of fugitive methane due to surface casing vent flow and equipment leaks and deliberate venting of gases (primarily methane). We obtained estimates of the rate of flow of those emissions at sites where we detected emissions.

We found that:

- On average, around 35 per cent of all abandoned, suspended (including water wells), shut-in and active oil wells in the Montney exhibit measurable and, in some cases, significant surface-casing vent flows of methane and hydrogen sulphide gas or a combination of both. The average rate of flow of methane gas from surface-casing vents was conservatively estimated to be on the order of between nine and 11 m^3/day. While we could not determine the cause of these "vent flows", we suspect much of the escaping gas is a result of issues related to well integrity. It is also apparent from our data that producers are identifying and repairing few of these leaking wells.
- More than 85 per cent of all actively producing gas wells were found to be venting methane gas directly to the environment daily while in operation through "LNG" vents on instrumentation buildings that house pneumatic control devices. This vented gas is not being captured or flared, and measurements taken with a gas monitor show it is almost pure methane. The rate of flow from shed LNG vents was estimated to be about 1.13 m^3/hr or 27.1 m^3/day per well.

Accordingly, we believe we can use these data to calculate an approximation of the total fugitive methane emissions associated with individual well sites in the upstream leg of oil and gas development in the Montney basin (Note: this calculation does not include large methane emission sources such as processing plants, compressor stations, etc.). Using a conservative estimate of one instrument shed per gas well site and only one vent venting, we can determine that a single, venting gas well would be emitting about 27 m^3/day, or roughly 9,898.8 m^3/yr. Considering that there are roughly 13,000 active gas wells in B.C. and, based on a random survey of at least 49 well sites (not all were operating) where at least 86 per cent were found to be venting methane gas through building vents, we can estimate, very conservatively, that around 10,983 well sites could be emitting a minimum of around 110,668,584 m^3CH_4/year, or 83,022 tonnes.

If we were to include methane venting from surface-casing vents and estimates of releases from compressor stations, we could conservatively estimate fugitive emissions from oil and gas infrastructure in the upstream oil and gas industry in the Montney to be about 130,888,000 m^3 CH_4/year, or 98,190 tonnes. Much of this gas (85 per cent) is being deliberately vented directly into the atmosphere. It is not being captured or used in any way.

This finding supports our companion research carried out in partnership with St. Francis Xavier University and described above (which is based on a much larger sample size: n=1,600; and includes larger emitting infrastructure), that methane emissions in B.C. are being under-reported. That study estimated that actual emissions from the Montney basin alone are higher than B.C. government estimates for the entire province (Atherton et al., 2017). We suggest that fugitive methane emissions from this industry are being heavily under-reported and/or underestimated and there is a need for mechanisms to properly quantify the impact of this industry from a greenhouse gas emissions perspective and to develop means to control these emissions.

We are asking the B.C. government to:

- Mandate that all oil and gas companies operating in B.C. immediately undertake leak detection and repair, at the very least, starting with the sites we have identified in this report.
- Immediately develop and implement regulations for mandatory quarterly leak detection and repair in all areas of the province, including on all abandoned and suspended wells.
- Immediately develop and implement regulations for industry to replace oil and gas infrastructure that is designed to vent fuel gas (e.g., pneumatic devices, pumps, compressors) with non-emitting devices.
- Immediately develop and implement regulations for mandatory and transparent reporting on all emissions and the steps being taken to address them; and where significant flows are measured, demand those wells be repaired.

- Require the industry to provide adequate resources for on-the-ground monitoring and enforcement of these regulatory measures and prioritize hiring locally affected First Nations to support independent monitoring.
- Develop and implement measures to ensure that the carbon tax applies to the oil and gas industry in relation to all methane emissions as an interim measure and that full carbon pricing or other mandatory regulations are implemented to achieve full phase-out of methane emissions.

1.0 Introduction

Natural gas development in the Montney basin

The Montney play in northeastern British Columbia is an active field from which oil and gas are being extracted. Estimates of the potential resources contained within the formation are around 449 trillion cubic feet of marketable natural gas, 14,521 million barrels of marketable natural gas liquids (NGLs) and 1,125 million barrels of oil (National Energy Board, B.C. Oil and Gas Commission, Alberta Energy Regulator, 2013).

The Montney formation has been identified as one of the largest “shale gas” and “shale oil” resources in the world. Shale gas (or oil) is natural gas (or oil) trapped within shale formations rather than in underground pools. The term used for this type of resource is “tight gas” (or “tight oil”) and the methods of extraction are deemed “unconventional”. The primary means of extraction of these resources is through processes like hydraulic fracturing and horizontal drilling. Conventional oil or gas comes from geological formations that are relatively straightforward to develop. They don’t need these specialized technologies to unlock their potential.

There is the common notion that “pools” of oil and natural gas can be found in underground voids and these pools can be tapped. Pools in which wells can be drilled so that oil and natural gas flows naturally or can be pumped to the surface are commonly referred to as “conventional” oil and natural gas.

Because they are easier and less expensive to produce, conventional oil and gas were the first targets of industry activity. Canada began producing conventional oil in the late 1890s and conventional natural gas in the early 1900s. However, decades of oil and natural gas production in North America and around the world have resulted in a decline of these conventional resources.

By contrast, unconventional resources are trapped in reservoirs with low permeability, meaning the oil or natural gas has little to no ability to flow through the rock and into a wellbore. To produce from unconventional reservoirs, industry uses a stimulation technique called hydraulic fracturing to create cracks in the underground rock that allow the oil or natural gas to flow.

Since 2005, the unconventional share of B.C.'s natural gas production has continued to increase. By 2011, the contribution of unconventionally sourced gas surpassed gas production from conventional reservoirs. By year-end 2015, B.C.'s unconventional gas production accounted for about 80 per cent of total gas production[1]. The majority, if not all, of the new gas and oil reserves in the Montney are being tapped using these "unconventional" means.

Drilling and production in the Montney has been taking place since the 1950s (NEB et al., 2013). According to the BC Oil and Gas Commission, as of October 2016, more than 25,000 wells have been drilled in the province[2], 13,850 of which have been drilled since January 2000. Currently there are around 12,771 active gas wells (Jeakins, 2016)[3], most of which have been hydraulically fractured. The remainder (12,310) are either oil wells (2,387) or wells that have been designated as abandoned, suspended or water-disposal wells.

As of November 2014, BC Oil and Gas Commission data indicate that there were 6,978 abandoned wells and 2,945 suspended wells — 9,923 in total[4].

What is natural gas?

Natural gas is a type of gas formed through decomposition and transformation of organic matter below the earth's surface. The gas may be composed of a number of chemical substances with different characteristics. Most of the substances are composed of hydrogen and carbon atoms, and we therefore call them hydrocarbons.
Natural gas consists primarily of methane, but also often consists of some ethane and smaller amounts of heavier hydrocarbons and CO_2.

When people talk about natural gas, you may hear them use the term LNG, or liquefied natural gas. LNG is simply natural gas that has been liquefied by cooling it to a very low temperature to make it easier for shipping. Through cooling, great volumes of natural gas can be condensed into a smaller volume for shipping (600:1).

Methane is a potent greenhouse gas

If methane leaks into the atmosphere before being used — from a leaky pipe, for instance — it absorbs the sun's heat, warming the atmosphere. For this reason, it's considered a greenhouse gas like carbon dioxide.
The Intergovernmental Panel on Climate Change chose carbon dioxide as the reference gas for global warming potential, and its GWP is equal to one.

Although methane, with an atmospheric lifetime of 12.4 years (IPCC, 2014), doesn't linger as long in the atmosphere as carbon dioxide, it is initially far more devastating to the climate because of how effectively it absorbs heat. Over a 100-year time horizon, methane has a global warming potential that is 28 times more potent than the equivalent amount of

1 www.nrcan.gc.ca/energy/sources/shale-tight-resources/17692
2 www.bcogc.ca/industry-zone/activity-levels
3 www.timescolonist.com/opinion/letters/oil-and-gas-commission-diligent-about-old-wells-1.2177149
4 http://worldmap.harvard.edu/data/geonode:british_columbia_oil_gas_wells_0cz

carbon dioxide (IPCC, 2014) and over 20 years, methane is 84 times more potent than carbon dioxide.
Controlling methane emissions is imperative if we want to have an immediate effect on reducing emissions that lead to global warming. Think of it as turning down the burner control on a gas stove. The effect of the reduced amount of gas on generating heat is almost immediate.

Fugitive emissions in the oil and gas sector

The oil and gas sector is the largest GHG emitter in Canada, accounting for 192 million MT (metric tonnes of CO_{2eq} (CO_2 equivalents) or 26 per cent of total emissions (Environment Canada, 2014). Most of these emissions are in the form of fugitive gas emissions, which include fugitive equipment leaks, venting and flaring. Most of the gas being released is methane (Canadian Association of Petroleum Producers, aka CAPP, 2004 a-c).

Estimated fugitive equipment leaks alone in Canada in 2000 had a global warming potential equivalent to the release of 17 million metric tonnes of carbon dioxide, or 12 per cent of all greenhouse gases emitted by the sector. By 2015, the amount more than doubled, to 49 million metric tonnes of CO_2 equivalents, or CO_2e (Le Fevre, 2017).
It is clear that fugitive emissions are a problem — one that is getting worse over time.

According to the B.C. Ministry of the Environment (2012), total fugitive methane emissions from the oil and natural gas industry were about 78,000 tonnes (2.1 million metric tonnes of CO_2e). According to the report, B.C. produced 41 billion cubic metres (or 30,757,689 tonnes) of gas in 2012. That would suggest that only about 0.28 per cent of the gas produced was released into the atmosphere. However, as this report shows, the actual amount of fugitive emissions in B.C. is significantly under-reported and the amount of methane being lost during drilling, handling and processing in the upstream oil and gas sector is much higher than current estimates suggest.

Government commitments to reducing fugitive emissions in the oil and gas sector

In March 2016, Canada and the U.S. committed to reducing fugitive methane emissions from the oil and gas sector by 40 to 45 per cent below 2012 levels by 2025[5]. To achieve this target, Canada and the U.S. committed to publishing their respective federal regulations as soon as possible, and to working collaboratively on programs, policies and strategies to reduce oil and gas methane emissions.

In August 2016, the B.C. government followed suit with the release of its Climate Leadership Plan (Province of British Columbia, 2016). That plan also calls for a targeted strategy to reduce fugitive and vented emissions in the B.C. oil and gas industry by 45 per cent by 2025, with a focus on fugitive and vented emissions from upstream oil and gas infrastructure built before January 1, 2015, and implementing new standards for mandatory leak detection and repair[6].

[5] https://www.canada.ca/en/services/environment/weather/climatechange/climate-action/technical-backgrounder-proposed-federal-methane-regulations-oil-gas-sector.html
[6] https://news.gov.bc.ca/releases/2016PREM0089-001501

What are fugitive emissions and how are they measured?

Fugitive emissions are emissions of gases or vapours from pressurized industrial equipment from leaks and other unintended or irregular releases of gases[7]. They are also deliberate releases of gases like fuel gas, which is used to power equipment. Fuel gas in the oil and gas industry is, more often than not, natural gas tapped from a well, and the pressure of that gas is used to operate equipment like pneumatic control devices that control such variables as pressure, gas level and temperature; positioners; and transducers (D'Antoni, 2014). According to the U.S. Environmental Protection Agency, the constant bleed of natural gas from controllers is collectively one of the largest sources of methane emissions in the U.S. natural gas industry, estimated at approximately 51 billion cubic feet, or 1.5 billion cubic metres, per year (USEPA, 2006). In greenhouse gas terms, that is equivalent to 31,507,876 tonnes of CO_2 (assuming the IPCC's 100-year GWP for methane of 28).

Not only do fugitive emissions result in losses of the relevant commodities producers handle, they also contribute to air pollution and climate change.

In general, fugitive emissions from oil and gas activities may be attributed to the following primary types of sources (Picard, 2008):

- fugitive equipment leaks,
- unreported process or intentional venting,
- evaporation losses,
- disposal of waste gas streams (e.g., by venting or flaring), and
- accidents and equipment failures.

Accidents and equipment failures can include well blowouts, pipeline breaks or leaks, tanker accidents, tank explosions, gas migration to the surface around the outside of wells, and surface-casing vent flows.

Gas migration to the surface may be caused by a leak in the production string at some point below the surface casing, or by the migration of material from one or more of the hydrocarbon-bearing zones that are penetrated (e.g., a coal seam). A surface-casing vent flow may be caused by a leak from the production casing into the surface casing or by fluid migration up into the surface casing from below. If a well is exhibiting surface-casing vent flow, there is a strong likelihood of a problem with the well infrastructure (poor cementing, fractured casings, etc.).

[7] http://en.wikipedia.org/wiki/Fugitive_emissions

The Intergovernmental Panel on Climate Change has developed guidelines for estimating fugitive emissions from oil and gas activities (Picard, 2008). These are based on a three-tier approach:

- Tier 1: Top-down average emission factor approach,
- Tier 2: Mass balance approach, and
- Tier 3: Rigorous bottom-up approach.

Tier 1 is the simplest and least reliable approach. It is a top-down approach in which average production-based emission factors are applied to reported oil and gas production volumes. This method is intended for use by countries with limited oil and gas industries, and with limited resources to develop more reliable estimates. According to the IPCC, it is, at best, an order-of-magnitude approach, and should only be used as a last resort.

Tier 2 is a mass balance approach. It is primarily intended for application to oil systems where the majority of the associated and solution gas production is vented or flared. In these cases, the total amount of associated and solution gas produced with the oil is assessed, and then control factors are applied to the results to account for conserved, reinjected and utilized volumes. The result is the amount of gas either flared or lost directly to the environment (whether through equipment leaks, evaporation losses or process venting). The flared, utilized and conserved volumes are determined from available production accounting data and engineering estimates. The rest of the gas, by difference, is lost directly to the atmosphere. The reliability of this approach increases as the portion of the total gas conserved, utilized or reinjected decreases. The total amount of associated gas per unit volume of oil production is given by the gas-to-oil ratio for the target oil fields. The amount of solution gas or product volatilization per unit oil production is determined from the change in product vapour pressure between the inlet separator at the field production facility (i.e., the vessel operating pressure) and the refinery inlet (e.g., a Reid vapour pressure of 30 to 55 kPa). Although the simple mass balance using national production statistics is a crude indicator of fugitive methane losses, it offers a greater degree of confidence than that offered by the Tier 1 approach.

Tier 3 relies on the rigorous assessment of emissions from individual sources using a bottom-up approach, and requires both process infrastructure data and detailed production accounting data. It may also include actual measurement work as well. The results are then aggregated to determine the total emissions.

A Tier 1 approach only captures the impact of any changes in gross activity levels. To show the impact of site-specific vapour and waste gas control measures, a Tier 3 approach is needed.

The B.C. government only estimates fugitive emissions by using a combination of inventory methods and information reported by industry based on field studies (Skuce, 2015). Inventory methods involve taking, for example, the expected leakage from a certain type of valve (based on things like manufacturer's specifications) and multiplying that factor by the number of such valves reported by companies to be employed in the field. Reports provided by industry are supposed to record emissions from combustion, leaks and venting of all greenhouse gases. These two methods are known as top-down or mass balance (or Tier 1 or 2) approaches and depend on equipment working as designed and on the operators fully reporting emissions.

At the national level, the federal government's GHG inventory published by Environment Canada and Climate Change uses a Tier 2 approach (Statistics Canada, 2007).

Entirely lacking in B.C.'s approach, however, are so-called bottom-up, or Tier 3 measurement approaches that researchers have used in gas fields throughout the United States. These techniques measure the methane concentrations in the atmosphere around gas-industry operations, using sensors mounted on towers as well as on ground and airborne vehicles.

Before the federal and provincial governments can actually develop a strategy for reducing fugitive emissions in the oil and gas sector, they first need to have a clear understanding of the true extent of those emissions and where those emissions are coming from. To achieve that understanding, a Tier 3 approach is needed to assess which components/ processes in the oil and gas industry are actually leaking or emitting and then determine the actual relative amount of methane that is being emitted from each source.

Bottom-up measurement of fugitive emissions in the Montney basin

For this study, we used a Tier 3 approach to investigate fugitive emissions in the Montney basin. Our methodology was informed, in part, by the results of a mobile fugitive emissions survey that we collaborated on with David Risk's Flux Lab at St. Francis Xavier University in Antigonish, Nova Scotia[8], carried out in the summer of 2015 (Atherton et al., 2017). Our study and results largely build on the detection of fugitive emissions using a mobile platform and are remarkably consistent with the findings of Atherton et al.

We conducted a simplified screening program to directly locate and identify fugitive emission leaks from infrastructure and equipment at oil and gas well sites (a large, if not the largest source of organic emissions at many facilities. CAPP, 2004). We then used a direct measurement technique (a form of "bagging") to try to measure actual leak rates.

2.0 Methods

As mentioned previously, in conjunction with St. Francis Xavier University in August 2015, we carried out mobile surveys (Atherton et al, 2017) using advanced fugitive emissions detection technology developed by David Risk at SFXU to try to assess fugitive emissions in the Montney on a broad scale.

[8] http://fluxlab.ca/ — FluxLab students and technicians work on large-scale emissions measurement problems in the energy sector.

We drove over 8,000 kilometres on pre-planned oil and gas development routes throughout the Montney formation (Figure 1) using a specially equipped vehicle designed to detect fugitive gas emissions. Our survey routes (six in all) brought us past more than 1,600 well pads and processing facilities developed by more than 50 different operators involved in oil and gas development.

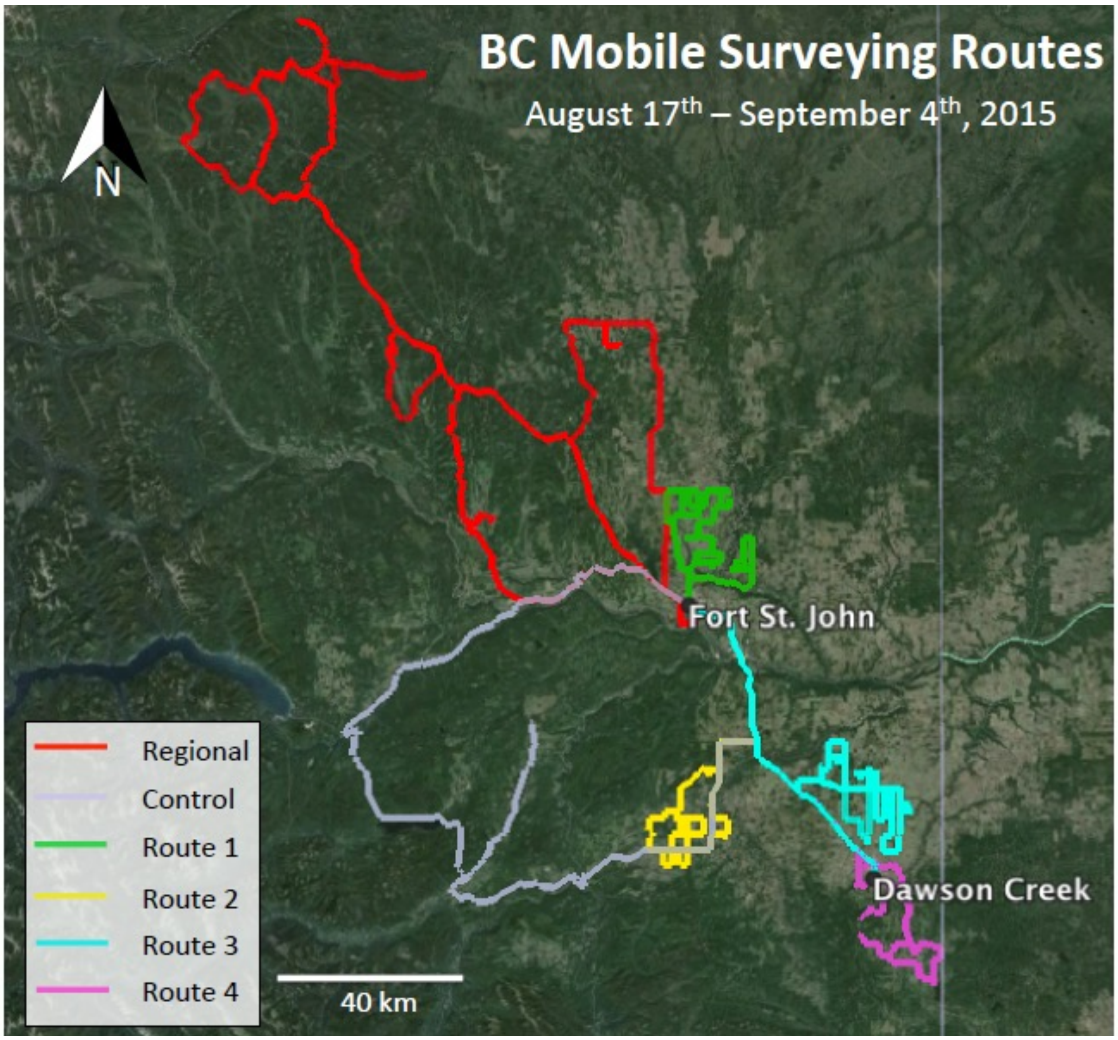

Figure 1. Survey routes driven by SFXU researchers using a mobile detection platform for detecting fugitive gas emissions in Montney field during the summer of 2015.

The results of that study (Atherton et al., 2017) found that roughly 47 per cent of active wells in the Montney emit methane-rich plumes to varying degrees. Methane-rich plumes were also found in the vicinity of abandoned, suspended and under-development well sites, but the incidence rate was below that of producing wells. To attribute on-road plumes detected by the mobile platform to infrastructural sources, gas signatures of residual excess concentrations (anomalies above background) less than 500 metres downwind from infrastructural sources were used.

Based on these surveys, multiple sites, including well pads, compressor stations and batteries[9], were found to be emitting methane (CH_4) and/or hydrogen sulphide (H_2S). Observed emissions from facilities of various types were, in some cases, highly repeatable.

Although we have very high confidence that methane-rich plumes from oil and gas infrastructure were being detected using mobile surveys (confidence is >95 per cent based on control routes and methodology for measuring gas concentrations in the field), actual source attribution (back trajectory analysis) for those oil and gas emissions is difficult because of infrastructural density, database inconsistencies, variable wind conditions and the distance from potentially emitting sites. In other words, the plumes exist, but it is difficult to be definitive as to their precise sources. For example, a detectable plume of methane may not be coming from a specific well in close proximity to the point of detection, but may be attributable to a nearby underground leaking pipeline or some other source more distant.

Follow-up field investigation: This report

Our objective for this second study was to access oil and gas infrastructure along the previously surveyed routes using mobile surveys and to attempt to directly measure emissions from specific infrastructure in areas where plumes were detected using mobile surveys. Prior to heading into the field, we were presented with maps of the mobile survey routes, along with information on the location of suspected sources/areas of detected fugitive emissions based on the findings in the mobile surveys. (See Figure 2 for an example.)

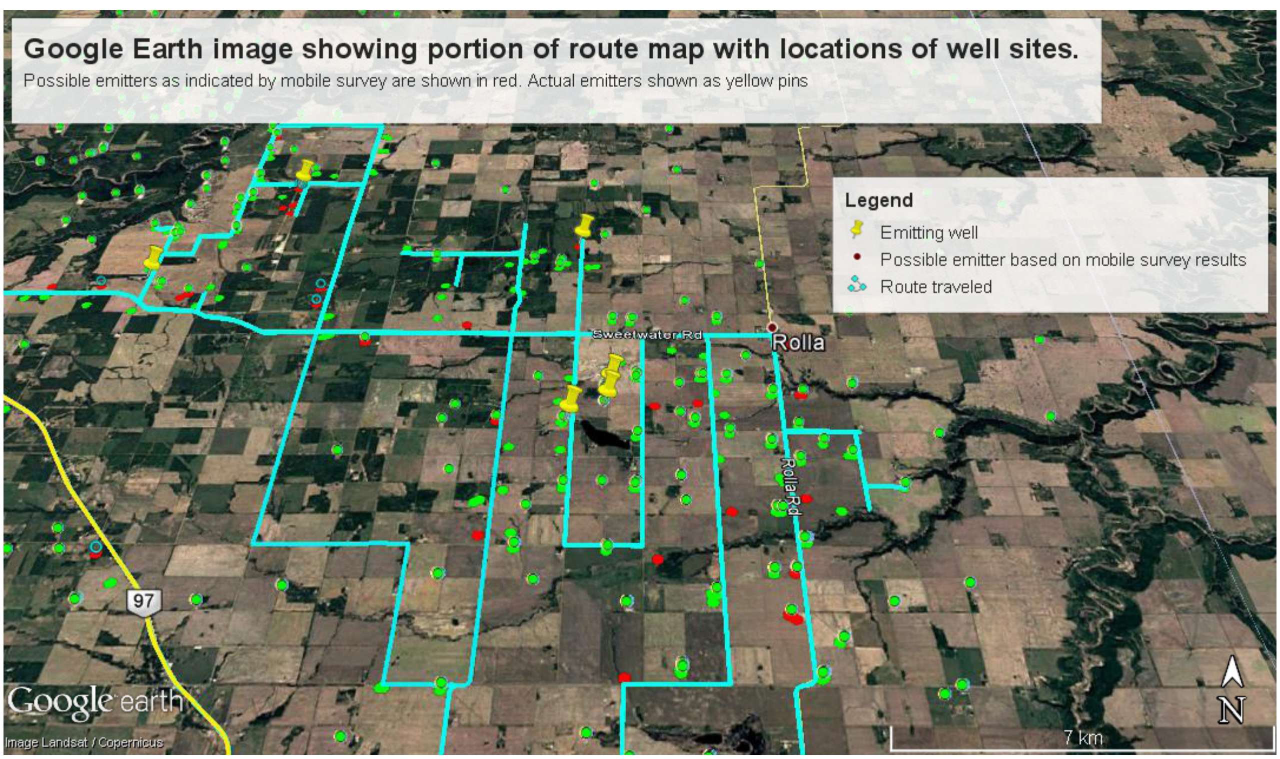

Figure 2. Google Earth image showing portion of route map with well sites and potential emitters indicated in red.

[9] A battery is an upstream facility in an oil or natural gas field that collects raw oil or natural gas from one or more wells. Oil, gas and water are separated at this facility, impurities removed and the purified liquids are piped for further processing or distribution.

We equipped ourselves with a Landtec GEM2000 Plus landfill gas monitor, which is capable of detecting per cent methane (CH_4), carbon dioxide (CO_2), oxygen (O_2), carbon monoxide (CO) and hydrogen sulphide (H_2S) by volume and static pressure and differential pressure of the gases. The device was also capable of displaying the percentage of the lower explosive level for methane. The GEM2000 Plus is designed and field-proven to monitor landfill gas extraction systems accurately and efficiently. The device was calibrated and tested for accuracy in a laboratory setting before being deployed in the field. It was equipped with 1.5 metres (five feet) of clear, 6 mm (quarter-inch) - diameter pressure-sampling hose, hose barb, spare internal particulate filter and spare water-trap filter. The device was plugged in and fully charged at the end of each day to ensure it was functioning properly upon each deployment.

We also obtained a FLIR ThermaCAM GasFindIR HSX infrared camera, which is manufactured by FLIR Systems Inc. FLIR cameras are specifically designed to detect volatile organic compounds and gases, including methane. The GasFindIR has been used extensively in oil and gas and petrochemical companies as a way to find gas leaks as part of their predictive maintenance programs. The GasFindIR HSX delivers high-volume scanning to productively spot leaks in tank cars, pipelines and facilities. The camera was owned, maintained and regularly calibrated by an established Calgary, Alberta–based company that provides professional leak detection and repair, as well as direct inspection and maintenance program services to chemical and oil and gas industries. It was properly calibrated and inspected prior to field deployment to ensure it was working properly. One drawback is that the FLIR GasFindIR HSX only “sees” in a narrow range of the electromagnetic spectrum (~3-4 um), and hydrogen sulphide (H_2S) — a gas commonly associated with hydrocarbon extraction — absorbs outside of FLIRs’ range (~2.6 um). Therefore, the camera cannot detect H_2S leaks, but the nose and gas monitors can.

Which route to survey on any given day depended on whether it had been surveyed previously, and/or prevailing weather and road conditions.

On each survey day, our field investigators would drive to the chosen area for investigation and access any or all oil and gas facilities (wells, batteries, compressor stations), depending solely on whether they were accessible (whether or not the well site or facility was flagged as a possible emitter was only one determining factor). Accessibility was key. If a facility was behind a locked gate or if the property housing the facility was marked “No trespassing”, the facility was passed by, unless it could be reasonably and safely inspected using the FLIR camera from public roadways. However, leaks at well sites were, more often than not, too small to be detected using the FLIR camera from such distances, which often could be several hundred metres. We could only effectively employ this option at large facilities, like compressor stations and batteries.

We were able to survey anywhere from 10 to 35 sites per day depending on local site density and access. Oil and gas development throughout the Montney is spread out over large areas and, in some areas, well sites and facilities were more concentrated than in other areas. This explains, in part, the variation in the number of sites accessed on any given day. Weather was also a factor on some days.

Once we accessed a site, we would first document and photograph the site identification number (see photo 1, Appendix A) that is required to be posted at all facility locations. We would then check our database of oil and gas wells provided to us by the BC Oil and Gas Commission to determine site status (abandoned, suspended or producing, etc.). We would then survey the site to determine whether it was safe for further entry (i.e., no dangerous levels of toxic gases or other hazards detected) and then, once on the site, we checked around the infrastructure for potential signs of fugitive emissions. We would first smell the air around the facility to see if we could detect the characteristic odour of gases, or listen to see if we could hear gas escaping from infrastructure (hissing or venting).

We note that although natural gas is predominantly composed of methane, an odourless gas, it does have a distinctive smell, largely due to the fact it contains other volatile organic compounds that actually do impart an odour. And of course, hydrogen sulphide has its own distinct and detectable aroma (like rotten eggs).

We inspected the wellhead (if present) and surface-casing vent pipes and all of the above-ground piping and buildings looking for leaks or vents.

If we detected gas odours at the wellhead, we would insert the sampling hose connected to the GEM2000 Plus landfill gas monitor into the opening of the surface-casing vent and check for escaping gases (primarily methane and/or H_2S). This is an accepted method of detecting vent flow as outlined in the Alberta Energy Resources Conservation Board Bulletin 2011-35 — Types of Surface Casing Annular Flow Testing Procedures and Gas Identification Techniques.
If we detected escaping gases (in this case methane or H_2S), we would then employ the FLIR camera to scan the surface-casing vent, wellhead and all surrounding pipes and flanges, looking for obvious leaks (photos 2 and 3, Appendix A). We would then apply a balloon to the SCV (if found to be emanating gas) and allow it to inflate (photo 4, Appendix A), and time how long it would take to for the balloon to fill. Full inflation, for the most part, was considered achieved when the balloon "snapped to attention" but did not necessarily appreciably or noticeably stretch beyond the dimensions of its resting state (e.g., photo 5, Appendix A) unless the positive pressure emanating from the SCV was sufficient to noticeably continue to stretch the balloon beyond its resting dimensions (as shown in photo 4). Some balloons are softer and easier to inflate than others, but any balloon, if pushed to a certain point, will cause back pressure to the inflating device, confounding the observer as to whether it is inflating further in response to the actual applied pressure). At inflation, the dimensions of the balloon (in the case of SCVs, the balloon was a cylindrical-shaped balloon, so length and diameter) and the time to fill were recorded. In other instances (discussed further on), we used a round balloon with a smaller inlet (the outlet of an SCV is on average 50 mm). In all cases, new uninflated balloons were first stretched by inflation and/or tugging on the balloon prior to applying it to the escaping gas source to allow the latex to relax in the event the positive pressure at source was enough to continue to inflate the object.

This "ballooning" of leaks at SCVs was a slight modification of the standard "bubble test" or "glove test" used in the oil and gas industry to detect leakage and positive pressure from SCVs but allowed us to assess whether there was positive pressure emanating from the SCV (or from vent pipes) and to estimate the volume of gas that was escaping at the time (within the limitations of the basic physics that allow for balloon inflation).

This method of detecting and estimating gas flow was employed to sample gas emanating from vents at active gas sites but it was modified slightly because the vent pipes we found at gas sites (photo 6, Appendix A) were much smaller in diameter (6mm - one-quarter inch - inside diameter) than that of SCVs (50 mm - two-inch - inside diameter pipes). For these cases, we used a balloon with a much smaller diameter inflation hole (like a standard party balloon. See photo 7, Appendix A).

If the particular site was designated as “suspended” or “abandoned”, we recorded the year that status was effective and we also documented and photographed the site conditions, including whether there was surface infrastructure in place.

2.1 BC Oil and Gas Commission data

Pursuant to S. 41 of the Drilling and Production Regulation under the B.C. Oil and Gas Activities Act, permit holders must check their wells routinely, which, according to the 2017, BC OGC Oil and Gas Operations Manual (Chapter 9: Completion, Maintenance and Abandonment) means annually, and they should check each well for evidence of a surface-casing vent flow as routine maintenance throughout the life of the well.

On discovery of a surface-casing vent flow that presents an immediate safety or environmental hazard, a well permit holder must:

(a) immediately take steps to eliminate the hazard,

(b) immediately notify the commission of the surface-casing vent flow, and

(c) submit to the commission without delay a report respecting the surface-casing vent flow and the steps taken under paragraph (a).

On discovery of a surface-casing vent flow other than one deemed to be “serious”, a well permit holder must:

(a) test the flow rate and buildup pressure of the surface-casing vent flow, and

(b) submit a surface-casing vent flow report to the commission within 30 days of the discovery of the surface-casing vent flow.

Serious surface-casing vent flow means:

- Vent flows with hydrogen sulphide (H_2S) present.
- Vent flow with a stabilized gas flow rate equal to or greater than 300 cubic metres per day (m^3/d).
- Vent flow with a surface-casing vent stabilized shut-in pressure greater than one half the formation leak-off pressure at the surface-casing shoe or 11 kPa/m times the surface-casing setting depth.

- Hydrocarbon liquid (oil) vent flow.
- Vent flow due to wellhead seal failures or casing failure.
- Water vent flow if the water contains substances that could cause soil or groundwater contamination.
- Vent flow where any usable water zone is not covered by cemented casing.
- Other vent flow constituting a fire, public safety or environmental hazard.

The BC OGC maintains records of these reports.

We obtained data files from the BC Oil and Gas Commission that included reports of observed surface-casing vent flow at wells throughout British Columbia from January 2005 to present. These were Excel files and included information such as well ID number, company, date(s) the well was visited, whether SCVF was observed and, if measured, the volume and type (gas, saline water, hydrocarbons) of flow observed and whether or not remedial measures (i.e., SCVF repair) were undertaken.

These data were aggregated and presented in date order but there was no analysis of the data provided. Several thousand entries were included in two separate data files (one covering the period January 2005 to August 2014; a second covering the period September 2014 to present), but not all entries related to different wells. In some cases, the data included several entries for one particular well under observation.

To determine how many wells with SCVF had been reported overall, we had researchers analyze the data and eliminate repeat (test and re-test) entries for individual wells. For example, one data file (September 2014 to present) had 1,471 separate entries, but the actual number of wells represented in the data file was 961. In addition, many of the data fields for specific wells did not include data, or comment, concerning SCVF other than vent flow was observed/detected (e.g., “gas”). Associated data fields for estimated vent flow were often either blank or contained a “0” entry.

In the case of the specific data file cited above (September 2014 to present), after accounting for blank entries and “0”s, the actual number of wells with observed and measured SCVF fell to 494 (roughly 50 per cent).

To calculate average vent flow (m^3/day) across all wells using these data, any blank entries with blank flow rate fields were eliminated. Fields with a “0” entry were retained and assumed to be emitting but only exhibited trace flows of gas. We also totalled the number of wells that were reported as having been remediated.

3.0 Results

We investigated 178 separate oil and gas well sites throughout the Montney over a period of 12 days during summer 2016 (August 14 to 25). The relative locations of the emitting wells are shown in Figure 3. Note that the geographic scale of the area is so large that many of the actual "pinned" emitting well sites do not show up on the map. That does not mean they do not exist; it is because they are "hidden" behind the visible icons.

The primary objective of these investigations was to try to ascertain whether and which well sites (or individual wells or facilities at multi-well sites) along these routes were actual (not possible or probable) sources of fugitive emissions of methane and, if present, hydrogen sulphide; and, if so, attempt to determine the sources of those emissions and try to measure their intensity (within the limits of our capability).

As mentioned previously, we chose sites for investigation mainly on whether they were accessible to investigators. The only assumptions made about which sites to investigate were based on prior knowledge of the existence of potential emitters along predetermined road routes that had been examined during mobile, vehicle-based fugitive emissions surveys conducted by researchers from SFXU in summer 2015 (Atherton et al., 2017). Possible emitters along these routes were plotted on Google Earth maps by researchers from SFXU based on geospatial attributions of publicly available data provided to them by the BC Oil and Gas Commission that showed and classified all known oil and gas infrastructure in the province, including the Montney play.

All in-place oil and gas infrastructure both upwind, and within 500 metres of an on-road methane-enriched anomaly or plume detected during the mobile surveys mentioned above (where CO_2:eCH_4 < 150) were considered as possible emitters and were plotted on maps (see Figure 2 above). We used these maps to help guide us to general areas of concern, but once in an area, we inspected all accessible well sites and facilities we encountered, regardless of whether they had been tagged by researchers as emitters or not.

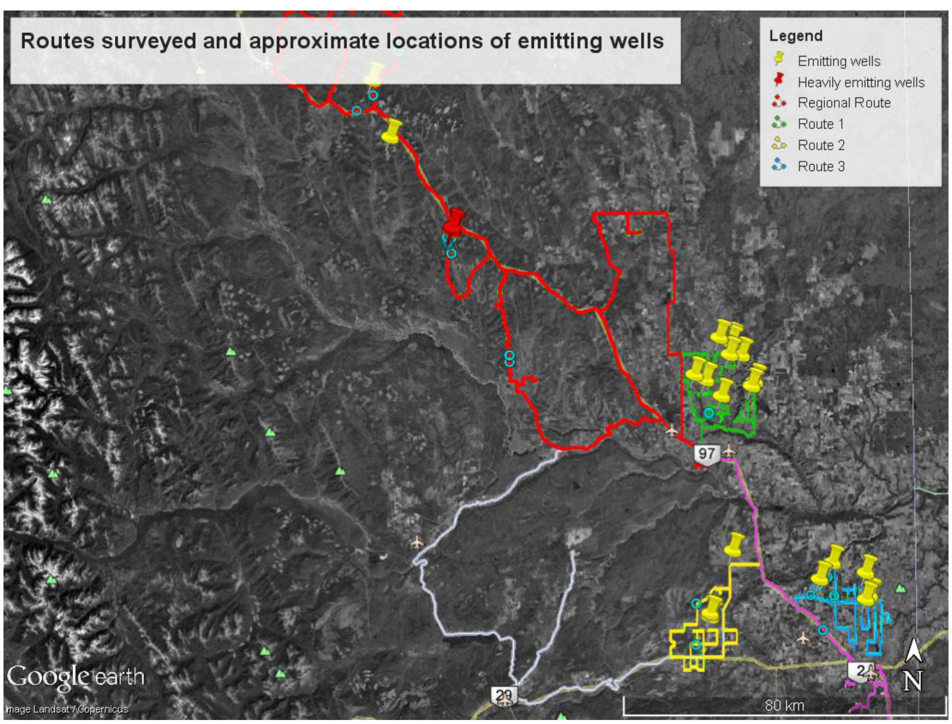

Figure 3. Map showing the routes surveyed for the purposes of this report and the approximate locations (yellow pins) of leaking or venting well sites.

3.1 Field observations

The results from our field survey (Table 1: Figure 4) suggest that upwards of 44 per cent of all wells encountered in the Montney are emitting methane and/or H_2S (or a combination of the two) at some level, ranging from trace emissions to relatively heavy emissions on the order of hundreds of cubic metres per day (m^3/day).

Methane emissions were more easily detectable than those for hydrogen sulphide, given the nature of the equipment we deployed. Although the GEM2000 Plus landfill gas monitor has the capability to measure H_2S in the range of 0-500 ppm (Landtec, 2008), the gas pods used to measure H_2S can suffer from cross-gas effects, and in the presence of high volumes of a cross gas (such as methane), the meter may fail to read the concentration of H_2S (Landtec, 2008). Further, the odour threshold for H_2S is only around 0.5 ppb (Ruth, 1986, Iowa State University, 2004), so its presence may be easily detected by the nose but may not be measurable with the landfill gas monitor. As mentioned earlier, the FLIR GasFindIR cameras cannot detect H_2S.

Table 1. The type (producing, suspended, abandoned, etc.) and number of wells in each category surveyed for this study and the corresponding number of wells determined to be either venting or leaking gas.

Type	Number	Leaking or venting	Percentage	Average flow rate m^3/hr	ODNLF	Trace**	H_2S present	Other
A/S	62	18	29%	1.48 (N=10)	4	6	2	
P-O	25	7	28%	0.28 (N= 3)	4	2	1	1(oil)
P-G	49	42	86%	1.13 (N=30)	3	3	6	2 (Danger) (high H_2S)
UND	10	3	30%	0.1 (N=1)		2		
Shut in	16	5	31%	0.37 (N=1)		3	1	Badly leaking wellhead
Other	9	4	44%	ODLNF	4		2	1 Pipeline leak 2 oil leak at wellhead
Water	7	4	57%	0.34 (N=4)				
Totals	**178**	**84**			**15**	**16**	**12**	**7**

A/S = Wells classified as abandoned or suspended.

P-O = Producing oil wells.

P-G = Producing gas wells.

UND = Status of well could not be determined. These wells were inactive or were, at times, partially dismantled.

Shut in = The gas field housing these wells (Blueberry, near Wonowon, B.C.) was “shut in” during the time we conducted our investigations. All wells were locked down so their status was uncertain.

Other = Facilities and former facility sites (e.g., compressor stations, batteries, test satellites) and wells designated as “completed”.

Water = Wells designated in BCOGC files as water wells. The majority of these were suspended wells that have been reclassified as water injection wells.

*ODLNF = Odour of gas detected on or around the site but no leak was found. Usually applies in the case where H_2S was encountered.

**Trace = Indicates that only a trace of gas (e.g. < 50% CH_4 detected with gas monitor) or only intermittent gas flow from SCV was detected.

Emitters included abandoned and/or suspended wells (primarily through surface-casing vents, or “SCVs”), producing oil and gas wells (either through SCVs or through deliberate venting) and to a much lesser extent (at least in terms of frequency as observed) oil and gas collection and compression facilities.

Surface-casing vent flow was detected at a total of 45 separate wells.

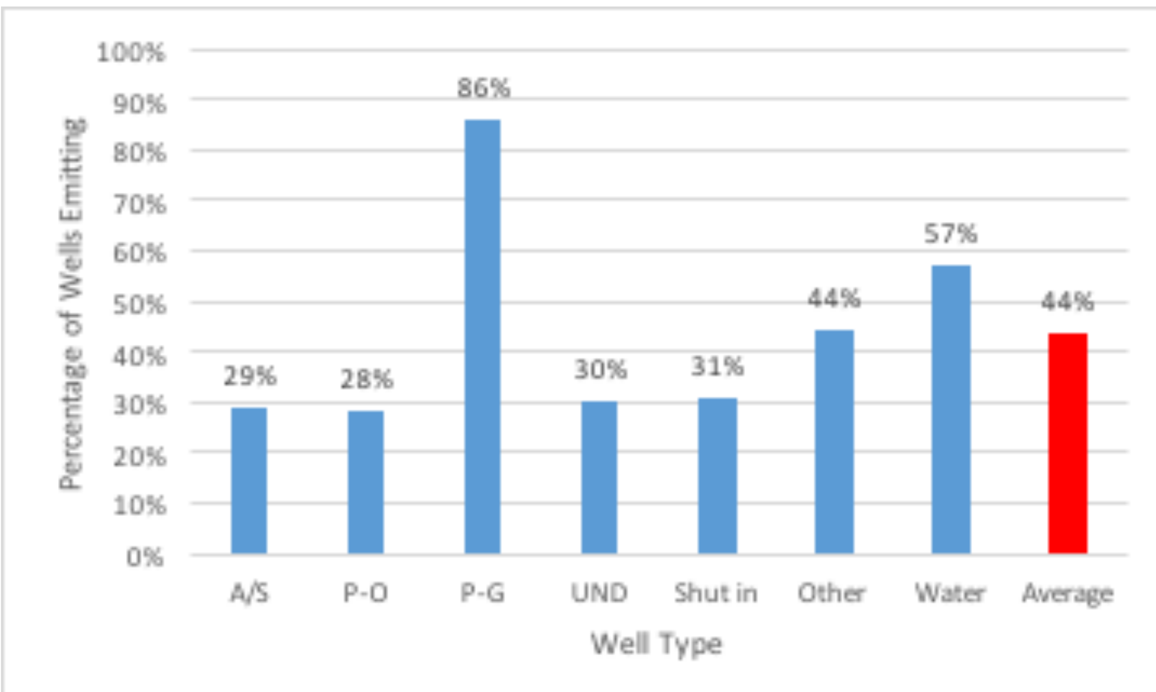

Figure 4. Percentage of wells found to be emitting, by well type.

A/S = Wells classified as abandoned or suspended.

P-O = Producing oil wells.

P-G = Producing gas wells.

UND = Status of well could not be determined. These wells were inactive or were, at times, partially dismantled.

Shut in = The gas field housing these wells (Blueberry, near Wonowon, B.C.) was “shut in” during the time we conducted our investigations. All wells were locked down so their status was uncertain.

Other = Facilities and former facility sites (e.g., compressor stations, batteries, test satellites) and wells designated as “completed”.

Water = Wells designated in BCOGC files as water wells. The majority of these were suspended wells that have been reclassified as water injection wells.

3.1.1 Abandoned and suspended wells

Surface-casing vent flow was detected at around 29 per cent of all abandoned and suspended well sites (n = 62). The average calculated flow rate of leaking/venting gases emanating from abandoned and suspended wells through the SCV where positive gas pressure was noted and balloon inflation occurred and could be measured (n=10) was 1.48 m^3/hr (29.5 m^3/day). However, this number is significantly inflated by one significant outlier (Shell Sunset 15-33-080-18 w6m), which was leaking badly and at a very high rate (estimated to be around 9.4 m^3/hr – 225 m^3/day). When this well is removed from the equation, the average rate of flow of gas from leaking abandoned or suspended wells was around 0.60 m^3/hr (n=9) or 14.6 m^3/day.

Bear in mind that six other abandoned and/or suspended wells were determined to be leaking gas at trace amounts where the rate of flow could not be measured (insufficient positive pressure to inflate the balloon) but gas could be detected with our gas monitor.

At two of those wells, we detected H_2S emissions but the actual level was too low to be detected with our monitoring equipment. For this we relied on our sense of smell.

There was also one well (Progress Blueberry C-A39-K/94-a-12. See photo 8, Appendix A) that was leaking badly from both the SCV and the wellhead where again the rate of flow could not be measured because when the balloon was affixed to the SCV, back-pressure from the balloon caused more gas to escape from the leaking wellhead so the balloon would not inflate.

If we include all the wells that exhibited SCVF, including those that were leaking only trace amounts of gas (n=6) and include the heavily leaking Shell Sunset well mentioned above, the daily leak rate averages out to around 22.2 m^3/day (n=16).

The well Shell Sunset 15-33-080-18 w6m was the heaviest emitter of all of the abandoned and/or suspended wells that we encountered. The force of the gas coming out of the SCV was so great it literally blew a balloon off the end of the pipe within three seconds.

A second well in the same area, Shell Sunset 11-28-80-18 w6, was the second heaviest emitter we observed. According to the BCOGC, this well was also reported to be emitting in 2015 but only at trace levels.

3.1.2 Producing oil wells

Surface-casing vent flow was detected at roughly 28 per cent of all operational and producing oil wells (n = 25). We have no explanation for this, but vent flows did occur. One thing we did observe, however, is that some of the vent flows at sites where the pumpjack, or one nearby, was actively pumping were intermittent and variable in terms of gas concentration. At one well site in particular (Pengrowth Oak 08-10-86-18 w6), SCVF pulsed and fluctuated between five and 45 per cent methane as detected with the GEM2000 Plus landfill gas meter. Perhaps this was related to the changing well-bore pressure caused by pumping the well.

The average calculated flow rate of leaking/venting gases emanating from producing oil wells through the SCV where positive gas pressure was noted and balloon inflation occurred and could be measured (n=3) was 0.28 m^3/hr or 6.72 m^3/day.

Two wells that we visited (CNRL Owl 08-16-86-18; CNRL Devon et al Owl 06-16-86-18) were not venting from the SCV but the wellheads were covered in oil (photos 9, Appendix A). At a third (Eagle A08-07-85-18), it looked like the well suffered a recent blowout because the wellhead and the ground all around the wellhead were soaked in oil (photos 10 and 11, Appendix A). It was obvious that these hydrocarbon leaks were known to be occurring because the wellheads and ancillary pipes attached to them were heavily wrapped in plastic and red duct tape. We can only assume this was done to try to stem the flow of leaking oil from these wells.

A fourth oil well (West Eagle 06-11-85-19 w6m) was found to be leaking liquid hydrocarbons from the SCV. A hose was attached to the SCV and allowed to drain into a 50-gallon drum (photo 12, Appendix A).

3.1.3 Producing gas wells

The number of active gas wells was by far the largest of all categories of emitters, and also emitted the most frequently. More than 85 per cent of all producing and operational gas wells (n = 49) were found to be venting pure methane directly to the environment either through external “LNG” vents found on buildings (a.k.a. instrument sheds) that house the instrumentation and pneumatic devices (photo 13, Appendix A) used to measure and control gas flow at wellheads, or were leaking at wellhead SCVs. In some cases, it was through both. With few exceptions, all operating gas well sites were found to be venting gas through such vents. In many cases, especially on multi-well sites with multiple instrument sheds servicing the on-site wells, every building we inspected had at least one external building vent that was actively venting gas.

The gases being vented through these external LNG vents at gas well (photo 14, Appendix A) was not being captured in any way. It was simply allowed to vent directly to the environment.

At some operational gas sites, we also found SCVF occurring, but the overall incidence was relatively low.

One anecdotal observation we made was that, if a gas well site was not actively drawing gas from wells (e.g., all compressors or pneumatic devices were silent, or the well was shut-in or locked down), there was a greater chance of finding SCVF at some of the wellheads on the site. In one case (Tourmaline Sunrise 05-23-080-16 w6m), a multi-well site composed of three wells and one instrument shed, we found that all three of the wells exhibited SCVF and there was one LNG vent protruding from the building that was also venting gas directly to the environment.

At another well site (Tourmaline Heritage 06-01-81-16 w6), two of the wells on this multi-well site were found dripping liquid (water?) from their SCV. It was obvious that someone had noticed this leakage prior to our inspection because the openings to the SCV on the two wells were encapsulated in rubber gloves. The gloves had been there for so long they were deteriorating and liquid was seeping from them.

The average calculated flow rate of leaking/venting gases emanating from LNG vents on instrument buildings at operational gas sites that could be physically reached, or accessed, and measured (n=30) was 1.13 m^3/hr or 27 m^3/day.

With regard to H_2S emissions, two wells stood out as being significant emitters of the gas. One well (CN South Beavertail d-69-h/94-A-15) was emitting H_2S so heavily it caused our personal gas monitors to emit an alarm. We even began to feel the effects of the gas (dizziness, burning eyes) on approach to this well, so we avoided getting too close to the wellhead. The odour of gas was detectable up to at least 100 metres away from the well. What was significant in our view is that cattle were grazing in close proximity to this site.

A second well (Arc HZ DOE 08-01-80-15 w6) was particularly noticeable in that, even though we were able to approach the well safely and measure the amount of gas being emitted from a “coffin-like” structure into which vented gas was being pumped and then subsequently emitted, we could smell H_2S from this site almost 500 metres away at an adjacent well.

3.1.4 Water wells

Even wells designated as “water wells” were found to be emitting methane through surface-casing vents. While few water wells were encountered, and inspected (n = 7), 40 per cent exhibited measureable SCVF.

It is worth noting that water wells are generally suspended oil or gas wells that have been converted from their original intended purpose.

The average calculated flow rate of leaking/venting gases emanating from water wells through the SCV where positive gas pressure was noted and balloon inflation occurred and could be measured (n = 4) was 0.34 m^3/hr or 8.0m^3/day

3.1.5 Shut-in wells

The gas field (Blueberry) containing the wells in this category was “shut-in” during the time we conducted our field investigation so we could not accurately determine the operational status of any wells in the area since they were all locked down or, in some cases, disconnected from pipelines. Needless to say, none of them were operating at the time. We did, however encounter one well (Progress Blueberry D-30-K/94-A-12) that was located on what appeared to be a field-servicing site and designated as a water well, so we included it in the “water well” category on Table 1. It was found to be leaking methane from the SCV quite heavily (approximately 0.37 m^3/hr). Five wells in all exhibited surface-casing vent flow but three were emitting only trace levels of gas. Two were emitting quite heavily through the SCV and one in particular (Progress Blueberry C-A39-K/94-a-12) was actually leaking through both the SCV and the wellhead. The leak at the wellhead was so severe that we could not get a balloon to inflate when placed over the SCV. This caused back pressure, which noticeably forced gas (methane) out through flanges on the wellhead (increase in flow observed with the FLIR camera).

The calculated flow rate of leaking/venting gases emanating from water wells through the SCV where positive gas pressure was noted and balloon inflation occurred and could be measured (n=1) was 0.37 m^3/hr or 8.9m^3/day.

3.1.6 Other and undefined well sites

Other well sites included those with well identification numbers assigned to them, but most of these sites were either facilities (compressor stations, batteries, test satellite stations) or former satellite or battery sites. One involved an above-ground pipeline junction.

Because of restricted access to compressor stations, we could not get on site at these locations to measure ambient gas levels or survey the sites for leaks/vents, and we could only surmise that gases were being emitted from these locations using the FLIR cameras from a distance and using our sense of smell. When compressor stations were operating, emissions could be seen using the FLIR camera (photo 15, Appendix A). However, these were generally from stacks and flues that also generated a lot of heat, so it was difficult to tell the heat signature picked up by the camera from the possible gas signature. That said, we surmised a significant portion of the visible plumes emanating from the stacks was, in fact, methane gas because the “gas clouds” did not dissipate as readily as they would have if the venting gas trails we observed using the FLIR camera were steam (it was mid-summer and temperatures were likely too high to allow for extended steam trails); and, the air around these stations was heavy with the smell of methane.

The strong odour of gas (either methane or H_2S) was noted at 12 well sites we visited (some are mentioned above) but, even with close inspection, we could not determine the source(s) of the gas at most of these sites. These were typically operating sites (either pumping oil or gas; or serving as collection points — e.g., batteries or test satellite stations) with buildings onsite housing processing or collection equipment that we could not access for inspection. It may be that many of the leaks were occurring inside these buildings. There were, however, four sites where we determined the sources of H_2S emissions were related to leaks or vents from site infrastructure (two associated with SCVF; one from a dehydrator vent; and one from a pipeline).

3.1.7 Summary

Taking into consideration all of the estimates of observed and measurable surface-casing vent flow from abandoned, suspended and producing oil wells, shut in wells and leaking water wells, we are able to determine that roughly 35 per cent of wells in these five categories exhibit surface-casing vent flow at average flow rates ranging from between 9.0 and 11.5 m^3/day (the higher estimate includes the heavily leaking "outlier" Shell Sunset 15-33-080-18 w6m, but also takes into account wells leaking at trace amounts).

3.2 BC Oil and Gas Commission data on industry-reported surface-casing vent flows

It is impossible to know how many of the 25,000 oil and gas wells in the province have been checked for SCVF. This is because prior to 2010 there was no requirement under B.C. law for permittees to document or report SCVF at wells if or when it occurred. However, with the introduction of the B.C. Oil and Gas Activities Act in 2010 and the associated Drilling and Production Regulations (B.C. Reg. 282/2010), there are now specified requirements for well permit holders to check for and report on surface-casing vent flow during initial completion of a well, as routine maintenance throughout the life of a well and during abandonment of a well.

It is our understanding that the BGOGC interprets this to mean that all wells abandoned after 1995 and wells drilled or completed or suspended after 2010 should be checked for SCVF. Indeed, the BCOGC maintains a database showing wells that are reported to have exhibited SCVF. These include data from as far back as 1995 up until December 31, 2016.

Currently, 2,739 wells in the entire BCOGC surface-casing vent flow reporting database are reported to have exhibited surface-casing vent flow (Josh Wisen, master's candidate, University of Quebec, Chicoutimi. Pers. Comm). Wisen has determined that if the directive stands that only those wells that are abandoned since 1995 or drilled or completed after 2010 stands then there are about 8,400 wells that, to date, should have been checked for SCVF.

If we only consider wells that should have theoretically been checked for SCVF based on this directive, then rate of leakage is estimated to be on the order of 32.5 per cent (2,739/8,400), which is on par with what we have observed by direct observation and inspection during our summer 2016 field inspections of random well sites.

The authors of the current study did not have access to the entire BCOGC surface-casing vent flow database. However, we did have that portion of the database that covered the period January 1, 2005, until December 2016. This portion of

the database contained reports of SCVF at 2,602 wells, which is 95 per cent of all wells reported.
We cross-referenced all of the well sites we visited during this field survey with the records in this database, looking for corresponding well sites where surface-casing vent flows had been reported at some time over the past decade (since 2005).

Only 26 of the 178 well sites we visited in summer 2016 appear in the BCOGC's database.

Of those 26 wells only 13 (50 per cent) reported any data regarding SCVF flow type (gas, hydrocarbon, brine) or rate (a required field). Accordingly, we could not determine if the 13 wells with unreported data were actually identified by industry as exhibiting any SCVF; or of they did, to what degree, but we assumed they did.

Of those 26 well sites that corresponded to the sites we visited, only eight have been reported on in the past year (2015 – 2016). Of those eight, only three had any data reported relating to SCVF type or rate.

Of the 13 well sites where SCV flow type or rate of any kind was actually reported in the BCOGC data, only eight corresponded with sites where we observed SCVFs in 2016. The remainder may have exhibited detectable SCVFs at some point in the past, but at the time of our inspection, we did not detect any SCVFs.

Seven of the sites that were reported on in the BCOGC database as having SCVF during past inspections were found to still have SCVF in 2016.

Five of those 13 sites reported SCVF that had occurred sometime in the past but after a follow-up check were no longer flowing.

Four of 26 sites reported no data on SCVF at sites where we observed flows.

Four of 26 sites reported SCVF at some point in the past at sites where we observed none.

One oil well in particular that appears in the BCOGC database (Pengrowth et al Oak 10-34-85-18) has been checked numerous times for SCVF, and was reported on in 2009, 2011 and 2012 as exhibiting fairly significant vent flows, on the order of 7.5 m^3/day. This site was still leaking gas from the SCV when we inspected it in 2016. At the time of our inspection, this well was still pumping/producing. The gas flowing from the vent was almost pure methane at an estimated flow rate of approximately 0.37 m^3/hr, or 8.8 m^3/day.

The BCOGC data also indicate if any of the leaking wells have been remediated and the dates on which remediation was undertaken. Only 115 of the 2,602 wells (four per cent) reporting SCVF had any form of remediation carried out on them. None of the wells listed in the database as having been remediated corresponded to any of the wells sites we visited in 2016 where SCVF had been detected. This was true even if they had been identified as leaking in the past. Using the BCOGC data from September 1, 2014, to December 2016, we were able to compute an average SCV flow rate. This included data from 961 wells. To do so, we excluded all blank fields where no type or flow rate was recorded (N = 335) but kept all entries where type of flow and rate (“0” or greater) were reported, assuming that “0” meant trace flows (N=626). Computed average vent flow was on the order of 9.31 m^3/day (N=626). This compares favourably with our average overall estimated SCVF rate of between 9.0 and 11.5 m^3/day based on direct observation and measurements of vent flow at abandoned and suspended wells, producing oil wells and water wells in the Montney. A similar analysis of the data set from January 1, 2005, to August 31, 2014, yielded an estimated SCVF rate of 20.48 m^3/day (N = 1641), but for the sake of being conservative in our estimates of SCVF, we will use a rate of 10 m^3/day (average between nine and 11).

We are unable to determine the cause of any of the observed SCVFs.

4.0 Discussion

Using a simplified screening program, we were able to identify emissions of fugitive methane due to SCVF and equipment leaks and deliberate venting of gases (primarily methane) at selected oil and gas well sites in the Montney gas field in northeastern B.C. and obtain estimates of the rate of flow of those emissions at sites where emissions were detected.

The percentage of well sites that we found exhibiting SCVF during our inspections (35 per cent) and the estimated average rate of flow from those SCVs (between 9.0 and 11.5 m^3/day) is remarkably consistent with the percentage and average flow rate reported by industry to the BCOGC (32.5 per cent and 9.9 m^3/day, respectively), assuming the reported flow rates are reliable.

Accordingly, we believe we can use these data to calculate a reasonable approximation of the total fugitive methane emissions in the upstream leg of oil and gas development in the area.

We found that:

- On average, around 35 per cent of all abandoned, suspended (including water wells), shut-in and active oil wells in the Montney exhibit measurable and, in some cases, significant surface-casing vent flows of methane and hydrogen sulphide gas, or a combination of both. The average rate of flow of methane gas from surface-casing vents was conservatively estimated to be between nine and 11 m^3/day. To be conservative and fair, we opted to use a value of 10 m^3/day.

- More than 85 per cent of all actively producing gas wells were found to be venting methane gas directly to the environment daily while in operation through "LNG" vents on instrumentation buildings that house pneumatic control devices. This vented gas is not being captured or flared and, based on the results of measurements taken with the Landtec landfill gas monitor, it is almost pure methane. The estimated rate of flow from LNG vents was estimated to be about 1.13 m^3/hr or 27.1 m^3/day.

According to the BC Oil and Gas Commission, the total number of wells drilled in the province to date is conservatively estimated to be about 25,000. Of those, 12,771 were recently reported to be active gas wells (Jeakins, 2016). The remainder are either oil wells or wells that have been designated as abandoned or suspended or as water-disposal wells.

As of November 2014, BC Oil and Gas Commission data indicate that there were 6,978 abandoned wells and 2,945 suspended wells for a total of 9,923. As of December 2016, there are 252 approved water-disposal wells in B.C. All of them are in the northeastern oil and gas fields (BC Oil and Gas Commission, 2016).

BC Oil and Gas Commission reports also show that 13,850 wells have been drilled in the province since January 2000. Using BCOGC data and statistics, we were able to determine that around 94 per cent of these are gas wells[10] (this is an average of the ratio of oil to gas wells over six years of data), bringing the total number of active gas wells to roughly 13,019 (13,850 X 0.94) with the remainder (831) being oil wells, which is on par with what Paul Jeakins, commissioner and CEO with the BC Oil and Gas Commission (2016) has stated publicly.

Based on our findings, approximately 35 per cent of active oil, abandoned and suspended wells (including water wells) exhibit SCVF and vent, on average, about 10 m^3/day. From what we can tell, this venting is continuous and likely occurs 24 hours a day as there was little in place at any of these sites in the way of infrastructure or instrumentation to control SCVF.

Considering that there are roughly 11,079 active oil, abandoned, suspended and water-disposal wells in B.C., we can estimate these wells to be emitting roughly (11,079 wells X 0.35 X 10 m^3 CH_4/day X 365 days/year) 14,153,422 m^3 CH_4/year.

At least 86 per cent of all active gas well sites were found be emitting methane gas at a rate of around 1.13 m^3/hour through vents on buildings that house instruments like pneumatic control devices. This is a minimum vent rate per site and, for the purposes of this report moving forward in our calculations, assumes only one well instrumentation building and one active vent per well site. However, in reality, there can be several buildings all housing instruments on multi-well sites and all of them could be venting gas at the same time.

[10] https://reports.bcogc.ca/ogc/f?p=AMS_REPORTS:WELLS_DRILLED_BY_STATUS:8736837906122:::::

In one case (Progress c-27-B/94-G-1), we found a new multi-well site with eight wells and eight instrument control buildings. We were able to determine, based on our investigations at this site, that at least five of the buildings were venting methane gas through at least two building vents on each building, before we were told to leave the site by Progress Energy employees. Each vent pipe had an estimated continuous flow rate of approximately 1.0 m^3/hr, which means that this one site alone was venting methane at a minimum rate of around 10 m^3/hr or 240 m^3/day!

Following a detailed investigation into fugitive methane emissions from well sites and facilities in Alberta in August 2016 (GreenPath, 2017), researchers determined there were, on average, 5.89 pneumatic devices per well site (across all areas) in that province. Similar work undertaken by Allen et al. (2014) in the U.S. estimated that there were an average of 5.8 pneumatic controllers per site (65 sites with 377 controllers, including both single wells and multi-well sites), or approximately 2.7 controllers per well.

There is no reason to think otherwise for B.C. since infrastructure across the industry is pretty similar for all operators. However, in the Montney, most of the gas wells use fuel gas (natural gas from the wellhead) to run their pneumatic devices because they are remote (D'Antoni, 2015), so the likelihood that the pneumatic devices used in the Montney gas field will bleed fuel gas rather than compressed air or use another power source to operate is high. (This was confirmed during our field investigation. Virtually every vent we found on instrument shacks was bleeding almost pure methane.)

Following the above, and using a conservative estimate of one instrument shed per gas well site and only one vent venting, we can determine that a single, venting gas well site would be emitting about 27 m^3/day or roughly 9,898.8 m^3/yr. Considering that there are roughly 13,000 active gas wells in B.C. and, based on a random survey of at least 49 well sites (not all were operating) where at least 86 per cent were found to be venting methane gas through building vents, we can estimate, conservatively, that around 10,983 well sites could be emitting a minimum of around 110,668,584 m^3CH_4/year.

It should be noted that much of this venting from pneumatic devices is not measured directly by industry, but is estimated (CAPP, 2004). It is also supposed to be reported regularly to regulators, but CAPP says that although there have been substantial improvements in reporting practices in recent years, there remains significant uncertainty in many reported vented (and flared) volumes mainly due to the fact that detailed estimation guidelines are lacking, there is the lack of any formal tracking of the activity data needed to make many of these estimates (e.g., frequency and details of equipment or piping blowdown events, frequency of compressor engine starts, etc.) and there are glaring differences in which sources of vented gas individual operators are even considering in their reporting (CAPP, 2004).

Therefore, total fugitive emissions in the upstream segment of oil and gas development in the Montney from SCVFs and deliberate venting at gas wells can be conservatively estimated to be around 124,822,000 m^3CH_4/yr, which is equivalent to 93,370 tonnes of gas (1,333 m^3 of gas = 1 tonne)[11].

[11] http://www.chemlink.com.au/conversions.htm

This does not include emissions from facilities like compressor stations, batteries or test satellite sites, which can be substantial. For example, compressor stations alone vent anywhere from 100 to 5,500 m^3 of waste gas per event at those facilities. An “event” at a compressor station can be any one of: compressor starts, booster vents, station blowdowns or scrubber blowdowns, and there can be several of these events per month (CAPP, 2004). The waste gas from these events in many cases is natural gas, or methane. For example, a blowdown is a complete venting of the natural gas within a compressor or pipeline to the atmosphere, to reduce pressure and empty the system (Kloczko, 2015). More often than not, this waste gas is vented directly to atmosphere, and not flared (unless it sour or malodorous).

The BC Oil and Gas Commission reports that 337 large compressor stations are now operating in B.C., most, if not all, in the Montney (Phil Rhygg, communications director, BCOGC, pers. comm. Note: this number does not include small-scale single compressors on individual well sites). If we assume just one event per month at these facilities (even though, as CAPP states, there could be several) with an average venting of around 1,500 m^3/event (CAPP, 2004; Table 18, page 37; average N=8), that could mean an additional 6,066,000 m^3/year, or 4,550 tonnes/year of methane being vented by the upstream oil and gas industry in this province that we could not measure, or estimate, based on the design of our field study.

Flaring is another source of methane that we do not account for in our analysis. CAPP reports that the methane composition of flare emissions is about 55 per cent (CAPP, 2004). Since we do not have any data on the amounts of gas that have been flared in the province, we are unable to compute or even approximate what the amount of methane emissions associated with this activity would be.

In summary, we have determined that fugitive emissions in the upstream oil and gas industry in the Montney can conservatively be estimated to be about 130,888,000 m^3 CH_4/year or 98,190.5 tonnes. This is equivalent to 2,749,335 tonnes (2,749 kilotonnes, or “kT”) CO_{2eq} (using the IPCC AR5 100-year equivalency value of 28). If we base this on the 20-year IPCC value (86), this amounts to 8,444,383 tonnes CO_{2eq}.

B.C. government GHG inventory 2012

According to the B.C. government’s 2012 GHG inventory (B.C. Ministry of Environment, 2012 — Table 3, page 14) total fugitive emissions for the entire energy sector in B.C. were estimated to be about 4,815 kT CO_2e (or 4,815,000 tonnes) of which the oil and gas sector contributed roughly 83 per cent, or 3,983 kT CO_2e. However, it should be noted that this estimate is extremely low relative to today’s understanding of the global warming potential of various greenhouse gases. This estimate is based on the IPCC's 100-year global warming potential for methane of 21, which was established back in 1995. The currently accepted international standard for the 100-year GWP for methane is 28. Of that total, it is estimated that only 1,632 kT CO_2e of all fugitive GHG emissions from the entire oil and gas industry in the province were due to methane emissions. Using the 1995 IPCC GWP value for methane, this translates to the equivalent of 78,000 tonnes of methane. This includes methane emissions from upstream (searching for, recovery and processing of oil and gas), midstream (processing, storage and transport) and downstream (refining and distribution) components of the industry.

However, our conservative estimate of fugitive emissions in the upstream industry alone in B.C. (98,190.5 tonnes) suggests methane emissions are at least 1.25 times higher than the total estimate for the entire oil and gas industry in B.C. (using the IPCC AR5 100-year equivalency value of 28). If we were to apply the IPCC's 20-year CO_2 equivalency value, our estimate of fugitive emissions of methane in the upstream oil and gas sector would be almost five times (4.8) higher than the estimated fugitive emissions for the entire sector in B.C.

5.0 Conclusions

Using a simplified screening program, we were able to identify emissions of fugitive methane due to SCVF and equipment leaks and deliberate venting of gases (primarily methane) at selected oil and gas well sites in the Montney gas field in northeastern B.C. alone, and can reasonably conclude that the amount of fugitive emissions, as measured by direct field observations are substantial and can conservatively be estimated to be higher than the B.C. government estimates for the entire oil and gas industry (upstream, midstream and downstream). These results, which correspond well to the companion study (Atherton et al., 2017), suggest that fugitive methane emissions in B.C. are at least 2.5 times higher than government estimates, based on an extrapolation where the Montney region represents 55 per cent of current production.

This strongly suggests that fugitive methane emissions from this industry are being heavily under-reported and/or estimated and there is a need for mechanisms to properly quantify the impact of this industry from a greenhouse gas emissions perspective and a means to control these emissions.

While it is currently acknowledged globally that fugitive emissions in the oil and gas industry are substantial, and governments say they have been working with industry to promote energy-efficient industrial practices, little has been done in the way of actually controlling these emissions, as our field work shows.

The most comprehensive and detailed assessment available on fugitive emissions from the upstream oil and gas industries in Canada are a series of reports prepared for the Canadian Association of Petroleum Producers by

Clearstone Engineering more than a decade ago (CAPP, 2004a-c). However, the results in those reports are based on estimates that are, in turn, based on assumptions, and while those assumptions may have seemed reasonable at the time, our results suggest they are not now. Given the scale and scope of the growth of this industry over the past 15 years, this reporting needs to be updated so that we have a reliable estimate of total methane emissions now.

The industry is aware that fugitive methane emissions occur with regularity in their industry (CAPP, 2004; PTAC, 2006; CAPP, 2007). They know the sources and they know how to mitigate them (Petroleum Technology Alliance of Canada, 2006; Allen et al., 2015) but few, if any, regulations are in place that actually require them to do so. It would seem the only time the industry acts to clean up after itself is if there are economic incentives to do so, and that includes subsidies from taxpayers (PTAC, 2006).

Methane leakage and venting should be a high priority for reduction as, with a warming potential of 21 tCO_{2eq}/tonne of methane, it is a much more powerful GHG gas than CO_2, and also has a significant economic and energy value. A number of studies have been done on mitigation options, particularly for methane and hydrocarbon emissions. Most of these options do not require new technologies, just the application of currently available technologies (see, for example, Allen et al., 2015). However, it would seem that for industry and regulators, the preferred solution for managing any source is to take the option that provides the highest net economic benefit, which usually means the lowest capital cost option. The other option seems to be to let these emissions occur until facilities and well sites are reclaimed (which means millions of tonnes of methane are likely being released into the atmosphere per year in Canada). However, our data and observations show that even abandoned wells can leak significant amounts of methane, that such leakage is occurring and that little to nothing is being done to prevent it.

We can say with certainty that after spending almost 40 days in the field in the Montney over a period of two summers and one winter, driving over 25,000 kilometres of roads and driving past or visiting hundreds of well sites, we did not encounter or observe a single crew of individuals doing any kind of well-site inspection, let alone undertaking well abandonment or suspension activities.

We are asking the B.C. government to:

- Mandate that all oil and gas companies operating in B.C. immediately undertake leak detection and repair, at the very least, starting with the sites we have identified in this report;
- Immediately develop and implement regulations for mandatory quarterly leak detection and repair in all areas of the province, including on all abandoned and suspended wells;
- Immediately develop and implement regulations for industry to replace oil and gas infrastructure that is designed to vent fuel gas (e.g., pneumatic devices, pumps, compressors) with non-emitting devices.

- Immediately develop and implement regulations for mandatory and transparent reporting on all emissions and the steps being taken to address them; and where significant flows are measured, demand those wells be repaired.
- Require the industry to provide adequate resources for on-the-ground monitoring and enforcement of these regulatory measures and prioritize hiring locally affected First Nations to support independent monitoring.
- Develop and implement measures to ensure that the carbon tax applies to the oil and gas industry in relation to all methane emissions as an interim measure and that full carbon pricing or other mandatory regulations are implemented to achieve full phase-out of methane emissions.

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APPENDIX A

Photo 1. Example of a well identification sign showing the unique well identification number (11-18-86-21 w6m) and contact number in case of emergencies. The well site is in the background.

Photo 2. Field investigator using the FLIR camera to check well-site infrastructure for gas leaks.

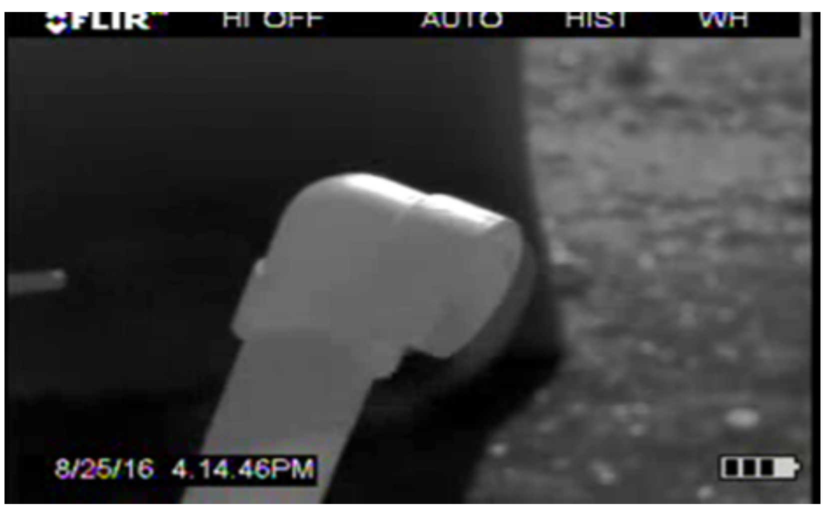

Photo 3. Still image captured from a video of a leaking surface-casing vent. The wisp of grey visible at the opening of the vent is escaping methane gas (as determined using a GEM 2000+ landfill gas monitor).

Photo 4. Picture of a balloon applied to the opening of the leaking surface-casing vent shown in Photo 3. The leaking gas has inflated the balloon.

Photo 5. Full inflation of a balloon applied to a surface-casing vent was considered to be achieved when the balloon “snapped to attention” but did not noticeably stretch beyond the dimensions of its resting state.

Photo 6. A natural gas vent extruding from the side of an instrument shed at a natural gas well site. The inside diameter of this pipe is about 10 mm (0.25 inch).

Photo 7. Applying a round balloon to a natural gas vent on the exterior of an instrument shed at an operating gas well site.

Photo 8. This well (Progress Blueberry C-A39-K/94-a-12) was leaking gas heavily from both the surface-casing vent and the wellhead (middle flange) on August 24, 2016. The well was not operating. It was “shut in”.

Photo 9. This is well CNRL Owl 08-16-86-18. Note that the entire wellhead and ground around the wellhead are soaked with oil. Photo taken August 19, 2016.

Photo 10. CNRL Eagle A08-07-85-18 appears to have suffered a recent blowout. The entire wellhead and ground around the well are soaked in oil. Photo taken August 18, 2016.

Photo 11. Pool of oil on the ground immediately adjacent to CNRL Eagle A08-07-85-18. Photo taken on August 18, 2016.

Photo 12. West Eagle 06-11-85-19 w6m. The surface-casing vent on this well was dripping liquid, the flow of which was directed to a 40-gallon metal drum. Photo taken August 19, 2016.

Photo 13. LNG vent pipes extruding from the walls of an instrument shed at well Tourmaline C05-14-18-16 W6M.

Photo 14. Vent pipe on well Tourmaline DOE 04-11-080-16 W6M venting natural gas to the external environment. This was a continuous flow, measured to be approximately 0.5 m3/hr. This is a still photo captured from a video taken with a FLIR camera.

Photo 15. Cloud of heat and methane gas being emitted from Spectra Energy Compressor Station 16 on August 15, 2016. The main plume is probably heat but the residual plume wafting away from the stack is likely unburned gas. The distinct odour of natural gas was very strong at ground level. This is a still photo captured from a video taken with a FLIR camera.