Comments on Environment and Climate Change Canada's (ECCC) Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)

Submitted by:

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I. Introduction

Canadian Association of Physicians for the Environment, Canadian Lung Association, David Suzuki Foundation, Pembina Institute, Clean Air Task Force and Environmental Defense Fund (Joint Environmental and Health Commenters) submit the following comments on Environment and Climate Change Canada's (ECCC) Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector). We greatly appreciate the opportunity to comment on ECCC's important proposal. Immediate and deep reductions of methane are critically necessary to address the climate crisis, ensure Canada meets its climate commitments and greenhouse gas (GHG) reduction goals, and secure important co-reductions of other harmful pollutants emitted during flaring and venting and from leaks.

Fossil-sourced methane is a dangerous and powerful greenhouse gas that is 82.5 times more potent than carbon dioxide on a molecule per molecule basis over a 20-year timeframe, and 29.8 times more potent over a 100-year time frame.[1] Methane is a short-lived GHG, lasting only approximately a decade in the atmosphere.[2] This makes reducing methane emissions critical for achieving short-term GHG reductions and slowing the rate of climate change.[3] Pursuing all mitigation measures now could slow the global-mean rate of near-term decadal warming by around 30%.[4] New research shows that immediate action to reduce methane emissions could help preserve Arctic summer sea ice this century.[5]

According to ECCC, the oil and gas sector is the largest contributor of GHG emissions. Oil and gas sources were responsible for 40% of all methane emitted in Canada in 2021.[6] Notably, multiple scientific studies indicate that actual methane emissions are much greater than offical estimates.[7] These studies and others were reviewed by the Commissioner for the Environment

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[1] IPCC, 2021: *Climate Change 2021: The Physical Science Basis, Contribution of Working Group to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change*, p. 1017, Table 7.15. Available at https://www.ipcc.ch/report/ar6/wg1/downloads/report/IPCC_AR6_WGI_FullReport_small.pdf.

[2] Atmospheric Lifetime and Global Warming Potential Defined, https://19january2017snapshot.epa.gov/climateleadership/atmospheric-lifetime-and-global-warming-potential-defined_.html.

[3] Smith, Kirk R., et al., U.S. Climate Change Science Programs Synthesis and Assessment Product 3.2, Climate Projections Based on Emissions Scenarios for Long-Lived and Short Lived Radiatively Active Gases and Aerosols at 64-65 (2008) https://www.globalchange.gov/sites/globalchange/files/sap3-2-draft3.pdf;.

[4] Ilissa B Ocko et al, Acting rapidly to deploy readily available methane mitigation measures by sector can immediately slow global warming, 2021 Environ. Res. Lett. 16 054042.

[5] EDF, New study: Swift methane action could help save Arctic summer sea ice, forestall global warming impacts (Mar. 15, 2022).

[6] Regulatory Impact Analysis, Issues section.

[7] Measurement campaigns undertaken by EDF and others found methane missions are 70% higher in British Columbia, 50% higher in Alberta and 30% to 40% higher in Saskatchewan relative to the federal inventory. *See* Conrad B M, Tyner D R, Li H Z, Xie D and Johnson M R, 2023b Measurement-Based Methane Inventory for Upstream Oil and Gas Production in Alberta, Canada Reveals Higher Emissions and Starkly Different Sources than Official Estimates Commun. Earth Environ. 4 [hereinafter "Conrad et al. (2023b)"]; Johnson M F, Lavoie M, MacKay K, Long M and Risk D 2023a Assessing the effectiveness and efficiency of methane regulations in British Columbia, Canada Clim. Policy 1–14 Online: https://doi.org/10.1080/14693062.2023.2229295; Seymour S P, Li H Z, MacKay K, Kang M and Xie D 2023 Saskatchewan's oil and gas methane: how have underestimated emissions in Canada impacted progress toward 2025 climate goals? Environ. Res. Lett. 18.

and Sustainable Development while assessing the ability of Canada's current methane regulations to achieve the federal government's 2025 target of 40%-45% emission reductions. The Commissioner concluded that they could not be certain these targets would be met due, in part, to poor compliance rates and emission underreporting. To achieve the government's 75% reduction target, the proposed amendments, and subsequent equivalency agreements, will need to address the challenges and recommendations found in the Commissioner's report[8] as well as the recommendations made in this submission. While ECCC estimates that the amendments will result in a 75% reduction over 2012 levels, the problem of underestimation makes it difficult to assess outcomes and regulatory efficacy, especially given uncertainty regarding emissions in the baseline year.[9] Indeed, ECCC acknowledges in the current proposal that current regulations designed to achieve a 40-45% reduction below 2012 levels "will not be sufficient to meet Canada's new methane commitment."[10]

A strong policy approach that leverages proven, low-cost solutions to drive down methane emissions will likewise make Canada's otherwise high-cost, high-carbon oil and gas more competitive in a shrinking global market that will increasingly favour low-carbon fuels.[11] The EU's provisional agreement on methane -- particularly its commitment to setting a methane intensity standard for imports -- is a clear signal of what's to come: market access will be determined in part by stringent global policies. Voluntary initiatives such as the COP28 commitment of 50 oil companies to achieve net-zero methane emissions by 2030 likewise show that competition to meet demand for low-carbon energy options will be steep. Fast-acting policy to drive down oil and gas methane emissions is needed not only to mitigate the climate emergency, improve air quality and health outcomes, and protect Canadians' right to a healthy environment; it will also keep Canada's oil and gas industry from being left behind.

Strong federal methane regulations are imperative not only for mitigating climate change but also for protecting human and environmental rights. With the recent recognition of the right to a healthy environment in Canada under the Canadian Environmental Protection Act (CEPA)[12], there is a duty to safeguard these rights when enacting environmental policies. This recognition underscores the significance of robust regulations to protect the health and well-being of both present and future generations, in alignment with Canada's adoption of the United Nations Declaration on the Rights of Indigenous Peoples and its legislative committment to promoting a clean, healthy, and sustainable environment for all Canadians.

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[8] https://www.oag-bvg.gc.ca/internet/English/att__e_44248.html#p69

[9] See e.g., Conrad B M, Tyner D R and Johnson M R, 2023a, The Futility of Relative Methane Reduction Targets in the Absence of Measurement-Based Inventories, Environ. Sci. Technol. 57, 50, 21092-21102 (2023), https://doi.org/10.1021/acs.est.3c07722, [hereinafter "Conrad et al. (2023a)"].

[10] Canada Gazette, Part I, Volume 157, Number 50: Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (Dec. 16, 2023), [hereinafter "ECCC Proposed Rules"], Issues section.

[11] Pembina Institute, Surival of the Cleanest Assessing the cost and carbon competitiveness of Canada's Oil, Nov. 27, 2023, https://www.pembina.org/pub/survival-cleanest#:~:text=A%20new%20Pembina%20Institute%20report,carbon%20emissions%20and%20breakeven%20price.

[12] June 13, 2023, Bill S-5, Strengthening Environmental Protection for a Healthier Canada Act became law (providing that every individual in Canada has a right to a healthy environment as provided under the Canadian Environmental Protection Act, 1999 (CEPA) and that the Government of Canada also has a duty to protect the right to a healthy environment when making decisions under CEPA).

Strong federal regulations that require operators conserve, rather than waste, natural gas also means increased royalty and corporate tax revenue for provincial governments. Gas that is vented, leaked, or flared is not subject to royalties or corporate taxes since the gas is not marketed. Recent analysis conducted by EDF demonstrates that the Alberta government missed out on $120 million in lost royalties and corporate tax revenue in 2022 due to wasted gas.[13]

We appreciate Canada's GHG commitments and are largely encouraged by ECCC's proposal. We strongly support the following elements of the proposal, which are in line with international best practices for reducing methane:

1. The fugitive emission detection and repair program that is comprised of a suite of frequent instrument-based inspections;
2. The prohibition on venting;
3. The hydrocarbon gas destruction equipment specifications.

We urge ECCC to strengthen the proposal in the following key ways:

1. Move up the coming into force deadlines to reflect established precedent for similar measures elsewhere, the urgency of the climate crisis and ensure Canada meets its 2030 GHG reduction target;
2. Require monthly screening inspections, unless the operator submits an engineering certification demonstrating that it is unsafe to conduct any of the inspections;
3. Narrow the exceptions for venting and in some instances add time limits to allowable venting;
4. Prohibit the routine flaring of solution and casinghead gas from oil wells and establish time limits for allowable temporary flaring of solution gas and casinghead gas;
5. Increase the protectiveness of the engineering demonstration needed to permit flaring by requiring an annual demonstration, require certification by an independent third-party engineer, and limit the exemption to demonstrations of technical, rather than economic, infeasibility for requests to flare solution or casinghead gas routinely;
6. Remove the opt-out alternative compliance pathway; and
7. Enhance the protectiveness of the continuous monitoring provision and allow operators to utilize this technology as part of fugitive emission detection and repair requirements.

We also urge ECCC to promptly propose proivisions requiring operators directly measure, rather than estimate, methane emissions from upstream oil and gas facilities, and report such measurements to ECCC as part of a national, publicly available, detailed, and granular methane inventory.

Improvements to the proposal are necessary to ensure Canada meets its GHG reduction target and keeps pace with leading international regulatory frameworks, as demonstrated by recent

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[13] EDF Blog, Wasted Gas, Wasted Royalties-How Common-Sense Climate Policy Can Put Money Back in People's Pockets, https://blogs.edf.org/energyexchange/2024/02/13/wasted-gas-wasted-royalties-how-common-sense-climate-policy-can-put-money-back-in-peoples-pockets/#more-23070

United States Environmental Protection Agency (U.S. EPA) rules and proposed EU Parliament and Council rules.

II. Background

Climate change is an existential threat to humanity. Scientific evidence overwhelmingly demonstrates that climate change is already causing immediate, devastating impacts on communities, and that these harms will worsen dramatically as greenhouse gas pollution continues to rise. Immediate and deep reductions in GHGs, particularly of methane, are critical. The contribution of Working Group III to the IPCC Assessment Reports highlights the importance of near-term methane reductions, finding with "high confidence" that "[a]s methane has a short lifetime but is a potent GHG, strong, rapid and sustained reductions in methane emissions can limit near-term warming and improve air quality by reducing global surface ozone."[14] Yet since 2007, atmospheric methane levels have been increasing at an accelerating pace, with the largest yearly rise in methane levels ever recorded occurring in 2020 and 2021 (15 and 18 ppb respectively).[15] A deep near-term reduction in methane pollution is therefore one of the most important actions needed to address the climate crisis. The oil and gas industry is the largest source of GHGs in Canada, and as such, ECCC's proposal for this sector represent an important step toward staving off the worst impacts of climate change.

Upstream oil and gas facilities also emit harmful co-pollutants, during venting and leaking, as well as combustion and flaring of natural gas. Co-pollutants released from venting and leaking include volatile organic compounds (VOCs) and other hazardous air pollutants. VOCs contribute to ground-level ozone. Ground-level ozone is a dangerous air pollutant. Exposure to elevated concentrations of ozone lead to serious, adverse health effects, including asthma, increased emergency room visits, and premature death - impacts that are particularly severe in sensitive populations, like children and the elderly.[16] Ozone also causes direct harm to the environment by impeding plant growth and vitality, decreasing crop yield,[17] and contributing to climate change.[18] Increasing temperatures caused by climate change exacerbates ozone pollution, thus creating a feedback loop between ozone and the climate crisis.[19]

Combustion of natural gas through flaring produces carbon dioxide (CO2), oxides of nitrogen (NOx) and black carbon. NOx, like VOCs, are ozone precursors. CO2 is a GHG that contributes

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[14] IPCC, 2023: Climate Change 2023: Synthesis Report. Contribution of Working Groups I, II and III to the Sixth Assessment Report of the Intergovernmental Panel on Climate Change [Core Writing Team, H. Lee and J. Romero (eds.)]. IPCC, Geneva, Switzerland, 184 pp., doi: 10.59327/IPCC/AR6-9789291691647.

[15] World Meteorological Organization, *More bad news for the planet: greenhouse gas levels hit new highs*, Press Release Number: 26102022 (Oct. 26, 2022), https://public.wmo.int/en/media/press-release/more-bad-news-planet-greenhouse-gas-levels-hit-new-highs#:~:text=Since%202007%2C%20globally%2Daveraged%20atmospheric,systematic%20record%20began%20in%201983.

[16] 80 Fed. Reg. 65292, 65322 (Oct. 26, 2015).

[17] *Id*. at 65369, 65370.

[18] EPA, Climate Change Impacts on Air Quality, https://www.epa.gov/climateimpacts/climate-change-impacts-air-quality#:~:text=Climate%20change%20can%20affect%20air,level%20ozone%20in%20some%20areas.&text=Ground%2Dlevel%20ozone%20is%20also,trapping%20heat%20in%20the%20atmosphere

[19] *Id*.

to climate change. Black carbon also drives climate change.[20] Black carbon is a major component of airborne particles that are commonly referred to as "soot." Black carbon is a product of incomplete combustion of fossil fuels and biomass, and its absorption properties contribute to warming. It is also harmful to human health when inhaled.[21] Strong regulations that reduce methane emissions in an expeditious manner will also lead to important reductions in harmful co-pollutants that will provide direct public health benefits to communities, in particular those living closest to oil and gas facilities.

In order to meet these daunting climate and public health challenges, ECCC must strengthen its proposal by (1) expediting the implementation timeframes, (2) narrowing exceptions to the inspection, venting and flaring provisions, and (3) removing the alternative compliance pathway for unproven continuous monitoring programs.

III. ECCC Must Move Up the Implementation Timeframes

We strongly urge ECCC to revise the compliance deadlines for new and existing sources. Specifically, ECCC must require new sources to comply with requirements in early 2025 and require existing sources to comply in early 2028. Immediate reductions in methane are critically needed to slow the rate of climate change. In addition, near-term reductions are necessary to ensure ECCC meets its 2030 GHG reduction goal. International regulations demonstrate that new sources can comply immediately with most new requirements after final rule promulgation. Existing sources may need more time than new sources, but can certainly comply within 4 years of the proposal date, as we suggest here. We provide examples below of significantly shorter implementation timeframes in other rules that demonstrate the feasibility of shorter implementation timeframes than ECCC proposed.

A. Operators can comply immediately with most requirements for new sources

Both the proposed EU regulation and the final EPA regulations require most sources to comply with methane requirements for new sources immediately upon rule promulgation. For all but two of the sources affected by EPA's rule, operators must comply within 60 days of final rule promulgation.[22] Specifically, operators must comply with the LDAR, storage tank, liquids unloading, well completion, and compressor requirements immediately.[23] EPA determined that operators of pneumatic controllers may need up to 1 year from final rule promulgation to comply with the new zero emissions standard for pneumatic devices and up to 2 years to comply with the prohibition on routine flaring.[24] The former reflects EPA's understanding that it may be challenging for new sources to obtain the equipment necessary to demonstrate compliance immediately upon the effective date of the final rule. The latter is based on allowing owners and

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[20] Schwartz, et al., Black Carbon Emissions from the Bakken Oil and Gas Development Region, *Environ. Sci. Technol. Lett.* 2015, 2, 10, 281-285 (Sept. 3, 2015), https://pubs.acs.org/doi/abs/10.1021/acs.estlett.5b00225
[21] Crouse et al. (2015), Ambient PM2.5, O3, and NO2 Exposures and Associations with Mortality over 16 Years of Follow-Up in the Canadian Census Health and Environment Cohort (CanCHEC). Environmental Health Persectives. Chen et al., "Changes in exposure to ambient fine particulate matter after relocating and long term survival in Canada." BMJ. CIRES, Emissions of Black Carbon from Flaring in the Bakken Oil and Gas Fields (Sept. 9, 2015).
[22] 40 CFR §60.5370b.
[23] *Id*.
[24] 40 CFR §60.5370b.a.(5); §60.5377b.

operators adequate time to incorporate the requirement into their development plans and to deploy any necessary equipment and controls.[25]

The EU rules are expected to come into force by April 2024, at the latest, with the first LDAR inspection required within 12 months of the coming into force of the regulation.[26] The other EU provisions are enforceable immediately upon the regulation coming into force, unless an operator can demonstrate a reason for delay, such as unavailability of equipment, in which case new sites have an additional 12 months to comply and existing sites have an additional 18 months.[27]

ECCC has proposed to allow new sources approximately 3 years to come into compliance from the date the rule was proposed. This is an unneccessarily protracted schedule-in particular for fugitive emissions monitoring and use of non-emitting equipment-and undercuts Canada's credibility as a climate leader. We strongly urge ECCC to require new sources to comply within 60 days of final rule promulgation, as EPA has done.

B. Operators of existing facilities must also be required to come into compliance more quickly than as proposed

ECCC has proposed to allow operators of existing facilities (i.e., those that begin operations before January 1, 2027) up to six years to comply with the new requirements, other than for LDAR, using the proposal as the start date. LDAR requirements come into force Jan. 1, 2027, for new and existing sources. Facilities that begin operations before January 1, 2027, that increase their production or gas receipts must come into compliance with new requirements by January 1, 2028, or Jan. 1, 2029, depending on when the increase occurs.[28] Specifically, for existing facilities that begin operations before January 1, 2027, the new fugitive emission, venting and flaring requirements apply on January 1, 2028 if the combined volume of hydrocarbon gas that is produced or received at the facility in 2027 is greater than the combined volume of hydrocarbon gas that is produced or received at the facility in each of the years 2024 to 2026.[29] The new fugitive emission, venting and flaring requirements apply on January 1, 2029 if the combined volume of hydrocarbon gas that is produced or received at the facility in 2028 is greater than the combined volume of hydrocarbon gas that is produced or received at the facility in each of the years 2024 to 2026.[30]

We strongly urge ECCC to move up the implementation deadlines for existing sources. As discussed above, the EU regulations come into force immediately, unless an operator can demonstrate a reason for delay. In EPA's final rule, the agency highlights that the compliance deadline included in the final emissions guidelines represents the furthest date into the future that the EPA finds appropriate, under the constraints of the U.S. Clean Air Act, for a state to allow as a final compliance deadline for the state's standards of performance. However, states may require

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[25] EPA, 40 CFR Part 60 Final Rule, Executive Summary, § A.
[26] European Parliament, Legislative Train Schedule, https://www.europarl.europa.eu/legislative-train/package-fit-for-55/file-reducing-methane-emissions-in-the-energy-sector.
[27] Proposed EU Rules, Art. 15, para 5c.
[28] ECCC Proposed Rules, § 8,1, Application of sections 46 to 53.3.
[29] *Id*.
[30] *Id*.

compliance with existing source requirements earlier, and in fact, EPA recommends states do so. EPA explains "states are free to establish compliance timelines within their state plan submittals for certain designated facilities that are shorter than 36 months, and indeed states should be examining shorter timelines as a possibility to ensure that sources come into compliance with their respective standards of performance as expeditiously as practicable."[31] As described below, the measures ECCC has proposed for existing source are based on well-established technologies, and many are already required in leading US states, so the present-day feasibility of these measures is clear. Immediate reductions in GHG are necessary to stave off the harmful impacts caused by a warming climate, as recognized by the IPCC: "All global modelled pathways that limit warming to 1.5°C (>50%) with no or limited overshoot, and those that limit warming to 2°C (>67%), involve rapid and deep and, in most cases, immediate greenhouse gas emissions reductions in all sectors this decade."[32] Accordingly, we urge ECCC to include expeditious implementation timelines in the rules that require existing sources to come into compliance in early 2028. There is no reason to wait for many years to reduce this unnecessary and harmful pollution.

C. Operators of new and existing facilities can comply with earlier deadlines without incurring significant additional costs

The following table recreates Table 9 from ECCC's Regulatory Impact Statement.[33] The values summarized differ from ECCC's estimates due to simplifying assumptions, as provided in the RIAS. However, the recreated estimates in Table 1 are quite close to the ECCC values using a 2% discount rate (0.52% larger for total discounted costs and 0.56% larger for annualized costs). As such, they provide a useful baseline to demonstrate the impact of different assumptions. For more details on the analysis, see Appendix A.

Table 1: Recreation of Table 9, Industry and compliance costs by source (millions of dollars)

Source	**Discounted total (2027- 2040)**	**Annualized**
Venting and flaring	4,809	397
Pneumatic instruments	3,341	276
Pneumatic pumps	864	71
Compressor seals	1,322	109
Glycol dehydrators	104	9
Fugitive equipment leaks	3,955	327
Surface-casing vent flow	749	62
Total	**15,144**	**1,251**

Table 2 estimates compliance costs using the same methods as ECCC, but assumes all new sources comply starting in 2025 and existing sources comply in 2028. In this case, we estimate total discounted compliance costs of 16.7 billion CAD when using a 2% discount rate. This is an

[31] EPA Final Rule, Exec. Summary, §E.
[32] IPCC Climate Change 2023 Synthesis Report Summary for Policymakers, §B.6.
[33] ECCC Proposed Rules, RIAS, Table 9.

11% increase in total costs and accounts for accelerated implementation timelines and an additional 2 years of expenditures. Moreover, the share of this increased expenditure is still less than 1% of the Canadian oil and gas industry's gross revenue in just one year.[34]

Table 2: Recreation of Table 9, Industry and compliance costs by source, with accelerated implementation timeline (millions of dollars)*

Source	Discounted total (2025- 2040)	Annualized
Venting and flaring	5,178	381
Pneumatic instruments	3,684	271
Pneumatic pumps	955	70
Compressor seals	1,395	103
Glycol dehydrators	114	8
Fugitive equipment leaks	4,615	340
Surface-casing vent flow	803	59
Total	**16,744**	**1,232**

**New facilities comply starting in 2025; existing facilities comply in 2028.*

Finally, conservatively speaking, compliance costs estimated with the 2% discount rate and the accelerated timeframes translates to an abatement cost of $79 per metric ton of CO_2e.[35] This assumes a total compliance and administrative cost of 17.1 billion CAD and a total emissions estimate of 217.08 metric tons of GHG reductions. Focusing just on methane, compliance costs are about $2,037 per metric ton of methane abated. Note that while this reflects a modest increase over ECCC's estimate of $71 per metric ton GHG (and $1,833 per metric ton of methane), this is an overestimate as this does not reflect additional years of emissions reductions achieved in the 2025-2026 period. Moreover, abatement costs for CO2e and methane both fall below social cost thresholds cited by ECCC in the RIAS. The 2022 thresholds are $273 per metric ton carbon and $2,456 per metric ton of methane..

IV. Source Specific Comments

In the following section we provide our comments and recommendations for improvement on ECCC's proposed requirements to reduce emissions from fugitive leaks, venting and flaring, including the continuous monitoring alternative compliance pathway.

A. Fugitive Emission Detection and Repair Program

We largely support ECCC's approach to reducing fugitive emissions. ECCC has proposed a risk-based approach to identifying and remediating fugitive emissions wherein inspection frequency

[34] Rystad Energy research and analysis; 2022 gross revenue estimates from UCube

[35] We follow ECCC's assumption of a 100-year global warming potential of 25 when reporting values in CO_2e terms. However, the IPCC's most recent reports indicate that 30 is more appropriate factor. See Appendix A for a detailed summary of abatement costs under different GWP assumptions, including a short-term, 25-year GWP of 83. (IPCC 2021).

is tied to the likelihood of a facility to leak and repair timeframes are tied to the size of the leak. Per the proposal, three different types of inspections apply to upstream oil and gas facilities: an operator-conducted "comprehensive inspection," which must be conducted using optical gas imaging equipment (OGI) or EPA's Method 21 (M21); a "screening" inspection which must be conducted with an instrument with at least a 90% probability of detecting (POD) a fugitive emission with a flow rate of 1 kg/h or more; and an inspection conducted by an auditor with an instrument with at least a 90% POD a fugitive emission with a flow rate of 10 kg/h or more ("auditor inspection"). ECCC's proposal requires quarterly comprehensive inspections of Type 1 facilities.[36] ECCC proposes annual OGI or M21 inspections at all other types of upstream facilities ("Type 2 facilities"). U.S. EPA and leading states similarly tie inspection frequencies and repair timeframes to the risks posed by facility types and the sizes of leaks which supports ECCC's approach. We support the quarterly inspection requirement for Type 1 facilities and discuss below studies demonstrating that equipment at such facilities is particularly leak-prone.

We suggest revisions to the screening inspection requirement in order to ensure that operators routinely inspect both Type 1 and Type 2 facilities for leaks. We recommend ECCC require monthly screening inspections, unless an operator submits an engineering certification demonstrating that conducting a monthly screening inspection is unsafe due to weather or other conditions that may pose a hazard to the inspector. Leading jurisdictional requirements demonstrate that monthly inspections are feasible. Operators can reduce travel time and emissions associated with travel by sharing inspection services.

We support ECCC's proposed layered approach to inspection requirements wherein operators may use a combination of technologies with differing minimum detection limits to conduct inspections. Layered inspection requirements, using different types of technologies, provide flexibility for operators while also helping to ensure leaks of differing sizes and types are detected and repaired.

We support the proposed repair times, other than the 90-day repair timeframe for leaks measured to be less than 1 kg/hr. Leading international precedent demonstrates such a lengthy repair timeframe is unwarranted and could result in significant emissions to the atmosphere that can be avoided with a repair timeframe of 30-days.

ECCC proposes to define fugitive emissions as "an unintentional emission of hydrocarbon gas from an upstream oil and gas facility."[37] We support this definition as it includes venting due to abnormally operating or malfunctioning equipment as well as traditional component or equipment leaks.

1. Many Leading Jurisdictions Require at Least Quarterly Inspections

We support ECCC's proposed quarterly inspection requirement to detect fugitive emissions from Type 1 facilities. At least quarterly inspections for upstream oil and gas facilities such as well production, tank battery and compressor stations, represent best practice for detecting

[36] Type 1 facilities are upstream oil and gas facilities that contain any of the following types of equipment: compressor, storage, flare, or gas-liquid separator.
[37] ECCC Proposed Rules, Amendment 1(5).

unintentional emissions. The following jurisdictions require, or have proposed, quarterly inspections for complex facilities similar to Type 1 facilities:

- **U.S. EPA:** EPA recently promulgated inspection requirements for new and existing oil and gas production and compression facilities that mirror the inspections ECCC proposes for Type 1 facilities. Specifically, operators must inspect well sites with major production and processing equipment and centralized production facilities[38] and compressor stations in the natural gas gathering and boosting and transmission segments, quarterly with OGI or M21.
- **EU:** The European Parliament and the Council of the European Union (EU) have proposed quarterly OGI inspections for compressor stations and underground natural gas storage facilities.[39] Operators also must conduct M21 inspections every 8 months at such facilities.[40]
- **Colorado:** Colorado has required quarterly OGI or M21 inspections at well sites with emissions over specified thresholds since 2014. Currently Colorado requires monthly inspections at new well sites, other than those without permanent storage tanks, and quarterly inspections at a suite of existing well sites, depending on the facility's location and emissions potential.[41]
- **New Mexico:** The New Mexico Environment Department similarly requires monthly or quarterly inspections for compressor stations and certain well sites, depending on emissions potential and the facility's location.[42]
- **Pennsylvania:** Pennsylvania requires quarterly inspections at compressor stations.[43]
- **California:** California has required quarterly M21 inspections at production, gas processing, and compression facilities in the gathering and boosting and transmission natural gas segments since 2017.[44]

Quarterly instrument-based inspections are a demonstrated practice for detecting unintentional emissions and must be the minimum required for identifying leaks at Type 1 facilities.

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[38] *Major production and processing equipment* means reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, control devices, natural gas-driven process controllers, natural gas-driven pumps, and storage vessels or tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water, for the purpose of determining whether a well site is a wellhead only well site. 40 CFR §60.5430b; *Centralized production facility* means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations. 40 CFR §60.5430b.

[39] EU Proposed Rules, Annex I.

[40] *Id*.

[41] 5 Colo. Code. Regs. § 1001-9-D-II.E.3, II.E.4 ("Colorado Reg.7")

[42] New Mexico Code R. § 20.2.50.116.C.(3)

[43] 25 Pa. Code § 129.127(c)(2); § 129.137(c)(2).

[44] 17 Cal. Code Regs. § 95669

2. ECCC's Risk Based Approach to Inspection Requirements Represents Best Practice

We support ECCC's risk-based approach to inspection frequencies that ties inspection requirements to the type of equipment at a facility; facilities with leak-prone equipment are subject to more frequent, i.e., quarterly, inspections whereas facilities without such equipment are inspected less frequently. This approach maximizes emissions reductions while minimizing costs.

It is appropriate to base monitoring frequency on the presence of certain types of equipment at a site because such equipment has been commonly observed as the source of large emission events through numerous field studies. Studies undertaken in the U.S. demonstrate that the presence of major equipment also indicates higher component counts, which correlate with increased probability of fugitive emissions. For example, Zavala-Araiza (2017) explains that abnormal process conditions, both persistent or episodic, include "failures of tank control systems, malfunctions upstream of the point of emissions (for example, stuck separator dump valve resulting in produced gas venting from tanks), design failures (for example, vortexing or gas entrainment during separator liquid dumps) and equipment or process issues (for example, over-pressured separators, malfunctioning or improperly operated dehydrators or compressors)."[45] Another study by Lyon et al. found that emissions from tank vents and hatches accounted for roughly 90% of all detected hydrocarbon sources emitting more than 3–10 kg per hour.[46] Lyon et al. also observed emissions from separator pressure relief valves, dehydrators, and flares.

A more recent study, Rutherford et al. (2021) found that tanks are the largest emission source and biggest reason for disagreement between the study results and U.S. EPA Greenhouse Gas Inventory (GHGI) data.[47] Rutherford et al. also found that flare methane emissions are underestimated in the GHGI, and that pneumatics and separators are also large sources of emissions.[48] Tyner and Johnson (2021) also recently found that "[m]ore than half of emissions were attributed to three main sources: tanks (24%), reciprocating compressors (15%), and unlit flares (13%)."[49] Robertson et al. (2020) found that simple sites with less equipment had lower

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[45] Daniel Zavala-Araiza et al., *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*, 8 Nature Commc'n 14012 (2017), https://www.nature.com/articles/ncomms14012#Sec6 [hereinafter Zavala-Araiza (2017)].
[46] David Lyon et al., *Aerial surveys of elevated hydrocarbon emissions from oil and gas production sites*, 50 Env't. Sci. Tech. 4877 (2016), https://pubs.acs.org/doi/full/10.1021/acs.est.6b00705 [hereinafter Lyon et al., *Aerial Surveys*].
[47] Jeffrey Rutherford et al., *Closing the methane gap in U.S. oil and natural gas production emissions inventories*, 12 Nature Commc'n. 4715, at Figure 3 (2021), https://www.nature.com/articles/s41467-021-25017-4.
[48] *Id.*
[49] David Tyner & Mathew Johnson, *Where the Methane Is—Insights from Novel Airborne LiDAR Measurements Combined with Ground Survey Data*, 55 Env't Sci. Tech. 9773 (2021), https://pubs.acs.org/doi/pdf/10.1021/acs.est.1c01572.

emissions than those with more equipment.[50] Finally, Zavala-Araiza (2015) found that stuck separator dump valves and tank flashing events were causes of super-emitters.[51]

EDF's PermianMAP project has observed many emission events from tanks and flares.[52] Helicopter surveys found 79% of methane plumes were from tanks; and among marginal wells, 17% of complex sites (with multiple pieces of equipment) had emissions, while none were detected at "pump-jack only" sites.[53] Ravikumar et al. (2020) similarly found the largest emissions from tanks, concluding that "[t]he outsized role of tanks in contributing to overall methane emissions at natural gas facilities has been a defining feature in many recent studies, and points to a critical need for tank-focused LDAR regulations."[54]

We agree with ECCC that separators are failure-prone equipment and support ECCC's inclusion of separators in Type 1 facilities subject to quarterly OGI inspections. Separators can be a large sources of emissions, particularly when experiencing an abnormal processing condition, such as being over-pressured.[55] A recent study identified separators as one of the four largest sources of methane emissions in Alberta.[56] One U.S. Department of Energy (U.S. DOE) study found three of the ten largest measured emissions events stemmed from separator dump valves,[57] and another U.S. DOE study found that 26% of separators at oil sites and 67% at gas sites had detectable emissions[58] using OGI.

ECCC's proposed equipment-based approach aligns with the substantial body of science and data characterizing emissions from certain types of failure-prone equipment, including flares, storage tanks, compressors, and separators.

3. Type 1 Facilities Should Include Facilities with Engines that Burn Produced Gas

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[50] Anna Robertson, et al., *New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates*, 54 Env't. Sci. Tech. 13926 (Oct. 15, 2020), https://pubs.acs.org/doi/10.1021/acs.est.0c02927.

[51] Daniel Zavala-Araiza et al., *Reconciling divergent estimates of oil and gas methane emissions*, 51 Proc. Nat'l Acad. Sci. 15597 (2015), https://www.pnas.org/content/112/51/15597. [hereinafter Zavala-Araiza (2015)].

[52] Observed emissions by equipment type: Tank-Vent 42.96%, Tank Thief Hatch 33.43%, Flare Stack 14.54%. PermianMAP, *Prevalence of Emissions by Equipment Type*, (Observed emissions by equipment type: Tank-Vent 42.96%, Tank Thief Hatch 33.43%, Flare Stack 14.54%).

[53] *Id.*

[54] Arvind P Ravikumar et al., Repeated leak detection and repair surveys reduce methane emissions over scale of years, Environ. Res. Lett. 15 034029 (2020).

[55] Zavala-Araiza et al. (2017), Figure 3 shows separators as large source of emissions within the equipment leak category. Jeffrey Rutherford et al., Closing the methane gap in U.S. oil and natural gas production emissions inventories, 12 Nature Commc'n. 4715, at Figure 3 (2021), https://www.nature.com/articles/s41467-021-25017-4 (In the second paragraph of their discussion, they cite stuck separator dump valves, design failures like vortexing or gas entrainment during separator liquid dumps, and equipment or process issues such as over-pressured separators as some of the many abnormal process conditions observed in field campaigns.).

[56] Conrad et al. (2023b), *supra* note 7.

[57] Richard L. Bowers, Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells Report at 19 (2022), https://www.osti.gov/biblio/1865859.

[58] Richard L. Bowers, Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells at Slide 21 (Aug. 2021), https://netl.doe.gov/sites/default/files/netl-file/21CMOG_OG_Bowers.pdf.

We suggest ECCC expand the definition of a Type 1 facility to include facilities that contain engines that burn produced gas. This would ensure the quarterly inspection requirement applies to Cold Heavy Oil Production with Sand (CHOPs) facilities which could help identify and mitigate venting from abnormal conditions. Numerous peer-reviewed studies have identified unreported venting at CHOPs facilities. A recent study by Seymour et al. (2023) found that the Saskatchewan inventory is underestimated by between 30% and 40%, and that much deeper emission reductions are possible under current regulations if such CHOPs emissions are accurately measured (and therefore reported and mitigated).[59] Conrad et al. (2023) similarly found that CHOPs sites are a key source of methane emissions in Saskatchewan.[60] A separate study conducted by Festa-Bianchet et al. (2023) using aerial measurement surveys found that CHOPS sites emitted ~3.9-times more methane than reported.[61] While most CHOPs facilities have storage tanks, and thus would fall under the Type 1 facility definition, given the importance of minimizing venting at CHOPs facilities, it is important to include all CHOPs sites in quarterly inspections, including those that do not have storage tanks.

4. ECCC's Layered Approach to LDAR Represents Best Practice

We support ECCC's layered approach to LDAR, wherein facilities are subject to different inspection requirements that allow for the use of different types of leak detection technologies. Specifically, operators may use any technology that can meet the POD and minimum detection limit (MDL) requirements for the screening and auditor inspections. OGI cameras, as well as some continuous monitors, have an MDL of 1 kg/h or more. We suggest below that ECCC allow for the use of continuous emissions monitors with an MDL of 1 kg/h as part of the fugitive emissions monitoring program rather than allowing operators to install this technology as an alternative compliance pathway to the leak, venting and flaring requirements.

A number of leading jurisdictions approach LDAR in a similar way:

- **U.S. EPA:** EPA's recently finalized LDAR requirements include an alternative compliance pathway for LDAR that allows operators to use a combination of advanced leak detection technologies, such as aerial surveys, ground-based surveys, and continuous emissions monitors, as well as an annual OGI inspection. EPA's approach is predicated on the understanding that certain technologies are better equipped to detect certain types of leaks (e.g., aerial surveys are best equipped to detect larger emissions, while ground-based inspections with OGI are better equipped to detect smaller leaks).
- **EU:** Operators must conduct both OGI and M21 inspections and may apply to use alternative detection technologies for inspections. For example, at production sites, operators must conduct semi-annual OGI inspections and annual M21 inspections.

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[59] Seymour *et al,* 2023, Saskatchewan's oil and gas methane: how have underestimated emissions in Canada impacted progress towards 2025 climate goals? *Environ. Res. Lett.* 18; Festa-Bianchet S A, Tyner D R, Seymour S P and Johnson M R 2023 Methane Venting at Cold Heavy Oil Production with Sand (CHOPS) Facilities is Significantly Underreported and led by High-Emitting Wells with Low or Negative *Environ. Sci. Technol.*

[60] Conrad et al. (2023a), *supra* note 9.

[61] Festa-Bianchet, et al., 2023, Methane Venting at Cold Heavy Oil Production with Sand (CHOPS) Facilities is Significantly Underreported and led by High-Emitting Wells with Low or Negative Value, Environ. Sci. Technol. 2023, 57, 8, 3021–3030.

We support the use of advanced LDAR technologies for purposes of detecting unintentional emissions. The field of advanced leak detection technologies is growing rapidly and we anticipate operators and auditors having a wide range of instruments to choose from when conducting screening inspections and auditor inspections.

5. ECCC Must Revise the Screening Requirement to Require Monthly Inspections Unless an Operator Demonstrates that An Inspection is Unsafe

We urge ECCC to revise the screening inspection to ensure that operators inspect Type 1 and Type 2 facilities monthly. Specifically, we suggest ECCC revise the screening inspection requirement to require operators, or their representatives, conduct a screening inspection monthly, unless the operator certifies that it is unsafe to do so. Monthly inspections are feasible, as demonstrated by requirements in leading jurisdictions.

The use of third-party contractors can minimize travel time and associated emissions. A recent study demonstates that operators can reduce travel time, and any emissions associated with travel, by sharing services for their leak inspections.[62] Methane regulations have created a robust market of third-party LDAR inspection companies who can efficiently conduct inspections on behalf of operators.[63] Operators have flexibility to use any type of technology that can meet the 1 kg/hr MDL and POD. Given the rapid advancements in advanced leak detection, we anticipate operators being able to choose from a suite of instruments, including installing continuous emissions monitors, to conduct monthly screening inspections.

Leading regulations, including recently promulgated EPA rules, require an operator, or its representative, to visit a site monthly to conduct inspections or maintenance activities:

- **Alberta (Peace River region):** Operators are required to conduct monthly instrument-based LDAR surveys at high-risk sources which include storage tanks, flare ignitors/pilots and compressor seals, and must quantify all leaks that are not repaired within 24 hours.[64]
- **EPA:** Requires operators conduct monthly AVO inspections at compressor stations.[65]
- **Colorado:** Requires monthly inspections for a suite of facilities. Specifically, operators must conduct monthly inspections of well production facilities constructed

[62] Gao, M, et al., A Cooperative Model to Lower Cost and Increase the Efficiency of Methane Leak Inspections at Oil and Gas Sites, Elementa: Science of the Anthropocene 11(1) (2023), https://online.ucpress.edu/elementa/article/11/1/00030/197387/A-cooperative-model-to-lower-cost-and-increase-the
[63] Methane Emissions Leadership Analysis, Canadian Methane Jobs Market Analysis (finding that one third of the Canadian companies providing methane emissions management solutions provide field inspection services to help their customers manage fugitive emissions), https://nebula.wsimg.com/66a97d89a3e3a07982edd10c0783d812?AccessKeyId=11FAD840D32A2D9CF9F1&disposition=0&alloworigin=1; See also Datu, Measuring Methane Emissions in the U.S. Oil & Gas Industry: Commercial Capabilities, 2023, https://acrobat.adobe.com/id/urn:aaid:sc:VA6C2:31ec26d5-65fa-4023-944c-6d0e820781a2?viewer%21megaVerb=group-discover
[64] Alberta Energy Regulator, Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace River Area, https://www.aer.ca/regulating-development/rules-and-directives/directives/directive-084
[65] 40 CFR §60.5397c (g)(1)(v)(A).

on or after May 1, 2022,[66] compressor stations with 50 tons per year of fugitive VOC emissions,[67] and well production facilities constructed before May 1, 2022 with either 20 tpy of VOC emissions from storage tanks, or 50 tpy of emissions if no storage tanks are present.[68] Colorado also requires monthly AVO inspections at all existing well production facilities.[69]

These examples demonstrate that operators, or their representative-such as a third-party LDAR contractor-can and do visit their sites at least monthly. Use of third-party contractors hired by more than one operator to inspect facilities in the same geographic area cuts down on travel time and associated emissions, as would installation of continuous emissions monitors.

6. Technologies Used to Conduct Monthly Screenings and Auditor Surveys Must Undergo Transparent Testing to Demonstrate Quantification Capabilities and be Accompanied by Clear Operating Procedures

We urge ECCC to require that any technologies or methods used to conduct monthly screenings and annual auditor inspections undergo rigorous testing to demonstrate that the monitoring approaches can meet the POD and minimum detection levels required by the rules. Testing must be done by independent third parties such as academics or as part of scientific studies rather than the company seeking to use the monitoring method. We also urge ECCC to establish clear operating procedures for the technologies or methods in a separate guidance document. Clear guidance will help ensure technologies and screening methods are deployed properly and thus will increase the reliability and accuracy of measurements.

7. Repairs Timeframes Must be Tightened

ECCC must revise the repair timelines to ensure that operators remediate leaks as quickly as possible. Repair timelines can significantly affect overall mitigation.[70] ECCC has proposed a risk-based approach to repair timeframes that allows repair timeframes between 24 hours to 90 days, depending on whether the repair can be undertaken while the leaking component is operating, whether the operator determines the flow rate of the leak, and the size of the leak if the flow rate is determined.

We support ECCC's proposal to require a 24-hour repair timeframe for leaks whose flow rates are not determined and where it is feasible to undertake the repair (i.e., the repair does not require a shutdown) as well as the 7 and 30 day repair timeframes for larger leaks (i.e., those with a flow rate between 10 kg/h and 100 kg/h and those with a flow rate between 1 kg/h and 10 kg/h). These are consistent with leading international repair timeframes.[71] However, we urge ECCC to remove the 90-day repair timeframe for leaks with flow rates under 1 kg/hr. Other

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[66] Colo. Code Regs. § 1001-9, D.II.E.4.e.(ii)
[67] Colo. Code Regs. § 1001-9, D.II.E.4.f.
[68] *Id*.
[69] *Id*.
[70] *See* Felipe J. Cardoso-Saldaña, *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities* 325 (2022), https://chemrxiv.org/engage/chemrxiv/article-details/636d4595afea7fcd1c9f5f67.
[71] 40 CFR §60.5397b; EU Proposed Rules, Art. 14, para 4a, Annex Ia.

leading jurisdictions require all repairs to be made within 30-days, unless a delay of repair is justified. Specifically:

- **U.S. EPA:** EPA requires leaks detected with OGI or M21 to be repaired within 30 days.[72]
- **EU:** EU similarly has a 30-day repair timeframe[73]
- **U.S. States:** A 30-day repair timeline is feasible and is already required by leading states, like Colorado and New Mexico.[74]

These examples demonstrate operators do not require such prolonged repair timeframes. In addition, ECCC has proposed a separate delay of repair provisions that allows operators up to one year to repair a leak where repair requires a shutdown.[75] This provision provides operators time to undertake repairs where emissions from a shutdown could exceed emissions from remediating a particular leak at a facility.

B. Venting Comments

As ECCC recognizes in the RIAS, available and cost-effective technologies exist that can eliminate venting altogether (e.g., zero emitting pneumatic devices) and numerous practices and technologies can be applied to minimize venting, where elimination of venting is not feasible with current technologies.76 We offer source-specific examples below that support ECCC's proposal to eliminate, or minimize, venting. We note that these examples demonstrate that venting is rarely necessary or justified. Accordingly, below we offer recommendations for narrowing the exceptions to venting-in particular the planned equipment maintenance or planned temporary depressurization of equipment or a pipeline exception and the exception for where use of hydrocarbon gas destruction equipment or hydrocarbon gas conservation equipment would prolong an interruption of the hydrocarbon gas supply to the public. We also urge ECCC to ensure that compliance promotion information and guidance clearly indicates when venting is allowable.

1. Scientific Studies Demonstrate the Need for Robust Measures to Eliminate, or Significantly Reduce Venting

Venting is a pernicious practice involving the direct release into the atmosphere of methane, as well as other harmful pollutants. ECCC proposes to prohibit venting at upstream oil and gas facilities, regardless of the source of venting, other than in the following circumstances:

- Exception 1. Planned equipment maintenance or planned temporary depressurization of equipment or a pipeline;
- Exception 2. To avoid serious risk to human health or safety arising from an emergency situation;

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[72] 40 CFR §60.5397b.
[73] EU Proposed Rules, Art. 14, para 4a.
[74] *See* Colo. Code Regs. § 1001-9-D-II.E.7; N.M. Code R. § 20.2.50.116(E) (2023).
[75] ECCC Proposed Rules, § 8.16, Period for Repair.
[76] ECCC Proposed Rules, RIAS, Regulatory cooperation and alignment section.

- Exception 3. Where the heating value of the hydrocarbon gas or its flow rate are insufficient to sustain stable combustion of the gas by hydrocarbon gas destruction equipment; or
- Exception 4. Where use of hydrocarbon gas destruction equipment or hydrocarbon gas conservation equipment would prolong an interruption of the hydrocarbon gas supply to the public.

Operators that vent during planned equipment maintenance or planned temporary depressurization must take measures to minimize the quantity of gas that is vented.[77] We recommend ECCC clarify that these measures include the use of a temporary compressor or rerouting gas to eliminate the need to purge gas from equipment under maintenance.

Despite ECCC's and current provincial limitations on venting, scientific measurement studies demonstrate that venting remains a considerable source of pollution that is significantly underestimated in operator reports. For example, Festa-Bianchet measured engine shed venting emissions at CHOPs sites , which were approximately 3.9 times greater than reported.[78] Similarly, Conrad et al. measured emissions in Alberta that were 1.5 times higher than reported, stemming from multiple venting sources including separators, tanks, pneumatic devices and compressors.[79] Another study by Conrad et al. measured vented emissions from CHOPs engine sheds, tanks and pneumatics in Saskatchewan and likewise found that emissions were 1.6 times higher than inventory-reported emissions.[80] These studies underscore the need for robust, comprehensive measures that eliminate venting from all sources, wherever feasible, and that minimize any allowable venting.

2. Venting Can be Eliminated from Gas-Powered Pneumatic Controllers

We strongly support ECCC's proposed amendments to prohibit venting which would require owners or operators to replace natural gas-driven pneumatic controllers, or instruments, and pumps with "non-emitting pumps and instruments." The technology and practices to comply with such a requirement are widely available and cost-effective. However, while some facilities that increase gas production would be required to comply with this proposed requirement by Jan. 1, 2027, it would not be until Jan. 1, 2030 that all facilities would be required to install the required "non-emitting" pneumatic instrument and pumps. Not only would this lengthy implementation time result in unnecessary air pollution, including methane and other volatile organic compounds, but it lags behind standards recently finalized by the U.S. EPA. As described more fully below, the U.S. EPA requires much earlier implementation of non-emitting pneumatic equipment and instruments thus delivering critical methane reductions in a timely manner. ECCC must match that ambition.

[77] ECCC Proposed Rules, 49(2)(a)
[78] Festa-Bianchet S A, Tyner D R, Seymour S P and Johnson M R 2023 Methane Venting at Cold Heavy Oil Production with Sand (CHOPS) Facilities is Significantly Underreported and led by High-Emitting Wells with Low or Negative Value, Environ. Sci. Technol. 2023, 57, 8, 3021–3030.
[79] Conrad et al. (2023b), *supra* note 7.
[80] Conrad et al. (2023a), *supra* note 9.

a. The use and availability of non-emitting pumps and controllers to replace pneumatic driven equipment is well demonstrated and supported.

We strongly support ECCC's requirement to prevent venting from pneumatic controllers and pumps by switching to non-emitting equipment. This approach to natural gas-driven pneumatic devices is a logical and cost-effective step that has been taken by jurisdictions and companies globally For example:

- **U.S. EPA:** In December 2023, the U.S. EPA finalized a rule requiring new and existing pneumatic controllers to be zero-emitting.[81] The rule also requires pneumatic pumps at certain facilities –sites with electricity or those with three or more diaphragm pumps – to be zero emitting.[82]
- **Colorado:** Since May 2021, the State of Colorado has prohibited the venting of gas-driven controllers at new and existing facilities. Additionally Colorado required operators to convert specified portions of their facilities to be non-emitting by certain dates in 2022 and 2023.
- **New Mexico:** In 2022, New Mexico required that new pneumatic controllers and pumps be non-emitting, and also required an increasing proportion of exisiting controllers to be converted to non-emitting designs. Operators were required to convert a portion of their emitting pneumatics to non-emitting designs by Jan. 1 2024, with further conversions required by 2027 and 2030. (The 2027 and 2030 provisions will effectively be pre-empted by US EPA's recent rules, which are more stringent in that time period. The 2022 rules also required measures to limit venting from existing pneumatic pumps.[83]
- **EU:** The proposal prohibits venting other than during emergencies or malfunctions, and requires replacement of equipment that vents with non-emitting alternatives when commercially available.[84]

In addition, numerous companies have made commitments or taken action to switch over to zero-emitting controllers in recent years, including:

- **EQT:** The largest natural gas producer in the U.S. recently converted its entire fleet of natural gas-driven pneumatic controllers to zero-emitting devices in the span of approximately one-and-a-half years.[85]

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[81] The U.S. EPA's final rules allow the capture and routing of gas to a process as well as self-contained natural gas-driven controllers to qualify as zero emitting for compliance purposes. *See* 40 C.F.R. § 60.5390b(a) (unpublished as of Feb. 5, 2024).
[82] U.S. EPA's final rules allow gas-driven pumps that are routed to a process or other control means to qualify as zero emitting. Sites with one or two diaphragm pumps and no electricity may still be natural gas-driven, but must route to a process utilizing a vapor recovery unit if such unit is onsite; otherwise such facilities may route emissions to a combustion control device.
[83] N.M. Code R. § 20.2.50.122.
[84] EU Proposed Rules, Article 15, Paras 2 and 4a.
[85] *EQT Eliminate Nearly 9,000 Natural Gas-Powered Pneumatic Devices*, PRNewswire (Jan. 4, 2023) https://www.prnewswire.com/news-releases/eqt-eliminates-nearly-9-000-natural-gas-powered-pneumatic-devices-301713418.html (last accessed Feb. 3, 2024).

- **Diamondback Energy:** Another U.S. producer, Diamondback energy has stated it anticipated replacement of "nearly all" of its controllers with zero-emitting controllers within four years.[86]
- **BP:** In comments submitted to EPA's then-proposed rule, BP stated it anticipated that over 95% of its wells in the Permian basin would use instrument air rather than natural-gas driven pneumatics by 2023.[87]

Collectively, such actions, both at the governmental and business levels, show that ECCC's proposal to eliminate emissions that are associated with venting from pneumatic instruments and pumps is eminently feasible.

b. Datu research report demonstrates strength in the supply chain.

A recent report by Datu Research underscores that the supply chain for the production of zero-emitting technologies is not a barrier for industry-wide adoption of zero-emission controllers and that, on the contrary, the supply chain is strong enough to support widespread conversion to zero-emitting pneumatic equipment.[88] While this report focuses on supply chain issues in the U.S., its demonstration that supply chain issues are surmountable should be largely applicable to Canadian producers as well.

Datu's report identifies forty providers of zero-emitting controllers and surveyed nine.[89] Its interviews with these providers demonstrate that suppliers are well equipped to meet anticipated increased demand for zero-emitting pneumatic equipment. The report's key findings include the following:

- *A well-established, capable set of zero-emission controller providers is in place.* The report identified 40 providers of zero-emitting pneumatic controller equipment, several of which manufacture long-established technologies used across industries. Many of the 40 listed are mature companies that have served the oil and gas industry for decades, with a median 43 years in operation.[90] These companies also serve on average five different industries, indicating providers have a wide demand base.[91]
- *Zero-emission controller components are mature and designed to integrate into existing systems.* Components like electric actuators and instrument air compressors have been in use for decades, and providers of these components emphasize that integrating them into existing natural gas-driven systems is fairly simple.[92]

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[86] Diamondback Energy, *2021 Corporate Sustainability Report* 8 (2021), https://www.diamondbackenergy.com/static-files/faf5ab25-5ab5-4404-8c04-c7bd387ae418.
[87] BP, *Comments on Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review*, 10 (January 31, 2022) (available at https://www.bp.com/content/dam/bp/country-sites/en_us/united-states/home/documents/who-we-are/us-advocacy/2022/bp%20Comments_EPA-HQ-OAR-2021-0317.pdf).
[88] Datu Research, *Zero-emission Alternatives to Pneumatic Control: How Ready are Technology Providers to Meet Increased Demand?* (Jan. 2023).
[89] *Id*. at 5, 9.
[90] *Id*. at 5.
[91] *Id.*
[92] *Id*. at 8.

- *Technology providers already see strong demand for retrofits and new installs*. In their interviews, providers noted that their oil and gas clients are already choosing alternatives to natural gas-driven controllers not only because of anticipated regulations, but also because of the economic benefits – including preserving saleable product, maintenance cost savings, and less downtime – and the safety benefits associated with reducing flammable product in the workplace.[93] Companies are also preferring electronic systems because of their intelligent connectivity capabilities that keep on-the-ground information flowing continuously.[94] Five companies interviewed indicated that 60-90% of their sales were for retrofits.[95]
- *Technology providers have strategies for meeting current supply chain challenges*. Though procurement delays have been a reality for some suppliers, they have employed strategies like paying higher prices, storing extra quantities of supplies, bringing in more procurement personnel, going to different distributors, spot-buying on the open market, and finding contract manufacturing sites. Larger companies reported facing fewer hurdles.[96]
- *Regulatory certainty steadies demand.* Even considering supply chain concerns, providers have confidence in their ability to expand production capacity so long as regulatory certainty helps keep demand steady over multiple years.[97]
- *Increasing demand for zero-emitting alternatives will likely bring innovation and new technology providers*.[98]

The report contains a number of direct quotes from providers illustrating the points above. Below is a small sampling:

- "We supply a lot of valves and pneumatic controls for the valves. They've been around a long time. They're just changing from natural gas actuation to compressed air, and there's no need to change the design; it's a cylinder actuated by pressure, and it doesn't matter whether it's gas or air."[99]
- "We are dealing with such basic materials and longstanding technology. The closest thing to a delay is crossing the [Canada-U.S.] border."[100]
- "We focus on pre-engineered configurations of different physical sizes and that allows us to integrate into different systems. We enable the use of typical off-the-shelf compressors. We have the ability to use a wide range of suppliers for different scales. We can use several manufacturers."[101]
- "It would not take us long to double our output. The skilled labor going into each unit is readily available [and] supply chain . . . will improve over time."[102]

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93 *Id*. at 9.
94 *Id*. at 14
95 *Id*. at 9.
96 *Id*. at 3.
97 *Id*. at 11–12.
98 *Id*. at 12–13.
99 *Id*. at 8.
100 *Id*. at 8.
101 *Id*. at 8.
102 *Id*. at 12.

These findings – individually, and certainly as a collection – indicate that suppliers are currently delivering zero-emitting solutions and prepared to continue to do so at scale. Dozens of providers of zero-emitting technologies are already well-established, many with long-lasting supplier relationships; operators are starting to voluntarily choose alternatives to natural gas-driven controllers for economic and safety reasons; components that have been on the market for decades are easy to integrate into retrofitted systems; and the existing high demand for zero-emitting equipment coupled with regulatory and legislative certainty provided by US and Canadian regulations will give suppliers the demand and confidence needed to commit to contracts and scale up capacity. All of these factors point to a stable, growing supply chain for zero-emitting equipment.

c. ECCC must require earlier implementation for all pneumatic instruments to achieve more timely methane emission reductions.

Though ECCC's proposal rightly recognizes the ability of the industry to use non-emitting technology to eliminate venting emissions from pneumatic instruments and pumps, the implementation timeline falls short of the timeline the U.S. EPA recently finalized. Pursuant to the proposal, it would not be until January 1, 2030 that *all* facilities would be required to address venting emissions from pneumatic instruments and pumps. As proposed, only pneumatic instruments and pumps at facilities that see an increase in gas production in 2027 or 2028 (as compared to a 2024-2026 baseline) would be required to address emissions earlier. Even then, those earlier dates are not until the end of this decade—January 1, 2028 or January 1, 2029. This delayed implementation would result in years of unnecessary vented methane emissions from pneumatic instruments and pumps.

Moreover, ECCC's proposed delay stands out because the U.S. EPA recently finalized standards for new and existing pneumatic instruments (EPA calls them process controllers) and pumps that require replacement with zero-emitting devices on an earlier timeline. For new pneumatic controllers and pumps, the U.S. EPA requires such devices to be zero-emitting in early 2025.[103] Operators must be in full compliance with all other existing pneumatic controller and pumps requirements by early 2029.[104] In some US states, as described above, emissions from pneumatic controllers at new/modificed sites have generally been prohibited for several years. And, as noted above, a number of operators have or are currently replacing existing pneumatic controllers and pumps, well before regulatory requirements kick in, underscoring the industry's ability to perform such replacements well ahead of the proposed timeline. We believe that a four-year timeline to replace pneumatic controllers and pumps is reasonable and prudent and call upon ECCC to require full nationwide adoption of non-emitting pneumatic instruments and

[103] Specifically, the final rule states that operators must comply with new source pneumatic (process) controller requirements 1 year and 60 days after publication in the Federal Register. [40 C.F.R. § 60.5370b(a)(5), (6) – pre-publication version at 903-04.] While publication has not occurred yet, we expect such publication to occur in February 2024, meaning that operators must comply with new source requirements beginning in April 2025.

[104] Existing sources in the U.S. are governed by each state, which is required to 1) submit an implementation plan within 2 years of publication of the rule in the Federal Register, 40 C.F.R. § 5367c, and 2) ensure that such plan will require compliance within 3 years after that submittal deadline, 40 C.F.R. § 5360c, Table 1. Because such publication is expected in February 2024, we estimate full compliance in the U.S. will be required by February 2029.

pumps by no later than Jan. 1, 2028. In any case, there is no reason to allow venting from these devices past the beginning of 2029, when EPA's rules will be fully in place.

3. Venting Can be Minimized from Storage Vessels

Storage tanks can be a significant source of venting. Venting occurs either from uncontrolled storage tanks, i.e., tanks not equipped with conservation or destruction equipment to control flash, working and breathing losses, or from controlled tanks that vent due to improper operation, including where tank controls do not work as intended. ECCC's proposed fugitive emission detection requirements address the latter type of emissions, as comprehensive inspections, screening inspections, and auditor inspections can detect venting due to improperly operating tank controls such as enclosed combustors. Provided the exceptions are applied narrowly, ECCC's prohibition on venting can ensure that most storage tank operators either conserve or destroy tank emissions.

Numerous scientific studies conducted in Canada demonstrate that tank venting is under-reported, representing an opportunity for robust controls on tanks. Conrad et al. found that tanks are one of the largest sources of methane emissions in Alberta, accounting for 25% of the measured inventory.[105] A similar finding exists for tanks in Saskatchewan, where a separate study from Conrad et al. also found that tanks are a major source of venting in the province, accounting for 23% of the measured inventory.[106] A separate study in British Columbia is in accord, finding that 24% of emissions are from tanks.[107] Numerous studies in the U.S. produced similar results.[108]

Fortunately, leading jurisdictions recognize that operators can capture or control emissions from all but the lowest emitting or producing tanks. These regulations demonstrate that the proposal should require that all storage tanks capture or control emissions from flash, working and breathing losses, other than from tanks with very low production where it is not technically feasible to utilize gas destruction or conservation equipment:

- **Colorado:** All new and existing tanks with actual uncontrolled emissions of 2 TPY of VOC (typically, about 0.3 tons of methane, according to U.S. EPA data) or greater are subject to a 95% emissions control limit, with extensive inspection, performance, and compliance requirements.[109] 98% control is required when a combustor is used instead of vapor capture. Open flares are not generally allowed.[110]
- **New Mexico:** All new or modified tanks with the potential to emit 2 TPY of VOC upon start-up must reduce emissions by 95%.[111] Existing tanks with a potential to emit 3 TPY of VOC located at multi-tank batteries, as well as existing tanks with a potential to emit 4 TPY of VOCs at single tank batteries, must also reduce emissions

[105] Conrad et al. (2023b), *supra* note 7, Fig. 3.
[106] Conrad et al (2023a), *supra* note 9, Fig. 3.
[107] Tyner, *supra* note 49.
[108] EDF, Methane research series: 16 studies, https://www.edf.org/climate/methane-research-series-16-studies.
[109] 5 Colo. Code Regs. § 1001-9-D.II.C.
[110] *Id*. at D.II.C.1.b.
[111] N.M. Code R. § 20.2.50.123.A, B.(1).

by 95%.[112] For all tanks, if combustion control devices are used, tanks must have a minimum design combustion efficiency of 98%.[113]

- **Pennsylvania:** All existing tanks at well sites, gathering and boosting segment, and processing plants must control emissions by 95% if emissions are 2.7 tpy of VOC or greater.[114] New tanks are also subject to the 2.7 tpy of VOC threshold.[115]

Additionally, Colorado and New Mexico have other critical measures to prohibit routine venting from many storage vessels. Since 2020 in Colorado[116] and 2022 in New Mexico,[117] both states have required that new and modified tanks be equipped with equipment to allow measurement of the quantity of liquid in the tank without opening the thief hatch; since 2021 Colorado has also required that new tanks have equipment allowing sampling of liquids without opening the hatch.[118] These provisions also include prohibitions on opening the thief hatch for the purposes of gauging, and in the case of Colorado, sampling the liquid in the tank. Both states also have provisions in place requiring control of emissions during liquid transfer from storage tanks into trucks.[119]

4. Venting Can Be Minimized from Pipeline Maintenance Activities, including Pigging and Pipeline and Equipment Blowdowns

Operators conduct a suite of maintenance activities on equipment and pipelines, many of which can be controlled either through practices or equipment that conserves natural gas or through the use of a flare combustion device. We provide examples below of requirements that prohibit venting during maintenance activities, furth underscoring the importance of narrowing the maintenance exception to venting.

a. Pigging

Pigging is a maintenance activity conducted on pipelines to expel liquids from the lines that can inhibit the flow of gas and can contribute to corrosion. If not controlled, pigging activities can lead to the direct release of methane and co-pollutant emissions to the atmosphere. Requirements in other jurisdictions demonstrate that operators can capture or control emissions from most pigging activities, which supports a narrow application of the maintenance exception to pigging activities.

Colorado and New Mexico require owners or operators to capture or control emissions during pigging operations at low emissions control thresholds, again demonstrating that most venting from this source can be abated. Colorado requires operators of natural gas compressor stations in the natural gas gathering and boosting segment and gas processing plants to capture or control

[112] *Id*. at § B.(1).
[113] *Id*.
[114] 25 Pa. Code § 129.123; 25 Pa. Code § 129.133.
[115] GP5 and GP5A; 25 Pa. Code § 129.121; 25 Pa. Code § 129.131. Note that while PA has set a protective limit for VOCs, it has set an unprotective limit for methane that we do not support and is not consistent with EPA's recently promulgated standards for new sources.
[116] 5 Colo. Code Regs. § 1001-9-D.II.C.2.a.
[117] N.M. Code R. § 20.2.50.123.C.
[118] 5 Colo. Code Regs. § 1001-9-D.II.C.4.b.
[119] N.M. Code R. § 20.2.50.120; 5 Colo. Code Regs. § 1001-9-D II.C.5.a.

emissions from pigging units attached to high-pressure pigging pipeline with an outside diameter of twelve (12) inches or greater. Colorado also requires operators of natural gas compressor stations in the natural gas gathering and boosting segment, compressor stations located in the natural gas transmission segment, and gas processing plants to capture or control emissions from pigging units with annual uncontrolled actual emissions equal to or greater than 0.5 tpy VOC or 1 tpy methane on a rolling 12-month basis located in disproportionately impacted communities, or those with annual uncontrolled actual emissions equal to or greater than 1 tpy VOC or 2 tpy methane on a rolling 12-month basis located elsewhere.[120]

New Mexico requires individual pig launcher and receiver operations with a PTE ≥1 tpy VOCs located within the property boundary of, and under common ownership or control with, the well sites, gas processing plants, and compressor stations in the natural gas gathering and boosting segment and transmission segments, to capture and reduce emissions by 95%.[121] If a combustion control device is used, it must have a minimum design combustion efficiency of 98%.

The EU regulations allow for venting or flaring during pigging but only where the gas cannot be contained or redirected into an unaffected portion of the pipeline. Furthermore, if operators wish to vent, rather than flare, they must demonstrate flaring is technically infeasible, risks endangering the safety of operations or personnel, or leads to a worse environmental outcome.[122]

b. Pipeline blowdowns

A suite of practices are available to eliminate or reduce venting during pipeline blowdowns on pipelines in the gathering and boosting and natural gas transmission segments.

Recently updated U.S. federal pipeline legislation contains a self-executing provision that directs pipeline operators to update inspection and maintenance plans to include provisions that minimize releases of natural gas from pipeline facilities.[123] The U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) issued an advisory bulletin in 2021 further clarifying this obligation:

> The PIPES Act of 2020 contains self-executing provisions requiring pipeline facility operators to update their inspection and maintenance plans to address the... minimization of releases of natural gas (including, and not limited to, intentional venting during normal operations) from their systems before December 27, 2021. PHMSA expects that operators will comply with the inspection and maintenance plan revisions required in the PIPES Act of 2020 by revising their operations and maintenance (O&M) plans required under 49 CFR 192.605, 193.2017, and 195.402, to ... minimize releases of natural gas from pipeline facilities.[124]

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[120] 5 Colo. Code Regs. § 1001-9-II.H.1,2.
[121] NMAC 20.2.50.121.A.B.
[122] EU Proposed Rules, Art. 15, para 4.
[123] 49 U.S.C. § 60108(a)(2)(D)-(E).
[124] U.S. Dept. of Transportation, Pipeline and Hazardous Materials Safety Administration, Advisory Bulletin, 2021, https://www.phmsa.dot.gov/sites/phmsa.dot.gov/files/2021-06/PHMSA%20Advisory%20Bulletin%20-%20PIPES%202020%20Section-114_0.pdf

In addition, PHMSA has proposed rules that require operators to choose from a suite of proven options to eliminate or minimize venting during pipeline maintenance activities.[125] These options include:

- installation and use of valves or control fittings to reduce the volume of gas that must be removed from pipeline facility segments. Isolating a shorter segment of pipe results in lower release volumes of natural gas;
- routing vented gas to a flare stack to be ignited or to other equipment to be collected for later use;
- reducing pressure of a pipeline segment prior to venting, thereby reducing total emissions volume. Operators may use a downstream compressor station, mobile compressor unit, or can transfer gas to a lower-pressure pipeline segment;
- alternative approaches provided "the operator can demonstrate that a proposed approach reduces the volume of released gas by at least 50% compared with taking no mitigative action."[126]

Colorado also requires operators eliminate, or reduce, venting during blowdown activities. Colorado has requirements for blowdowns of piping and equipment located at natural gas compressor stations and natural gas processing plants. For facilities located in Disproportionately Impacted Communities,[127] operators must capture and recover hydrocarbon emissions from blowdowns of compressors where the total uncontrolled actual blowdown emissions from all compressors are greater than 0.75 tpy VOC or 1.5 tpy methane on a rolling 12-month basis. Blowdown events from compressors or equipment, where between isolation valves the total volume is less than 50 cubic feet, do not need to be included in emission calculations toward the thresholds nor do they need to be captured or controlled; however, the operator must maintain records of the dates and number of such events.[128]

For facilities not located in a Disproportionately Impacted Community, operators must capture and recover hydrocarbon emissions from blowdowns of compressors, where the total uncontrolled actual blowdown emissions from all compressors are greater than 1 tpy VOC or 2 tpy methane on a rolling 12-month basis.[129] Blowdown events from compressors or equipment, where between isolation valves the total volume is less than 50 cubic feet, do not need to be

[125] PHMSA, Notice of Proposed Rulemaking, 88 Fed. Reg. 31890 et seq., (May 18, 2023), https://www.federalregister.gov/documents/2023/05/18/2023-09918/pipeline-safety-gas-pipeline-leak-detection-and-repair.

[126] *Id*. at 31948.

[127] Colorado defines a Disproportionately Impacted Community as a census block group that satisfies one or more of the following: The proportion of the population living in households that are below two hundred percent of the federal poverty level is greater than forty percent; The proportion of households that spend more than thirty percent of household income on housing is greater than fifty percent; The proportion of the population that identifies as people of color is greater than forty percent; The proportion of the population that is linguistically isolated is greater than twenty percent; or Multiple factors, including socioeconomic stressors, vulnerable populations, disproportionate environmental burdens, vulnerability to environmental degradation or climate change, and lack of public participation may act cumulatively to affect health and the environment and may contribute to persistent disparities. 5 CCR 1001-5, Reg. No. 3, § I.B.23.

[128] 5 CCR 1001-9, Reg. No. 7, Part D, § II.H.1.a.

[129] 5 CCR 1001-9, Reg. No. 7, Part D, § II.H.1.b.

included in emission calculations toward the thresholds nor do they need to be captured or controlled but the operator must maintain records of the dates and number of such events.[130]

Colorado's rules also incorporate best management practices into the rules regarding blowdowns. Midstream segment owners or operators must utilize best practices to minimize emissions from blowdowns during normal operations, including all midstream pipelines not located within the boundaries of a compressor station or processing plant. Where feasible for pipeline blowdowns other than for pigging operations, operators must reroute gas to the low-pressure system using existing piping connections between high- and low-pressure systems, temporarily resetting or bypassing pressure regulators to reduce system pressure prior to maintenance, or installing temporary connections between high- and low-pressure systems. Operators must also create or update operating and maintenance plans to provide for the use, where practicable, of the following best practices. Planning for venting-reduction steps, such as pipeline pump-down techniques (e.g., in-line compressors, portable compressors, ejector), when large vessels and pipelines need to be isolated and depressurized; minimizing the volume that must be released; using inert gases and pigs to perform pipeline purges; hot tapping to make new connections to pipelines; and coordinating operational repairs and routine maintenance to minimize the number of emissions events and volume.

Colorado's rules and PHMSA's proposal demonstrate the suite of available practices to eliminate, or minimize, venting during blowdown activities.

5. Venting of Produced Gas from Oil Wells Is Only Justified in Very Limited Circumstances and for Short Periods of Time

Operators of oil wells may seek to vent, rather than flare, solution or casinghead gas ("produced gas") produced from oil wells. Routine venting, meaning ongoing and continuous venting of produced gas, is never justified, as demonstrated by the regulations discussed below. Temporary venting, during specific activities or for safety, may be necessary in limited circumstances, however any such venting must be time limited.

The EU proposal and the recently finalized U.S. EPA regulations demonstrate that routine venting of produced gas is not necessary under any of the exceptions ECCC proposes. The first two exceptions proposed by ECCC, on their face, apply to temporary, non-routine circumstances (i.e., the first exception is limited to planned maintenance activities and "planned temporary depressurization" activities. The second is limited to safety and emergencies). Ongoing venting is not justified or necessary during the third or fourth exceptions, either, as discussed below.

U.S. EPA prohibits the routine venting of produced gas, demonstrating that routine venting of produced gas is never justified or necessary. EPA only allows for temporary venting of produced gas in the following circumstances and subject to time limits:

- Where necessary for safety, up to 12 hours;
- during bradenhead testing up to 30 minutes, or

[130] *Id.*

- during packer leakage test up to 30 minutes.[131]

In all instances, venting may not exceed 24 hours per incident for any calendar year.[132]

Rather than allowing operators to vent during maintenance activities or during a temporary interruption in service from the gathering or pipeline system, EPA's rules require operators flare or capture the gas.[133] The following table lists the instances when operators may flare, rather than capture, produced gas.

Situations Where Temporary Routing Associated Gas to a Flare or Control Device is Allowed	Maximum Duration
During a deviation caused by malfunction, including for reasons of safety	24 hours
During repair, maintenance including blowdowns, a bradenhead test, a packer leakage test, a production test, or commissioning	24 hours
During temporary interruption in service from the gathering or pipeline system	30 days
If associated gas does not meet pipeline specifications	72 hours

EPA's rules, therefore, demonstrate a narrow application of the venting exceptions to produced gas at well sites that allows operators to vent only for time-limited instances, during specific exceptions. Venting is not allowed during maintenance or during a temporary interruption in service from the gathering or pipeline system, unless necessary for safety.

6. Narrowing the Planned Equipment Maintenance or Planned Temporary Depressurization Exception

ECCC must narrow the maintenance exception. As we point out above, leading regulations demonstrate that operators can capture or control gas during planned maintenance or depressurization activities. While there may be instances involving small amounts of gas that cannot be captured or combusted where operators may need to vent, such venting can and must be the exception, and not the rule. As proposed, the first exception could allow for substantial venting during maintenance and depressurization activities that is preventable. Below, we outline several potential approaches to narrowing this broad exception.

We urge ECCC limit venting during planned equipment maintenance or planned temporary depressurization activities to instances where an operator demonstrates that both conservation and destruction are technically infeasible. As we propose below in the flaring comments, we propose operators submit an annual demonstration of the technical infeasibility of capturing or destroying emissions during maintenance activities, certified by an engineer who is independent from the operator. This demonstration must be made each year the operator intends to vent and must set forth the reasons, with specificity, that capturing or combusting, natural gas during maintenance or depressurization activities is necessary based on technical infeasibility grounds.

[131] 40 C.F.R. § 60.5377b.
[132] 40 C.F.R. § 60.5377b.
[133] 40 C.F.R. § 60.5377b.

Claims of economic infeasibility must not suffice as regulations in other jurisdictions do not allow for venting based on economics.

Alternatively, we recommend ECCC specify, in the final rule, where operators must conserve or destroy, rather than vent, during specific maintenance activities for specific types of equipment. ECCC can use the examples provided above. Examples for other sources, such as liquids unloading and glycol dehydrators, exist in requirements adopted in multiple U.S. jurisdictions, including U.S. requirements. Setting forth specific rules that require capture or combustion of natural gas from specific activities and equipment sets clear rules that operators can follow and are less likely to abuse than a broad exemption for maintenance and depressurization activities.

7. ECCC Must Remove, or at Least Narrow the Applicability of the Fourth Exception

Lastly, we urge ECCC to remove or significantly narrow the 4th exception where venting is allowed if "the use of hydrocarbon gas destruction equipment or hydrocarbon gas conservation equipment would prolong an interruption of the hydrocarbon gas supply to the public."[134] We understand this exception is meant to apply in instances where an upset condition or some other type of malfunction at a facility could impact a pipeline operator's delivery of natural gas to downstream users.

EPA rules demonstrate that operators can flare, rather than vent, during upset conditions that can impact pipeline operators. EPA does not allow venting during a temporary interruption in service from the gathering or pipeline system. EPA allows for flaring during such an event, however, limits flaring to no more than 30 hours.[135]

Both New Mexico and Colorado allow operators to vent or flare for a limited period of time in the event of loss of a connection to a gathering line. Colorado allows for venting or flaring up to 24 cumulative hours pursuant to its Upset Condition exception.[136] New Mexico allows for venting or flaring up to 8 hours pursuant to its emergency exception.[137]

We suggest ECCC remove the fourth exception, or at a minimum, clarify that the exception only applies to venting from transmission facilities, and impose a strict time-limit on venting, consistent with what Colorado and New Mexico have implemented.

C. Flaring Comments

[134] ECCC Proposed Rules, para. 49(2)(d).
[135] 40 C.F.R. § 60.5377b.
[136] Colo. Oil & Gas Conservation Comm., Statement of Basis, Specific Statutory Authority, and Purpose: New Rules and Amendments to Current Rules of the Colorado Oil and Gas Conservation Commission, 800/900/1200 Mission Change Rulemaking at 76, (Dkt. No. 200600115), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/800-900-1200MissionChangeDraftSBP.pdf [hereinafter "Colo. 800/900/1200 SBP"].
[137] N.M. Code R. §§ 19.15.27.7.H.(4).

We urge ECCC to strengthen its requirements applicable to flaring to prohibit routine flaring of natural gas, impose time limits on specific types of flaring, and strengthen the technical infeasibility demonstration.

ECCC has proposed two requirements to address flaring. First, any flaring must be supported by an engineering study demonstrating that use of the hydrocarbon gas to produce useful heat or energy is not feasible in the circumstances.[138] The exception to this is flaring necessary for safety. The second flaring requirement is that hydrocarbon gas destruction equipment must have a combustion system that has a pilot flame, an automatic ignition device and an automatic flame failure detection system and a carbon conversion efficiency of at least 98%. Catalytic oxidation systems with carbon conversion efficiency of at least 85% have separate requirements.[139]

We urge ECCC to strengthen the flaring provision that allows operators to flare if supported by an engineering study demonstrating that use of the hydrocarbon gas to produce useful heat or energy is not feasible. We have serious concerns with this proposal as it applies to routine flaring of produced gas. Routine flaring, "meaning ongoing, continuous flaring in the absence of a method for capturing and selling, putting to beneficial use, or storing associated gas,"[140] does not represent international best practice as demonstrated by requirements in leading U.S. jurisdictions, proposed in the EU and various commitments made by leading oil and gas companies.

We support ECCC's strong requirements for hydrocarbon gas destruction equipment. Regulations in leading U.S. states and in EU's proposed regulations demonstrate that destruction equipment is available that can meet efficiencies of 98% or better, and that can be equipped with a combustion system that has a pilot flame, an automatic ignition device and an automatic flame failure detection system.

1. Routine Flaring Does Not Represent Best Practice

Numerous leading companies, and consortiums of companies, have agreed to eliminate routine flaring. The World Bank's Zero Routine Flaring by 2030 Initiative "brings together governments, oil companies, and development institutions who recognize [routine flaring] is unsustainable from a resource management and environmental perspective, and who agree to cooperate to eliminate routine flaring no later than 2030."[141] As of 2022, there were 54 oil companies representing almost 60 percent of total global gas flaring that have committed under the Initiative to avoid routine flaring at new fields and end ongoing routine flaring by 2030.[142] Another industry group, the Texas Methane and Flaring Coalition, consisting of seven state trade

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[138] ECCC proposed Rules, para. 47, 4032
[139] ECCC proposed Rules, Amendment 46.
[140] EPA rules, Unoffiicial draft, p. 475.
[141] The World Bank, Zero Routine Flaring by 2030 (ZRF) Initiative https://www.worldbank.org/en/programs/zero-routine-flaring-by-2030/initiative-text
[142] The World Bank, Global Initiative to Reduce Gas Flaring: "Zero Routine Flaring by 2030" List, https://thedocs.worldbank.org/en/doc/a903b5e6456991faf3b5e079bba0391a-0400072021/related/ZRF-Initiative-text-list-map-104.pdf

associations and over 40 Texas operators, has stated that "The Coalition agrees we should strive to end routine flaring…."[143] Exxon has halted all routine flaring in the Permian Basin.[144]

In addition, many jurisdictions prohibit routine flaring as demonstrated below:

- **EU:** The EU proposal does not allow for routine flaring.[145]
- **EPA**: EPA's final rules forbid routine flaring from new wells beginning in mid-2026.[146] EPA also found that multiple abatement options are available to operators that can capture rather than release associated gas. Even where EPA allows for flaring, EPA recognizes that the best system of emission reduction is routing associated gas to sale.[147]
- **Alberta (Peace River region):** Routine venting of solution gas is not allowed, non-routine flaring is limited to 3% of total annual gas production volumes, and conservation rates at heavy oil and bitumen wells and facilities must exceed 95%.[148]
- **State Rules:** Several major oil and gas producing states–New Mexico, Colorado, and Alaska–have recognized that routine flaring is no longer either acceptable or necessary and have adopted regulations that effectively prohibit the practice. In 2020, Colorado adopted regulations that prohibit venting and flaring during oil and gas production except as allowed by specified exemptions for temporary activities such as upset conditions and pursuant to a one-time, time-limited advance approval by the regulator under specified conditions.[149] New Mexico adopted regulations in March 2021 that similarly prohibit routine venting and flaring during production other than during specific temporary exemptions.[150] In addition, Alaska has severely restricted routine flaring for decades through regulations that treat as waste venting or flaring that continues after one hour, absent regulatory approval.[151]

As the commitments of many oil and gas companies, and leading jurisdictional requirements demonstrate, routine flaring is readily preventable. In order to remain carbon competitive with other producing basins, the goal should be the prohibition of routine flaring as a practice.

2. Cost Effective Solutions Exist to Eliminate Routine Flaring and Venting, and Significantly Reduce Temporary Venting and Flaring

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143 Texas Methane and Flaring Coalition, Flaring Recommendations and Best Practices, 2 (June 16, 2020), https://texasmethaneflaringcoalition.org/wp-content/uploads/2020/06/6-16-20-TMFC-Flaring-Recommendations-Best-Practices-Report.pdf.

144 Sabrina Valle, *Exclusive: Exxon halts routine gas flaring in the Permian, wants others to follow* (Jan. 24, 2023), https://www.reuters.com/business/energy/exxon-halts-routine-gas-flaring-permian-wants-others-follow-2023-01-24/.

145 Proposed EU Rules, Art. 15, para. 1.

146 40 CFR §60.5377b.

147 EPA Final Rule, p. 487 & 494 of Internet version.

148 Alberta Energy Regulator, *Directive 084: Requirements for Hydrocarbon Emission Controls and Gas Conservation in the Peace* River *Area* (2018). https://static.aer.ca/prd/documents/directives/Directive084.pdf

149 2 Colo. Code Regs. 404-1 § 903d.

150 New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A).

151 Alaska Administrative Code, 20 AAC § 25.235.

Reports produced by various consulting firms and consultants underscore the availability of multiple cost-effective technologies to capture produced gas.

- **Dunsky:** EDF commissioned Dunsky Energy & Climate to analyze the most cost-effective pathway for Canada's upstream operators to achieve a 75% reduction in methane emissions below 2012 levels. The Dunsky report found casinghead gas recovery at crude bitumen sites to be one of the most cost-effective measures to reduce methane at oil sites. Per the report, operators can capture casinghead gas at crude bitumen sites for approximately $40 per ton of CO2e and connecting to a sales line at an oil battery can be achieved for a cost of $1,836.[152]
- **Rystad Energy:** A separate report,[153] conducted by Rystad Energy of flaring practices and flaring abatement costs in the U.S. states of North Dakota, Texas, New Mexico, Colorado and Wyoming also found that routine flaring can be avoided by implementing one of several cost-effective abatement options, discussed below.
- **New Mexico Methane Advisory Panel:** The state of New Mexico convened a panel of experts from industry, ENGOs, and the public sector, to identify cost-effective solutions to abate methane emissions. The report identified compressing associated gas into CNG for transport and sale as a cost-effective alternative to venting or flaring of associated gas.
- **Thomas M. Alexander:** Mr. Alexander, a former oil and gas executive with over 18 years of experience working in the oil and gas industry, submitted an expert report to EPA supportinga rule that requires operators to capture associated gas from oil wells, other than during temporary, limited exceptions.[154]

a. Routing to a Sales Line

Connecting wells to gathering infrastructure is not only highly cost-effective but profitable for operators, with an average net profit to operators of $3.10 per thousand cubic feet (kcf) and average negative cost of $162 per metric ton of methane flaring avoided.[155] Operators will pay between $0.40 and $1.20 per kcf handled by third party processing and gathering, netting profit after gas sales of $2.70 to $3.50 per kcf.[156] This corresponds to a range of negative $141-183 per metric ton of methane abated.[157] Gathering is an effective and available option for sites flaring any amount of gas.[158]

b. Truck Transport/Compressed Natural Gas

In cases where existing well sites lack adequate existing gathering system infrastructure, or where gathering systems are at capacity on a temporary or ongoing basis, well operators may

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152 Dunsky, Figure 5, p.8 and p.20. Figures are in Canadian dollars.
153 Rystad Energy, Cost of Flaring Abatement, Final Report, Jan. 31, 2022 (hereinafter "Rystad Report"), https://blogs.edf.org/energyexchange/wp-content/blogs.dir/38/files/2022/02/Attachment-W-Rystad-Energy-Report_-Cost-of-Flaring-Abatement.pdf. All figures are in U.S. dollars,
154 Expert Report of Thomas Michael Alexander, Alexander Engineering, Feb. 9, 2023, Exhibit 1.
155 Rystad Report, at 11.
156 *Id*. at 45.
157 *Id.*
158 *Id.* at 40.

choose to forego construction of additional gathering capacity or coordination with third-party gatherers and instead convert associated gas onsite into compressed natural gas (CNG)[159] and transport it by road in specialized tanker trucks.[160] The trucks transport the gas to processing plants, where the gas is prepared to meet pipeline requirements.[161] Trucking can be both a long-term option for existing wells lacking adequate gathering line infrastructure or capacity, and a short-term solution in cases of low capacity due to outages, maintenance activities, or temporary system overload—either at the processing plant (in which case trucks could transfer the gas to an alternative plant) or on the gathering system (in which case the trucks can bypass the initial pipelines and transfer the gas directly to the plant).[162] Rystad's report finds that on average, CNG trucking will cost operators $1.8/kcf, or $94 per MT of methane flaring avoided.[163]

A report from the New Mexico state Methane Advisory Panel, specifically examining CNG trucking, found that CNG trucking is a "portable, scalable and low or negative cost" approach to gas capture.[164] Indeed, as noted above, in many cases truck transport ultimately presents little or no additional cost to well operators because operators will incur only minimal net costs or achieve net benefits by reselling the gas. Various factors play into the total expense of a trucking operation, including distance traveled. The New Mexico report, for instance, found that trucking is most efficient when well sites are within 20-25 miles of a processing plant.[165] For CNG, operators must purchase an onsite compressor, the total one-time cost of which can be approximated at $200,000 for the equipment and $50,000 for the installation.[166] Operators will also need to pay the truck drivers, and may need to lease the appropriate trucking assembly.[167]

c. Reinjection

In some circumstances, well operators may prefer to reinject associated gas. Reinjection is used widely in Alaska, where 90% of associated gas is injected into oil-bearing formations.[168]

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[159] As discussed in the Rystad Report at 10–11. LNG trucking is another option for gas transport. However, at this time we lack adequate data on overall emissions associated with LNG trucking to determine whether this would be an appropriate approach to emissions mitigation.

[160] *See* Anders Pederstad, Martin Gallardo, and Stephanie Saunier, Improving Utilization of Associated Gas in U.S. Tight Oil Fields, Carbon Limits AS (Prepared for Clean Air Task Force) (Oct. 2015), https://www.catf.us/wp-content/uploads/2015/04/CATF_Pub_PuttingOuttheFire.pdf at 33 [hereinafter Carbon Limits].

[161] *See id.*

[162] *Id.* at 33.

[163] Rystad Report, at 39. Rystad further finds that LNG trucking will cost $5.6/mcf, or $292 per MT of methane flaring avoided. *Id.*

[164] *See* New Mexico Environment Department & New Mexico Energy, Minerals and Natural Resources Department: Methane Advisory Panel (2019), https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/OCD-Exhibit6-NMENRDNMED-MethaneAdvisoryPanel-Technical-Report.pdf [hereinafter Methane Advisory Panel] at 178. In March of 2021, the state of New Mexico joined Colorado in implementing regulations which banned flaring except in limited circumstances. *See generally* New Mexico Administrative Code, Venting and Flaring of Natural Gas, § 19.15.27.8(A) (accessible at https://www.emnrd.nm.gov/ocd/wp-content/uploads/sites/6/Part27-FinalRule3.25.21a.pdf). Figures are expressed in U.S. dollars.

[165] *See* Methane Advisory Panel at 173, 178.

[166] ICF INTERNATIONAL, Breakeven Analysis for Four Flare Gas Capture Options, 4 (Apr. 22, 2016) [hereinafter ICF].

[167] *See id.*

[168] *See* EIA, *Natural Gas Weekly Update: Alaska Natural Gas Infrastructure* (May 27, 2021), https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/05_27/ (last accessed Apr. 18, 2023).

Reinjection as a method of gas capture has significant emissions reduction benefits, because it largely eliminates emissions of methane and other pollutants.[169] Operators choosing to reinject associated gas may do so either by drilling a new injection well or by reappropriating an existing inactive production well.[170] Shale reservoirs are particularly well suited to injection because of their large storage capacity: "nanopores" in the rock formation can trap and store greenhouse gasses in an absorbed state.[171] Associated gas may also be injected and stored in natural aquifers, which may be suitable for gas storage when the sedimentary rock formation is overlaid with impermeable "cap" rock,[172] or in salt caverns.[173] Reinjection costs vary depending on various factors, but Rystad finds that on average, costs are $3.4/mcf, and $177 per MT of methane flaring avoided.[174]

d. Use Onsite as a Fuel Source or Gas-to-Wire

In addition to the various methods of gas capture and redirection explored above, well operators can use associated gas for power needs on site, and implement a gas-to-power system for local loads.[175] For wells that are not yet connected to the power grid, on-site gas-to-power technology can replace the diesel generators that would otherwise be used to power operations.[176] This is very beneficial from an emissions perspective, since diesel is a highly polluting fuel that results in elevated levels of nitrogen oxides, particulate matter other and toxic pollutants.[177] It can also provide significant cost saving, because purchasing and transporting fuel from offsite carries a significant cost. As a result, Rystad reports that fully displacing diesel with associated gas for power demand at the well amounts to $7-$10/mcf saved–subtracting the cost of power generator and treatment and assuming 50 mcf per day of power used.[178] Rystad estimates that on average, on-site use of gas nets a profit of $8.60/mcf.[179] This makes it a compelling alternative to routine flaring.

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[169] *See* Fengshuang Du and Bahareh Nojabaei, *A Review of Gas Injection in Shale Reservoirs: Enhanced Oil/Gas Recovery Approaches and Greenhouse Gas Control*, MDPI: ENERGIES (June 19, 2018), https://www.mdpi.com/1996-1073/12/12/2355 at 25.

[170] See Sadiq J. Zarrouk & Katie Mclean, "Geothermal Wells", Geothermal Well Test Analysis, 39-61, 54 (2019) ("Geothermal reinjection wells [including gas reinjection wells] are generally designed and drilled to the same standards as production wells. In some fields, reinjection wells have been converted to production wells and vice versa.")

[171] Fengshuang Du & Bahareh Nojabaei, A Review of Gas Injection in Shale Reservoirs: Enhanced Oil/Gas Recovery Approaches and Greenhouse Gas Control, 25 (2019) https://www.mdpi.com/1996-1073/12/12/2355. *See also* Yuan Chi , Changzhong Zhao, Junchen Lv, Jiafei Zhao and Yi Zhang, Thermodynamics and Kinetics of CO2/CH4 Adsorption on Shale from China: Measurements and Modeling, MDPI: ENERGIES (Mar. 13, 2019) at 1, https://www.mdpi.com/1996-1073/12/6/978.

[172] *See* EIA, The Basics of Underground Natural Gas Storage (Nov. 16, 2015), https://www.eia.gov/naturalgas/storage/basics/ (last accessed Apr. 18, 2023).

[173] *See id.*

[174] Rystad Report at 69.

[175] Pederstad et al., *supra* note 160, at 38.

[176] *Id.* at 36. *See also* Rystad Report, at 51.

[177] *See* EPA, About Diesel Fuels (last accessed April 14, 2023), https://www.epa.gov/diesel-fuel-standards/about-diesel-fuels.

[178] Rystad Report, at 51.

[179] *Id.* at 11.

Another option is to use the associated gas to power a small electricity generation plant that sends power to the grid.[180] This approach requires an ongoing supply of a relatively large quantity of gas to make the necessary investments worthwhile, so it is not suitable for every application.[181] But where the gas volumes and grid access are available, it can also be a net negative cost option.[182]

Similarly, a former Southwestern Energy Vice President, Thomas Alexander, submitted an expert report to EPA supporting strong rules that prohibit routine flaring.[183] Mr. Alexander's report demonstrates that routine flaring can be avoided using the technologies summarized above, proper planning, and temporary well shut-ins.[184] Mr. Alexander noted that "it is rare that shutting in a well will adversely affect short to long-term performance. Conversely, in some cases, shutting in can enhance performance."[185]

3. Routine flaring at New Wells is Entirely Preventable

We urge ECCC to prohibit routine flaring at new wells. Operators of new wells have the ability to plan in order to ensure conservation of produced gas.

The Rystad report makes clear that the main drivers of routine flaring are timing of well hookups and infrastructure capacity.[186] Proper planning can allow for coordination between well site operators and pipeline facility operators to ensure adequate takeaway capacity and gas processing capacity.[187] Operators of new wells have the ability to address both timing and infrastructure capacity challenges and therefore routine flaring from such wells need not ever occur. As such, operators of new wells have the ability to address both timing and infrastructure capacity challenges. EPA's final rule reflects this fact. EPA received extensive information during the comment period to the rule regarding alternatives to routine flaring, state-level requirements to limit or prohibit routine flaring, and commitments that owners and operators have already made voluntarily to phase out routine flaring in the near future. Based on this information, EPA's final rule requires a phase out and eventual prohibition on routine flaring of associated gas from newly constructed wells that are developed after the effective date of this rule.[188]

4. Routine Flaring at Existing Wells Can be Eliminated or Controlled

Routine flaring from existing wells is also avoidable or preventable.[189] In the event an existing well is not currently connected to a gathering line, cost-effective options to manage the gas are available. These options include converting the associated gas to compressed natural gas (CNG), using it to replace a different fuel source for onsite fuel purposes, converting the gas to

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[180] *Id.* at 72.
[181] *See id.*
[182] *See id.*
[183] Expert Report of Thomas Alexander, *supra* note 154.
[184] *Id*. at 4.
[185] *Id*. at 3.
[186] Rystad Report, at 8 (noting that infrastructure capacity constraints account for 84% of flaring in North Dakota and 62% of flaring in Texas).
[187] *Id.*
[188] Exec. Summary, §A., p. 22-23 of Internet version of rule.
[189] *Expert Report of Thomas Alexander*, *supra* note 154, at 4; EPA Final Rule, p. 473 of Internet version.

electricity, or reinjecting the gas into the well.[190] Prudent operators are prepared for events that can result in loss of takeaway capacity such as midstream and downstream interruptions, changes in gas composition requirements, and changes in line pressure.[191] Such operators can quickly employ one of the alternative abatement options above, or flare temporarily.[192]

In the event an operator loses its connection to a gathering line without warning due to events outside its control, a limited exception for flaring during the upset condition can address an operator's need to flare temporarily.[193] Operators can also temporarily shut in wells if time is needed to restore access to a pipeline or arrange for alternative gas recovery. Shutting in wells does not necessarily harm the productivity of a well and may, in some instances, enhance performance.[194]

We urge ECCC to prohibit routine flaring from all wells, to align with the EU proposal and rules adopted by Colorado and New Mexico– which categorically prohibit routine flaring from existing wells. Alternatively, we urge EPA to prohibit routine flaring from new wells, as EPA has done.

5. Engineering Demonstration Must be Strengthened.

In the event ECCC does not prohibit routine flaring, we recommend revisions to the engineering study provision. ECCC proposes that any flaring, other than safety flaring, must be supported by an engineering study that concludes that the use of the hydrocarbon gas to produce useful heat or energy is not feasible in the circumstance. We recommend ECCC improve the rigor and enhance the enforceability of this exemption by: (1) requiring that an independent third party certify the infeasibility study; (2) requiring operators to submit detailed, certified technical infeasibility documentation at least annually if they intend to flare; (3) defining "infeasibility" to mean "technically infeasible" not economically infeasible; and (4) requiring operators to maintain records and report the amount of flaring that occurs. Better clarifying this language will also give operators greater confidence that their operations align with the regulations.

a. ECCC Should Require Certification by an Independent Third Party and Clarify Potential Enforcement Actions for Submission of Fraudulent Certification

We recommend that ECCC require certification by an independent third party. ECCC has proposed to allow a demonstration of infeasibility based on an engineering study. There is no requirement that the engineer be independent from the operator, nor that the study be certified as to the truth, completeness, and accuracy of its contents. We recommend ECCC require certification by an independent third party, not an in-house individual or a person with significant

[190] *EPA at 476;* Rystad Report, at 8, 10-11.
[191] *Id.*
[192] *Id.*
[193] *Expert Report of Thomas Alexander*, *supra* note 154, at 4–5.
[194] *Id.* at 3.

ties to the company. This will enhance the credibility and reliability of the report.[195] Certification by an independent third party of all demonstrations seeking a flaring exception is necessary to ensure a robust, complete, and accurate demonstration of the reasons underlying the flaring request.

b. Operators Must be Required to Submit a Certified, Thorough Analysis of the Technical Feasibility Each Year if they Intend to Flare

Operators seeking to routinely flare must submit a thorough analysis and engineering certification each year. This demonstration should include a detailed analysis documenting the technical infeasibility and an explanation as to why there are no technically feasible conservation options available. If the operator requests permission to flare produced gas, the operator must demonstrate that none of the abatement options discussed above, i.e., routing to sales, using it as an onsite fuel source, using it for another useful purpose that a purchased fuel or raw material would serve, or reinjecting the gas, are technically feasible.

EPA requires operators to certify annually the reasons for flaring produced gas from wells with produced gas greater than 40 tpy of methane. This is because EPA found, "routing associated gas to a sales line is an adequately demonstrated method for reducing methane emissions," and "the cost effectiveness of routing the gas to a sales line for wells with associated gas containing greater than 40 tpy methane is at levels considered reasonable by the EPA, especially in situations where the well is relatively near the gathering system."[196]

c. ECCC Should Clarify that Infeasible Means Technically Infeasible

We recommend ECCC clarify that "not feasible" refers to technical infeasibility, not economic infeasibility, at least where operators wish to flare produced gas on an ongoing basis. As discussed above, EPA either prohibits routine flaring, or where it is not prohibited, EPA only allows operators to flare based on a certification that all of the abatement options discussed above are technically infeasible. ECCC should require records and reporting of flared amounts.

d. Additional Records and Reporting

Finally, we recommend additional recordkeeping and reporting requirements to bolster the enforceability of the demonstration and prevent abuse of the exemption. These recommendations are based on requirements in Colorado[197] and New Mexico.[198] Specifically, we recommend that operators' initial and annual demonstrations include an estimate or measurement of the volume and content of vented or flared gas. This information should also be provided in the operator's annual report. As Colorado regulators have found, requiring records of the estimated duration

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[195] Maureen Lackner & Kristina Mohlin, Env't Def. Fund, *Certification of Natural Gas With Low Methane Emissions: Criteria for Credible Certification Programs* 11 (2022), https://blogs.edf.org/energyexchange/files/2022/05/EDF_Certification_White-Paper.pdf (Attachment W).
[196] EPA Final Rule, p. 494 of Internet version.
[197] 2 Colo. Code Regs. § 404-1-903.d.(2) (2023).
[198] N.M. Code R. § 19.15.27.8.G.(2) (2023).

and time of flaring helps prevent abuse and enhances enforcement.[199] Flaring data should also be publicly disclosed.

D. Alternative Compliance Pathway

ECCC must remove the alternative compliance pathway that allows operators to opt out of the fugitive emissions, venting and flaring provisions if they install a continuous monitor. We have serious concerns with this proposal. First, while continuous monitors are a very promising technology, recent scientific studies indicate that they are not presently accurate at quantifying emissions.[200] A recent study by Bell et al., found that "The large variability in performance of continuous monitor solutions, coupled with highly uncertain detection, detection limit, and quantification results, indicates that the performance of individual continuous monitor solutions should be well understood before relying on [their] results."[201] Similarly, a study conducted by Standford University found "Among 5 [continuous monitoring] systems tested for quantifying the daily average emission rate release by the Stanford team, all underestimated by an average of 74.38% emissions. This indicated that their application in emissions reporting or regulation may be premature."[202] Tying Canada's necessary 75% GHG reduction goal to the successful implementation of one type of technology that is still being tested and developed, and which has been shown to be poor at quantification of emissions, inputs too much uncertainty into the achievement of this goal. Rather than allowing operators to rely solely on the installation of continuous monitors to achieve critical methane reductions, we suggest ECCC include continuous monitors as one of the permissible options operators may use when conducting fugitive emissions inspections. We offer recommendations below on ways ECCC can strengthen the continuous monitoring system requirements, and how ECCC can incorporate continuous monitors into the fugitive emissions inspection program.

Secondly, we do not support regulatory frameworks that rely solely on operator compliance with performance standards, particularly in the absence of rigorous monitoring, measurement, reporting and verification requirements. Work practice standards and emissions limitations are tried and true regulatory standards that have achieved significant emissions reductions in the past. We urge ECCC to require operators to comply with proposed venting and flaring requirements, subject to the improvements we recommend above, and conduct either frequent instrument-based inspections or install continuous monitors, or a combination of both. For example, the State of Colorado is currently developing an Intensity Verification protocol, that will require operators to verify their emissions based on a measurement informed inventory, with continuous monitoring systems likely being one of the acceptable measurement technologies.[203] However, this verification program is built on already existing and robust work practice standards, will include rigorous monitoring, reporting and verification requirements, and the deployment of a measurement program does not exempt operators from complying with work practice standards.

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[199] Colo. 800/900/1200 SBP, *supra* note 136, at 78.
[200] Bell, et al., Performance of Continuous Emission Monitoring Solutions under a Single-Blind Controlled Testing Protocol, Environ. Sci. Technol. 2023, 57, 14, 5794-5805, March 28, 2023.
[201] *Id*.
[202] Chen et al., Comparing Continuous Methane Monitoring Technologies for High-Volume Emissions: A Single-Blind Controlled Release Study, (Jan. 2024). https://eartharxiv.org/repository/view/6569/.
[203] 5 CCR 1001-9, § B.VIII.F.

1. Continuous Monitors Should be One of the Options Operators Can Use to Fulfill Fugitive Emissions Inspections

We urge ECCC to finalize a pathway that allows operators to use continuous monitors as one of the ways operators inspect for fugitive emissions. To do so, ECCC could allow operators to install continuous monitors in lieu of or in addition to conducting monthly screenings or required OGI inspections. There is precedent for this approach:

- **EPA:** Allows operators to install continuous monitoring in lieu of or in combination with required OGI or AVO inspections. EPA permits systems with detection thresholds of 0.40 kg/hr of methane or lower. Systems must transmit data at least once every 24 hours. EPA has established short- and long-term action levels and timeframes for operator responses to detected emissions. Wellhead-only well sites action-levels are as follows: rolling 90-day average of 1.2 kg/hr of methane over the site-specific baseline; rolling seven-day average of 15 kg/hr of methane over site-specific baseline. Well sites with major production and processing equipment, small well sites, centralized production facilities, and compressor stations action levels: rolling 90-day average of 1.6 kg/hr of methane over the site-specific baseline; rolling seven-day average of 21 kg/hr of methane over the site-specific baseline.
- **Colorado:** Has approved several types of continuous monitors for use as an alternative to required OGI or M21 inspections.[204]
- **EU:** Allows operators to apply to use advanced detection technologies; however all advanced detection technologies must be capable of taking measurements at the level of each individual potential emission source[205] which could prohibit the use of continuous monitors unless operators can use a combination of technologies (e.g., source-level measurements + continuous emissions monitors).

If ECCC allows operators to use continuous monitors as part of its program for identifying fugitive emissions, it must set forth specific system and operating requirements in the rule that ensure continuous monitors achieve equivalent emissions reductions as the required OGI or screening approaches. This can be done with modeling, such as the FEAST model.

2. Recommended System Requirements

We suggest several improvements to the proposed system requirements to ensure the accuracy of the system, if ECCC accepts our recommendation and allows operators to use continuous monitors as part of the fugitive emission monitoring requirements, or in the event ECCC retains the alternative compliance pathway. First, any continuous monitoring technology should be validated to meet the 90% probability of detection at1 kg/hr requirements in a reasonable period of time. The technology must be proven to be able to meet this standard in the real world, as discussed below. Appropriate ways to validate the capabilities of the technology include published reports or scientific reports demonstrating the technology has been independently

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[204] For example, Colorado has approved a continuous OGI system, "Clean Connect", as a means for operators to inspect for fugitive emissions, in lieu of the required OGI or M21 inspections. https://cdphe.colorado.gov/oil-and-gas-and-your-health/approved-instrument-monitoring-method-aimm-for-oil-gas

[205] EU Proposed rules, Art. 14, para. 2f.

evaluated at the given site type (e.g., compressor station, oil or gas well site, etc.) for which the operator plans to deploy the system and blinded controlled release testing. A system may work differently at different facility types, depending on e.g. site complexity and equipment present, site topology, presence of hot exhaust or equipment causing convection, weather conditions, etc., and thus it is important that an operator demonstrate the particular system they plan to deploy has been tested or demonstrated to be reliable at the specific type of facility at which the operator intends to deploy the system.

Second, we recommend ECCC require sensor readings every 1-2 minutes. ECCC has proposed sensors provide readings at least once every 15 minutes for Type 1 facilities and at least once every 12 hours for Type 2 Facilities. Most continuous monitors can put out concentration readings every 1-2 seconds.

Third, operators must be required to first test the technology at each particular location they wish to deploy the technology before deploying it. This is very important as the exact wind pattern, site layout, and sensor layout and sensor quantity will directly impact detection capabilities.

V. Measurement and Reporting

As international policy for oil and gas methane rapidly evolves, leading nations are recognizing that measurement, monitoring, reporting, and verification (MMRV) are critical components of effective regulation. The proposed amendments strengthen Canada's approach to monitoring and verification by introducing a comprehensive fugitive emissions detection and repair program, as well as a requirement for independent audit. However, the amendments do little to move Canada away from outdated and inaccurate bottom-up estimation or to improve Canada's minimal reporting requirements. These are areas in which Canada's policy approach is quickly and clearly falling behind other global leaders.

The amendments to the methane regulations present an important opportunity for Canada to require a shift toward a measurement-based inventory and greater accountability through improved reporting. A strong, measurement-based reporting system is necessary to assess operator compliance, to maintain an accurate national inventory, and to ensure that provincial equivalency agreements are robust.

As many sources of existing measurement data suggest higher methane emissions than reported, it is likely that ECCC's estimated abatement cost of $71 per metric ton CO_2e is an overestimate. For example, best available data from a Bridger-based hybrid inventory compiled by EDF suggest annual emissions of about 21 kt/y from glycol dehydrators and 360 kt/y from pneumatic instruments and devices.[206] In comparison, ECCC's annual average reduction from 2027-2040 is about 6 kt/y for dehydrators and 130 kt/y for pneumatics.[207] If we assume that a large share of these emissions can be abated over the 14-year period in the RIAS, this could translate to roughly a 3-fold increase in abatement potential for glycol dehydrators and a 2.5-fold increase in

[206] Estimates from Johnson et al. (2023); Conrad et al. (2023a), *supra* note 9; and Conrad et al. (2023b), *supra* note 7. We highlight these sources as they are close to being direct comparisons with ECCC's sources. Note that Bridger relies on emissions factor estimates for pneumatics. However, we believe these higher estimates offer a more accurate picture of emissions.
[207] Estimates derived from ECCC Proposed Rules, RIAS, Table 12

abatement potential for pneumatics. Accounting for this increased abatement potential could have large impacts on compliance costs. Accounting for measured emissions from these sources alone would shift compliance costs (not including administrative costs) from $70 metric ton CO_2e abated to about $52 per metric ton of CO_2e.

The proposed amendments neglect to address measurement and reporting — a significant oversight we urge be rectified with a provision in the final regulation that spells out specific and comprehensive data that producers must provide that will help form the pillars of a minimally adequate reporting system. These include:

1. Regular, mandatory emissions reporting for all facilities above a certain emission threshold;
2. The submission of granular information, including source-resolved data about equipment counts, number of leaks found, survey instruments, and leak quantification method and similar granular information about venting at the equipment level;
3. Quantification based on direct measurement;
4. Transparent public access to all data that is not considered confidential.

The Government of Canada can better integrate measurement and reporting into its policy mix the following ways:

A. Update and Improve Canada's Greenhouse Gas Reporting Program to Require More Granular Equipment Level Data, Including Measurement Data.

Canada's Greenhouse Gas Reporting Program (GHGRP) is rudimentary compared with the programs of our international counterparts.[208] Under the Canadian Environmental Protection Act, it requires submission only of total estimated emissions of CO_2, CH_4, N_2O, HFC, PFC, and SF_6 per year, by facility.[209] It requires no equipment level information, no measurement data, and no specification of quantification methods.

By contrast, the U.S. EPA's GHGRP currently requires the submission of significant amounts of activity data, individual measurements of compressor vents, leak inspection data, and quantification methods by source, among many other things.[210] All of the equipment and emissions data is publicly available for every reporter, at the facility level. Essentially none is restricted from release as confidential business information.

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[208] Environment and Climate Change Canada. *Greenhouse Gas Reporting Program.* https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823

[209] Environment and Climate Change Canada. *Canadian Environmental Protection Act, 1999.* 46. https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/canadian-environmental-protection-act-1999.html

[210] U.S. EPA. *Title 40, Code of Federal Regulations*. Part 98. https://www.ecfr.gov/current/title-40/chapter-I/subchapter-C/part-98

Moreover, proposed amendments to Subpart W of the U.S. EPA's GHGRP will update calculation methods, incorporate more empirical data, and enable improved accuracy and data verification, effective January 1, 2025.[211]

The U.S. EPA's GHGRP an excellent example of a best practice for a mandatory reporting program that requires a high level of granularity of submitted data and is moving toward greater integration of measurement data.

B. Build Strong Measurement and Reporting Requirements Into Oil and Gas Methane Regulations.

ECCC should create strong reporting requirements that cover all sources of methane emissions, including leaks/fugitives, equipment vents, and combustion exhaust (including from engines/turbines and flares).

For example, the EU's provisional agreement on energy sector methane significantly strengthens measurement and reporting requirements by basing regulation on OGMP 2.0, the internationally leading reporting framework for oil and gas methane.[212] In particular, the provisional rules require a shift from estimation to direct measurement of asset-level methane emissions at source, with a requirement for independent verification. The EU also plans to incorporate MMRV data into a public "methane transparency database," which will include data about exporter companies' and countries' methane measurement and abatement. The EU's integration of site-level measurement aligned with the requirements of OGMP 2.0 and its development of a methane transparency database show leadership and a clear commitment to measurement-based and transparent reporting.

Within Canada, B.C. has developed mandatory and transparent reporting requirements for methane leaks from oil and gas. As of January 1, 2024, it is a requirement under B.C.'s Drilling and Production Regulation 41.1 for operators to submit LDAR surveys to an e-submission system annually.[213] Required data includes facility name, information about survey type, detection instrument, leaking components, quantification of leak rate, method of quantification, and date of repair. This information is posted on the BCER's website unredacted. B.C.'s approach is a good example of granular and transparent regulatory reporting , although we urge ECCC to include all sources of methane, not just leaks.

In sum, there are a variety of novel, leading-edge policy approaches to improve measurement and reporting through regulation. We urge ECCC to bring Canada in line with international best practices such as these.

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211 EPA Press Office. "EPA Proposes Updates to Greenhouse Gas Emissions Reporting Requirements for the Oil and Gas Sector," news release, July 6, 2023. https://www.epa.gov/newsreleases/epa-proposes-updates-greenhouse-gas-emissions-reporting-requirements-oil-and-gas

212 European Commission. *Proposal for a Regulation of the European Parliament and of the Council on methane emissions reduction in the energy sector and amending Regulation (EU) 2019/942.* Article 12. https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2021%3A805%3AFIN&qid=1639665806476
The Oil and Gas Methane Partnership 2.0. https://ogmpartnership.com/

213 BCER. *Drilling and Production Regulation 41.1*. https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/282_2010

Finally, our coalition was pleased to see Minister Guilbeault's COP28 announcement that the promised Methane Centre of Excellence will be funded. If the Centre becomes a hub of multi-stakeholder expertise with a central role for academic researchers and otherwise independent experts, then it should have a role in continuing to improve reporting requirements and related measurement standards. We would welcome the opportunity to contribute under separate cover to the vision for the Centre's design and implementation. Having long advocated for this Centre, our coalition is eager to ensure that it set up to serve the vital needs we have identified in our advocacy, including the need for more coordinated collection and analysis of measurement data, as well as knowledge-sharing and training.

VI. Conclusion

We greatly appreciate the opportunity to comment on this important regulation and look forward to opportunities to strengthen the proposal, as detailed above.

Sincerely,

Robb Barnes
Canadian Association of Physicians for the Environment

Terry Dean
Canadian Lung Association

Tom Green
David Suzuki Foundation

Amanda Bryant, PhD
Pembina Institute

Darin Schroeder
Clean Air Task Force

Ari Pottens
Elizabeth Paranhos
Environmental Defense Fund

APPENDIX A

EDF Analysis - RIAS CBA recreation - alternate assumptions

2/14/2024

Version 1 - Compliance costs differ only due to rounding differences and simplifying assumptions

Table 9: (EDF Recreation) Industry compliance costs by source (millions of dollars)

Source	Undiscounted 2027	Undiscounted 2030	Undiscounted 2040	Discounted Total 2027–2040	Annualized
Compressor seals	32	929	54	1,322	109
Fugitive equipment leaks	340	340	340	3,955	327
Glycol dehydrators	2	57	7	104	9
Pneumatic devices	19	332	73	864	71
Pneumatic instruments	77	1,311	276	3,341	276
Surface-casing vent flow	17	460	39	749	62
Venting and flaring	148	2,195	339	4,809	397
Total	635	5,624	1,128	15,144	1,251

Assumptions

New sources comply in 2027

Existing sources comply in 2030

(EDF Recreation) Abatement costs per metric ton of GHG (denominator specified in table)

Source	Cost per tonne CH4	Cost per tonne CO2e (GWP = 25)	Cost per tonne CO2e (GWP = 30)	Cost per tonne CO2e (GWP = 83)
Venting and flaring	2,987	88	77	33
Pneumatic devices	714	29	24	9
Pneumatic instruments	5,568	223	186	67
Compressor seals	2,448	108	88	30
Glycol dehydrators	1,156	46	39	14
Fugitive equipment leaks	1,202	48	40	14
Surface-casing vent flow	713	36	29	9
Total	**1,805**	**70**	**58**	**22**

Assumptions

Costs exclude admnistrative costs

Emissions estimates match CG1 Table 12 and 13

Detailed revised GHG emissions reductions, 2027-2040 (million metric tons)

Source	Methane	CO2	Combined CO2e (GWP = 25)	Combined CO2e (GWP = 30)	Combined CO2e (GWP = 83)
Venting and flaring	1.610	14.20	54.450	62.50	147.830
Pneumatic devices	3.025	0.00	75.625	90.75	251.075
Pneumatic instruments	1.500	0.00	37.500	45.00	124.500
Compressor seals	0.540	-1.24	12.260	14.96	43.580
Glycol dehydrators	0.270	0.00	6.750	8.10	22.410
Fugitive equipment leaks	3.290	0.00	82.250	98.70	273.070
Surface-casing vent flow	1.050	-5.65	20.600	25.85	81.500
Total	**11.285**	**7.31**	**289.435**	**345.86**	**943.965**

Assumptions

Where possible, we have scaled methane emissions to match empirically derived emissions estimates.

Glycol dehydrators emissions reductions are scaled by factor 3.

Pneumatic instrument and device emissions are scaled by factor 2.5.

Revised abatement costs per metric ton of GHG (denominator specified in table)

Source	Cost per tonne CH4	Cost per tonne CO2e (GWP = 25)	Cost per tonne CO2e (GWP = 30)	Cost per tonne CO2e (GWP = 83)
Venting and flaring	2,987	88	77	33
Pneumatic devices	286	11	10	3
Pneumatic instruments	2,227	89	74	27
Compressor seals	2,448	108	88	30
Glycol dehydrators	385	15	13	5
Fugitive equipment leaks	1,202	48	40	14
Surface-casing vent flow	713	36	29	9
Total	**1,342**	**52**	**44**	**16**

Assumptions

Costs exclude admnistrative costs.

Where possible, we have scaled methane emissions to match empirically derived emissions estimates.

EDF Analysis - RIAS CBA recreation - alternate assumptions

2/14/2024

Version 2 - Compliance costs reflect accelerated implementation timelines

Table 1: (EDF Recreation) Industry compliance costs by source (millions of dollars)

Source	Undiscounted 2025	Undiscounted 2028	Undiscounted 2040	Discounted Total 2025–2040	Annualized
Compressor seals	28	925	50	1,395	103
Fugitive equipment leaks	340	340	340	4,615	340
Glycol dehydrators	1	56	6	114	8
Pneumatic devices	17	328	70	955	70
Pneumatic instruments	67	1,298	267	3,684	271
Surface-casing vent flow	15	458	37	803	59
Venting and flaring	129	2,174	321	5,178	381
Total	**597**	**5,579**	**1,091**	**16,744**	**1,232**

Assumptions

New sources comply in 2025

Existing sources comply in 2028

(EDF Recreation) Abatement costs per metric ton of GHG (denominator specified in table)

Source	Cost per tonne CH4	Cost per tonne CO2e (GWP = 25)	Cost per tonne CO2e (GWP = 30)	Cost per tonne CO2e (GWP = 83)
Venting and flaring	3,216	95	83	35
Pneumatic devices	789	32	26	10
Pneumatic instruments	6,140	246	205	74
Compressor seals	2,583	114	93	32
Glycol dehydrators	1,267	51	42	15
Fugitive equipment leaks	1,403	56	47	17
Surface-casing vent flow	765	39	31	10
Total	**1,996**	**77**	**65**	**24**

Assumptions

Costs reflect accelerated implementation timeline.

Costs exclude admnistrative costs

Emissions estimates match CG1 Table 12 and 13

Costs are overestimated as analysis does not account for emissions reductions in 2025-2026

Detailed revised GHG emissions reductions, 2027-2040 (million metric tons)

Source	Methane	CO2	Combined CO2e (GWP = 25)	Combined CO2e (GWP = 30)	Combined CO2e (GWP = 83)
Venting and flaring	1.610	14.20	54.450	62.50	147.830
Pneumatic devices	3.025	0.00	75.625	90.75	251.075
Pneumatic instruments	1.500	0.00	37.500	45.00	124.500
Compressor seals	0.540	-1.24	12.260	14.96	43.580
Glycol dehydrators	0.270	0.00	6.750	8.10	22.410
Fugitive equipment leaks	3.290	0.00	82.250	98.70	273.070
Surface-casing vent flow	1.050	-5.65	20.600	25.85	81.500
Total	**11.285**	**7.31**	**289.435**	**345.86**	**943.965**

Assumptions

Where possible, we have scaled methane emissions to match empirically derived emissions estimates.

Glycol dehydrators emissions reductions are scaled by factor 3.

Pneumatic instrument and device emissions are scaled by factor 2.5.

Analysis does not account for emissions reductions in 2025-2026.

Revised abatement costs per metric ton of GHG (denominator specified in table)

Source	Cost per tonne CH4	Cost per tonne CO2e (GWP = 25)	Cost per tonne CO2e (GWP = 30)	Cost per tonne CO2e (GWP = 83)
Venting and flaring	3,216	95	83	35
Pneumatic devices	316	13	11	4
Pneumatic instruments	2,456	98	82	30
Compressor seals	2,583	114	93	32
Glycol dehydrators	422	17	14	5
Fugitive equipment leaks	1,403	56	47	17
Surface-casing vent flow	765	39	31	10
Total	**1,484**	**58**	**48**	**18**

Assumptions

Costs reflect accelerated implementation timeline.

Costs exclude admnistrative costs.

Where possible, we have scaled methane emissions to match empirically derived emissions estimates.

Costs are overestimated as analysis does not account for emissions reductions in 2025-2026.

compliance_action	source	capex_CAD	opex_CAD	affected_count	share_existing	PV_mlnCAD	proposal_table
VRU	Venting and flaring	84900	3900	5700	0.48	574	1
Pipeline tie-in	Venting and flaring	1137700	38870	600	0.48	743	1
Flare ignition system	Venting and flaring	6600	0	29800	0.48	169	1
Combustors	Venting and flaring	52000	15140	3800	0.48	580	1
Oxidizers	Venting and flaring	36500	5420	17100	0.48	1,204	1
Redesign blowdown systems	Venting and flaring	8800	0	4300	0.55	32	2
Capture and route gas to portable combustor	Venting and flaring	72300	600	4300	0.55	277	2
Install blowdown gas capture and conservation equipment	Venting and flaring	85000	0	1700	0.55	128	2
Install plunger lift systems in gas wells	Venting and flaring	38600	0	11500	0.5	378	3
Reduce liquids unloading venting with flaring,	Venting and flaring	57000	0	13600	0.5	660	3
Replace pneumatic pumps with electric pumps (solar and onsite power)	Pneumatic devices	9500	1000	55100	0.53	835	4
Replace pneumatic instruments with non-emitting solutions such as electrified or air-driven instruments	Pneumatic instruments	10100	1000	206200	0.53	3251	4
Install wet seal degassing system	Compressor seals	85000	3400	300	0.67	30	5
Replace wet seals with dry seals	Compressor seals	100000	500	75	0.67	7	5
Install vent capture devices and re-route to combustion equipment	Compressor seals	178000	3000	7200	0.67	1299	5
Combined solutions for existing facilities	Glycol dehydrators	31200	2250	2000	0.72	94	6
Combined solutions for new facilities	Glycol dehydrators	10400	900	800	0.72	12	6
Non-producing Wells	Fugitive equipment leaks	465	0	372900	1	2,022	7
Wells	Fugitive equipment leaks	175	0	189700	1	779	7
Gas Processing Facilities	Fugitive equipment leaks	7040	0	500	1	83	7
Compressor Stations (small)	Fugitive equipment leaks	4700	0	4800	1	527	7
Batteries	Fugitive equipment leaks	350	0	38300	1	323	7
Compressor Stations (large)	Fugitive equipment leaks	7040	0	1500	1	249	7
Install casing gas recovery and combustion equipment	Surface-casing vent flow	110000	2800	5150	0.65	647	8
Install casing gas recovery and compression equipment for gas conservation	Surface-casing vent flow	89500	8500	1000	0.65	162	8

source	year	CH4_abatement_MT	CO2_abatement_MT
Venting and flaring	2027	0.01	0.07
Venting and flaring	2030	0.14	1.27
Venting and flaring	2040	0.15	1.3
Venting and flaring	2027-2040	1.61	14.2
Pneumatic devices	2027	0.01	0
Pneumatic devices	2030	0.11	0
Pneumatic devices	2040	0.11	0
Pneumatic devices	2027-2040	1.21	0
Pneumatic instruments	2027	0	0
Pneumatic instruments	2030	0.05	0
Pneumatic instruments	2040	0.05	0
Pneumatic instruments	2027-2040	0.6	0
Compressor seals	2027	0	-0.01
Compressor seals	2030	0.06	-0.15
Compressor seals	2040	0.04	-0.08
Compressor seals	2027-2040	0.54	-1.24
Glycol dehydrators	2027	0	0
Glycol dehydrators	2030	0.01	0
Glycol dehydrators	2040	0.01	0
Glycol dehydrators	2027-2040	0.09	0
Fugitive equipment leaks	2027	0.24	0
Fugitive equipment leaks	2030	0.23	0
Fugitive equipment leaks	2040	0.24	0
Fugitive equipment leaks	2027-2040	3.29	0
Surface-casing vent flow	2027	0.09	-0.49
Surface-casing vent flow	2030	0.08	-0.43
Surface-casing vent flow	2040	0.07	-0.38
Surface-casing vent flow	2027-2040	1.05	-5.65