CAPP CANADA'S OIL & NATURAL GAS PRODUCERS

February 13, 2024

The Honourable Steven Guilbeault
Minister of Environment and Climate Change
Government of Canada
200, boul. Sacré-Coeur
Gatineau, Quebec K1A 0H3
(via email: ministre-minister@ec.gc.ca)

Dear Minister Guilbeault:

Re: Regulations Amending the Regulation Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)

The Canadian Association of Petroleum Producers (CAPP) is a constructive and solutions-oriented partner in addressing the triple challenge of reducing emissions while assuring domestic and western alliance energy security and affordability for Canadians. In this regard, CAPP and our member companies respectfully submit the following comments regarding the *Regulations Amending the Regulation Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* as published in the Canada Gazette on December 16, 2023 ("the draft amendments").

It is CAPP and our members' view, following in-depth analysis by subject matter experts, that the current draft amendments and their *Regulatory Impact Analysis Statement* (RIAS), do not represent a predictable regulatory framework that uses commercially available technology to efficiently reduce methane emissions. Key components of the draft amendments are unclear and, potentially, represent obligations that are incompatible with upstream oil and natural gas operations. Clarity of regulatory requirements is vital to support meaningful consultation. As written, **the draft amendments do not represent a workable path to 75% by 2030.**

We recognize the merits of reducing methane emissions from industrial operations in an ambitious, efficient, and technically achievable way. Clearly defining equitable reduction targets is critical for success. It is our view that regulations to reduce methane emissions from the conventional upstream oil and gas industry should not be relied upon to achieve a 75% methane reduction target for the larger oil and gas sector. **Amendments to the current regulatory framework should target a 75% reduction of regulated emissions, not a reduction in total upstream emissions from oil sands mining area emissions and other non-regulated sources.**

It is also our view that a path to efficient, achievable, and ambitious methane emissions reductions through a sustained, transparent, and two-way dialogue, between industry and government, is possible. In fact, it is needed to advance a pragmatic and realistic approach, building on Canada's current methane emissions reduction record. It is with this intent that we respectfully **request the creation of an industry-government working group, including ECCC and Natural Resources Canada, for meaningful consultations to identify an optimized approach to a 75% methane emissions reduction by 2030 for the conventional oil and natural gas sector.**

Conventional Upstream Methane Emissions Performance to Date

The provinces of British Columbia, Alberta, and Saskatchewan are all on track to meet or exceed their 45% methane emissions reductions targets by 2025. Alberta achieved its 45% reduction target in 2022.[1] British Columbia expects to exceed a 50% reduction by 2025. And Saskatchewan announced in 2022 that it had reduced methane emissions from venting and flaring by 64% from 2015 levels.[2] This provincial leadership has been driven by targeted and nuanced regulations, economic instruments, and investment in innovation.

British Columbia[3] and Alberta[4] have aimed at further methane reductions. Both provinces have identified 75% reduction targets by 2030. The provinces are creating ecosystems to successfully reduce methane emissions and **CAPP strongly supports continued provincial leadership** that utilizes unique approaches to recognize different operations.

Relation to the Proposed Cap on Oil and Gas Sector Greenhouse Gas Emissions

An effective, efficient, and feasible methane abatement approach is imperative as ECCC has tied methane emissions reductions directly to the proposed emissions cap. The achievability of the proposed cap is heavily contingent upon the feasibility, the success, and reductions achieved by the draft methane amendments. Unachievable methane ambitions for the conventional upstream oil and natural gas industry would have follow on negative effects to other additive climate policies. Canada's methane requirements must be appropriately scoped and achievable.

Unclear Regulatory Expectations

The draft amendments **prohibit venting and flaring** with limited exceptions. Eliminating venting is infeasible. Small, infrequent, remotely located releases have no commercial opportunities for mitigation. The draft

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[1] Alberta announced in achieved its 45% reduction target in 2022. See < Methane Performance | Alberta Energy Regulator (aer.ca) >

[2] Saskatchewan Ministry of Energy and Resources "The Oil and Gas Emissions Management Regulations Annual Report for 2022". Available at < Publications Centre (saskatchewan.ca) >

[3] Clean BC Roadmap to 2030, available at < cleanbc_roadmap_2030.pdf (gov.bc.ca) >

[4] Alberta emissions reduction and energy development plan, available at < Alberta emissions reduction and energy development plan - Open Government >

amendments provide exemptions to the venting prohibition; however, their application is uncertain. Vents that could reasonably fall within the exemptions are accounted for in the RIAS as reductions achieved by the regulation. The draft amendments prohibit flaring, but the RIAS anticipates that the most common way for operators to achieve the proposed venting prohibition is through destruction, including flaring.[5] The draft amendments read as "**no flaring**", while the RIAS indicates "**significant flaring**". These and other inconsistencies obscure the regulatory intent and limit industry's ability to provide meaningful feedback.

There are gaps between commercially available technologies and requirements in the draft amendments. **CAPP members are unaware of the equipment needed to support compliance with some of the proposed regulatory requirements**. This includes meeting the RIAS's expectation for mitigating venting and extends to proposed leak detection technologies and the alternative continuous monitoring program. The Canadian industry is testing scores of methane detection and monitoring technologies. We support alternatives to what is currently in regulation, but public data and available studies do not readily identify compliant technologies.[6]

Resource Intensive Actions Unlikely to Reduce Emissions

We believe the public data, and industry data, strongly indicates that many of the proposed requirements have extremely high costs, but zero or near zero incremental emissions reductions. We see value in exploring the science, regulatory rationale, and modelling behind these requirements and the proposed regulatory approach. We support ambitious, science-based, and economically optimized paths to reduce methane emissions from the conventional upstream oil and natural gas industry; further refinement of draft amendments is required to achieve these principles.

Defining the 75% Ambition

The 75% reduction target was identified as a suitable level of ambition by international groups such as the United Nation's Global Methane Alliance, and the International Energy Agency (IEA).[7] To be achievable, Canadian regulations should also target that ambition. These international targets do not identify oil sands mining methane emissions in their approach to 75%. This is unsurprising given these source's low abatement potential and uniqueness to Canada. It is CAPP's understanding that Canada's current 75% target includes all methane emissions from a broadly defined "oil and natural gas sector", including non-abatable area sources from the oil sands mines, emissions associated with distribution, pipeline ruptures, and other sources excluded from the current methane regulations[8] and the draft amendments.

[5] See "venting" under the subheading "Cost of Compliance" within the "Regulatory Analysis" Section of the RIAS.
[6] Bell *et al.*, "Performance of Continuous Emissions Monitoring Solutions under a Single-Blind Controlled Testing Protocol" *Environmental Science and Technology* 57:14 p 5794, 2023.
[7] International Energy Agency, "Curtailing Methane Emissions from Fossil Fuel Operations; Pathways to a 75% cut by 2030". 2021 Available at < Curtailing Methane Emissions from Fossil Fuel Operations – Analysis - IEA >
[8] Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (SOR/2018-66)

We believe the conventional upstream oil and natural gas industry can reduce its own methane emissions by 75% by 2030, but it is unreasonable to ask conventional operations to be responsible for reducing total sector emissions by 75%. Canadian ambition should align with internationally accepted achievable targets. Oil sands mining area emissions, and other non-regulated methane emissions, should be removed from the 75% target.

Without this alignment, the conventional upstream industry will incur an estimated cost of compliance for the draft amendments that is beyond the Government's estimate of $15.4 billion contained in the RIAS.[9]

Toward an Improved Approach

The draft amendments include important clarifications and changes to approach from ECCC's initial 2022 *Proposed regulatory framework for reducing oil and gas methane emissions to achieve 2030 target*. Methane emissions from natural gas fired engines, and offshore methane emissions, will now be addressed through dedicated non-duplicative regulations.[10] Draft amendments ensure that methane emissions management is not prioritized over safety and a risk-based leak detection and repair approach has been proposed. These are beneficial changes that demonstrated the value of engagement.

To support a further improved approach, we have appended detailed technical comments to this letter. This feedback should not take the place of additional industry engagement. A collaborative sharing of information will be the most effective way to find a workable path to minimize venting and address other areas of uncertainty. The appended feedback identifies areas in the proposed amendments that we believe merit clarification as well as requirements that public data indicates will not meaningfully reduce actual emissions.

We believe the only path to efficient, achievable, and ambitious methane emissions reduction is through a sustained, transparent, and two-way dialogue between industry and government experts. **We request the creation of an industry-government working group, including ECCC and Natural Resources Canada, for meaningful consultations to identify an optimized approach.**

[9] See appendix Section 1 for examples of how costs are underestimated
[10] The *Multi-Sector Air Pollutants Regulations* and the *Canada-Newfoundland and Labrador Offshore Area Petroleum Operations Framework Regulations*, respectively.

We look forward to discussing all aspects of the draft amendments with your team.

Sincerely,

Lisa A. Baiton, MBA, ICD.D
President & Chief Executive Officer

Cc: Hon. Jonathan Wilkinson, Minister of Energy and Natural Resources
Hon. Chrystia Freeland, Deputy Prime Minister and Minister of Finance
Hon. Seamus O'Regan, Minister of Labour and Seniors
Hon. François-Philippe Champagne, Minister of Innovation, Science and Industry
John Hannaford, Office of the Clerk of the Privy Council

Appendix – Industry Technical Feedback

1. Estimated cost of compliance

CAPP has reviewed the cost estimates in the RIAS and the *Techno-Economic Assessment of Methane Pathways for the Upstream Oil & Gas Sector in Canada* completed by Process Ecology.[11] The Process Ecology report is frequently cited in the RIAS as a primary source supporting its economic impact analysis. CAPP and its members support economic assessments based on the most recent and accurate industry data; while the Process Ecology report is dated August 2023, it contains few current cost estimates and appears to primarily compile outdated assessments that do not reflect modern operations.

We have identified some of the assumptions made in the Process Ecology report that will lead to significant cost underestimates, including:

- The reliance on outdated EPA Natural Gas STAR reports from 2003, 2006 and 2022 for key cost inputs.
    - Design standards vary significantly between the USA and Canada. Cold Canadian weather, higher health and safety standards, and higher engineering standards increase the cost of Canadian operations.
    - The Process Ecology report uses the consumer price index to convert historic costs to current, but that index is explicitly for consumer costs, not industrial costs that in many cases have increased at a much higher rate.
- The report assumes that existing equipment is compatible with potential retrofits. For example, Section 7.3.2 estimates the costs of installing Vapour Recovery Units (VRUs) on tanks. The estimate does not consider that many tanks are incompatible with VRUs due to the internal pressure they exert on the tank. The cost of installing a VRU frequently includes the cost of a new tank, but this is omitted by the report. The estimate also does not address the costs and logistics associated with supplying makeup gas to ensure the VRU functions properly.
    - The Process Ecology report provides an underestimated (by our assessment) "conservative average" cost of $170,000 to $240,000/VRU on page 60 and 61. The RIAS estimates the cost to purchase and install a VRU at $84,900, a major cost underestimate.

CAPP's assessment is that the cost estimate for compliance is a significant underestimate. **Actual compliance costs may be more than the projected $15.4 billion.** This does not represent an optimized approach.

[11] August 2023 available at < https://processecology.com/thehub#! >

2. Definitions and scope

Application of regulation to non-producing wells

Although it is not clearly specified in the draft amendments, it is clear in the RIAS that the draft amendments are expected to apply to non-producing wells, including leak inspection requirements. Completing annual comprehensive leak inspection at all "non-producing wells" represents an enormous, if not impossible, undertaking that will result in very few emissions being identified for mitigation.

The RIAS does not define non-producing wells, but the plain meaning of the RIAS would naturally include all wells in Canada, including inactive, abandoned, and reclaimed wells. The Alberta Energy Regulator's 2023 well status report[12] exemplifies the challenge and the lack of value:

- There are 309,586 non-producing wells in the province.
- Nearly 45% (138,905) have been abandoned and reclaimed, meaning they have been permanently sealed, the land has been returned to a similar state as before the well existed, and the operator's land access has been rescinded. Access roads no longer exist and accessing the sites would have a negative impact on vegetation.
- Roughly 30% (91,846) have been abandoned – permanently sealed and taken out of service. These wells require significant testing prior to abandonment to verify there are no emissions. Surface casing vent flows and gas migration must be repaired prior to a well being abandoned. In other words, work needed to eliminate methane emissions from these wells has already been accomplished.
- Close to 25% (78,790) are inactive and are not used for hydrocarbon production. These wells are closely managed by provincial regulations and directives, including Alberta Directive 013. Prior to abandonment, these wells are tested for surface casing vent flows and gas migration. AER maintains a public record of inactive wells with surface casing vent flows and gas migration. There are roughly 7,300 inactive (suspended) Alberta wells with either a surface casing vent flow or gas migration.

75% of non-producing wells in Alberta have been permanently sealed and have near zero potential for methane emissions (reclaimed and abandoned wells). Of the remaining 25%, about 10% of those wells have emissions that are already known, publicly documented, and require regular inspection. Including these wells in the regulations and mandating additional, or more frequent, leak inspections represent a massive undertaking, almost certain increased total emissions, and no potential for commensurate, or even incremental, emissions reductions.

We recommend clarifying early in the amendments that they do not apply to non-producing oil and natural gas sites.

[12] Well Status | Alberta Energy Regulator (aer.ca)

We also recommend retaining the conditional requirements established by subsection 20(1) of the current federal regulations, to exclude low risk, low production wells, including non-producing wells, from the regulation.

Relation to similar regulations

The draft amendments' interaction and overlapping compliance expectations with other related regulations, such as including the *Reduction in the Release of Volatile Organic Compounds Regulations (Petroleum Sector)*, is unclear and should be identified in the regulation or published guidance.

3. Venting

The venting prohibition proposed by draft amendment Section 49 is potentially the most impactful requirement proposed by the draft amendments. Subsection 49(1) on its own describes a venting prohibition that is incompatible with an upstream oil and natural gas industry. Subsection 49(2) identifies some exemptions to the proposed prohibition that recognize a few of the unavoidable vents associated with operations, but the exceptions are insufficient, and a venting prohibition will always represent an impossible compliance obligation.

Meaningful consultation on draft amendment Section 49 can only be accomplished through open dialogue as CAPP cannot discern the regulatory intent. We cannot align a plain language interpretation of the draft amendment with its description in the RIAS, with a reasonable/commercial path to compliance, or with its proposed administration. Draft paragraph 49(2)(c) is potentially a reasonably broad exception to the venting prohibition. When plainly interpreted, it could account for numerous small and infrequent sources that make the "near elimination of venting" much more feasible than a "venting prohibition". However, the RIAS clearly overestimates the number of small sources that can be mitigated, rather than vented, accounting for emissions mitigations that are not technically feasible with current technology. In addition, draft Section 50 mandates a record be made of all venting activity. This represents an incomprehensibly large administrative obligation that is not justified by the incremental quantity of associated emissions.

It is additionally impractical, due to cost, gas quality/quantity, and pressure to connect all components of an upstream operation to destruction equipment as proposed by Subsection 49(3). Finally, while we support the phase-in of venting requirements for existing facilities, a simple production trigger is impractical and unpredictable. A facility's production can increase in a given year due to various minor maintenance activities or changes to a well pad. These small changes would not justify a complete facility redesign to align with a new vent limit. The feasibility of modifying an existing facility will vary significantly depending on age, product, location and numerous other factors. A "feasibility test", completed by an engineer is the appropriate way to identify when it is appropriate to retrofit facilities. These test must incorporate an assessment of economics, the impact to total greenhouse gas (GHG) emissions, and the availability of commercial technologies. **We recommend existing facilities be subject to a new vent limit only if it is**

determined by an engineer to pass a "feasibility test". The definition of a feasibility test should be added to the amendments and explicitly include economic, total GHG, and commercial availability of technologies.

We wish to work with ECCC to identify a reasonable regulatory approach that drives toward the near elimination of venting, rather than a prohibition. It must have clear compliance expectations and allow industry to direct resources at mitigating the largest sources with the greatest potential for long-term impacts.

Industry maintains a strong understanding of its vented sources and we can see a path to developing a simplified venting intensity metric that could simultaneously reduce methane emissions and administration.

4. Flaring

Limitations on flaring

Draft amendment Section 47 significantly limits industry flaring, unless it is required to address an emergency situation or if the hydrocarbon gas cannot be used to produce useful heat or energy. While industry makes every effort to conserve and commoditize methane as natural gas, there are instances where this is not possible or the economics are so unfavourable that the cost to conserve the gas dramatically outweighs its value.

Industry requires the flexibility and autonomy, to destruct (flare) methane when appropriate and to conserve where reasonable. In practice, while we are making major efforts to minimize methane emissions as part of operations, it is currently true that there are cases where flaring will have a lower climate impact than conservation.

Draft Section 47 clearly mandates the conservation and management of a non-renewable natural resource (methane/natural gas). The proposed requirement dictates how the resources is to be used (conserved versus destroyed), it does not directly manage methane emissions.

Industry on principle prefers methane conservation over destruction and destruction over venting; however, we believe a federal regulation limiting industry's ability to flare is not a regulatory requirement directed at emissions reductions.

We recommend deleting draft Section 47.

5. Leak detection

Definition of Type 1 and Type 2 facilities

CAPP and its members support a risk-based approach to leak detection that aligns with industry's experience and B.C. leak detection and repair data. It is appropriate to direct leak detection resources at larger facilities with the types of vibrating equipment that are more prone to repeated leaks. These sites include compressor stations, gas plants, and multi-tank batteries. In contrast, individual wells have a low potential for methane leaks. Data from B.C. indicates a surveyor is 12 to 16 times less likely to find a leak at a well as compared to a facility. Leaks found at wells are also smaller than those found at facilities.

The proposed distinction between Type 1 and Type 2 facilities does not appear to recognize the relative disparity between high and low risk facilities. The draft amendments propose more frequent leak surveys for Type 1, "high-risk" facilities, but the definition of Type 1 facilities will also capture the majority of low-risk well sites. Many wells have a "gas-liquid separator", that has been identified as sources of emissions, but are not associated with "leaks".

Recent aerial studies have identified "separator buildings" as comparatively large sources of emissions, but aerial surveys are incapable of distinguishing leaks from normal operations.[13] Separator buildings can contain low-bleed pneumatics and catalytic heaters. This equipment will emit methane from the building's exhaust, but these are not leaks and will not be "reduced" by more frequent leak surveys.

When leaks do occur at separators, they are small and infrequent. In 2021, about 9,600 wells were surveyed in B.C., leaks from separators were found at only 2.5% of wells, with an average leak size of 4.8m3/d. This magnitude and frequency of these leaks are reasonably managed through annual leak inspections.

In addition, proposed Type 1 facilities include any site with "a flare". While we recognize that unlit flares have been identified as potentially large sources of emissions, we believe the risk of unlit flares will be effectively mitigated by the draft Subsection 46(1). CAPP members support the use of equipment to minimize the potential for a flare to become unlit and for operators to be notified if flares become unlit so that quick action can be taken. At the same time, once this equipment is installed, the relative risk of unlit flares drops significantly and with it the justification for any site with a flare qualifying as high-risk, Type 1 facility. CAPP provides further feedback on Subsection 46(1) below, under the topic of Hydrocarbon Gas Destruction.

We recommend that ECCC looks to the provinces, and historical LDAR data, to distinguish higher-risk facilities, which merit more frequent leak detection, from low-risk wells. In their proposed methane amendments to achieve 75% reduction, **B.C. has identified the value of 4x surveys at gas processing plants,**

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[13] See Conrad *et al*. "A measurement-based upstream oil and gas methane inventory for Alberta". *Communications Earth and Environment* 4:416 (2023)

compressor stations, and batteries. Alberta Energy Regulator's Report: *ST102 Facility List* provides a similar, but more detailed list of higher-risk facilities. CAPP and its members would support quarterly comprehensive inspections at these high-risk facilities. This represents a significant expansion of inspections, increasing many sites that currently receive annual inspections to quarterly inspections. Smaller, medium-risk facilities with limited vibrating equipment such as booster compressors, single-well batteries, and multi-well test satellites should get annual comprehensive inspections. All other sites would be deemed low-risk and receive an internally documented audio, visual, olfactory screening in every quarter that an operator is on site. **Flexibility should also be provided for inspections and screenings to use alternative technologies to address access constraints at wells and encourage technology innovation.**

<u>The value and feasibility of monthly screenings</u>

The draft amendments propose that if a facility is visited, for any reason, by the operator in a given month, that facility must also receive a leak screening inspection that same month. A leak screening inspection relies on a "monitoring instrument that, under standard conditions, has a 90% or greater probability of detecting fugitive emissions with a flow rate of 1kg/h or more".[14]

This technology has a different detection threshold than what is required for "comprehensive inspection". Public leak data indicates that most emissions come from larger leaks and it therefore makes sense to complete more frequent, low-cost, surveys to find and repair those leaks quickly. Industry supports this type of data-driven, risk-based, and resource-efficient, approach, if it relies on commercial technologies and is focused on actual potential leak sources.

CAPP and its members have not yet identified a commercially available and efficient instrument that complies with the proposed screening sensitivity: a 90% probability of detection of 1kg/h of fugitive emissions. Optical Gas Imaging (OGI) cameras can achieve this standard, but their cost and reliance on highly experienced technicians makes them impractical for monthly screenings. In the absence of multiple commercial efficient technologies, the proposed regulatory requirement does not represent a resource-efficient approach. It also risks broad industry non-compliance with the regulations due to the unavailability of compliant instruments and qualified technicians.

A review of the 2021 B.C. leak inspection data at wells indicates the threshold proposed for the screening inspection technology is likely to have a minimal impact on emissions, but will require an enormous expenditure of resources. In 2021, there were roughly 8,400 leak inspections at B.C. wells and only 21 leaks were identified as above 1kg/h. None of those 21 leaks were large, with an average leak rate of 2kg/h and the largest leak was 3.8kg/hr. CAPP anticipates that an inquiry with the B.C. Energy Regulator will show that even fewer leaks were found above 1kg/h at wells in 2022.

[14] Subsection 8.12(2) of the draft amendments

The detection rate for leaks over 1kg/h at wells in B.C. was only 0.2%. Wells are an infrequent source of emissions, and a very infrequent source of leaks over 1kg/h. The draft amendments and associated RIAS propose more frequent surveys at wells, but they do not anticipate that more leaks will be found.[15] On this basis, we anticipated screening inspections at wells will have a significantly lower probability of detection (below 0.2%) and does not represent a risk-based, efficient, reasonable leak detection requirement.

We recommend excluding wells from additional screening surveys and working with industry to identify an appropriate standard for conducting screening surveys of high-risk sources at facilities using cost-effective, commercially available technologies.

Annual inspections

Draft amendment Sections 8.13 and 53.2 require operators to conduct annual third-party leak detection audits using a technology capable of a 90% probability of detecting a leak rate of 10 kg/hr. These proposed audits create an additional cost for industry without a reasonable expectation of achieving incremental emissions reductions.

There is little public data that indicates a meaningful difference between internal and third-party leak inspections. Studies that distinguish the results of internal and third-party leak inspections consistently conduct this comparison for surveys utilizing optical OGI cameras. Industry experience and public research consistently shows that the efficacy of OGI surveys is highly dependent on the expertise of the surveyor. The impact of surveyor experience on results[16] likely overwhelms any conclusions that can be drawn regarding a surveyor's employer. Weather, leak size, and the presence of reflective surfaces are also major variables in OGI surveys, further obscuring efficacy studies.

A review of the 2021 B.C. leak detection data at facilities indicates that internal surveyors tend to find leaks more frequently than external third parties and those leaks tend to be larger. In 2021, roughly 800 leaks were found by 500 "internal" surveys (the average survey finding 1.7 leaks) while third party surveyors conducted nearly 1,900 surveys and found fewer than 3,000 leaks (each survey found 1.6 leaks). These results are not conclusive, and should not be the basis for regulation, but they do indicate that internal surveyors are as capable, if not more proficient, at finding leaks – perhaps due to their familiarity with operations and potential leak sources.

In the absence of compelling evidence to the contrary, we do not believe it is reasonable to conclude that third-party surveys result in greater emissions reductions than in-house surveys.

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[15] See "Fugitive Emission Detection and Repair Program" under the subheading "Cost of Compliance" within the "Regulatory Analysis" Section of the RIAS.
[16] Zimmerle *et al*. "Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions". *Environmental Science and Technology* 54:18 (2020)

The proposed amendments do not require audits to be conducted with OGI cameras, but allow the use of less sensitive technologies. The relatively low sensitivity of the proposed auditing technology (10kg/h) creates an exceptionally low potential for these inspections to identify actual emissions on a per-survey basis.

CAPP is unaware of any compelling data identifying the relative value of the proposed audit inspections. We are open to discussing this with ECCC as part of the proposed working group, but our assessment indicates that audits are likely to represent high-cost and redundant surveys that find few additional leaks. The use of third parties to conduct these inspections is uncertain to provide any additional value.

We recommend removing Sections 8.13 and 53.2 from the draft regulations.

6. Repair

Repair timelines

CAPP and its members generally support the intent of the draft amendments to provide greater nuance and flexibility for repairs than what exists in the current federal regulations. While industry makes every effort to repair leaks quickly, many being repaired at the time of discovery, technical and procurement challenges can delay repairs. In principle, focusing repair efforts on the largest leaks, repairing them more quickly, makes sense; however, we believe the proposed paragraph 8.16(5)(b) has the real potential to result in overall higher methane emissions.

Draft paragraph 8.16(5)(b) mandates that any leak requiring a facility shutdown for the purpose of repair must be repaired within one year of detection. This requirement is provided without clear opportunity for exception and is irrespective of leak size. This requirement is not only practically challenging and hugely expensive – the cost and logistics of undertaking a shutdown of a large facility are immense – it also will likely result in overall higher emissions. Depressurizing a facility to complete a shutdown and undertake a repair is frequently associated with very high emissions of methane and carbon dioxide. This new requirement could easily result in some facilities undertaking near-annual shutdowns, with high associated emissions, to repair comparatively small leaks.

The current federal regulation acknowledges that we should not create more emissions in the pursuit of leak repair. A shutdown for the purpose of leak repair is only required if the emissions from the leaking components would exceed the emissions associated with the shutdown. **We recommend deleting paragraph 8.16(5)(b) to ensure leak repair does not result in increased total emissions.**

Repair verification

The draft amendment's proposed Subsection 8.16(6) creates a new requirement that repairs must be verified using the same equipment that identified the initial leak. It is industry's expectation, based on current leak detection and repair programs, that the majority of leaks under the draft regulations will be identified by comprehensive surveys. OGI cameras and EPA Method 21 are capable of finding small leaks in large operations that may go undetected using other methods, such as less sensitive technologies such as audio, visual, and olfactory inspections, and soap screenings. However, once a leak is discovered and properly identified, a confirmation of repair (of a known leak) can be safely and assuredly completed using a soap test.

Soap tests are an effective and safe method for confirming the absence of a gas leak post-repair. The soap test is used by those installing commercial, industrial, and residential natural gas to ensure there are not natural gas leaks in peoples' homes, a high standard for safety and reliability.[17] A requirement to confirm repair with the equipment used for comprehensive survey is unnecessary and removes that equipment – and the experts capable of its effective use – from conducting other surveys. Industry is not aware of any data that indicates the use of an OGI camera or EPA Method 21 to confirm a repair results in lower emissions than a soap test. Soap tests are also significantly more sensitive than 1kg/h, the confirmation technology referred in Subsection 8.12(2) and paragraph 8.16(6)(b).

We recommend amending the draft amendments to allow leak repairs to be confirmed by a standard soap test.

7. Hydrocarbon destruction equipment

Requirements for destruction equipment not using a catalytic oxidation system

CAPP and its members support the use of auto-ignition devices and automatic flame failure detection systems as part of combustion systems. This is an optimal way to ensure these sources represent a low risk of fugitive emissions and to minimize the need for individual inspections. In practice, flare ignition can be reliability maintained using a pilot flame or an auto-ignitor, both are not necessary. **We recommend amending paragraph 46(1)(a) to state that a pilot flame or auto ignition devices is required, in conjunction with a flame failure detection system.**

For existing flares, we recommend applying the same "feasibility test" described for implementing venting retrofits to the decision criteria for retrofitting flares. Where the test determines that it is inappropriate to retrofit existing equipment, weekly visual observations of flares can be undertaken to ensure flares are operating as designed. Weekly observations would continue until retrofits are completed.

[17] See Canadian Standards Association "Natural Gas and Propane Installation Code Handbook" B149.1HB-00

We support “98% destruction efficiency” as the manufacturer specification standard for any new destruction equipment using combustion. Recent research has shown that operating flares are capable of, and frequently achieve, greater than 98% efficiency and combustors have been shown to be equally capable.[18]

Canada’s upstream oil and natural gas industry relies on flares and combustors to maintain safe operations and to minimize methane emissions. Many existing flares, although capable of high destruction efficiency, pre-date manufacturer destruction efficiency documentation. CAPP is concerned that this equipment may be out of compliance with the draft amendments, irrespective of its actual efficiency. To ensure that the regulatory amendments do not result in equipment being exchanged without meaningful emissions reductions: **we recommend clarifying that destruction efficiency standards under subparagraph 46(1)(a)(ii) only apply to <u>newly</u> installed equipment.**

<u>Requirements for destruction equipment using a catalytic oxidation system</u>

The efficiency of catalytic oxidation systems is currently established by the Canadian Standards Association’s (CSA) standards for *Gas-fired tubular and low-intensity infrared heaters*.[19] Destruction efficiency is established by the testing requirements specified by Section 5.6. Heaters compliant with the CSA standard achieve approximately 80% methane destruction efficiency.

CAPP is aware of some manufacturers of catalytic oxidizers testing new equipment to efficiencies as high as 90%, but this testing is ongoing. The equipment being tested is not commercial, and it is not clear that it would be suitable for all the upstream oil and natural gas industry’s requirements.

The proposed 85% efficiency would achieve nominal emissions reductions over the existing 80% standard, but would require an enormous expenditure of resources to replace existing equipment. There is also no clear, commercial pathway to compliance with 85% at this time. CSA standards are reviewed regularly (at least every 5 years) to ensure continuous improvement and market relevance.

In recognition of the existing CSA standard and the absence of a commercial path to compliance, **we recommend that draft amendment Subsection 46(2) be amended to ensure that all new catalytic oxidization systems comply with appropriate CSA standards.**

[18] *Plant et al.* in the journal *Science*, Volume 377, page 1566-1571 (2022)
[19] ANSI Z83.20-2016 CSA 2.64-2016