Submission to the British Columbia Oil and Gas Commission on their proposed approach to regulating methane emissions from B.C.'s oil and gas sector

October 15, 2018

Submitted by: Clean Air Task Force, David Suzuki Foundation, Environmental Defense Fund, Pembina Institute

Introduction

The David Suzuki Foundation, Pembina Institute, Clean Air Task Force and Environmental Defense Fund submit the following comments on the B.C. Oil and Gas Commission's proposed approach for regulating methane from oil and gas facilities.

We urge the BCOGC to strengthen its proposed approach for regulating methane from oil and gas facilities. The current proposal falls far short of requiring leading, cost-effective, feasible measures that have been adopted by multiple jurisdictions in North America. Implementation of such "best practices" by British Columbia is essential to the province being able to meet its greenhouse gas target of reducing its 2007 emissions by 40 per cent by 2030. This is particularly true in light of the recently announced LNG Canada export terminal, which at full capacity is anticipated to increase the province's total emissions by 3.45 million tonnes CO2e, including from increased upstream development as per government briefing.

There are three simple improvements that the BCOGC can make that will significantly strengthen the proposal:

(1) require frequent inspections to detect leaks at all production facilities, other than stand-alone wellheads, as well as processing and compression facilities;
(2) impose strict limits on tank venting; and
(3) require controls of existing pneumatic pumps.

These three improvements are essential if B.C. wishes to meaningfully reduce methane emissions from oil and gas facilities. In addition, the draft regulatory text needs to be shared in order to enable a more detailed response.

Methane regulations are highly cost effective, especially in gas-rich areas such as British Columbia, where operators can sell or reuse captured natural gas. According to a 2015 study by ICF International, using costs and the value of natural gas prevailing at the time of the study (C$5/Mcf), British Columbia can reduce methane emissions for less than $0.01/Mcf of gas produced, using existing technologies.[1] Adjusting for lower prices for natural gas than currently prevail, the average cost of mitigation remains below $10/tCO$_2$e (well below B.C.'s carbon tax) and slightly over $0.01/Mcf of gas produced, an increase that does not materially impact the financial viability of the industry.[2] ICF further estimated that requiring operators to inspect for leaks quarterly at well sites can be accomplished for approximately $13 per ton of CO_2-

[1] ICF International, Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries, Sept., 2015 pdf. P. 14, http://www.pembina.org/pub/economic-analysis-of-methane-emission-reduction-opportunities-canadian-oil-and-natural-gas. Exhibit A.

[2] Adjusting ICF's figures to replace a credit for conserved gas of $24 million at $5/Mcf with a credit of only $6.7 million at $1.40/Mcf.

equivalent emissions abated,[3] and replacing existing pneumatic pumps with solar chemical injection pumps can be accomplished for under $11/tCO_2e$.[4] Furthermore, even assuming a persistently low gas price, replacing all Kimray pumps in the province can be achieved at a negative net cost.[5]

These costs must be considered in the context of the support the province is offering to the industry. The Clean Growth incentive program offers industry relief from increments to the carbon tax beyond $30/tonne CO_2e by recycling this revenue to industry based on performance against an industry benchmark and through funding credible emission reduction projects.[6] Furthermore, even though the economic rationale for retaining the Deep-Well Royalty Program is questionable in a context when the technology has matured, the upstream natural gas industry continues to benefit from it. This program, first introduced to stimulate drilling in deeper formations, gives credits to companies for drilling deep wells, allowing them to offset a proportion of their drilling and completion costs against their royalties.[7] As of December 31, 2017, companies hold more than $3.1 billion in royalty credits under this program.

The paucity of reliable, recent and publicly available data on equipment counts and the fact that royalty data is now only available in aggregated form presents challenges for developing more detailed, reliable cost-effectiveness estimates of implementing different regulatory provisions. A study of equipment counts initiated by the provincial and federal governments is due this fall. Information in that study should be used to inform the final regulations. Until that information is publicly available and subject to analysis, we urge the BCOGC to take a precautionary approach to the development of its regulations. Specifically, the BCOGC should adopt time-tested best practices, such as quarterly inspections and strict venting limits, in order to ensure that its regulatory framework is sufficiently robust to ensure the province meets its ambitious greenhouse gas reduction targets.

II. Technical comments

A. B.C. must increase the inspection frequency at production facilities to at least three times a year in order to achieve meaningful reductions from leaks

We have grave concerns about the proposed leak detection and repair provisions. The proposal only requires reasonably frequent (i.e., three times a year) inspections at 7 per cent of facilities in B.C. The remaining 93 per cent are subject to annual surveys or screenings — 58 per cent and 35 per cent, respectively. These include single well batteries, serving both unconventionally and

[3] Again adjusting for a $1.40/Mcf gas price.
[4] Id.
[5] ICF estimates the cost per Mcf of gas abated to be $1.34/Mcf without crediting the value of conserved gas.
[6] https://www.bcbudget.gov.bc.ca/2018/bfp/2018_Budget_and_Fiscal_Plan.pdf#page=82
[7] https://www2.gov.bc.ca/gov/content/industry/natural-gas-oil/oil-gas-royalties/royalties-royalty-programs/deep-royalty-program.

conventionally produced gas and single wells. Single well batteries and single unconventional wells must be surveyed only once a year with an optical gas imaging camera or a hydrocarbon analyzer. Conventional wells need only be "screened" annually. These screenings, we understand, will likely allow for sensory-based methods, such as audio-visual-olfactory or "AVO," which would not be expected to achieve significant emissions reductions compared to business as usual, [8] since we believe most operators are regularly checking sites in this fashion and address any leak large enough to be detected in this rudimentary way.

The absence of frequent inspections for the vast majority of production facilities, combined with the absence of a meaningful instrument-based inspection requirement for conventional wells, all but guts the efficacy of the proposed LDAR requirement. We discuss below the best available science that demonstrates the need for operators to conduct instrument-based inspections at least three times a year at conventional and unconventional production facilities, other than single-wellhead-only sites, in order to reduce leaks.

1. *B.C. must require at least triannual surveys to achieve meaningful reductions in production leaks*

The proposed annual LDAR surveys or screening for all but a handful of sites doesn't conform to practices across many North American jurisdictions. This approach is not suitable. A wide body of independent research across the United States and Western Canada has shown that emissions at oil and gas sites from leaks, broken or worn out equipment, and improper operations are substantial and greatly underestimated in inventories. Regular LDAR is needed to mitigate these unnecessary, harmful emissions, and regular instrument-based surveys of sites can substantially reduce emissions at a reasonable cost.

Results of these studies demonstrate that measured emissions greatly exceed those reported to emission inventories. A recent synthesis of U.S. studies conducted over the past six years concluded that U.S. production emissions are 60 per cent higher than the EPA emission inventory suggests.[9] Data for this study included measurement of emissions from more than 400 individual well pads in six different U.S. basins, validated against "top-down" airborne measurements of emissions from nine oil and gas producing basins. The authors of this synthesis study, as well as the underlying studies analyzed in the synthesis paper, include academics from 25 different research institutions. These scientists have concluded that the substantial extra emissions observed in these studies, compared to official inventories, likely arise from improper

[8] See Armstrong, K. J. (2017). Leak Inspection and Repair at Oil and Gas Well Sites Boulder County Voluntary Inspection Program Results 2014–2016, https://assets.bouldercounty.org/wp-content/uploads/2017/09/boulder-county-voluntary-oil-and-gas-inspection-program-results-20170831.pdf.
[9] Alvarez, et al., *Assessment of methane emissions from the U.S. oil and gas supply chain*, Science, June 2018, http://science.sciencemag.org/content/early/2018/06/20/science.aar7204.full.

and abnormal operating conditions at the site level that are best addressed by frequent, if not continuous, inspections. Annual inspections would fall far short of meeting this standard.

Recent measurements taken in Canada are in accord with the observations from the U.S.

Measurements taken in B.C. underscore the importance of requiring frequent inspections of both older conventional wells and newer wells. In 2015, researchers measured site level emissions at more than 1,600 well pads and facilities in the Montney region of British Columbia.[10] The researchers surveyed fixed routes repeatedly, and found that 47 per cent of active well sites were emitting methane at a level that could be measured from roads — typically several hundred metres downwind — consistently (these wells were emitting detectably half or more of the times they were surveyed). Given the detection limit of the surveys, the measured emissions were typically at least four times higher than would be expected from pneumatic equipment at wellsites, given the "gas well" pneumatic equipment counts and emissions factors B.C. provided,[11] so it is very likely that most of these emissions come from leaks or improper operations and are, therefore, preventable and best addressed with a strong LDAR program.

By assuming that each detected site was only emitting at the minimum detectable level — and that other sites, including sites where emissions were detected, but not during at least half of the surveys — were zero, the researchers created a "minimum reasonable inventory" for methane emissions from the Montney region. Their calculated emissions level for just this region — about 112,000 tonnes per year of methane — significantly exceeds the most recent B.C. estimate of *all* oil and gas emissions, *province-wide*. Only about 55 per cent of B.C. natural gas production is in the Montney. Combining all this, Atherton et al. clearly indicate that leaks are an important source of methane emissions in B.C.

---

[10] Atherton, E., Risk, D., Fougère, C., Lavoie, M., Marshall, A., Werring, J., Minions, C. (2017). *Mobile measurement of methane emissions from natural gas developments in northeastern British Columbia*, Canada. *Atmos. Chem. Phys.*, *17*(20), 12405–12420. https://www.atmos-chem-phys.net/17/12405/2017/

[11] We used the average counts for pneumatic controllers and pumps at gas wells, together with emissions factors and factors for the split between hi-bleed and low-bleed controllers, from pages 5-6 of the document provided by BC OGC in response to questions from stakeholders, to calculate the expected emissions from pneumatic equipment at wellsites. This data suggests that emissions from the sum of all pneumatic equipment (including each type of controller and pump, at its average BC count at gas wells) is about 23 scfh per site. For this calculation, we assume that the gas bled from pneumatic equipment is 100%, and we assume that pneumatic pumps are operating at the higher injection rates / pressures; thus this calculation provides an upper limit on pneumatic emissions of methane. For 100% methane, 23 scfh is ~0.13 g/s of methane (neglecting temperature corrections), which is far smaller than that minimum detection limit used by Atherton et al., 0.59 g/s of methane. Recognizing that the average pneumatic equipment counts are fractional, we rounded up the count for each type of pneumatic controller and pump, to model an ever more liberal upper limit for pneumatic emissions. In this case, we assume one controller of each type listed in the tables (level, temperature, pressure, etc.), one "other" chemical injection pump, and two methanol pumps. In this case, emissions would be ~70 scfh, or ~0.4 g/s methane (again, assuming 100% methane bleed gas) – still below the detection limit stated by Atherton et al. In summary, pneumatic equipment emissions will not be sufficient to account for the emissions observed by Atherton et al.

Similarly, a recent study based on measurements taken from gas and oil facilities in Alberta measured site level emissions 15 per cent higher than reported in inventories.[12] The measured facilities included 35 sites that produce natural gas, of which 32 were single well sites. Researchers excluded sites with the potential for flash emissions. Researchers concluded that the most likely explanation for the higher measured emissions are abnormal operating conditions best addressed by frequent leak inspections, as flash emissions from tanks could not explain the higher measured emissions.[13]

The B.C. and Alberta studies, just like the U.S. studies, demonstrate the need for frequent inspections.

2. *Quarterly inspections represent the best practice and are required by multiple jurisdictions*

We have routinely advocated for at least quarterly inspections.[14] Environment and Climate Change Canada requires operators inspect well sites, including single well batteries and conventional wells (other than stand-alone well heads) three times a year. Our understanding is that the ECCC rules, if applied to B.C., would require B.C. operators to inspect 4,694 facilities three times a year. The B.C. proposal, in contrast, only requires inspections three times a year at 675 facilities. At a minimum, B.C. must require the same number of inspections as ECCC, although to represent leading practices, B.C. should require quarterly inspections.

- **Mexico** recently proposed a national rule that applies to onshore and offshore facilities, including production, compression and processing facilities, that requires quarterly instrument-based inspections.[15]

- **California** recently finalized a rule requiring operators in the production and processing segments, as well as those operating compressor stations in the gathering and boosting and storage and transmission segments, to conduct quarterly inspections to detect methane emissions.[16]

---

[12] Daniel Zavala-Araiza, et al., *Methane Emissions from Oil and Gas Production Sites in Alberta, Canada* (March 2018) ("Zavala-Araiza (2018") Elem Sci Anth, 6: 27. DOI: https://doi.org/10.1525/elementa.284 .
[13] Id.
[14] See e.g., EDF comments to ECCC on Proposed Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector), Exhibit B.

[15] On file with EDF and CATF.
[16] CARB § 95668(g).

- **Colorado** requires that operators inspect for and repair hydrocarbon leaks, consisting of methane as well as other organic compounds, at three types of new and existing facilities: compressor stations, well sites and storage tank batteries. The rules require quarterly inspections at mid-sized facilities.[17] The size of the facility is determined based on the potential to emit volatile organic compounds, although operators are required to repair all hydrocarbon leaks, including leaks from components that primarily emit methane.[18] Operators may use OGI, Method 21 or another approved instrument.

- **Wyoming** requires quarterly instrument-based inspections at all new and existing well sites in its Upper Green River Basin with the potential to emit four tons of VOCs from fugitive components.[19] Like Colorado, Wyoming operators may use either M21, an optical gas imaging instrument or another approved instrument.

3. *Quarterly inspections are cost effective*

Information from various U.S. jurisdictions and independent consulting groups demonstrates that quarterly inspections are highly cost effective.

- As noted above, **ICF International** estimated that requiring operators to inspect for leaks quarterly at well sites can be accomplished for approximately $1.5 per Mcf of gas produced (assuming gas prices of C$5/Mcf).[20]
- Similarly, the **California** Air Resources Board has found that the cost of conducting quarterly inspections at production facilities to be highly cost effective. CARB estimates the costs are $23/metric ton of CO_2e reduced (accounting for savings from recovered product) to $26/metric ton of CO_2e reduced (not accounting for savings).[21] These estimates assume a 20-year global warming potential for methane.
- The final cost benefit analysis prepared by the **Colorado** Air Pollution Control Division in support of its LDAR program demonstrates that quarterly inspections are cost effective. For mid-sized well sites, Colorado found the cost effectiveness of quarterly LDAR inspections to be $1,019/ton of VOC reduced and $679/ton of CH4/ethane reduced for facilities located in the Denver non-attainment area. For remote facilities

[17] Colorado 5 C.C.R. 1001-9, Reg. 7, § XVII.F
[18] Id. at XVII.a.5.
[19] WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6.
[20] Id., Figure C-7 (using a 20-year GWP in CO2e).
[21] CARB. Revised Emission and Cost Estimates for the Leak Detection and Repair Provision. (February, 2017). Available at: https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasatt2.pdf.

located outside the Denver-Julesburg basin, Colorado determined quarterly inspections to be cost effective at $1,268/ton of VOC reduced and $648/ton of CH4/ethane reduced.[22]

- **Carbon limits:** This study is based on actual leak data from more than 4,000 LDAR inspections of oil and gas facilities, such as well sites, gas compressor stations, and gas processing plants. The inspectors used infrared cameras to identify more than 58,000 individual components that were leaking or venting gas. The inspection firms provided facility inspection costs and for every leak they found, data such as the size of the leak and how much it would cost to repair. LDAR surveys performed quarterly would abate methane at a net cost of less than $280/metric ton ($11/ton CO_2e using a global warming potential of 25) for all types of facilities. Per this study, more than 90 per cent of the gas leaking from these facilities is from leaks that can be fixed with a payback period of less than one year (assuming gas prices of $3/1,000 cubic feet).[23]
- **Center for Methane Emissions Solutions**, **Colorado case study** CMES interviewed 10 companies in Colorado operating after the state adopted its leak detection and repair program in 2014. It found that seven out of 10 companies interviewed reported that additional revenues from fixing leaks more than covers the costs of finding and fixing leaks.[24]

4. *The BCOGC significantly underestimates emissions from single well production facilities, thereby overestimating the efficacy of its LDAR proposal*

We have serious concerns with BCOGC's modelled reductions for its proposed LDAR requirement and believe that the model significantly underestimates leak emissions from single well production facilities. The presentation provided in the September 14, 2018 meeting shows that B.C.'s modelling of the proposed LDAR approach would achieve almost as many reductions as ECCC's LDAR requirement. This is based on assumptions we believe are incorrect. Specifically, the model assumes unrealistically low component counts for SWP facilities. These low component counts are based on data and assumptions from ECCC and the ECCC Enterprise Asset Management. As a result of assuming such unrealistically low component counts and component count leak emissions, the model significantly underestimates reductions from the proposed annual LDAR requirements. Accordingly, the BCOGC's model shows a similar amount of overall reductions as compared to ECCC's comparatively stronger LDAR requirement

[22] Colorado Air Pollution Control Division, Cost-Benefit Analysis for Proposed Revisions to AQCC Regulations No. 3 and 7 (February 7, 2014) ("CAPCD Cost-Benefit"), at 28, Table 34, *available at* https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

[23] Carbon Limits, Fact Sheet, Fixing the Leaks: What would it cost to clean up natural gas leaks?, available at http://www.catf.us/resources/factsheets/files/LDAR_Fact_Sheet.pdf. Full report available at http://www.catf.us/resources/publications/files/Carbon_Limits_LDAR.pdf .

[24] Center for Methane Emissions Solutions, Colorado Case Study, available at https://static1.squarespace.com/static/558c5da5e4b0df58d72989de/t/57110da386db43c4be349dd8/1460735396217/Methane+Study.pdf.

because it assumes that most leak emissions in B.C. come from the larger multi-well facilities, gas processing plants and compressor stations that are subject to inspections three times a year under the B.C. proposal.

The unrealistic assumptions in the B.C. model are most clearly seen in the table "Component and Pneumatic Device Information" on page five of the "Responses Sept 25" document that BCOGC provided to stakeholders. For "Gas Wells," which is the facility type for SWP gas facilities in this table, the B.C. model assumes that the site has a total of six valves and 19 connectors (no open-ended lines or pressure relief values) in gas service, and a single connector in liquid service. This may be an appropriate number of components for a single wellhead–only site, but is not a reasonable assumption for a SWP facility. However, B.C. is using this component count for all gas SWP facilities in B.C., and using a similarly unrealistic, although slightly higher, component count for SWP oil sites. We strongly believe that this set of facilities — which includes thousands of oil wells and conventional gas wells — includes a substantial number of sites not associated with a separate battery. This can be seen from the B.C. facility counts. For example, for 2016, BCOGC reports that the province had 5,876 conventional SWP facilities, 39 tight SWP facilities and 29 shale SWP facilities. But, the province only had 69 conventional multi-well batteries, 31 tight MWBs and no shale MWBs, in addition to a total of only 29 single well batteries (across all resource types). The high (or infinite in the case of shale) ratio of batteries to SWP facilities makes it clear that many SWPs in the B.C. fleet are not connected to batteries. Separation, liquids storage and any needed treatment must be occurring somewhere, and it's likely that a portion of the needed separation and storage of liquids is occurring on SWP sites in B.C. The component count in the B.C. model is far too low for sites with these processes — it simply isn't possible to build a facility with a separator and a tank with so few components.

We understand that B.C. has an unusual development pattern where liquids are typically not stored at the wellsite, at least for unconventional development. It is our understanding that these sites do have separation (for metering purposes). In this case, the component count used by B.C. to model leaks emissions is still too low. Moreover, we believe that this pattern is not universal at SWP sites in B.C., given the large number of oil and conventional gas SWP sites in the province. In the September 25 response to inquiries from stakeholders, BCOGC provided the following definition of "wells":

> "A facility directly associated with one or more wells that typically includes a simple piping and equipment configuration with equipment such as effluent (orifice) meters, test and / or group separators, sand separators, emergency shut down valves, pressure control valves, **and can also include production tanks** and flare systems." [Emphasis added.]

This appears to confirm that liquids storage does occur at some SWP sites.

As a comparison to B.C.'s low component count for SWP facilities, U.S. EPA recently created a "model plant" for a gas wellpad to analyze LDAR regulations. This model plant is for a two-well pad, but the component count is far higher than the component count used by B.C. for SWPs. EPA estimates that a two gas–well pad will contain 139 valves, 509 connectors, 14 open-ended lines, and seven pressure relief valves.[25] If the two wells on the pad share no equipment, then a single-well pad would be expected to have half the number of components as this model two-well pad — or about 70 valves, 250 connecters, seven OELs and three PRVs (rounding down). This is conservative, since a two-well pad would actually share equipment between the wells, the component count for a single well pad would likely be higher than half of the component count for a two-well pad. Obviously, these component counts are far higher than the component count B.C. is using. We recognize that site configurations vary between regions, but the huge disparity between the EPA component count and the component count that B.C. is using shows that it is not appropriate to use the B.C. count to model leak emissions from BC SWPs.

Given the undercounting of components and the complete exclusion of leakier PRVs at SWPs in the B.C. model, it follows that B.C. is dramatically underestimating leak emissions from these facilities. We believe that if the B.C. model included appropriate emissions from leaks at these facilities, by properly accounting for the production equipment patterns at all B.C. SWPs (including sites with higher component counts, liquids storage, etc.) it would show that B.C. cannot achieve adequate mitigation without a stronger LDAR program at these facilities (including conventional SWPs, see below).

B.C. must require the same number of inspections per year as ECCC in order to best reduce emissions from leaking production facilities. If B.C. concludes that, despite the numerous precedents described above broadly requiring frequent LDAR at production facilities, some facilities should be inspected less frequently than required by ECCC, we urge BCOGC to only allow less frequent inspections at facilities that actually have less propensity to leaks, such are facilities without any liquids storage. In contrast, the approach OGC described in September allows infrequent LDAR based on the facility classification, not the actual equipment present on site.

5. *B.C. must require instrument-based comprehensive triannual surveys at conventional wells to achieve meaningful reductions in production leaks*

The proposal to allow for annual *screenings* instead of instrument-based comprehensive surveys at individual conventional wells is far from a best practice to reduce leaks, and also flies in the face of recent study data from B.C. and the U.S. that demonstrate that conventional wells leak in excess of what inventories suggest (see below). As we understand B.C.'s proposal, these

[25] US EPA. Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources. Background Technical Support Document for the Final New Source Performance Standards. 40 CFR Part 60, Subpart OOOOa. May 2016. Supporting Spreadsheet: "Final Rule OOOOa TSD Section 4 - OGI Well Pad 050216". Available at:https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7631.

screenings could use methods as insensitive as sensory-based AVO screening, which are extremely limited in their ability to detect leaks. Not only must B.C. increase the inspection frequency for conventional wells to at least three times a year, but it must also require operators always use reliable instrument-based methods to conduct leak surveys.

The backbone of a rigorous LDAR program is the use of a reliable leak detection method. The first LDAR requirements in the U.S. for the oil and gas industry, dating back to 1987, required operators use M21 to detect gas leaks.[26] EPA, and then a suite of states, eventually expanded the allowable LDAR detection method to include the use of OGI cameras. Now, EPA and six states require the use of either M21 or OGI.[27] In some instances, operators may use AVO as a supplement to M21 or OGI; however, no jurisdiction currently allows for the use of AVO in lieu of these methods to fulfil its LDAR requirement. The reason for this is simple: AVO has not been demonstrated to achieve equivalent emission reductions as M21 or OGI. Most analyses have concluded that operators would, under current standard practice, generally fix any leak that is so large and noticeable that it will be detected using AVO.[28] Thus, we do not expect emissions reductions from AVO inspections, relative to current levels, despite the high emissions from leaks and improper/abnormal operating conditions that can be readily reduced with instrument-based LDAR. In contrast, as numerous jurisdictions have concluded, substantial reductions can be achieved with instrument-based programs.

Independent scientific research has indicated that leaks are not lower at conventional well sites than at tight/shale wells. Atherton et al. (2017), described above, found that "[M]ultiple sites **that pre-date the recent unconventional natural gas development** were found to be emitting, and we observed that the majority of these older wells were associated with emissions on all survey repeats."[29] Data from that study shows that older wells (> 20 years old) are at least as likely to emit methane at detectable levels, and the average emissions from older wells are equivalent, or

---

[26] 40 C.F.R. KKK (1987) (requiring the use of M21 to conduct LDAR at gas processing plants).

[27] CARB § 95668(g); Colorado 5 C.C.R. 1001-9, Reg. 7, § XVII.F; WY Permitting Guidance; Wyoming Department of Environmental Quality, Air Quality Division Standards and Regulations, Nonattainment Area Regulations, Ch. 8, Sec. 6; Pa. Dep't of Envtl. Prot., General Permit for Natural Gas Compression and/or Processing Facilities (GP-5), Section G and General Permit for Unconventional Natural Gas Well Site Operations and Remote Pigging Stations, (GP-5A), Section G, *available at* http://www.depgreenport.state.pa.us/elibrary/GetDocument?docId=12968&DocName=FINAL%20DRAFT%20GP-5A%20-%20UNCONVENTIONAL%20NATURAL%20GAS%20WELL%20SITE%20OPERATIONS%20AND%20REMOTE%20PIGGING%20STATIONS.PDF%20%20%3Cspan%20style%3D%22color:blue%3b%22%3E%28NEW%29%3C/span%3E;Ohio Envtl. Prot. Agency, *General Permit-Natural Gas Compressor Stations and Similar Facilities, GP 18.1, available at* https://epa.ohio.gov/dapc/genpermit/ngcs.

[28] See e.g., CAPCD Cost-Benefit , at 18 (noting that the Division assumes most operators are already conducting AVO screenings, so declining to estimate additional costs for these types of inspections which are in addition to instrument-based inspections).

[29] Atherton et al. (2017) at 12405 (emphasis added).

at best slightly less, than emissions from newer wells such as unconventional wells.[30] Thus, there is no justification in the available B.C. data for treating unconventional wells differently than conventional wells.

The results of the Atherton study are in accord with measurements taken at conventional and unconventional well sites in Pennsylvania. The Pa. measurements included measurements at 18 low-producing conventional well sites. Using the EIA definition for a gas well (i.e., GOR > 6 Mcf/barrel), 15 out of the 18 sites were gas well sites, with measured emissions ranging from 0.06 kg/h to 4.5 kg/h. The conventional well site emissions, expressed as a fraction of total gas production, was high (range: 0.3 per cent to 88 per cent, average about 20 per cent).[31] This suggests that leaks contributed to these excess emissions.

To our knowledge, B.C. is not modelling lower emissions from conventional SWPs than from tight or shale SWPs. Rather, B.C. cites "[A]ccess issues" and "large distances apart making economics challenging" in describing the reasons for only requiring screenings at these sites. We note first that the methane abatement cost associated with LDAR at these sites will be overestimated if leak emissions are underestimated, as discussed above. Secondly, other jurisdictions have not generally allowed lower standards for leak programs at conventional well sites than at unconventional well sites, although industry stakeholders have raised this concern elsewhere. As demonstrated above, instrument-based LDAR surveys are inexpensive, even accounting for travel time and overhead costs for survey teams, including in remote areas such as Western Colorado. When LDAR is required under regulatory standards, operators and contractors are able to economize surveys by travelling from site to site performing surveys in series and can cover a huge number of facilities in a limited time period.

We urge B.C. to extend the instrument-based comprehensive survey requirement to conventional wells in order to ensure meaningful reductions from these types of facilities; as noted above, the minimum inspection frequency for conventional wells must be at least three times a year.

B. Must decrease the storage tank venting limit

B.C has proposed a tank limit slightly over twice as high as ECCC's site level limit for new facilities, and seven times higher than ECCC's site level limit for existing facilities. We understand that low emissions from tanks in the B.C. emissions inventory is the basis for this high limit, relative to that in the ECCC rule. We are concerned that the inventory likely underestimates emissions from storage tanks, including controlled tanks. Data from the U.S. demonstrates that tank emissions are often underestimated in emission inventories due to leaks

---

[30] Id, see figure 10.
[31] Omara, M., et al., Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin, Env'tl Science & Tech., 2016. *0* (4), pp 2099–2107, available at https://pubs.acs.org/doi/abs/10.1021/acs.est.5b05503.

and excess venting caused by abnormal operations, including the failure of tank controls. This data supports frequent inspections at sites that contain storage tanks, including controlled tanks and robust controls such as low control thresholds or vent limits. We summarize this data below and offer recommendations for improving the proposal in order to ensure that tank emissions are minimized.

1. *Data from the U.S. underscores the importance of controlling tanks and inspecting controlled tanks for leaks*

Scientific studies and agency investigations, including a helicopter study described below, demonstrate that access points on controlled storage tanks are significant sources of emissions if not properly designed and operated. Frequent inspections, coupled with rigorous provisions to prevent uncontrolled venting, are critical to ensuring meaningful reductions from storage tanks in B.C.

A 2016 helicopter study of 8,220 well pads in seven basins confirms that storage tanks are responsible for emissions in excess of what inventories report.[32] That study focused only on high emitting sources, given the helicopter survey detection limit which ranged from 35 to 105 metric tons per year of methane. The paper reported that emissions exceeding these high detection limits were found at 327 sites. Notably, ***92 per cent*** of the emission sources identified were associated with tanks, including some tanks with control devices that were not functioning properly.

Inspections and enforcement actions by EPA and the state of Colorado confirm the findings of the helicopter study. In 2012, the Colorado Air Pollution Control Division and EPA inspected 99 storage tank facilities. They discovered that emissions were not making it to their intended control devices at 60 per cent of the facilities, due to inadequately designed and operated storage tank vapour control systems. These inspections formed the basis for a $73-million settlement between Noble Energy, the U.S. EPA and the state of Colorado wherein the operator, in addition to paying a $4.95 million fine, agreed to a suite of measures to better reduce flash emissions and ensure the proper operation of tank controls.[33]

More recently, EPA and Colorado entered into a second settlement agreement with another operator in Colorado, PDC Energy, Inc., to address the same problem. Pursuant to this settlement, PDC agreed to implement $18 million worth of mitigation actions to address excessive venting from its tank. These actions include engineering evaluations of its vapour control systems, periodic infrared camera inspections, and the installation of pressure monitors

[32] Lyon, et al., "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," *Environ. Sci. Technol.*, 2016, *50* (9), pp 4877–4886, available at http://pubs.acs.org/doi/abs/10.1021/acs.est.6b00705.
[33] https://www.epa.gov/enforcement/noble-energy-inc-settlement

with continuous data reporting to verify that over-pressurized tanks are not contributing to excess emissions.[34]

In 2014, Colorado implemented a suite of rules to address the problems identified in the Noble and PDC settlements. These rules included periodic instrument-based inspections at production facilities with tanks, analysis of the design of storage tank control equipment, and lowering the statewide emission threshold for installing controls on tanks from 20 tons per year of VOCs to six tons per year.[35]

Thus, it is not sufficient to require operators to install control devices on tanks or to assume compliance with a tank venting limit based on assumptions that a control device is operating effectively. There is ample evidence of improperly functioning tank controls across a variety of study areas. To address this issue, tanks should be inspected as part of the leak detection and repair program and strict limits should be set to minimize any allowable venting.

2. *The threshold proposed by BCOGC is too high, and the cost of installing a vapour recovery unity justify a lower threshold for both new and existing sites*

Analysis published during rulemaking in Colorado and California include costs of installing a VRU and/or flare on a tank, and they shed light on the appropriate and cost-effective emissions threshold for tanks.

The analysis that CARB used in its rulemaking uses costs from EPA's Natural Gas Star to estimate annualized costs of installing a VRU. It finds annualized costs of just under $12,000 for a VRU capable of handling 25 Mcf of gas/day (according to CARB, this size VRU is adequate for 316 of the 317 systems that need to be installed).[36]

[34] https://www.epa.gov/enforcement/pdc-energy-inc-clean-air-act-settlement#violations
[35] 5 C.C.R. 1001-9, Section XVII.C.1.b.
[36] CARB, Economic Analysis, Table B-7, pgs. B-23,B-24.
https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasappb.pdf. Based on the middle of the cost range presented in "Lessons Learned from Natural Gas Star Partners: Installing Vapor Recovery Units on Storage Tanks".
https://www.epa.gov/sites/production/files/2016-06/documents/ll_final_vap.pdf

CARB (25 mscf/day)	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
VRU	$20,421			
Installation		$15,316		
Maintenance			$7,367	
Subtotal costs	$20,421	$15,316	$7,367	
Capital recovery factor	0.130	0.130		
Annualized costs without value of saved gas	$2,645	$1,983	$7,367	$11,995

Colorado estimates annualized costs of approximately $22,700. [37]

Colorado	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	Annualized total costs
VRU	$90,000			
Freight/engineering		$1,648		
Installation		$11,154		
Maintenance			$9,396	
Subtotal	$90,000	$12,802	$9,396	
Capital recovery factor[38]	0.130	0.130		
Annualized costs without value of saved gas	$11,655	$1,658	$9,396	$22,709

Thus, the existing literature has various estimates for the cost of installing a VRU. On the low end of these estimates, CARB uses costs from the U.S. EPA'a Natural Gas Star. On the high end are Colorado and U.S. EPA (in the 2012 OOOO rule making). In both cases, the underlying cost data was provided by industry.

Colorado also estimates the cost of installing a flare and the annualized costs of installing a flare.[39]

---

[37] CDPHE, Cost-Benefit Analysis. Table 17. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573. In the Final TSD for the OOOO rule (Table 7-4. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4887), EPA references the Initial Economic Impact Analysis for the CDPHE rule published in 2008 (Table 4. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-0026). These vary due to adjustments for inflation.

[38] Note: Colorado annualized costs over 15 years at five per cent, here CRF is adjusted to match CARB: annualized over 10 years at five per cent. In attached spreadsheet (Exhibit C), BCOGC can adjust amortization period and interest rate.

[39] CDPHE, Cost-Benefit Analysis. Table 1. https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-7573.

	Capital costs (one time)	Non-recurring costs (one time)	O&M costs (recurring)	annualized total costs
Flare	$18,169			
Freight/engineering		$1,648		
Flare installation		$6,980		
Auto igniter	$1,648			
Pilot fuel			$768	
Maintenance			$2,197	
Subtotal costs	$19,817	$8,628	$2,965	
Capital recovery factor[40]	0.13	0.13		
Annualized costs without value of saved gas	$2,566	$1,117	$2,965	$6,649

We created a model to calculate the costs of various control thresholds (the spreadsheet is included as Exhibit C). For a given control threshold, the spreadsheet calculates the abatement costs of VRU and flare using the Colorado and CARB cost estimates. For the VRU option, it calculates the costs both ignoring and accounting for the value of the saved gas. For the flare option, there is no saved gas, so only one abatement cost is presented.

For example, at the proposed threshold for existing sites of 9,000 m^3/month, the abatement cost using the CARB cost is $272/ton and using the Colorado cost it is $514/ton. Once we account for the value of saved gas, the abatement cost using the CARB cost is $14/ton and using the Colorado cost is $257/ton.[41] The cost associated with installing a flare would be $151/ton. Thus, we know that the proposed threshold is far too high, because it results in abatement costs well below the social cost of methane of $1,200/ton.[42] At emissions thresholds between 1,678 m^3/month and 3,176 m^3/month, the VRU gas capture option would still be at or below the social cost of methane. The threshold could be even lower using the flare option: 1,130 m^3/month. We invite the BCOGC to use our spreadsheet tool to set a tank control threshold that is consistent with its determination of reasonable abatement costs. Regardless of which cost estimate is used, a threshold far lower than 9,000 m^3/month would be cost-effective.

We urge B.C. to follow Colorado's lead and lower the proposed storage tank venting limit while also increasing the inspection frequencies for single well batteries, as discussed above.

---

[40] Note: Colorado annualized costs over 15 years at five per cent, here CRF is adjusted to match CARB: annualized over 10 years at five per cent. In attached spreadsheet (Exhibit C), BCOGC can adjust amortization period and interest rate.

[41] Assumes that gas is 60 per cent methane by volume, 98 per cent gas recovery and a price of gas of $3/mcf.

[42] Using three per cent discount rate, 2020 central estimate. Table 1. https://www.epa.gov/sites/production/files/2016-12/documents/addendum_to_sc-ghg_tsd_august_2016.pdf.

C. B.C. must require inspections of natural gas–powered pneumatic controllers at least three times a year in order to ensure reductions

We commend the BCOGC on proposing a robust requirement to address venting and leaks from pneumatic controllers. Per the proposal, all controllers at new facilities, and existing controllers at large compressor stations (i.e., those with three megawatts or greater of compression), must not vent natural gas. Controllers at other existing facilities, such as batteries and well sites, must be low bleed. ECCC, by contrast, does not prohibit venting from any controllers, new or existing, but rather requires low-bleed controllers for all facilities.

The installation of use of zero-bleed controllers is highly cost effective. ICF International analyzed the cost of replacing high-bleed controllers and intermittent vent controllers with instrument air in Canada. Per ICF's analysis, replacing high-bleed controllers has a payback of 0.8 years and replacing intermittent-bleed controllers has a payback of 2.1 years.[43]

California, which requires that all new continuous-bleed controllers should not bleed gas to the atmosphere, and all existing controllers to be low-bleed, similarly found its requirement to be highly cost effective. California estimated its requirement at $1/metric ton of CO2e reduced, accounting for gas savings, and using a global warming potential of 20 years for methane.[44]

The BCOGC has estimated significant reductions from this requirement. We note that the accuracy of this prediction will turn, in part, on how operators choose to comply with the zero-bleed requirements. If operators replace natural gas–powered controllers with instrument air or electricity, vented emissions and leaks will be reduced to zero. This is optimal. However, if operators route the discharge emissions from natural gas–powered controllers to a closed vent system, vented emissions due to improper operation and leaks remain a possibility. Routine leak inspections will be critical to ensuring that such controllers do not vent and do not leak. Similarly, routine inspections will be critical to ensuring that low-bleed natural gas controllers do not vent above low-bleed levels. Such inspections of low-bleed controllers should include an annual direct measurement of emissions as required by California.[45] The potential for excess emissions from abnormally operating pneumatic controllers, even with the robust requirements proposed, underscores the importance of requiring routine inspections at all production facilities.

[43] Exhibit A, Table C-9.
[44] CARB Final Statement of Reasons, available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilandgas2016.htm.
[45] CARB § 95668(e)(2)(A)(3)-(4).

D. B.C. must require controls on existing pneumatic pumps

We're concerned by the lack of proposed requirements for existing pumps. According to the ECCC's EAM model, pneumatic pumps account for nine per cent of oil and gas methane emissions in B.C.[46] The BCOGC notes "limits on venting at new facilities are more cost effective than at existing facilities," uncertainty in pump emissions and that existing pumps will be addressed by other government programs, as the rationale for the lack of existing pump controls.[47] These reasons are not sufficient to exclude existing pumps from the rule.

We note that CARB will require all new and existing pumps to be zero-bleed as of January, 2020. CARB grouped the two together in analyzing cost-effectiveness, finding that this requirement would reduce emissions at a cost of roughly US\$1/tCO_2e when accounting for gas savings.

According to ICF (2015), existing pneumatic chemical injection pumps in Canada can be replaced by solar-powered pumps that have zero emissions at an average net cost of \$10.52/tCO2e emissions abated.[48] This is well below the predicted average cost of \$30/tCO_2e for the other proposed regulations outlined in the September 14, 2018 presentation by the BCOGC.

Using B.C.-specific data on facility and equipment counts provided by BCOGC, it is possible to assess the abatement that could be achieved by regulating existing pneumatic pumps for the province. We follow ICF (2015) in assuming that only 60 per cent of pumps could be replaced cost-effectively due to differences in real world operating conditions (which is likely conservative). If these devices emit 2.17 tonnes of methane per year per device (the EPA GHGRP's default emission factor), replacing 60 per cent of these pumps would reduce emissions by an additional 16,000 tons of methane per year (400,000 tCO2e).

Although the exact emission factor may differ for pumps in B.C., there's no question that regulating existing pumps is an opportunity to achieve substantial emission reductions at low cost to help the province achieve its 40 per cent target. In addition to the requirement that all new devices be zero-bleed, we strongly recommend B.C. require operators to replace at least 60 per cent of existing pneumatic pumps with zero-bleed devices.

Finally, ICF's analysis found that existing pumps can be cost effectively controlled at a negative net cost — even adjusting for low current gas prices. We strongly recommend B.C. require operators to replace all existing Kimray pumps with zero-bleed devices.

---

[46] ECCC EAM model, version from October 2018.
[47] Sept. 14 OGC Powerpoint at 17.
[48] We again update ICF's assumed gas prices to C\$1.40/Mcf.

E. B.C. should include robust compliance monitoring provisions to verify compliance

The BCOGC has requested feedback on record keeping and reporting provisions. In response, we offer these high-level suggestions as the draft proposal does not contain any such provisions, and we have not seen any specific regulatory language.

Robust, detailed, site-specific compliance monitoring provisions are essential to ensuring compliance and verifying reductions. We urge the BCOGC to require operators to maintain records demonstrating compliance with each of the mandatory methane reduction measures. Such records must document how the operator complies with the requirement, as well as any instances of non-compliance, and the reasons for such non-compliance. Adequate, detailed records are particularly important for demonstrating compliance with the LDAR provisions given the complexity of this requirement. The ECCC rule contains robust record keeping requirements for LDAR, which we recommend the BCOGC require.

We urge the BCOGC to require operators submit an annual report certifying compliance with each methane reduction requirement. A summary compliance report can provide the BCOGC and the public with important information about the efficacy of the rules, which can be used to guide future regulatory efforts. For the LDAR provision, we recommend a report that includes:

- Total number of facilities inspected
- Total number of inspections conducted at each facility
- Total number of leaks requiring repair, broken out by component type, monitoring method and inspection frequency, if differing frequencies per facility are allowed
- Total number of leaks repaired per type of facility
- Total number of leaks on delayed repair list, broken out by component type, and facility type, and the basis for each delay of repair[49]

F. B.C. must require robust GHG reporting to track progress towards its GHG reduction goal

We also recommend B.C. require a detailed categorization of emissions similar to the U.S. EPA's GHG Reporting Rule (Subpart W). We recommend these categories for methane emissions:

1. Atmospheric storage tanks (solution/associated gas)
2. Casing gas vents (solution/associated gas)
3. Pneumatic instruments
4. Pneumatic pumps
5. Reciprocating compressors packing vents

[49] See Colorado Reg. 7, 5 CCR 1001-9, § XVII.F.10.

6. Centrifugal compressor seal vents
7. Dehydrator still column vents
8. Pressure vessels and piping blowdowns
9. Pressure relief valves
10. Compressor engine starters
11. Liquids unloading
12. Fugitive emissions
13. Well completions and testing
14. Surface casing vent/gas migration

Conclusion

For the reasons listed above, we strongly urge the BCOGC to strengthen its proposed approach for regulating methane. The current proposal fails to represent leading best practices nor require cost-effective solutions. Without significant strengthening of the LDAR, tank venting and pneumatic pump provisions, we fear B.C. will be unable to meet its GHG targets. At a minimum, we urge B.C. to take a precautionary approach, as the current proposal is not based on the best available data, and more robust data on B.C. emissions will be forthcoming in the following months.

Acknowledgements:
This report was made possible by the generous support of the Metcalf Foundation, the Echo Foundation and the Energy Foundation.