

## **Reply to Tony Wakelin – SC2**

We would like to thank Tony Wakelin from the BC Oil and Gas Commission for his interest in our manuscript. It is helpful to have critical feedback from members of the provincial regulatory organization, as they often have important knowledge about the inner-workings of the local oil and gas industry. We have addressed each comment below, and have included the related edits made to the manuscript.

*The British Columbia Oil and Gas Commission (Commission) is the provincial regulator for the oil and gas industry. Depending on the activity the Commission is either the primary regulator, or works with other regulatory agencies to ensure activities are managed for the benefit of British Columbians. In August 2016, the province released the BC Climate Leadership Plan (CLP) which set a goal to reduce methane emissions from the upstream natural gas sector by 45 per cent below 2014 levels by 2025 from extraction and processing infrastructure built before Jan. 1, 2015. The Commission is working with the B.C. Government to determine how to effectively meet this CLP goal.*

*The Atmospheric Chemistry and Physics discussion paper is of considerable interest to the Commission. Therefore, we have reviewed this discussion paper to determine if the findings agree with the regulator's extensive understanding of the oil and gas sector from the perspectives of protecting public safety, respecting those affected by oil and gas activities, conserving the environment, and supporting resource development.*

*Relevant to this discussion paper is that the Commission performs 4,000 to 5,000 inspections per year on oil and gas infrastructure and if methane releases are identified during an inspection, deficiencies are noted and industry is required to take corrective action. Also, routine checks on wells for surface casing vent flow are performed and if significant leaks are found industry is required to take corrective action.*

*In reviewing this discussion paper, considerable discrepancies were noted between the study findings and the Commission's understanding of oil and gas infrastructure within B.C. Our findings are as follows:*

While we appreciate that many inspections are done annually, the nature of these inspections is not clear to us (are they OGI, volumes quantification, or other?), nor are the results of these inspections visible or open to scrutiny in terms of methodology quality control, etc. Furthermore, the relationship between these inspections, and the provincial inventories, is also not clear. Are the inventories updated on the basis of these measurements? While we do know the OGC is very active, and that its people are working in the best interest of environmental protection, we can't measure our study in relation to these inspections because they are neither visible nor open to evaluation.

For reference, in our campaigns we sampled more than 1,740 pieces of infrastructure in triplicate. In other words, we sampled 5,238 locations. This number of "inspections", collected in under a month, is comparable to the BC

OGC annual total. The BC OGC might therefore consider mobile surveying as a supplementary way to collect more data on infrastructure (more passes, more visits, or other) with the same amount of effort. Truck pre-screening would allow the OGC to target its use of OGI and other more time-intensive methods, and to use it for emitting infrastructure only – rather than spending considerable effort to find that no emissions exist. Since the BC OGC has legal access to the well pads and facilities in question, its staff members are also in a favourable position to overcome many of the methodological uncertainties that are communicated within their comments. We would always prefer our surveys to be on-pad if possible because a full pass around the infrastructure provides definitive upwind and downwind data - all in close proximity where concentrations are high. We would be happy to assist the BC OGC where necessary to find an optimal balance between measurement methodologies, and we are presently working with operators on projects similar in theme.

**Overall:**

- **Location of infrastructure:** *The facility data downloaded from the BC Oil and Gas Commission has NTS or DLS coordinates which are accurate to approximately 400 by 400 area. The discussion paper should provide clarity on whether the NTS or DLS locations were used or if and how the study refined the locations.*

We obtained shapefiles with locations of both wells and facilities from the online BC OGC Open Data Portal, which was publicly accessible directly before and after this field campaign took place. Both of these shapefiles (wells and facilities) were projected in BC Albers (ESPG 3005) and recorded as point locations. None of the locations in the infrastructure inventory we compiled from the BC OGC Open Data Portal used NTS or DLS coordinates. Furthermore, we used aerial imagery to verify point locations, the majority of which were located on well pads. And although we could not verify the identification numbers or statuses of the infrastructure during our mobile surveys, we did verify the locations of infrastructure when it was visible from public roads. For additional information please see our response to comment from Anonymous Referee #1 p9 1.7-8.

- **Emissions attribution:** *There are numerous situations where multiple permits are issued by the Commission at the same general physical location. The discussion paper does not address how this was handled. When a methane plume is detected the discussion paper should indicate how this is attributed to a source when multiple wells and facilities are attributed to the same geographic location. How was a single release anomaly tied to estimating releases that could be tied to multiple permits at the same physical location?*

In section 3.2 *Emission Sources and Trends* we discuss the potential for inaccurately tagging infrastructure as emitting due to the wide radius (500 m) that had to be used because we were surveying from public roads. In this section of the manuscript we clarify that our analysis includes

“probable emitting infrastructure, *plus* possibly emitting co-located infrastructure”.

- ***Emissions rates may be overstated due to the use of averages:*** *In calculating emissions, the STFX/DSF study assumed, even for facilities that had emissions detected just over 50 per cent of the time, that their leak rate was constant and ongoing. The study noted that, especially with venting emissions, the release of methane may not be constant. This assumption has high potential to lead to an overstatement of methane emissions.*

We only included the persistent emission sources we encountered so that we were providing a conservative estimate of CH<sub>4</sub> emission sources in the area. We did not include the episodic emitters in our volume calculations. We combined the fraction of persistent emission sources with our minimum detection limit (g/s) to estimate the total emission volume, which makes it highly likely that this is an underestimation of the total emission volume in the area. Furthermore, we did not include emissions from flowback and liquid unloading, which are likely very large contributors to emissions in an unconventional natural gas development. As described in Allen et al. (2013), these operations have proved to be very large emission sources in these types of developments, but without prior knowledge to when these events were happening we could not include them in our mobile surveys.

*Specific discrepancies within the text are as follows:*

*Page 8 line 22 Well status of:*

- *“Cancelled” means the well permit expired without drilling commencing. So these wells do not physically exist in the field and can not be attributed to the release of methane.*
- *“Well Authorization Granted” (WAG) means that a well has been approved, but drilling has not commenced. Therefore these can not be attributed to methane releases.*

In both our field surveys as well as the independent study by the David Suzuki Foundation (which was submitted to the BC OGC), multiple locations with wells and/or facilities that were classified as Abandoned still had infrastructure standing. So it should be noted that the infrastructure status information was not always correct. Please also see our response to comment from Anonymous Referee #1 p9 1.7-8 for revised text we have now included in the manuscript.

Although these emission sources might not have been in place at the time of surveying, we are confident that a persistent plume exists at each of those locations. In the manuscript (Section 3.1 *Measured Gas Signatures*) we are clear that confidence is high for detection of plumes, but comparatively low for

geospatial attribution. Plume detection confidence is high in part because of the excess ratio approach, but particularly because of the persistence requirement in this study where an emission must have been observed > 50% of the times it was surveyed, which was normally on different days. The manuscript also already describes how we benchmarked our rate of false positives using a Control route to validate our level of certainty around detection.

Despite our confidence in detection, the attribution of those plumes to known infrastructure during on-road campaigns can be imperfect. Local wind eddies can serve to complicate back-trajectory analysis. Also, emissions originating farther upwind might cause false tagging of a proximal source. The manuscript does already acknowledge that mis-tagging is possible, and we did provide relative confidence values for detection and attribution in section *3.1 Measured Gas Signatures*.

In response to this comment, we did undertake a new geospatial analysis to search for proximal infrastructure at these Cancelled and WAG locations in question, which numbered only 35 in actual emission inventory calculations. In this analysis we searched for source-types (i.e. possible emission sources in our database) within 3 km. As we expected, there was almost always other infrastructure nearby. Most of the Cancelled and WAG sites were within 1 km of other infrastructure and all but one were within 1.5 km of other infrastructure. We can, in fact, resolve leaks from those distances, given sufficient source strength, and favourable Pasquill stability. In our analysis we had excluded possible sources > 500 m but in these cases it is reasonable that another nearby source could have been emitting the plumes we observed repeatedly at those locations.

Sources we did not have in our infrastructure inventory may also explain some of the observed plumes. In the region there is an extensive pipeline network that circulates natural gas between pads and facilities. Since we did not include pipelines and associated sources in our study, we therefore implicitly assumed that pipeline, and flow line infrastructural leaks were equal to zero – which is obviously not the case but was a necessary simplification since we did not have these files of these locations. These 'ghost' sources may also explain plumes in these areas where we detected them repeatedly.

To find the actual source of emissions at these locations, we are happy to work with the OGC. As the OGC knows from having accompanied us on surveys in the field, the technique we used excels at localizing emissions quickly - when used for that purpose, and when site clearances are available. We look forward to working with the OGC to help define the source of these emissions and others that may not be resolved well (or quickly) by OGI. An OGI camera is obviously incapable of resolving ground-dispersed emissions

such as pipeline leaks, or low-level plumes coming from infrastructure farther upwind – all of which we can detect. We feel that mobile approaches could enhance the efficacy and efficiency of BC OGC measurement and oversight operations, and we look forward to more conversations in the future on the topic.

Page 8 line 23

*It is difficult to understand how the text “for the class defined in the databases as Well Authorization Granted, most of which were somewhere in the stages of development during our visits” could be correct. While some wells with a status of WAG would have commenced drilling between the time the well data was acquired in July 2015 and the study completed Sept. 5, 2015, this number is quite small compared to the total number of wells with a status of WAG. While it is unclear when in July 2015 the researchers obtained well data from the Commission, if we assume the data was obtained on July 1, 2015, there were 1,797 wells with a status of WAG. Between July 1, 2015 and Sept. 5, 2015, 146 of these wells commenced drilling. As this data is for all of northeast B.C., a subset of these wells are located in the study area. In any event, a maximum of 8 per cent of WAG wells were somewhere in the stages of development during the field visits and the remaining 92 per cent did not physically exist at the time of the study and therefore were incapable of emitting methane.*

*In conclusion, for page 8 line 22 the text should be revised from “25% for Cancelled” should indicate no releases from cancelled and “27% for well authorization granted” should read close to zero for well authorization granted.*

We have changed the following line in the manuscript:

*“We calculated an emission frequency of 26% for Abandoned, 25% for Cancelled, 30% for Completed, and 27% for the class defined in the databases as Well Authorization Granted.”*

Please see our response to comment 43. Page 8 from Anonymous Referee #3 for the text we have added to clarify status type definitions, as well as our explanation for why we included well locations with statuses of Cancelled and WAG.

Page 9, line 5

*The text refers to a category of “Undefined”. It should be noted the term “Undefined” is not used to describe the well status (Well Authorization Granted, Drilling, Cased, Completed, Active, Cancelled, Suspended, Abandoned). “Undefined” is used to describe the well operational status (Production, Injection, Disposal, and Observation). For example, a cased well would have an operational status of undefined since it was never completed. In addition, undefined is used for the well fluid type (Gas, Oil, Multiple Gas, Multiple Oil, Multiple Oil and Gas or Water) if a*

*well has not flowed in order to define the fluid type. For example, a well that was completed, but did not flow when tested would have an undefined fluid type. An active water disposal well would have a status of ACTIVE WATER DISPOSAL, not UNDEFINED.*

In this section of the text we refer to Figure 6 (Figure 7 in the revised manuscript), which is a plot of the emission frequencies based on operation status (including Production and Undefined wells). We did not include Injection, Disposal, or Observation wells in our emission frequency analysis because our sample size was low. We have revised the text in this section of the manuscript to clarify this and to refer to these descriptions as the operational statuses of the wells.

*“A portion of the wells had operational statuses of Production wells, and another portion as Undefined. Only Active Production wells were predictable emitters, with high statistical coherence from route to route (Fig. 7). We did not have a high enough sampling frequency of wells with other operation types (such as Injection, Disposal, and Observation wells) to delineate emission frequencies so we excluded them from the analysis.”*

*Page 11 Line 11 to 18*

*The development of the MDL or release rate in the study involves significant uncertainty which is not adequately discussed in the text. Further information should be provided on the laboratory experiments used to determine a mean level of dilution of 70 per cent to demonstrate “realistic field conditions” and should include the range of results from those experiments.*

The MDL is established with a standard Gaussian technique similar to that of OTM 33A and others. These methods have been used extensively by industry and academics for nearly half a century. The dilution experiments are extremely straightforward. They consist of exposing the analyser, in a configuration like the field, to different durations of known standard concentration, and to calculate the % dilution. Dilution fraction is a function only of pump rate and cavity size. These analyzers control flow rate extremely closely, and of course cavity size does not change – which means that these offsets are highly repeatable. The process is similar to calibrating a piece of lab equipment – relating peak height to actual concentration under a tightly controlled flow regime. It is a form of calibration that is part of instrument use for an experienced user, and scientific manuscripts will assume that these checks have been done – but these procedures don't generally merit description in the peer review literature.

*Page 11, line 19 to 32*

*NOAA states that the Gaussian dispersion model is recommended as a teaching tool to understand basic concepts and does not recommend its use for dispersion studies. This paper should answer the question as to why this particular model was used*

*when there are a multitude of other dispersion models to choose from.*

*Regardless of the dispersion model used, a sensitivity analysis should be completed for the main inputs used for the analysis in this study. As currently written, it is unclear which meteorological inputs (wind speed, wind direction, temperature, etc.) the researchers used, and whether they were representative of the region. Dispersion modelling can be highly sensitive to input parameters, and as such a further discussion of this uncertainty should be included, especially as the outputs from this modelling are used to determine as the release rate and to estimate a regional emissions inventory.*

*In conclusion, for Page 11 (lines 11 to 32), the technique used to develop the emission factor of 0.59 g/s is questionable.*

The primary purpose of the paper was to determine emission frequencies, not to create a highly accurate volumetric inventory. In crafting this response we moved to using the Gaussian equations directly, since we have existing projects in which they are being used. They provide the same numbers as the NOAA tool, and while the NOAA tool is useful for teaching because of ease of use, that does not make it inaccurate. In our study we have provided a minimal realistic inventory. The fact that it compares very closely to an independent regulator-commissioned study conducted within a comparable timeframe (GreenPath, 2017), provides validation for our work.

The meteorological inputs for the dispersion model were measurements recorded at 1 Hz frequency by the anemometer on our mobile surveying vehicle. We have added text to section 3.3 *Minimum Detection Limit* to clarify that these are the values we used as inputs to the dispersion model.

[“The NOAA dispersion model computed the mixing depth using the wind speed, wind direction, and weather data we collected from our anemometer at 1 Hz sampling frequency throughout our surveys.”](#)

*Page 12, line 20*

*The term “facility” in the Omara study refers to the sum of wells and equipment at a multi-well site. Facility type as outlined in Figure 8 of this study is not the same as defined in the Omara study. There is no basis for using the emission factor 2.2 g/s in this discussion paper.*

Please see our response to Comment 1 from the review by Brian Crosland. We would also be interested in learning the BC OGC’s estimate of facility emissions for the study area.

### **Conclusion and Recommendation**

*The fact significant quantities of emissions were attributed to wells that do not exist (i.e. 25 per cent of cancelled wells were reportedly emitting) calls into question the*

*accuracy and validity of the discussion paper. Also, the basis for determining emission factors used in this discussion paper is highly questionable - therefore, this study should not infer that the estimates constitute an emission inventory that could be compared with what is reported under the Greenhouse Gas Emission Reporting Regulation. The Commission would welcome further dialogue to improve this study prior to publication.*

We too would like to work together. New proposed Canadian federal regulations strongly move the industry toward measurement (up to 3x annually per piece), and altogether away from estimation models / emissions factors. This will be a change for everyone. In this new scheme, new sources of data (mobile, satellite) will make oversight easier. These tools are evolving rapidly, and inevitable public availability of such data will force more transparency. It will push not only companies, but also regulators, to step up their game as measurement experts. The industry has been relatively dogmatic in its use of monitoring technology, but must look at the new options, of which many good ones already exist. We would offer that the costs of oversight and compliance could be defrayed significantly by combining methodologies in sensible ways – along the way acknowledging the strengths and limitations of these various methods. As a university laboratory, we are available, willing, and eager to help in this type of research. We thank the OGC for its response, and hope we can work together in the near future.