POLICY BRIDGE

A case study in competing methane regulations: Will Canada’s and Alberta’s contrasting regulations achieve equivalent reductions?

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The Canadian federal government and the Province of Alberta (the dominant oil and gas producing province) have released competing methane regulations for the oil and gas sector intended to take effect between January 2020–2023. Provisions in Canadian law could allow the provincial regulations to take precedent, but only if they are deemed to be equivalent in effect. This paper presents a comprehensive technical comparison of these upcoming regulations by considering potential site-by-site mitigation impacts on active oil and gas facilities in Alberta in 2018. This analysis was made possible by first creating a detailed inventory using recent pneumatic device count data and current production and activity data, which allowed detailed site-level calculations of regulatory impacts on a monthly basis as required by the regulations. The federal regulations are found to be stronger, achieving ~26% more methane mitigation at full implementation. Key differences are in limits on pneumatic pump emissions, vented emissions, and expected reductions in fugitive emissions through leak detection and repair surveys. The full analysis was repeated using production and inventory data for 2012 and 2017 to examine sensitivities to changing production patterns and facilitate comparisons to the 2012 baseline referenced in federal policy targets for methane reduction. The results were robust in all scenarios. Through a “Potential to Emit” threshold, the federal regulations also impact slightly fewer sites overall by exempting small sites handling limited gas volumes, while achieving greater overall methane reductions. Relative to a 2012 baseline, if fully implemented in 2018 the federal regulations would just reach the bottom of the 40–45% methane reduction target through a combination of past reductions (13%) and additional regulated mitigation (27%). However, recent trends in emissions from mined oil sands operations in particular (which are not affected by these regulations) suggests the 40–45% reduction goal for the overall sector may not be achieved by the 2025 target. Different scenarios to make the regulations equivalent are briefly discussed where the contrast in achieved mitigations for different key sources is important case study data for design of effective and efficient methane regulations.

Keywords: Methane regulations; Oil and gas sector; Methane mitigation; Equivalency; Inventories; Venting

Introduction
The Canadian Government has passed new oil and gas sector methane regulations developed by Environment and Climate Change Canada (ECCC), which are scheduled to come into force starting in January 2020 (ECCC, 2018a). The province of Alberta, responsible for 67% of gas and 80% of crude oil and equivalent production in Canada, has released its own competing regulations as a January 2020 version of Directive 60 of the Alberta Energy Regulator (AER) (AER, 2018a). Both regulations are intended to reach full implementation by January 1, 2023, with specific components being introduced as early as January 1, 2020. The federal government has indicated (ECCC, 2018b), consistent with Part 1, Section 10 of the Canadian Environmental Protection Act (Government of Canada, 1999), that “provinces and territories can put in place methane regulations that make sense for their circumstances, provided they can clearly demonstrate emission reductions equivalent to the federal measures”. Thus, the federal ECCC regulations serve as a “backstop”, and the proposed AER regulations could take precedence if they are deemed equivalent. This sets up a critical and urgent ruling by the federal government on whether the proposed AER rules will be allowed to stand. Both ECCC and AER have each publicly committed (Government of Canada, 2016) to achieving 40–45% reductions in methane emissions from the oil and gas sector by 2025, although the stated ECCC and AER reduc-
tion targets are relative to 2012 and 2014 methane levels respectively (Government of Alberta, 2018; Government of Canada, 2016).

The objectives of this paper were to (i) conduct a quantitative assessment of the new ECCC and AER regulations governing methane emissions in the upstream oil and gas sector, (ii) estimate the number of impacted sites for different parts of each regulation relative to the achieved mitigations as a potential measure of regulatory efficiency, (iii) perform a comprehensive, direct comparison of anticipated total and source-category-specific methane reductions for each regulation, and (iv) assess the anticipated reductions in the context of stated 40–45% policy targets for reducing oil and gas sector methane. The analysis was completed considering individual facilities in the Alberta upstream oil and gas sector using reported production accounting data coupled with presently derived updated inventory estimates for 2018. Because of the numerous complexities in how each regulation is to be implemented, a more finely resolved and updated methane emissions inventory was necessarily developed that enabled evaluation of site-level applicability thresholds and anticipated mitigation impacts. The analysis directly compares the anticipated impacts of ECCC and AER regulations at full implementation on a 2018 baseline and differences in the structure and impact of the regulations on different emission sources are examined. Potential sensitivities to changing production patterns are further considered by repeating the full analysis instead using production and inventory data from 2012 and 2017. The anticipated mitigations are discussed in the context of stated 45% methane reduction objectives for the entire oil and gas sector and relative to a 2012 baseline, matching ECCC’s policy goals. Potential scenarios that could make the regulations equivalent are briefly considered in the discussion and implications. Finally, an additional analysis modelling the 5-year phase-in period between 2020 and 2025 (the intended date for achieving stated methane emissions reduction targets) during which specific components of the regulation are to be introduced, is provided in the Supplemental Materials (SM), Section S10.

Comparison of ECCC and AER regulations

Table 1 presents a summary direct comparison of the Canadian Federal (ECCC) and Provincial (AER) regulations (when fully implemented) governing methane emissions at upstream oil and gas facilities. All regulated sources (matching the major categories in the national inventory) are included in the table and specific limits have been converted to common units. Broadly, each regulation similarly categorizes emissions and includes separate rules for intentional venting, pneumatics, fugitive leaks, and compressors. However, the details and implementation of these rules are quite different in several important ways. At first glance, the venting limits of AER are significantly weaker than those of ECCC, e.g. the AER fleet average limit of 3000 m³/mo for crude bitumen sites – historically the largest source of reported venting in Alberta (AER, 2018b; Johnson et al., 2017; Tyner and Johnson, 2018) – is more than double the ECCC vent limit of 1250 m³/mo. For existing non-crude bitumen batteries, the difference initially appears even more stark; however the simple comparison is complicated by the fact that the AER overall vent gas (OVG) limit of 15,000 m³/mo includes pneumatics and other sources which are excluded from the ECCC limit. ECCC regulations generally require use of low-bleed pneumatic equipment exclusively, whereas AER rules include additional options for either destroying (combusting) methane, using improved relay systems to minimize transient/dynamic venting or reduce actuation frequencies, or doing nothing in the case level controllers actuating less frequently than every 15 min. Rules for leak detection and repair (LDAR) programs for mitigating fugitive emissions appear more directly comparable – ECCC generally requires 3 times per year inspection and repair of leaks, while AER requires similar frequency only at select facilities (mostly larger facilities handling sweet gas) and 1 time per year at others. However, there are thresholds for when the ECCC inspections must be applied, as elaborated below, such that the methane emission impact of this difference in LDAR frequency within the overall structure of the regulations is not obvious. Finally, AER includes rules for glycol dehydrators that are absent in the ECCC regulation and the AER regulations for centrifugal compressors are nominally more than twice as stringent as those of ECCC, but the opposite is true for limits on reciprocating compressors.

**Rule applicability – AER fleet average vs. ECCC potential to emit**

Beyond the differences in the limits and specific source requirements of Table 1, there is a critical difference in how these are applied in the regulations. The AER rules apply broadly to all facilities, with the exception of the “fleet average” venting limit for crude bitumen batteries that allows operators to selectively take mitigation actions at a few facilities so long as the overall average limit is met. By contrast, with the exception of compressor limits, the ECCC rules are applied only to facilities that pass a “Potential to Emit” (PTE) threshold of producing or receiving more than 60,000 m³ of gas in a preceding non-consecutive twelve-month period. Furthermore, the ECCC venting limits are only applied in any given month at sites that pass a further threshold of having vented, destroyed, and/or delivered more than 40,000 m³ of gas in the 12 consecutive months preceding the month in which rules may be applied (See SM Section S6.2). Thus, the mitigation impact of the differences noted above is less obvious. From a modelling perspective, accurate calculation of AER fleet average emissions and the ECCC PTE and venting limit thresholds was particularly complex (See flowcharts in SM, Sections S6.1 and S6.2). The AER regulation required monthly tracking of ownership of crude bitumen facilities, which may change hands frequently. The ECCC regulations necessitated repeated analysis of monthly facility history data to determine applicability of PTE and venting limit thresholds in any given month.
Table 1: Comparison of ECCC and AER methane regulations when fully implemented on Jan. 1, 2023. DOI: https://doi.org/10.1525/elementa.403.t1

| FEDERAL (ECCC)† | PROVINCIAL (ALBERTA) |
|-----------------|-----------------------|
| **EXISTING**    | **NEW (after Jan. 2023)** | **EXISTING** | **NEW (after Jan. 2022)** |
| Venting Non-Crude bitumen batteries | 1250 m³/mo (excl. pneumatic devices, compressor seals, glycol dehydrators)† | Overall Vent Gas (OVG) limit of 15000 m³/mo (incl. pneumatics etc. – see Figure 1) | Defined Vent Gas (DVG) limit of 3000 m³/mo (excl. pneumatics etc. – see Figure 1) |
| Crude bitumen batteries | 3000 m³/mo (fleet average excl. pneumatics, starting Jan. 2022) | |
| Pneumatics Instruments | Manufacturer’s documented operational bleed rate must be ≤124.1 m³/mo (low bleed) | Control to 85.5% destruction* or ≤124.1 m³/mo (low bleed) | Control to 85.5% destruction* for 90% of installed pneumatics and ≤124.1 m³/mo (low bleed) |
| Level Controllers | If actuation period is <15 min: control to 85.5% destruction* or minimize transient venting or increase actuation period to >15 min | Control to 85.5% destruction* for 90% of installed controllers and if actuation period is <15 min, minimize transient venting or increase to >15 min |
| Pumps | 0 m³/mo for pumps > 20L methanol/day | N/A | Must not emit if operated >750 h |
| Fugitive sources | All facilities except isolated wells: LDAR @ 3/yr | Sweet gas plants, comp. stations, gas gathering systems: LDAR @ 3/yr Batteries (incl. on pad wells), sour gas plants, etc.: LDAR @ 1/yr Well sites not on a facility pad: AVO @ 1/yr |
| Compressors Centrifugal | 29804 m³/mo (≥5 MW) 14 902 m³/mo (<5 MW) | 6136 m³/mo | 7451 m³/mo |
| Reciprocating | 1008 m³/mo/throw§ | 44 m³/mo/throw§ | 3652.5 m³/mo/throw (606 m³/mo/throw fleet average) |
| Glycol dehydrators | N/A | 6633 m³/mo | 3317 m³/mo |

† Rules applicable to sites exceeding the “Potential to Emit” (PTE) threshold of having produced or received more than 60,000 m³ of gas in twelve preceding non-consecutive months.
‡ Rules applicable to sites that vented, destroyed, or delivered >40,000 m³ of gas in the prior consecutive 12-month period, where venting volumes in any given month are considered if they pass this vent inclusion threshold (See SM, Section S4.2) The ECCC regulation specifies a vent limit of 15,000 m³/y, which is equivalent to 1250 m³/mo assuming all months meet the vent inclusion threshold.
* Control is defined as 95% destruction 90% of the time in operation, thus 90% × 95% = 85.5%.
§ Specified as per “per cylinder” in the ECCC regulation which is understood to be equivalent to “per throw”.

Methodology

Data sources

Data from several sources were leveraged to complete the analysis as extensively detailed in the Supplementary Materials (SM). Monthly production volumes at individual upstream oil and gas facilities in the Province of Alberta reported by industry through the Petrinex system were obtained (Petrinex, 2018) for years spanning 2011–2018. These data, reported in whole gas units, included gas produced, received, flared, vented, used for on-site fuel, and delivered into pipelines. Importantly, these data included “from/to” node information allowing data reported in aggregate at some crude bitumen sites (so-called “paper batteries”) to be disaggregated back to the source wells or facilities (Johnson and Coderre, 2011; Tyner and Johnson, 2018). Comprehensive well activity data contained in the separate AER “General Well Data File” (AER, 2018c) were also utilized, which allowed tracking of well types and locations that ultimately feed into production batteries and/or gathering systems. National greenhouse gas inventory report (NIR) (ECCC, 2018c) data were obtained from ECCC, which included official estimates of unreported source emissions as well as emission estimates for oil sands operations and downstream facilities that are not subject
to the ECCC or AER methane regulations, but are factored into the stated 45% methane reduction target across the oil and gas sector. Recent 2018 methane inventory data derived for AER (Clearstone Engineering Ltd., 2019) were also utilized as elaborated in the SM. Facility and well-level gas composition estimates (where necessary to determine methane content from reported whole gas volumes) were derived by linking well-production information with an AER dataset of approximately 300,000 individual well gas analyses building on procedures outlined by Johnson and Codere (2012). Finally, as elaborated below and in SM Section S2, facility and component count data from a recent field survey led by Clearstone Engineering Ltd. in collaboration with the authors (Clearstone Engineering Ltd., 2018) were used to create facility-level pneumatic equipment estimates and when evaluating the LDAR components of the regulations.

**Analysis procedures for comparing anticipated methane mitigation**

The potential mitigation impact of each regulation was compared via a comprehensive, site-by-site application of the ECCC and AER requirements, calculated on a monthly basis. Calculations were performed in an Access database environment, and key aspects of the analysis are summarized here. Comprehensive details of the calculation methodology are provided in the SM. The analysis approach allowed diligent calculation of the AER overall vent gas (OVG) limits and defined vent gas (DVG) limits at individual facilities (AER, 2018a), which are based on monthly venting. Ownership of crude bitumen batteries was also tracked and updated on a monthly basis, which was essential for accurately computing the AER fleet average emissions given the frequency in which facilities change hands. Similarly, the ECCC PTE and venting inclusion thresholds were computed on a site-by-site and monthly basis. As elaborated in SM Section S6, this added the complexity of needing to consider previous reported activity (i.e. monthly production accounting data from 2012–2017) to accurately evaluate the applicability of the thresholds as written in the regulation.

The quantitative methane mitigation impact of each regulation at full implementation was compared, using activity, component count, production, and inventory data for 2018 (the most recent available). The full analysis was then repeated using production and inventory data from 2012 and 2017 to test the potential sensitivity of results to changing production patterns, while facilitating quantification of anticipated methane reductions relative to a 2012 baseline consistent with stated federal policy targets. Finally, the cumulative mitigation impact of each regulation during the 5-year implementation period from January 1, 2020–December 31, 2024 was assessed. For this latter scenario, detailed production patterns for 2018 were used to represent the comparison period (i.e. equivalent to a neutral or static production projection) and the rate of introduction and abandonment of new and old facilities was mapped to match 2014–2018 data (most recent 5-year period) as elaborated in SM Section S10.

**Specific analysis procedures for each source type**

**Pneumatic equipment**

In the AER rules for existing sites, the prescribed overall vent gas (OVG) limit of 15,000 m³/mo specifically includes pneumatic instrument (e.g. level controllers, positioners, pressure controllers, transducers) and pump venting. Because this venting limit is applied at the site-level, it was thus necessary to consider pneumatic emissions on an individual facility basis. Unfortunately, the ECCC national greenhouse gas inventory only estimate these emissions aggregated by facility type, and neither ECCC nor AER currently inventory pneumatic equipment at oil and gas facilities. To overcome this challenge, as detailed in the SM (Section S2), site-level estimates of pneumatic equipment counts were derived from field survey data of oil and gas production sites carried out in Alberta in 2016 and 2017 (Clearstone Engineering Ltd., 2018; Green-Path Energy Ltd., 2016). Existing pneumatic instruments (excluding level controllers) were estimated to, on average, have a vent rate of 0.2784 m³/hr (whole gas), calculated as a weighted average of pneumatic positioner, pressure controller, and transducer counts and emissions measurements from recent field survey data (Clearstone Engineering Ltd., 2019, 2018). For both regulations, emissions from low-bleed pneumatics (after replacement) were assumed to fall to 0.039 m³/hr (matching the 1.39 scf/hr estimate from the U.S. Environmental Protection Agency U.S. EPA) (U.S. EPA, 2013), which is below the regulated limit of 0.17 m³/hr.

The rules for pneumatic level controllers were more challenging to assess. The ECCC rules focus on limiting steady-state bleed rate emissions by only permitting low-bleed devices to be used. As detailed in in Section S6.3 of the SM, recent field measurements suggest 9% of currently installed level controllers are high-bleed variants (Clearstone Engineering Ltd., 2019), and the ECCC regulations can be expected to reduce methane emissions from these devices only by the differences between manufacturer specified steady bleed rates when moving to low-bleed alternatives.

The AER rules take a starkly different approach to level controllers, differentiated by whether their actuation period is shorter or longer than every 15 minutes. AER rules are also slightly different for existing vs. newly installed controllers (i.e. installed after January 1, 2023).

At existing sites, controllers actuating at <15 minute intervals must either have this period increased to >15 minutes, must be modified to minimize transient venting (D’Antoni, 2018; Spartan Controls, 2018), or must have their methane emissions controlled to an effective 85.5% destruction (i.e. 95% destruction, 90% of the time). By contrast, pneumatic controllers actuating less frequently than every 15 minutes require no specific action. It was thus necessary to determine the fraction of <15-minute interval level controllers in addition to determining site-level equipment counts. As elaborated in Section 57.1 of the SM, this was accomplished by considering well- and facility-specific produced liquid volumes (e.g. oil, water, condensate) and either two- or three-phase separator dynamics depending on how many distinct liquids were
reported in the production data for each site. In aggregate, approximately 11.3% of level controllers installed in Alberta in 2018 were expected to be actuating at intervals of <15 minutes. Additional analysis presented in Section S11 of the SM shows that even if this fraction were increased to 44%, mitigation would only increase by ~25 kt. Moreover, as noted at the end of Section S7.1 in the SM, this additional mitigation may be overstated given the potential importance of abnormally operating level controllers to overall emissions as seen in recent comprehensive field measurements of Luck et al. (2019) and as noted in recent field measurements in Alberta (Spartan Controls, 2018).

Calculated results presented below separately consider scenarios where operators choose either of the three options for <15-minute controllers at existing sites. At new sites, consistent with the AER regulations as summarized in Table 1, <15 minute controllers were assumed to first choose equipment that minimizes transient venting, and then all controllers (including those with actuation intervals >15 minutes), were assumed to be controlled to 77.5% effective destruction (90% of installed equipment, controlled to 95% destruction, 90% of the time). This effectively rendered level controller emissions at new sites negligible under the AER rules.

Rules for pneumatic chemical injection pumps were similarly complicated to assess. Chemical injection pumps (commonly used to inject methanol to suppress hydrate formation during winter temperatures) were assumed to be used 6 months per year (from October through March). During this period, pumps were assumed to emit an average rate of 0.961 m³/hr based on a weighted-average of emission factors in AER Manual 15 (AER, 2018d) using device distributions from recent field count data in Clearstone Engineering Ltd. (2018). Under the ECCC regulation, pumps flowing >20 L methanol/day would need to be replaced with zero emission alternatives. As further detailed in Section S6.3 of the SM, the proportion of pumps flowing >20L/day were determined on an individual well basis, by modelling methanol requirements using the Nielsen-Bucklin correlation (Nielsen and Bucklin, 1983) considering site-specific reported water volumes and well depth.

**Glycol dehydrators**

Glycol dehydrator emissions, representing ~1.4% of the current methane inventory as presented below, are specifically considered by the AER regulations but excluded from the ECCC regulations. However, based on separate modelling (See SM, Section S4 and S8), the new AER fleet average limit for glycol dehydrators was found to be well above current average emissions estimates in the national inventory such that the AER regulations are expected to have negligible impact on these sources. These emissions are nevertheless included when assessing the impact of AER’s overall vent gas limit as noted below, which allows for the additional mitigation that may be achieved under AER rules at sites where vented emissions must be reduced to this limit.

**Compressor seals**

Compressor seal emissions represent 5.2% of current methane emissions in the upstream sector and are explicitly included in both regulations. Referring to SM
Sections S4 and S8, compressor seal emissions in the national inventory were attributed to different facility types (e.g. oil and gas batteries, gas plants, etc.). Average monthly emissions were calculated considering the number of active months and compared with emissions expected under the regulations, where reciprocating compressors make up the vast majority of compressors in service. Any reductions were noted, and these reduced emissions were subsequently considered in the calculation of the AER overall vent gas limit when applicable.

Vent gas limits
At full implementation, the AER overall vent gas limit of 15,000 m$^3$/mo includes the remaining emissions from the sources described above (after application of any required mitigation actions), as well as emissions from storage losses, compressor starts, and tank loading and unloading. These additional sources appear in inventory estimates (see Figure 1 below) but are not included in currently reported venting volumes and are not otherwise specifically considered in the regulations. As further detailed in Section S4 of the SM, these additional source magnitudes were calculated as in the inventory and attributed by facility sub-type (e.g. single-well oil battery, multi-well gas battery, etc.). Average emissions for each sub-type were then applied to individual facilities, prior to calculating total venting for each site on a monthly basis and assessing potential impacts of the overall venting limit. Similarly, for sites passing the ECCC PTE and vent inclusion thresholds, the ECCC allowable venting limit of 1250 m$^3$/mo includes currently reported venting, storage losses, and tank loading/unloading, but unlike the AER overall limit, excludes any venting from pneumatic equipment, compressor starts, compressor seals, and glycol dehydrators.

Fugitive sources
As detailed in SM Section S3, baseline fugitive emissions estimates by facility type were derived (see Table S5) using active facility counts for each month to update detailed ECCC national inventory data (ECCC, 2018c), which are ultimately based on a 2011 reference year as prepared by Clearstone Engineering Ltd. (2014a). Isolated wells (which are exempt from LDAR requirements in the ECCC regulations) were identified based on their associated facility sub-type. Similarly, consistent with the pending AER regulation (Directive 60) (AER, 2018a), fugitive sources subject to 1- or 3-times per year LDAR were categorized by facility sub-type. Wells not located within a facility lease (and thus not subject to LDAR requirements) were identified based on facility sub-type as elaborated in SM Section S9.3, matching the procedure used when assessing the LDAR component of the ECCC regulation. Mitigation of fugitive leaks via LDAR was calculated based on detailed modelling (Ravikumar and Brandt, 2017), where once and three-times per year LDAR inspections are anticipated to lead to average fugitive emissions reductions of 40% and 68% as elaborated in SM Section S9.1.

**Results and discussion**

**Baseline methane emissions for 2018**

Figure 1 shows a detailed breakdown of methane emissions in the Alberta oil and gas sector in 2018. As elaborated in the SM, this up-to-date 2018 inventory was created by the authors following the same general procedures (Clearstone Engineering Ltd., 2019, 2014) used to produce the ECCC National Inventory Report (NIR) (ECCC, 2018c) (which had available emissions estimates up to 2016 at the time of writing) and the recently released Alberta methane inventory (Clearstone Engineering Ltd., 2019), with a few key improvements. Most significantly, emissions from pneumatic equipment were estimated in the present analysis using detailed site-by-site count data obtained in a recent field study of facilities and well sites at 333 locations in Alberta operated by 63 different companies (Clearstone Engineering Ltd., 2018; GreenPath Energy Ltd, 2016), rather than projected forward in time starting from 2011 estimates (the most recent comprehensive national inventory update) using a range of simple activity or production data (ECCC, 2018d). Not only does this give a better estimate of actual emissions than projections from 2011 based on the less detailed component count information available at that time, but the underlying resolution allows accurate assessment of the regulations on a site-by-site basis. It is expected that future national inventory reports will be similarly updated to incorporate these more refined and up-to-date equipment counts as has been done in the recent Alberta methane inventory (Clearstone Engineering Ltd., 2019). Facility-level reported venting and flaring data obtained from the Petrinex reporting system (Petrinex, 2018) were also used, which are the underlying data for the public aggregated AER report (AER, 2017) used in the 2016 NIR inventory (ECCC, 2018d) (note this is a recent update to the ECCC method (Johnson et al., 2017)). Methane emissions from fugitive equipment leaks were calculated using current facility count data similar to Clearstone Engineering Ltd. (2019) but with a slightly improved approach to accounting for sites coming in and out of production as detailed in SM Section S3. Methane emissions from combustion sources were similarly updated as detailed in SM Section S5. Finally, for remaining sources, calculations followed ECCC inventory procedures but with up-to-date activity and count data derived directly from the 2018 site-level well activity and production volume data used in this work (See Tables S7-S15).

For 2018, the derived total methane emissions in the Alberta oil and gas sector were 1034.4 kt of CH$_4$. The majority of this emitted methane (76%) is from sources that are nominally subject to the new ECCC and AER regulations. Oil sands mining and upgrading (19%), and downstream refining, transmission, and distribution (4%) are excluded. However, the stated 40–45% reduction target of ECCC (Government of Canada, 2016) is understood to be applied to the entire Canadian “oil and gas sector, including offshore activities”. Similarly, Alberta has committed to “reduce methane gas emissions from oil and gas operations by 45%” under the Pan-Canadian framework.
Interestingly, the more recent Alberta “Climate Leadership Plan” (Government of Alberta, 2018) commits only to “reduce methane emissions from upstream oil and gas production” (emphasis added), which presumably does not include the 4% of downstream emissions and is ambiguous about whether oil sands mining and upgrading emissions are to be considered.

The right panel of Figure 1 shows a more detailed breakdown of the 787 kt of upstream methane emission sources excluding mined oil sands. Pneumatic instruments and pumps (37.2%), unintentional surface casing vent flow (15.3%), fugitive equipment leaks (15%), and currently reported venting sources (14.8%) are the largest methane sources in the 2018 inventory and are subject to specific requirements in each regulation. These high-level breakdowns and emissions totals are generally consistent with those in the currently available 2016 national inventory (ECCC, 2018c), with a few notable exceptions. Fugitive equipment leak emissions are lower (consistent with the recent Alberta methane inventory (Clearstone Engineering Ltd., 2019)), due primarily to decreases in active facility counts (See SM Section S1) that aren’t captured in the current ECCC inventory procedure of projecting 2011 estimates forward to 2018 based on changes in produced gas or oil volumes. Combustion emissions are similarly decreased. The breakdown in pneumatic instrument and pump emissions is different, although the total is within 2% of the current national inventory. However, as noted above, the current estimate is expected to be more accurate as it is based on recent, more comprehensive field count and emission factor data (Clearstone Engineering Ltd., 2019, 2018; D’Antoni, 2018; Spartan Controls, 2018), and the distribution of active facility types in Alberta has changed since 2011.

The dashed- and solid-red outlines in Figure 1 illustrate sources included in the ECCC vent limit of 1250 m$^3$/mo, and the AER overall vent gas limit of 15,000 m$^3$/mo at existing facilities, respectively. Sources included in the AER defined vent gas (DVG) limit of 3000 m$^3$/mo for new facilities match those of ECCC. Storage losses (3.7%) and tank loading/unloading emissions (0.3%) are included in relevant vent limits of both ECCC and AER but are not separately considered in the regulations. Glycol dehydrators (1.4%), shown with cross-hatching, are specifically considered in AER regulations and included in the overall
vent gas limit, but are excluded from ECCC regulations. Compressor start emissions (1.8%, shown with dotted fill) are similarly included in the AER overall vent gas limit and excluded from ECCC limit, but aren’t otherwise addressed. Neither regulation considers combustion sources, flaring, or accidental venting (shown in grey), which account for 5.3% of emissions.

Notably, venting limits in both regulations include sources that are not generally included in current reported venting volumes. This has implications for increased site-level measurement or estimation requirements to accurately assess upcoming vent limits as further discussed below. This is also reflected in new AER reporting guidelines released in anticipation of new regulations (AER, 2018d).

**Numbers of sites impacted by specific components of each regulation**

Figure 2 plots the estimated number of facilities or components in 2018 that will be affected by different aspects of the new ECC or AER regulations. The baseline number of sites or components in 2018 are shown as green bars. In general, the federal (ECCC) regulations impact fewer facilities overall due to the PTE threshold that exempts small sites. For example, in the 2018 baseline there are 22,837 facilities potentially subject to pneumatic replacement rules and venting limits. The AER regulations apply to essentially all of these facilities. By contrast just over 10% of the smallest facilities are exempted in the ECCC rules, leaving 20,334 facilities that exceed the PTE threshold. Of these, 18,599 facilities (81% of the total) also pass the ECCC vent inclusion threshold and are thus subject to ECCC venting limits.

There are further important differences in the number of sites required to take mitigation actions. As shown in Figure 2, the various AER vent limits would potentially affect 3054 sites in the 2018 baseline, with 898 existing sites hitting the overall vent gas limit, 169 new sites in 2018 hitting the defined vent gas limit of 3000 m³/mo, and 1987 crude bitumen sites included in common operator sites exceeding the fleet average. By contrast 2266 sites would be required to take mitigation action in response to ECCC limits and the required mitigation actions for these sites is generally stronger in all cases than the AER rules. This raises important considerations for the potential cost, efficiency, and enforceability of the regulations. For the AER overall vent gas (OVG) and fleet-average vent limits to be effective, all sites must make a concerted effort to accurately measure or estimate all sources included in the limits to assess whether mitigation action is required. As noted in the discussion of Figure 1, this specifically includes several key sources not generally included in current reported venting volumes such as “pneumatic devices, compressor seals, and glycol dehydrators” (AER, 2018d, 2018a). By contrast, other than storage losses and tank loading/unloading emissions, these additional sources would not need to be estimated to assess the applicability of the ECCC venting limit (see Figure 1).

Also shown in Figure 2 are the numbers of different pneumatic equipment types anticipated to be impacted by each regulation. Both rules are expected to result in the replacement of almost all pneumatic instruments (excluding level controllers) with low-bleed alternatives. The AER rules would impact slightly more level controllers as further discussed below and in Section S7.1 of the SM. However, the biggest difference is with the number of pneumatic pumps. As detailed in SM Section S6.3, ECCC rules are expected to require elimination of emissions from ~32,000 pneumatic pumps which are not directly regulated in the AER rules for existing sites (although their emissions are supposed to be included when assessing the applicability of the overall vent gas limit as is done in the current analysis).

Finally an estimated 20,155 facilities in 2018 would be subject to ECCC LDAR rules, where each would be required to inspect for leaks three times per year. This compares to 21,915 facilities subject to LDAR under the AER rules, 2308 facilities at 3/yr and 19,607 at 1/yr. Thus, in terms of number of required LDAR inspections, the ECC rules would require 60,465 inspections per year, whereas the AER rules would require 26,531.

**Comparison of methane mitigation with regulations at full implementation**

Figure 3 compares the anticipated methane reductions from ECCC and AER regulations in the reference scenario at full implementation using 2018 baseline data. All aspects of the regulations were applied as if rules from January 1, 2023 were enacted on January 1, 2018 (or equivalently, if current production and emissions patterns were the same as those entering January 2023). This includes the rate at which new sites were introduced, as these sites are subject to different rules in the AER regulations. The two slightly varying bars for the AER regulations bound the range of reductions depending on which option operators choose for addressing emissions from level controllers actuating at <15-minute intervals. Higher total reductions of ~257 kt CH₄ are anticipated via modifications to minimize transient venting or control of emissions versus ~251 kt CH₄ by instead adjusting systems to increase the actuation intervals. The colors within each set of bars illustrate how different components of each regulation contribute to the total anticipated mitigation.

As shown in Figure 3, for this reference scenario using 2018 data, the ECC regulations are expected to reduce methane by 320 kt, which is approximately 25–27% greater than that achieved via the AER regulations. Differences between ECC and AER reductions are most apparent in fugitive emissions (LDAR), pneumatic pump emissions, and venting emissions. The difference achieved through LDAR is directly related to the difference in prescribed inspection frequencies. ECC regulations would be expected to achieve 75 kt and 25 kt reductions in fugitive equipment leaks and accidental venting (SCVF), which combined is 66% more than the 45 kt and 15 kt that would be achieved by the AER regulation. This gap would close if AER inspection frequencies were increased to match those of ECC.

The differences in achieved reductions through venting limits are less directly comparable since the AER rules...
involve three separate and sometimes overlapping limits (overall vent gas limit, defined vent gas limit for new sites, and fleet average limit for crude bitumen sites). The overall vent gas limit also applies to a broader range of sources (including pneumatic pumps, See Figure 1) than the ECCC vent limit. Combining the yellow and dark green bars in Figure 3, these AER vent limits are expected to achieve a 126 kt reduction in methane emissions from the 2018 baseline. This compares to the 154 kt reduction (+18%) from ECCC rules for reported venting (74.5 kt) and pneumatic pumps (79.2 kt). Although the AER regulations include rules for glycol dehydrators, the impact is negligible beyond the effect of including dehydrators in the overall vent limit, consistent with the minor significance of these emissions in the inventory.

As expected, changes from high-bleed to low-bleed pneumatic instruments (excluding level controllers) have effectively identical absolute reductions for both regulations. However, methane reductions from level controllers is also curiously similar for both regulations, even though the way in which these reductions are achieved is starkly different. For the ECCC rules, reductions are achieved by replacing the ~9% of high continuous bleed controllers currently in service with low-bleed alternatives (See SM, Section S6.3), while transient emissions are not directly considered. By contrast, the AER regulations focus on the estimated 11.3% of level controllers actuating at <15 minute intervals, achieving comparable (slightly larger) reductions through relay retrofits, combustion control, or to a lesser extent, process adjustments to increase the actuation interval. Although the proportion of <15-minute level controllers in the reference scenario is rigorously estimated using site-level liquids production data as detailed in SM Section S7.1, it is recognized that the AER regulations would achieve greater reductions if this fraction were higher. This is further considered in Figure S14. However, even if as many as 44% of all level controllers in Alberta were actuating at <15 minute intervals, the added net mitigation under the AER rules would only be 25 kt and a gap of 38 kt between the regulations would remain. Because pneumatic equipment emissions are included in the AER overall vent gas limit, assuming full compliance and accurate accounting of emissions, there is some compensating effect where the portion of additional level controller emission captured assuming a higher fraction of <15-minute controllers would otherwise have been captured in the overall vent gas limit.

As shown in Figure S11 and S12 of the SM, consistent differences between the two regulations persist when the analysis is repeated using data for 2012 and 2017. This is true even as industry production patterns and associated inventory estimates have notably varied (see Figures S1 and S8–10). In particular, Table S1 of the SM shows that there were approximately 8,000 more facilities operating in 2012 than 2018, with the biggest changes in numbers of gas and oil batteries. During this same period, the
number of in-situ oil sands facilities increased from 54 in 2012 to 75 in 2018, and associated production of oil at these facilities nearly doubled. The relative proportions of vented, pneumatic instrument, and fugitive emissions also changed significantly during this period as shown in Figures S8 to S10. The fact that the analysis shows consistent differences in methane mitigation between the two regulations across all years is compelling. This suggests that the observed differences between the regulations are not particularly sensitive to changes in the inventory associated with recent evolution of the industry.

**Practical considerations**

The present analysis also reveals broader implications for design of effective oil and gas sector methane regulations. Both of the considered regulations suffer from practical implementation challenges that could reduce their effectiveness. For example, quantification challenges in distinguishing permissible venting from abnormal fugitive emissions is likely to reduce the effectiveness of LDAR relative to the presented model. Although the switch to low-emitting (low-bleed) pneumatics that continuously emit no more than 0.17 m$^3$/hr should significantly reduce emissions under both regulations as shown in Figure 3, low-bleed devices are still prone to malfunction and abnormal operation leading to excess emissions far above the ECCC and AER regulated limit (Allen et al., 2015; Luck et al., 2019; Spartan Controls, 2018). In theory these sources should be identified as fugitive leaks and repaired as part of the prescribed LDAR programs using optical gas imaging (OGI) in the absence of approved alternatives. However, OGI is non-quantitative and subject to biasing errors (Ravikumar et al., 2017), thus the ability for an inspector to correctly distinguish fugitive emissions beyond normal continuous low-bleed pneumatic venting limit is not guaranteed. Similarly, sources such storage losses, which are included in both the ECCC and AER vent limits are difficult to quantify and not generally measured (AER, 2018d) such that effectiveness of vent limits may be hindered by poor estimates of emissions. In this sense, the mitigation effectiveness of the AER overall vent gas limit is restricted by the accuracy with which an operator might estimate, or an inspector might verify, all of the included sources identified in Figure 1. The AER fleet average limit for crude bitumen batteries may also be less effective than modelled if operators choose to keep low production, low vent-rate sites in service longer as an economically sensible means of reducing fleet average emissions relative to direct mitigation actions. In general, if emissions source distributions are skewed, a fleet-average limit will always achieve less mitigation than an equivalent limit applied to each site (See SM, Section S7.3).

**Implications for regulatory equivalency and achieving 45% methane reductions**

All of the considered scenarios – comparisons of the regulations using 2018 baseline data, repeated scenarios using varied inventories for 2012 and 2017, consideration of a 5-year phase-in of the regulations presented in the SM (Section S10), and a scenario where as many as 44% of all pneumatic level controllers are in high-frequency operation (SM, Section S11) – suggest that the regulations are not equivalent, with ECCC rules achieving additional methane reductions of 38–96 kt. While the AER regulations – through stricter provisions for new sites – would be expected to strengthen over time, the analysis in Section S10 shows that the mitigation wouldn’t match that of the ECCC regulation until 2033, and the cumulative mitigation wouldn’t be equivalent until 2043.

There are additional relevant factors that must also be considered. First is whether the stated 45% reduction targets might be reached by either regulation. The right axis of Figure 3 shows the anticipated percentage reduction in total oil and gas sector methane emissions via each regulation relative to a 2018 baseline. Referring to Figure 1, total Alberta oil and gas sector methane emissions (including mined oil sands and downstream refining and distribution) were 1034 kt in 2018. Relative to the 2012 baseline, neither regulation achieves a 45% cut in emissions (31% reduction for ECCC vs. 25.0% for AER). If only “upstream” sources are considered (i.e. the right panel of Figure 1), then the ECCC rules would achieve a 41% cut in the 2018 baseline emissions vs. a 33% cut with the AER rules. However, the Pan-Canadian framework federal target of 40–45% reductions in oil and gas sector methane is from 2012 levels (Government of Canada, 2016).

Figure 4 compares the anticipated remaining methane emissions after full implementation of the ECCC and AER regulations. As indicated in the detailed legend, the different colors show the contributions of specific emissions sources to total methane emissions in the Alberta oil and gas sector. The data are plotted alongside the 2012 and current (2018) baseline emissions prior to the implementation of regulations. Several key insights are apparent in the figure. First, the updated inventory suggests that baseline methane emissions from the Alberta oil and gas sector have decreased by 13% from 2012 levels. This is primarily driven by a large decrease in reported venting (light green) (AER, 2018b) as also shown in Figures S8–10. Absolute decreases have also occurred in fugitives and pneumatic emissions, consistent with the large drop in number of active production sites from 30,649 to 22,837 (See Table S1). These decreases are partly offset by marked increases in methane emissions from mined oil sands production (+54%). Overall, methane emissions from sources not covered by either the ECCC or AER regulations (i.e. mined oil sands plus downstream refining, transmission, and distribution of oil and gas – bottom three sections of the bars – as well as combustion, flaring, and accidental releases – grey bars) have increased by 34% since 2012. Continuation of these trends could put the 40–45% overall reduction targets out of reach. At present using 2018 data, Figure 4 suggests that the 31% reduction directly attributable to the ECCC regulations, combined with past methane reductions from 2012–2018, would achieve a net 40% reduction in oil and gas sector methane emissions just reaching the stated federal government policy objective. Relative to this same 2012 baseline, the anticipated 25% reduction from the AER regulations combined
with past reduction would fall short with a net reduction of 35%.

**Figure 4** can also be used to provide context for the potential uncertainties in the national inventory, especially with respect to reported venting volumes. Several recent Alberta field measurement studies using airborne (Johnson et al., 2017) and ground-based (O’Connell et al., 2019; Roscioli et al., 2018; Zavala-Araiza et al., 2018) measurements have consistently found higher than expected methane emissions, especially in heavy oil production regions with the highest levels of reported venting. At the extremes, the potential underestimation in venting could approach the apparent differences between the 2018 and 2012 baselines. Similarly, if the number of active facilities were to increase significantly in the coming years back toward the numbers seen in 2012, then associated baseline emissions from pneumatic equipment might also approach those from 2012. The additional sensitivity analysis using production and inventory data for the 2012 and 2017 baseline years (see Figure S11 and S12) suggests that, if emissions approached 2012 levels, both regulations would adapt to achieve greater mitigation but the absolute difference between them would grow.

**Potential options to achieve regulatory equivalency**

In principle, it is possible that carbon pricing that includes methane might be used to augment the impact of the AER regulations to achieve combined mitigation equivalency. Recently published analysis (Tyner and Johnson, 2018) suggests that significant economic methane mitigation opportunities would exist if even a modest (<30 $/tonne CO₂e) were applied to vented gas at upstream sites. How-
ever, there is currently no broad carbon pricing in Alberta, and the recently elected Premier has cancelled the carbon-price that had previously applied to heating and transportation fuels (Government of Alberta, 2019a). Similarly, the recently introduced Technology Innovation and Emissions Reduction Implementation Act (TIER) only directly applies to large facilities emitting greater than 100,000 tonnes of greenhouse gas emissions per year, and although aggregated oil and gas facilities may choose to “opt-in”, only their stationary fuel combustion emissions are considered (Government of Alberta, 2019b, 2019c).

Finally, there has been much discussion of the burden to industry of higher LDAR frequencies in the ECCC regulations. It is also apparent that other aspects of the regulation are possibly less onerous. Fewer sources are included in the vent limit, which could reduce measurement and analysis/estimation burden in complying with the regulation. Similarly, the combined results of Figures 2 and 3 suggest that greater reductions are achieved while focusing on slightly fewer sites. The PTE threshold allows some small sites to be exempted from action, and the vent limit, though much more stringent, is selectively applied through the vent inclusion threshold to achieve greater overall mitigation. Nevertheless, if the structure of the AER regulations were preferable, it is possible to use the present analysis to back-calculate required modifications to make the regulations equivalent. If the LDAR frequency in the AER rules were increased to 3/yr to match the ECCC rules, then the remaining methane mitigation gap could be closed by reducing the AER overall vent gas limit to ~10,100 m³/mo (which is still much higher than the ECCC limit of 1250 m³/mo that is applied to a smaller subset of sources). Alternatively, if the lower AER LDAR frequency is left as written in the regulation, then equivalent mitigation could be achieved by reducing the AER overall vent gas limit to ~5500 m³/mo. Given the significant contribution of pneumatic pumps to the current inventory, a third option would be for AER to prohibit venting from pumps (i.e. apply the AER rules for new sites to existing sites as well), in which case the AER reduction would exceed ECCC by ~11 kt. Finally, if AER mandated changing all pneumatic controllers and pumps to zero bleed devices (e.g. air driven, electric, etc.) it would be possible to eliminate all LDAR requirements and achieve approximately the same mitigation as the ECCC rules which rely on 3/yr LDAR. This type of detailed analysis and case study data could be useful in defining alternate paths to equivalent mitigation outcomes.

Supplemental file

The supplemental file for this article can be found as follows:

- Text S1. Supplemental materials. DOI: https://doi.org/10.1525/elementa.403.s1

Funding Information

This work was supported by Natural Resources Canada (Project Manager Michael Layer) and the Natural Sciences and Engineering Research Council of Canada (NSERC, grant numbers 06632 and 522658).

Competing Interests

The authors have no competing interests to declare.

Author Contributions

- Contributed to conception and design: MRJ, DRT
- Contributed to acquisition of data: MRJ, DRT
- Contributed to analysis and interpretation of data: MRJ, DRT
- Drafted and/or revised the article: MRJ, DRT
- Approved the submitted version for publication: MRJ, DRT

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