Canada's Methane Abatement Opportunity

A Marginal Abatement Cost Curve for Methane Emissions in Canada's Upstream Oil & Gas Sector

Submitted to:

Environmental Defense Fund

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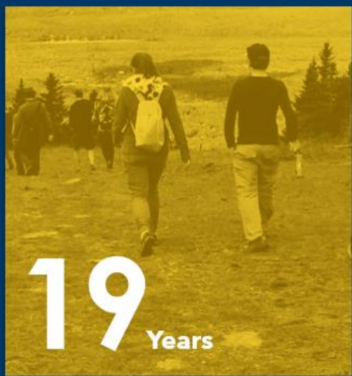

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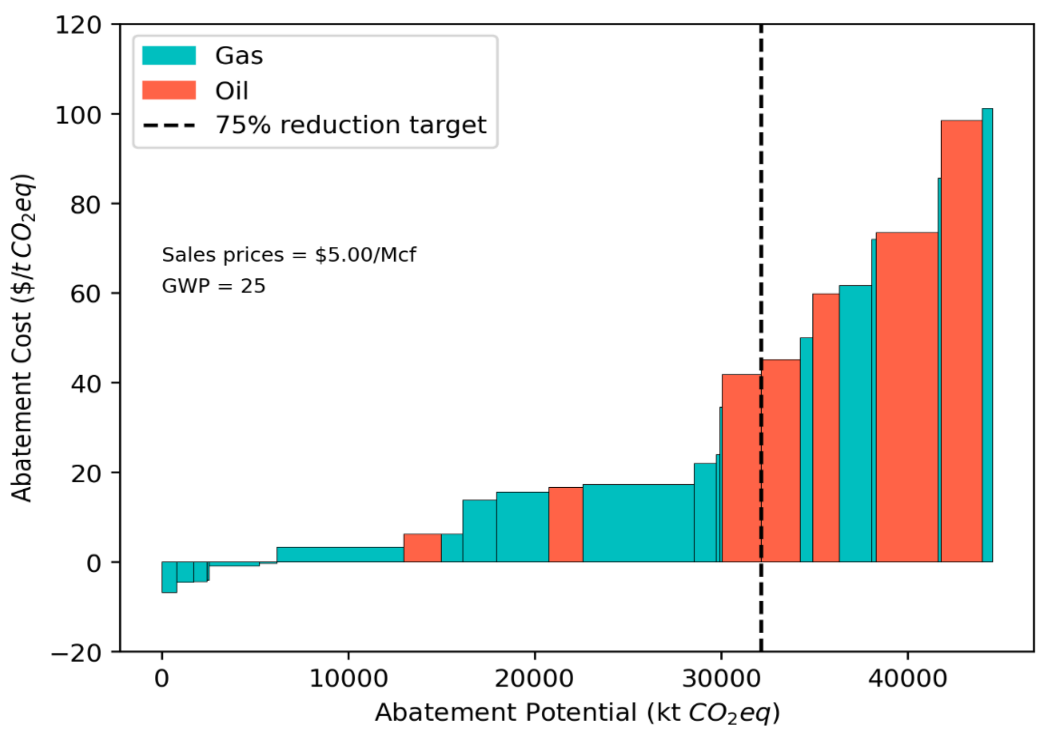
Executive Summary

This report evaluates the most cost-effective reduction pathway available for the Canadian upstream oil and gas industry to achieve the federal methane emissions reduction target of 75% by 2030 relative to 2012 levels. The sector is responsible for 30% of the country's methane emissions (IEA, 2023). **The report finds that a 75% reduction is achievable at an average cost well below the current and projected federal carbon price.**

Key Findings

Implementing the 24 least expensive measures across all candidate sites would achieve the required 75% reduction in annual emissions by 2030, at an average cost of $11/tCO_2e (GWP-100), as illustrated by the dotted line in the chart below. (Abatement becomes even more favorable at an average cost of about $3/tCO2e if using a GWP-20 factor).[1]

Marginal Cost & Potential of Methane Abatement Measures at Gas Sites



A 75% reduction in annual emissions requires an annual reduction of 32,000 ktCO2e relative to updated 2020 levels. This is equivalent to 67,000 bcf of gas conserved per year. In energy

[1] This value better reflects methane's short-lived, but powerful warming impact relative to CO_2 over a 20-year period (GWP-20=83; IPCC 2021). The values throughout this report use a 100-year global warming potential (GWP) factor of 25 to convert methane into CO_2 equivalent terms, per the NIR. However, the latest science indicates a GWP-100 of 30 for fossil methane (IPCC 2021).

terms, the methane gas saved annually could produce more than 70 PJ, or the total energy consumed by 790,000 Canadian homes in a year.

Relative to the projected federal price per tonne of carbon equivalent, which will increase from $65 in 2023 by $15 per year to $170 by 2030, upstream methane is a low-cost way to abate greenhouse gas emissions. However, fugitive and vented emissions are priced inconsistently across Canada, with certain provincial equivalency programs allowing their exemption. Because of this distortion in the carbon pricing signal, most measures cannot be considered cost effective based on gas price alone, and provinces must mandate their adoption instead.

Methods

This report adjusts NIR data to account for aggregated empirical measurement data and relies on existing cost data that is appropriate for Canadian emission sources. More detailed emissions data and more transparency around abatement costs would improve the accuracy of this report. However, our sense is that site-level measured emissions data may reveal even higher emissions estimates and that updated cost values may have declined to reflect industry learning. If true, both drivers would cause our estimates to represent a conservative picture of abatement costs for upstream Canadian oil and gas methane emissions.

We begin our analysis by establishing an updated estimate for 2012 and current sectorial emissions. Research consistently shows that the federal government's official greenhouse gas inventory, the National Inventory Report (NIR), underestimates upstream methane emissions by 50-90%. To fully achieve the targets established by the government, we must better understand the current levels of emissions and then determine the reductions required.

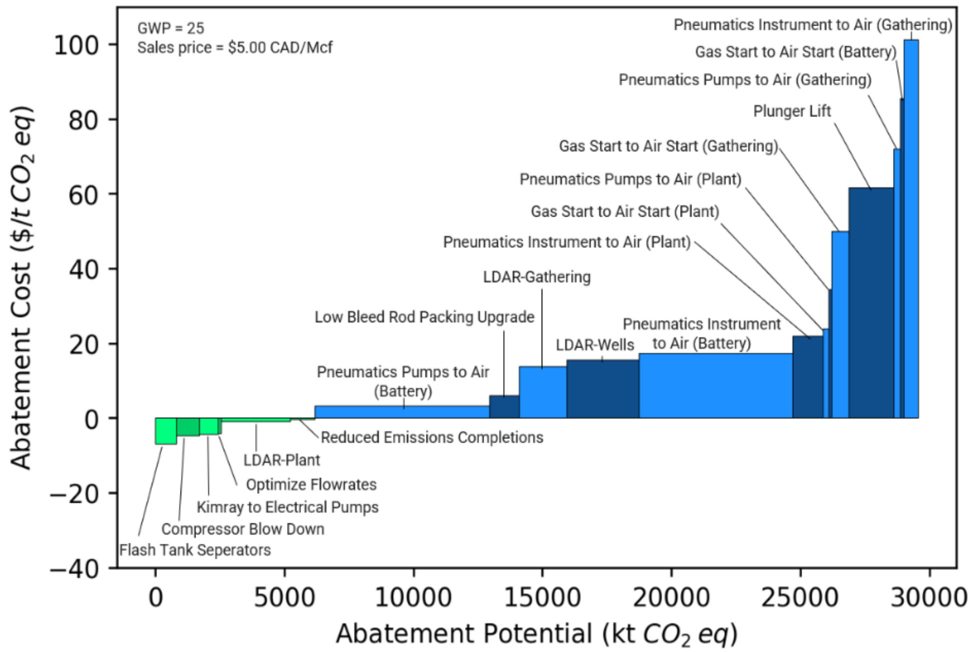
Our analysis applies an escalation factor of 1.7 to the overall NIR emissions, which represents the mid-range of our literature review. However, we believe a factor of 1.7 remains on the conservative end and is extensible across Canada, given that a recent study by Johnson et al. (2022) found an underreporting factor of 1.7 for British Columbia, where gas production is prominent. Emissions are expected to be higher at oil sites where gas collection is less convenient. Indeed, looking at the marginal abatement cost curves, we can see that the abatement measures at gas sites are generally more cost effective than those at oil sites.

We then attribute emissions to the different facility types across the industry according to provincial databases and inventories, resulting in an updated portrait of where emissions are generated.

Finally, we establish a list of 33 abatement measures and assessed the potential applicability of the measure across the industry and potential emissions reduction the measure could achieve at different facility types. We then assess cost effectiveness by estimating the net present value of implementation and operation of a measure at a given facility divided by emissions abated over the measure's lifetime.

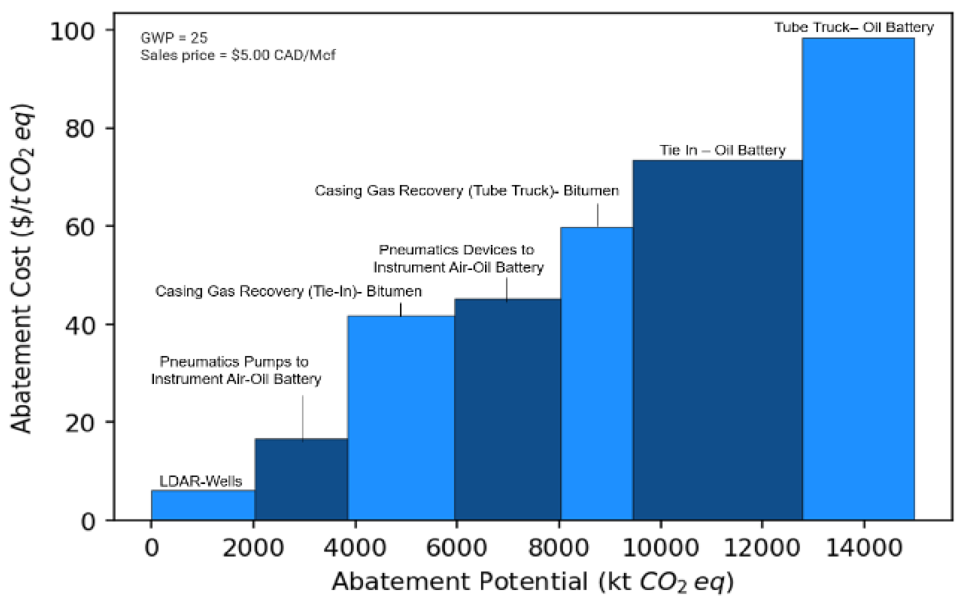
Looking more closely at opportunities at gas sites, we can see that more than 75% of the abatement potential lies below a cost of $20/tCO2e, including several cost-effective measures, mainly targeting venting from dehydrators and compressor blowdowns.

Marginal Cost & Potential of Methane Abatement Measures at Gas Sites



At oil sites, the options are not as diverse, and the cost increases almost linearly with the abatement potential. Roughly 25% of measures are below $20/tCO2e. The main opportunities are a more aggressive leak detection and repair program, and casing gas recovery at crude bitumen sites.

Marginal Cost & Potential of Methane Abatement Measures at Oil Sites



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1. Introduction

Canada has set ambitious targets to reduce its oil and gas methane emissions, aiming for a reduction relative to 2012 of 40-45% by 2025 and 75% by 2030. In the upstream oil and gas sector alone, a 75% reduction represents 1,300 kt of methane conserved annually. Ensuring that these targets are met efficiently depends on understanding the true distribution of methane emissions and having a plan for where to apply efforts to reduce them.

Methane is the main component of natural gas, produced both in Canadian gas wells and as a by-product in the production of other fossil fuels. The exploitation and primary processing of these fuels (grouped as the "upstream" oil and gas sector) is responsible for 30% of the country's methane emissions. Because upstream facilities are a leading causes of methane emissions, they also provide an important opportunity for emission reductions. Given the concentrated nature of the emissions, focused interventions can abate large amounts of gas compared to similar efforts downstream such as local distribution network inspection.

Accurately tracking methane emissions in the upstream sector requires the use of emissions detection and measurement technologies. Although cost-effective options for measurement are increasingly available, these technologies remain relatively novel. Thus, current emissions estimates rely mainly on simple emission factors and engineering calculations rather than measurement. As a result, research consistently shows that the federal government's official greenhouse gas inventory, the National Inventory Report (NIR), underestimates upstream methane emissions by 50-90% (see section 2.2 for a list of studies). This underestimated baseline severely jeopardizes the government's abatement targets. The NIR acknowledges this fact in the 2022 release, though compensatory action has not yet been taken.

In this report, we establish an updated estimate for current emissions for upstream oil and gas by facility type based on the best available research, for Alberta, Saskatchewan, and British Columbia (Sections 2.2 and 3.1). This includes all well sites in each of the three provinces, but not oil sands production. Next, we propose a suite of abatement measures (Section 2.3) and estimate the associated abatement costs (Section 3.2). Finally, based on the newly updated facility-level emissions inventory, we examine which combinations of measures would achieve the most cost-effective reductions, as well as the volumes of reduction achievable (Section 4). Our methodology is described in Section 2.

2. Methodology

2.1 General Approach

To establish an accurate marginal abatement cost curve for the projected period, we first built the updated inventory based on current estimates from the federal inventory prorated by an escalation factor determined from the literature. Second, we projected the level of future emissions based on the Canadian Energy Regulator's Energy Futures production projections, as well as estimates of the impact of legislation implemented since 2020, the year captured in the NIR. Finally, we characterised a suite of abatement measures, estimating cost and emissions saved for each measure, and applied this suite to the previously established inventory projection to determine the potential impacts. A summary of the methodology with relevant input sources is presented in Figure 1 and further details are provided in the following sections.

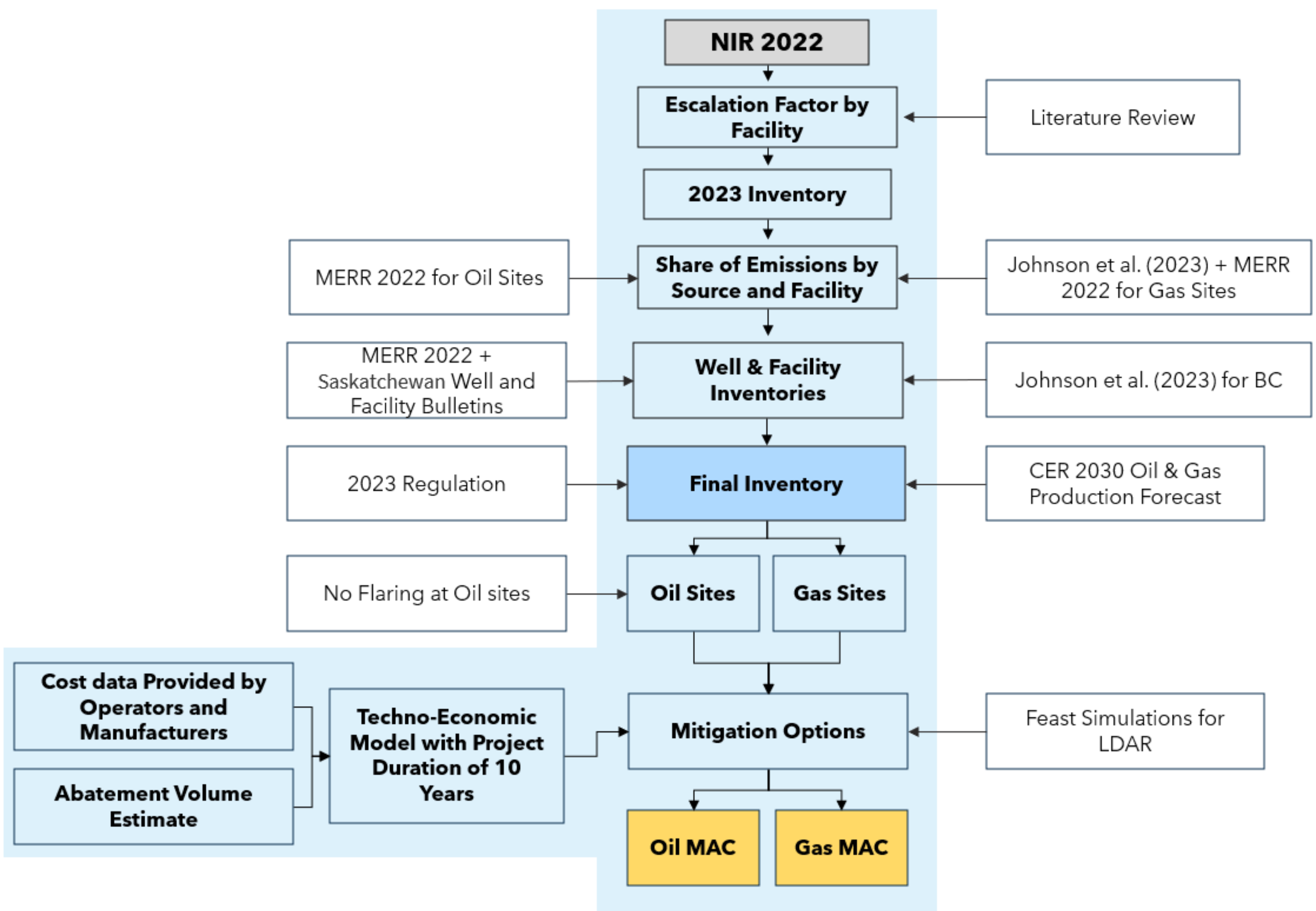

Figure 1: Flow chart of the marginal abatement cost curve with relevant data input

2.2 Inventory Update

Field measurement studies consistently show that methane emissions are under-reported in the upstream oil and gas sector. The federal government's initiatives to reduce sector emissions creates an even greater imperative to develop a more realistic inventory.

Many studies have been conducted at the provincial level in British Columbia (Tyner et al., 2021; Johnson et al., 2022; Johnson et al., 2023), Alberta (Johnson et al., 2017; Tyner & Johnson, 2018; O'Connell et al., 2019; Chan et al., 2020) and Saskatchewan (Baillie et al., 2019; Chan et al., 2020) with calculated methane emission underestimation factors, or escalation factors, ranging from 1.5 to 1.9. However, factors derived from these studies are region-specific and therefore not necessarily scalable to other jurisdictions where production techniques, geology, and fluid type (oil or gas) differ. Indeed, gas production sites have a lower relative methane emission rate on average than oil production sites simply because gas is the main product and there is an incentive to minimize flaring and venting, whereas for oil sites not connected to gas collection infrastructure gas is a burden.

The present study applies an escalation factor of 1.7 to the overall NIR emissions, which represents the mid range of our literature review. We believe a factor of 1.7 is on the conservative end and is extensible across Canada, given that a recent study by Johnson et al. (2022) found an underreporting factor of 1.7 for British Columbia, where gas production is prominent, and emissions are expected to be higher at oil sites.

As shown in Figure 1, our inventory is further broken down by emission source, depending on the composition of each province's sector. Emissions in Alberta and Saskatchewan were attributed to sources based on Alberta's Methane Emission Reduction Regulation (MERR) 2022 reported shares. However, aerial surveys exhibit very different distribution sources than the federal and provincial inventory (Chan et al., 2020; Johnson et al., 2023), calling into question the accuracy of this source. The breakdown for oil sites, therefore, remains a limitation of this study. More accurate data and measurements in Alberta and Saskatchewan would better illustrate mitigation opportunities.

For gas sites, we leveraged recent results of aerial surveys by Johnson et al. (2022), that show methane emissions sources in British Columbia's gas sector are principally compressors, intentional venting (uncontrolled tanks, unlit flares, and uncontrolled compressors), and unintentional venting (controlled tanks, and abnormally operating pneumatics).

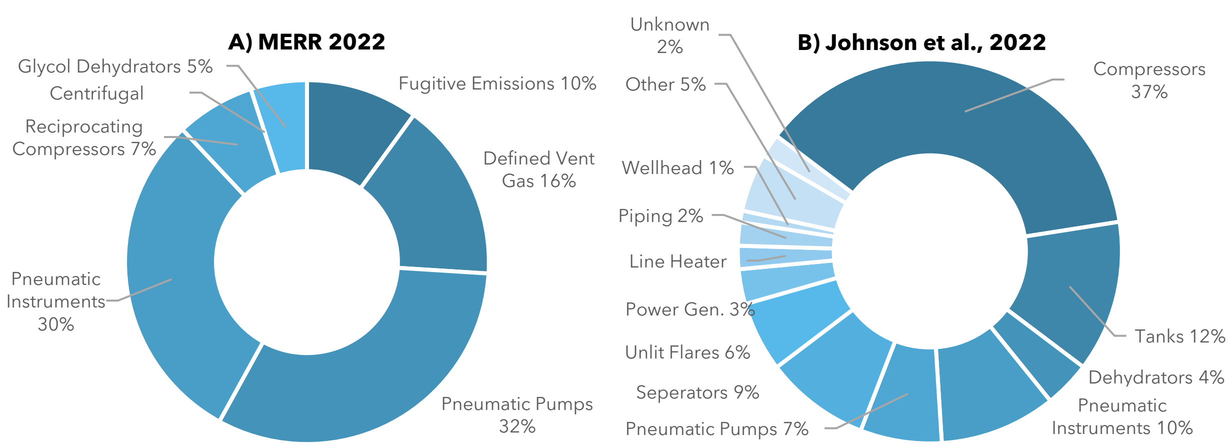

Figure 2: Emission breakdown: A: MERR 2022 gas site emissions by source; B: Breakdown of emissions for British Columbia (Johnson et al., 2022)

To reconcile the contrast between the MERR source breakdown for gas sites and the Johnson et al. (2022) breakdown for British Columbia (which is dominated by gas sites), we applied different escalation factors to the various sources in the MERR (Figure 2 and Table 1), which was used to calculate Alberta and Saskatchewan's breakdowns. The combined effect of the factors still represents an overall increase of 1.7 relative to the NIR, but we assume that the underreporting comes primarily from fugitive emissions, compressors, and venting (compressors, tanks, and wells). The factors were obtained by limiting the deviation between the MERR and Johnson et al. (2021) source breakdown for gas sites. The value of 4.0 for the fugitive emissions factor is also attributable to the MERR's acknowledgement that it underreported fugitive emissions because of COVID-19 requirements.

Table 1: Escalation factor by source for gas sites

Source	Factors
Pneumatic Pumps	1.1
Pneumatic Instruments	1.1
Reciprocating Compressors	2.0
Glycol Dehydrators	2.0
Fugitive Emissions	4.0
Venting (Compressors, Tanks, Wells)	2.0

For the breakdown of emissions by facility type (battery, plant, and compressor/gathering station), the British Columbia breakdown is based on the Johnson et al. (2022) data (Table 2) while the Alberta and Saskatchewan breakdowns are based on the MERR 2022. Though the MERR is composed of Albertan facilities, the overall breakdown in facility types was judged to be sufficiently representative of Saskatchewan's mix, the principal difference being a higher concentration of heavy oil facilities relative to Alberta.

Table 2: Emissions by facility sub type in British Columbia (Johnson et al., 2022)

Description	Inventory (ktCO_2e/y)	Share (%)
Gas Single Well Battery	7.75	0.21%
Gas Multi Well Group Battery	127.75	3.5%
Gas Multi Well Battery	382.25	11%
Gas Plant	679.25	19%
Compressor Station	1164.25	32%
Crude Oil Single Well Battery	11.5	0.32%
Crude Oil Multi Well Battery	26.75	0.76%
Gas Wells	1053.5	29%
Oil Wells	56	1.5%
Other	106	2.9%
Total	3615	100%

Finally, we determined facility counts and average equipment populations for compressors, dehydrators, pumps and instruments by province based on data from the Alberta Energy Regulator and Johnson et al. (2022).

2.3 Abatement Measure Analysis

Measure Selection

Having established an adjusted portrait of current and projected emissions, we next assembled a suite of measures to abate methane emissions.

The measures we selected for evaluation were based on several sources, including previous marginal abatement cost work by EDF, Canadian and American industry studies and the federal framework proposed in November 2022. We created an exhaustive list of measures in collaboration with EDF's experts, prioritising measures we suspected could be most cost effective and could abate significant volumes of gas.

We subsequently broke down each measure according to facility types to which they could be applied (crude bitumen battery, crude oil battery, gas battery, compressor station or gas plant). For each facility type, we identified any resulting redundant measures, and retained what we judged to be the most cost-effective option.

The suite of 33 options selected does not exhaustively cover the emissions of the entire sector, but our aim was for it to be at least sufficient to meet the 2030 target of 75%, assuming the remaining portion emissions would be those prohibitively expensive and too diverse to consider. Figure 3 lists the 33 measures analysed.

Measure
Instrument Air Pumps - Oil Battery
Instrument Air Devices - Oil Battery
Gas Pipeline Tie-In - Bitumen Battery
Tube Truck Tie-In - Bitumen Battery
Gas Pipeline Tie-In - Oil Battery
Tube Truck Tie-In - Oil Battery
Monthly LDAR - Oil Wells
Capture Compressor Blow Down - Gas Battery
Capture Compressor Blow Down – Gas Plant
Flash Tank Separators – Gas Gathering
Kimray To Electrical Pumps – Gas Battery
Optimize Dehydrators Flowrates – Gas Gathering
Flash Tank Separators – Gas Battery
Kimray To Electrical Pumps – Gas Battery
Optimize Dehydrators Flowrates – Gas Battery
Pneumatic Pumps to Air – Gas Battery
Capture Compressor Blow Down – Gas Gathering

Measure
Pneumatic Instrument to Air – Gas Battery
Pneumatic Instrument to Air – Gas Plant
Pneumatic Pumps to Air – Gas Plant
Reduced Emissions Completions – Gas Wells
Gas Start to Air Start – Gas Plant
Pneumatic Pumps to Air – Gas Gathering
Plunger Lift – Gas Wells
Pneumatics Instrument to Air – Gas Gathering
Gas Start to Air Start – Gas Gathering
Convert Gas Starter to Air Start – Gas Battery
Monthly LDAR - Gas Wells
Monthly LDAR – Gas Gathering
Monthly LDAR – Gas Processing
Low Bleed Rod Packing Upgrade – Gas Plant
Low Bleed Rod Packing Upgrade – Gas Gathering
Low Bleed Rod Packing Upgrade – Gas Battery

Figure 3: List of abatement measures characterised

Measure Characterisation

Following the identification of high potential measures, we characterised each measure to detail the key factors driving its abatement potential.

We first estimated implementation cost for a single site for each measure, based on information from suppliers and previous studies for similar measures. We then determined the impact of each measure applied to each facility type. We accounted for the degree of existing implementation of each technology through various means, such as industry data, previous abatement studies and expert judgements. We also developed high-level estimates of which measures have likely been implemented since the 2020 NIR, based on historic adoption rates and new federal requirements. We then determined the proportion of the sites to which the measure could be applied, considering factors like site remoteness and age. Finally, we determined the potential emissions reduction from each measure-facility application, accounting for the relevant emissions by facility type.

Cost effectiveness was determined based on net present value of implementation of a measure at a given facility type and subsequent operation over the life of the measure divided by the emissions abated over that time. We accounted for annual maintenance costs and increased revenues from redirected gas, and residual value was assumed to be zero. We applied a standard measure life of 10 years based on typical duration of savings (except for leak detection and repair, which is renewed annually). We applied a gas price of $5.00 CAD/Mcf, a discount rate of 5% to reflect the low-risk and long-term nature of methane savings measures, and a methane GWP of 25 (in accordance with the NIR).

Specific Measure Considerations

A limitation of our study is that single well batteries and multi wells batteries are not discretized. Our model considers an average battery site and uses the high end of the cost estimates for the implementation of mitigation measures.

For the leak detection and repair (LDAR) program, our choice of inspection frequency (12 times per year) was based on simulations with the open-source Fugitive Emissions Abatement Simulation Toolkit (FEAST) conducted by Kemp et al. (2021). Developing an accurate distribution of fugitive emissions is challenging, especially for super-emitters that are generally accounted for by a heavy-tailed distribution. In their paper, Kemp et al. (2021) populated their empirical emission-size distributions in FEAST with publicly available database of component-level emission surveys. This method avoids biasing the data with a parametric model but is limited by the finite sample size and does not simulate any emissions larger than those captured in the empirical data. Kemp et al. (2021) simulations were conducted for the US oil and gas sector and showed that a monthly optical gas imaging (OGI) survey frequency leads to a mitigation of 85% of emissions. Further FEAST modelling for specific Canadian contexts could lead to more precise estimates of mitigation.

Marginal Abatement Costs and Curve Production

For each measure applied at a facility type, we categorized results based on emissions abated and the total marginal cost of abatement. We then sorted the measures by cost (see Appendix A) and created the abatement cost curves shown Section 3.2.

3. Results

3.1 Updated Inventory

Applying the overall 1.7 escalation factor to the NIR inventory results in an updated inventory of 52,000 ktCO_2e for 2020. This figure is consistent with the recent IEA Methane Tracker Report (IEA, 2023), which estimates 53,750 ktCO_2e of vented, fugitive, and flared emissions from onshore oil and gas, representing the majority of the 63,750 ktCO_2e of emissions from the energy sector.

As seen in Figure 4, even with our variable escalation factor by source for gas sites, our updated inventory shows that pneumatic pumps and pneumatic instruments remain a significant source of emissions, especially at gas battery sites. On oil sites, emissions are mainly driven by defined vent gas (gas emitted from routine venting, excluding vent gas from pneumatic devices, compressor seals, and glycol dehydrators) with a share of over 75% at crude bitumen batteries. The share of fugitive emissions also shows that significant methane emissions persist under the current regulatory framework for LDAR requirements.

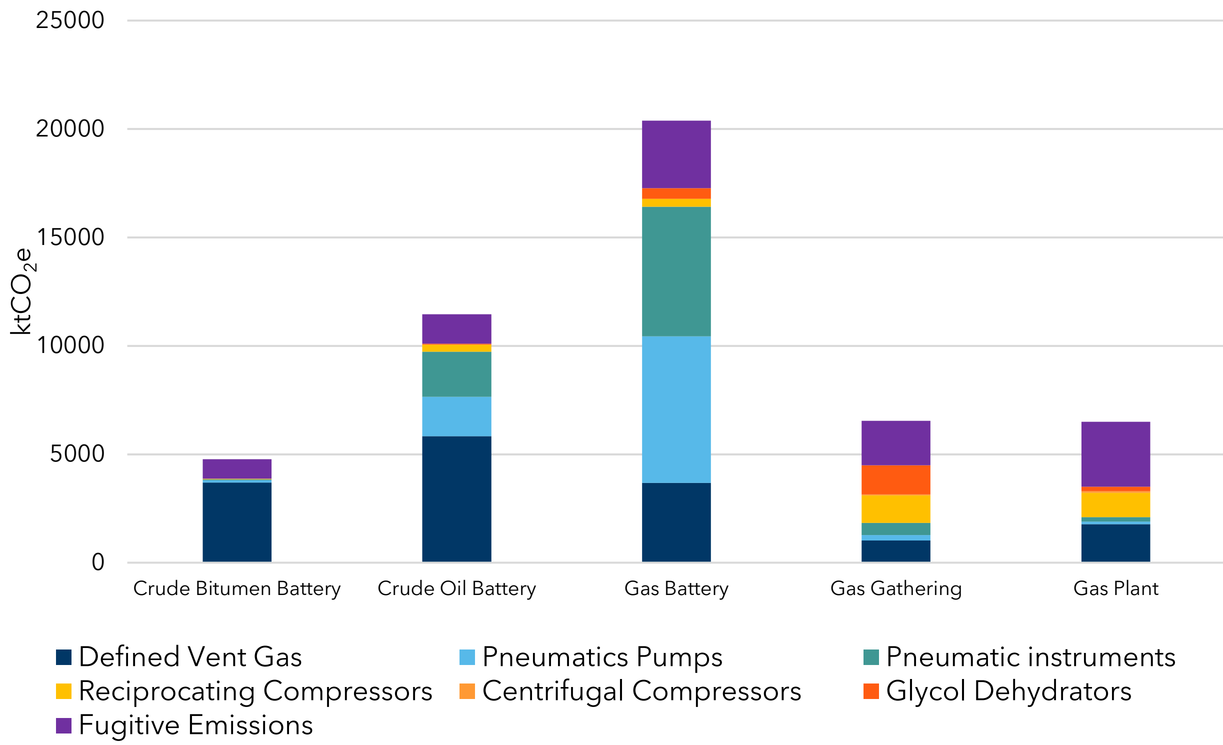

Figure 4: Updated inventory for Canadian upstream oil and gas sector

3.2 Marginal Abatement Cost Curves

The marginal abatement curves are presented independently for gas (Figure 5) and oil (Figure 6) sites, since many of the measures analysed do not all fit on a single curve.

For gas sites, more than 75% of the abatement potential lies below a cost of $20/t$CO_2$e, including several cost-effective measures, mainly targeting venting from dehydrators and compressor blowdowns.

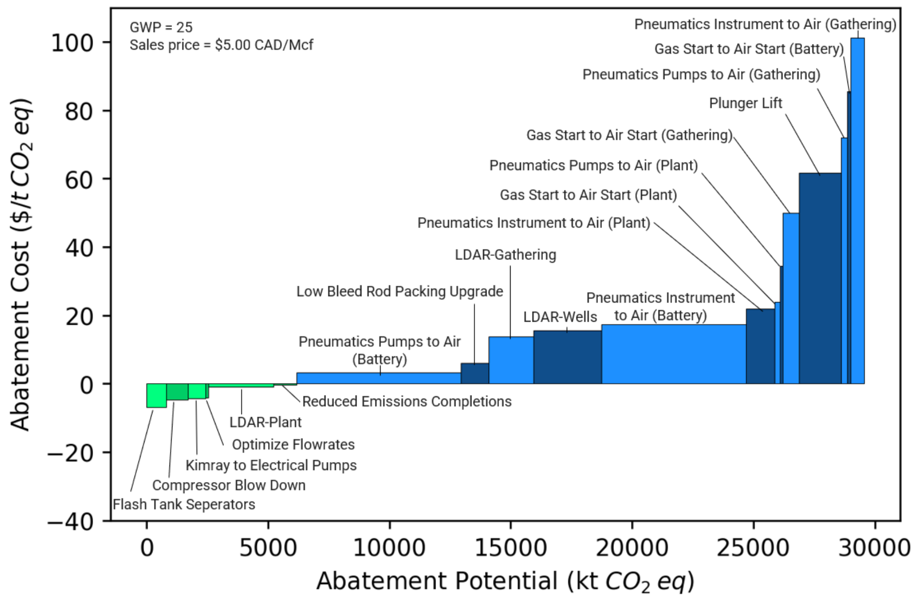

Figure 5: Marginal abatement cost curve for gas sites

On the oil curve, the options are not as diverse, and the cost increases almost linearly with the abatement potential. The main opportunities are the LDAR program and casing gas recovery at crude bitumen sites.

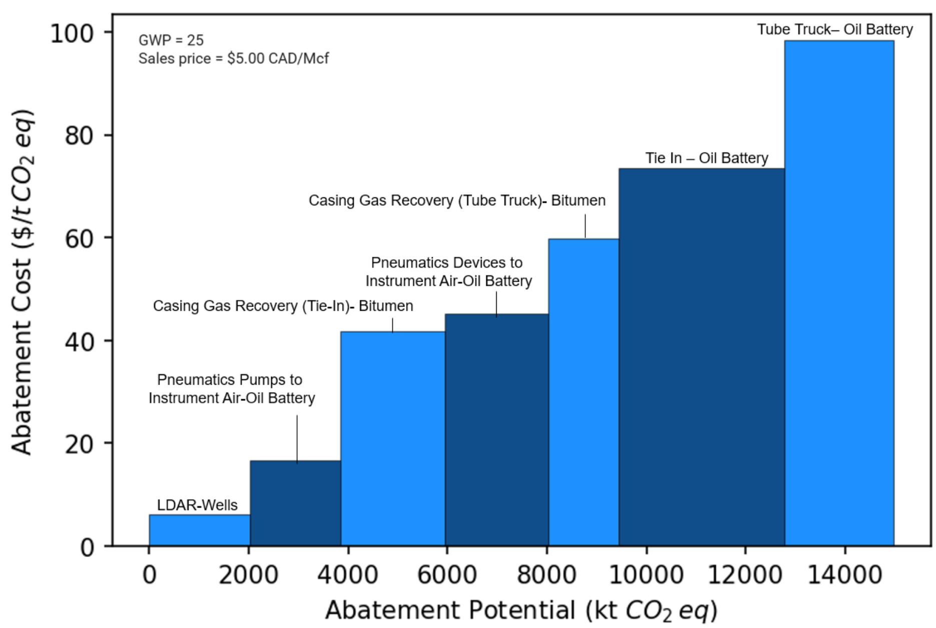

Figure 6: Marginal abatement cost curve for oil sites

3.3 Sensitivity Analysis

To assess the risk inherent in the implementation of the measures, we carried out a sensitivity analysis for the escalation factor and the gas resale price. The sensitivity analysis was performed on the average cost of implementing the 24 most cost-effective measures, which reflects the federal emission reduction target of 75% with an escalation factor of 1.7.

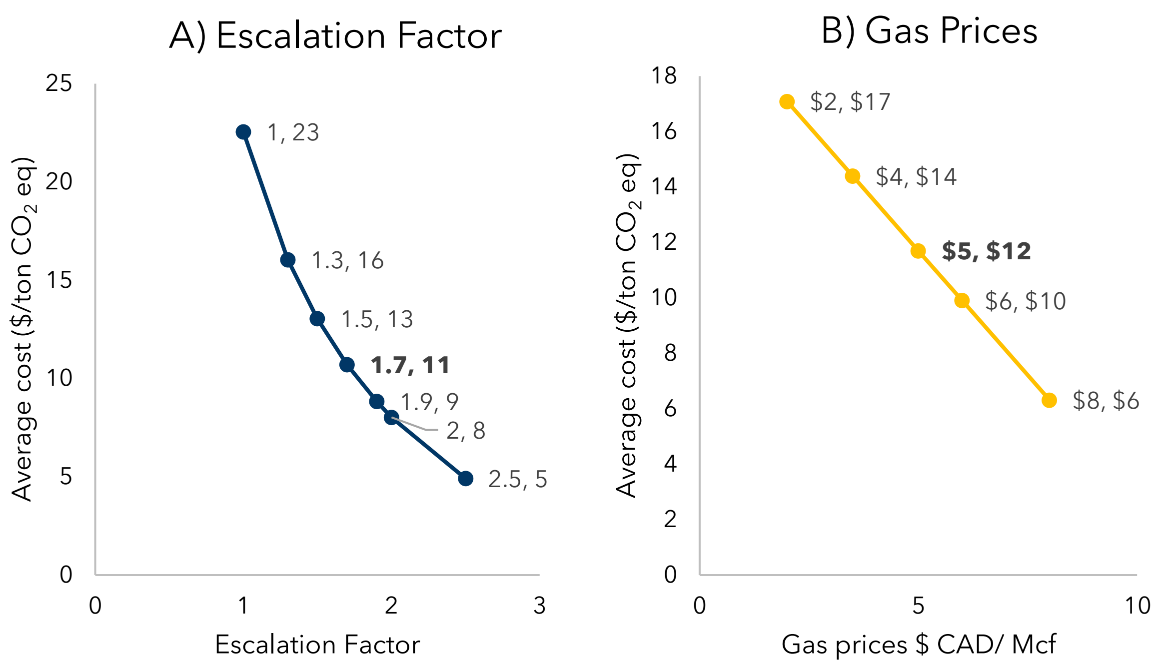

Figure 7: Sensitivity analysis on the average cost of implementing the 24 most cost-effective measures: A: Escalation factor; B: Gas prices

Results show a second order relationship between the average cost effectiveness and the escalation factor. This is because increasing the amount of gas assumed to be vented means each abatement measure covers more emissions, while also increasing revenues generated by redirecting this gas to be sold. The sensitivity to variations in the escalation factor is significant, with a decrease from 1.7 to 1.0 more than doubling average cost. Indeed, with the current NIR emissions estimate, implementing the 24 most cost-effective measures would result in an average cost of $23/t$CO_2$e. Our analysis was conservative in selecting the escalation factor; we suspect any variations would in fact result in improved cost effectiveness. However, this sensitivity analysis only illustrates what happens with changes in the overall underreporting while keeping the emissions breakdown equal. It does not capture the full effect of more accurate data. As shown in the recent study conducted by Johnson et al. (2022), there may be significant discrepancies between the estimated and actual emissions breakdowns in other provinces, impacting the cost effectiveness by measure.

Gas price has a linear relationship with cost effectiveness, as a change in gas prices only impacts revenue generated by redirection to sales, without impacting the volume of gas saved by each measure. The relationship to cost effectiveness is not as dramatic as that of the escalation factor, because not all measures benefit from increased revenue.

4. Discussion

4.1 Reaching Canada's Targets

The table below compares the upstream oil and gas sector methane emissions levels from the NIR, the updated inventory we have assembled in this report, and the federal government's total emission targets relative to both the NIR and the updated starting points for the provinces of Alberta, Saskatchewan, and British Columbia. The 2012 total emissions level reported in the NIR is prorated according to the same overall escalation factor as 2020 to obtain the updated 2012 inventory, and the 2030 business as usual (BAU) emissions are equal to the 2020 updated inventory prorated according to the Canadian Energy Regulator's oil and gas production projections for the evolving policies scenario.

Annual Emissions (ktCO_2e)	**2012**	**2020**	**2025**	**2030**
National Inventory Report	46,000	31,000		
Updated Inventory	78,000	52,000		
Projected Updated inventory (BAU)				52,000
Federal Target (vs NIR)			28,000	12,000
Federal Target (vs Updated)			47,000	20,000

Figure 8: Past and future levels of methane emissions

Up to 6,200 ktCO_2e (12% of updated 2020 total sector emissions) can be abated cost-effectively based solely on gas prices. This includes measures that can generate revenue by redirecting gas flow to sales lines such as capturing compressor blowdowns, low-cost measures such as optimization of dehydrator flowrates, or measures that generate significant savings through electrification such as converting pneumatic pumps and Kimray (glycol) pumps. Such measures will naturally be adopted by industry over time, as operators overcome the uncertainty associated with the change in technologies. Please see Appendix A for the exact list of measures by cost.

However, to achieve the updated 2030 federal annual emissions target of 20,000 ktCO_2e, an absolute reduction in annual emissions of 32,000 ktCO_2e (equivalent to 69,700 bcf of gas conserved per year) is required relative to updated 2020 levels.

Based on the measures analysed, this volume could be achieved at lowest cost by implementing the 24 least expensive measures at all candidate sites, as per the measure list provided in Appendix A. The implementation of all 24 measures would result in an overall average abatement cost of $11/t$CO_2$e, or $5.25/Mcf abated. The measures retained vary heavily by facility type, and realistically will be implemented unevenly across the sector. However, this result shows that the federal targets are within reach, and at a cost highly competitive with other emissions abatement options.

4.2 Impact of Carbon Pricing

Relative to the projected federal price per tonne of carbon equivalent, which will increase from $65 in 2023 by $15 per year to $170 by 2030, upstream methane is a low-cost way to abate greenhouse gas emissions. However, fugitive and vented emissions are priced inconsistently across Canada. The federal framework governing provincial carbon pricing requires provinces to apply a price to a minimal proportion of greenhouse gas emissions. As a result, certain provincial equivalency programs have put fugitive methane emissions into this exemption category. Because of this distortion in the carbon pricing signal, most measures cannot be considered cost effective based on gas price alone, and provinces must mandate the adoption of these measures instead.

4.3 Limitations

These conclusions are subject to several limitations.

- Our study did not discretize single well and multi wells batteries. Our model considers an average battery site and applies the high end of the cost estimates for the implementation of mitigation measures.
- Though this study did use specific inventory and population data by province, regional variability in costs and conservation potential can be expected to vary in cost-effectiveness based on remoteness of facilities, labour rates, geological characteristics of wells or average age of equipment.
- Though there is a significant amount of information available on methane abatement measures, it has been historically difficult to quantify average methane reductions over a large sample size, which creates uncertainty in the abatement potential assessment. This uncertainty applies as much to the national inventory report as it does to individual technology characterisations. Fortunately, inspection technology and practices are improving rapidly as further attention is being paid to this field. Aerial and orbital inspection is becoming more accessible and is already informing more precise and timely studies.
- The emission source breakdown for oil sites remains a limitation of the study, and unlike British Columbia, reliable aerial surveys are not available everywhere. More accurate data and for both Alberta and Saskatchewan would better illustrate mitigation opportunities.
- Though this study does anticipate increased revenues from flaring redirection to sales lines, it does not account for the CO_2 savings generated by avoided combustion, as these are not part of the methane reduction initiatives.

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Appendix A

List of abatement measures ranked by cost ($ktCH_4$)

	Abatement Cost ($/ktCH4)	Abatement Potential (ktCH4)	Cumulative potential (ktCH4)	Cumulative cost ($1,000)	Cumulative average cost ($/tCH4)
Flash Tank Seperators – Gas Gathering	-$176	24	24	-$4,173	-$176
Flash Tank Seperators – Gas Battery	-$162	8	32	-$5,526	-$172
Capture Compressor Blow Down - Gas Battery	-$158	3	35	-$5,989	-$171
Capture Compressor Blow Down – Gas Plant	-$132	21	56	-$8,769	-$156
Kimray To Electrical Pumps – Gas Battery	-$125	21	77	-$11,389	-$148
Optimize Dehydrators Flowrates – Gas Gathering	-$119	3	80	-$11,772	-$147
Capture Compressor Blow Down – Gas Gathering	-$75	12	93	-$12,686	-$137
Kimray To Electrical Pumps – Gas Battery	-$64	7	100	-$13,160	-$132
Optimize Dehydrators Flowrates – Gas Battery	-$52	1	101	-$13,220	-$131
Monthly LDAR – Gas Processing	-$22	108	209	-$15,612	-$75
Reduced Emissions Completions – Gas Wells	-$8	38	247	-$15,905	-$64
Pneumatics Pumps To Air – Gas Battery	$83	271	518	$6,692	$13
Low Bleed Rod Packing Upgrade – Gas Gathering	$89	15	533	$8,057	$15
Low Bleed Rod Packing Upgrade – Gas Plant	$125	22	556	$10,853	$20
Monthly LDAR - Oil Wells	$153	81	637	$23,248	$36
Monthly LDAR – Gas Gathering	$343	74	711	$48,602	$68
Low Bleed Rod Packing Upgrade – Gas Battery	$375	7	719	$51,398	$72
Monthly LDAR - Gas Wells	$388	112	831	$94,932	$114
Instrument Air Pumps - Oil Battery	$415	73	903	$125,022	$138
Pneumatics Instrument To Air – Gas Battery	$432	239	1,142	$228,203	$200
Gas Start To Air Start – Gas Plant	$549	47	1,189	$253,944	$214
Pneumatics Instrument To Air – Gas Plant	$600	8	1,197	$258,879	$216
Pneumatics Pumps To Air – Gas Plant	$863	5	1,202	$262,877	$219
Gas Pipeline Tie-In - Bitumen Battery	$1,046	84	1,286	$351,031	$273
Instrument Air Devices - Oil Battery	$1,129	83	1,369	$445,051	$325
Gas Start To Air Start – Gas Gathering	$1,251	27	1,397	$478,983	$343
Tube Truck Tie-In - Bitumen Battery	$1,495	56	1,453	$562,969	$388
Plunger Lift – Gas Wells	$1,541	69	1,522	$669,909	$440
Pneumatics Pumps To Air – Gas Gathering	$1,798	10	1,532	$687,975	$449
Gas Pipeline Tie-In - Oil Battery	$1,836	133	1,665	$932,360	$560
Convert Gas Starter To Air Start – Gas Battery	$2,139	6	1,671	$944,930	$565
Tube Truck Tie-In - Oil Battery	$2,462	89	1,760	$1,163,331	$661
Pneumatics Instrument To Air – Gas Gathering	$2,528	22	1,782	$1,219,080	$684

List of abatement measures ranked by cost (ktCO2e)

	Abatement Cost ($/tCO₂e)	Abatement Potential (ktCO₂e)	Cumulative potential (ktCO₂e)	Cumulative cost ($1,000)	Cumulative average cost ($/tCO₂e)
Flash Tank Seperators – Gas Gathering	-$7	593	593	-$4,173	-$7
Flash Tank Seperators – Gas Battery	-$6	209	802	-$5,526	-$7
Capture Compressor Blow Down - Gas Battery	-$6	73	876	-$5,989	-$7
Capture Compressor Blow Down – Gas Plant	-$5	528	1,404	-$8,769	-$6
Kimray To Electrical Pumps – Gas Battery	-$5	524	1,928	-$11,389	-$6
Optimize Dehydrators Flowrates – Gas Gathering	-$5	81	2,009	-$11,772	-$6
Capture Compressor Blow Down – Gas Gathering	-$3	305	2,314	-$12,686	-$5
Kimray To Electrical Pumps – Gas Battery	-$3	185	2,499	-$13,160	-$5
Optimize Dehydrators Flowrates – Gas Battery	-$2	28	2,528	-$13,220	-$5
Monthly LDAR – Gas Processing	-$1	2,698	5,226	-$15,612	-$3
Reduced Emissions Completions – Gas Wells	$0	959	6,184	-$15,905	-$3
Pneumatics Pumps To Air – Gas Battery	$3	6,769	12,953	$6,692	$1
Low Bleed Rod Packing Upgrade – Gas Gathering	$4	384	13,337	$8,057	$1
Low Bleed Rod Packing Upgrade – Gas Plant	$5	561	13,899	$10,853	$1
Monthly LDAR - Oil Wells	$6	2,029	15,927	$23,248	$1
Monthly LDAR – Gas Gathering	$14	1,850	17,777	$48,602	$3
Low Bleed Rod Packing Upgrade – Gas Battery	$15	186	17,963	$51,398	$3
Monthly LDAR - Gas Wells	$16	2,807	20,771	$94,932	$5
Instrument Air Pumps - Oil Battery	$17	1,815	22,585	$125,022	$6
Pneumatics Instrument To Air – Gas Battery	$17	5,967	28,552	$228,203	$8
Gas Start To Air Start – Gas Plant	$22	1,173	29,725	$253,944	$9
Pneumatics Instrument To Air – Gas Plant	$24	206	29,931	$258,879	$9
Pneumatics Pumps To Air – Gas Plant	$35	116	30,047	$262,877	$9
Gas Pipeline Tie-In - Bitumen Battery	$42	2,107	32,154	$351,031	$11
Instrument Air Devices - Oil Battery	$45	2,083	34,236	$445,051	$13
Gas Start To Air Start – Gas Gathering	$50	678	34,915	$478,983	$14
Tube Truck Tie-In - Bitumen Battery	$60	1,405	36,319	$562,969	$16
Plunger Lift – Gas Wells	$62	1,735	38,055	$669,909	$18
Pneumatics Pumps To Air – Gas Gathering	$72	251	38,306	$687,975	$18
Gas Pipeline Tie-In - Oil Battery	$73	3,327	41,633	$932,360	$22
Convert Gas Starter To Air Start – Gas Battery	$86	147	41,780	$944,930	$23
Tube Truck Tie-In - Oil Battery	$98	2,218	43,998	$1,163,331	$26
Pneumatics Instrument To Air – Gas Gathering	$101	551	44,549	$1,219,080	$27

List of abatement measures ranked by cost (Bcf)

Measure	Abatement Cost ($/Bcf)	Abatement Potential (Bcf)	Cumulative potential (Bcf)	Cumulative cost ($1000)	Cumulative average cost ($/Bcf)
Flash Tank Separators (Battery)	-$3	1,235	1,235	-$4,173	-$3
Flash Tank Separators (Plant)	-$3	436	1,671	-$5,526	-$3
Capture Compressor Blow Down	-$3	153	1,824	-$5,989	-$3
Capture Compressor Blow Down	-$3	1,100	2,924	-$8,769	-$3
Kimray to Electrical Pumps	-$2	1,093	4,017	-$11,389	-$3
Optimize Flowrates (Dehydrators)	-$2	168	4,185	-$11,772	-$3
Capture Compressor Blow Down	-$1	636	4,821	-$12,686	-$3
Kimray to Electrical Pumps	-$1	386	5,206	-$13,160	-$3
Optimize Flowrates (Dehydrator)	-$1	59	5,265	-$13,220	-$3
LDAR-Processing	$0	5,621	10,886	-$15,612	-$1
Reduced Emissions Completions	$0	1,997	12,883	-$15,905	-$1
Pneumatics Pumps to Air (Battery)	$2	14,100	26,983	$6,692	$0
Low Bleed Rod Packing Upgrade (Gathering)	$2	801	27,784	$8,057	$0
Low Bleed Rod Packing Upgrade (Plant)	$2	1,169	28,953	$10,853	$0
LDAR-Wells	$3	4,226	33,179	$23,248	$1
LDAR-Gathering	$7	3,853	37,033	$48,602	$1
Low Bleed Rod Packing Upgrade (Battery)	$7	388	37,421	$51,398	$1
LDAR-Wells	$7	5,848	43,269	$94,932	$2
Instrument air pumps for oil battery sites	$8	3,780	47,049	$125,022	$3
Pneumatics Instrument to Air (battery)	$8	12,430	59,478	$228,203	$4
Gas Sart to Air start (Plant)	$11	2,444	61,922	$253,944	$4
Pneumatics Instrument to Air (plant)	$12	429	62,351	$258,879	$4
Pneumatics Pumps to Air (plant)	$17	241	62,592	$262,877	$4
Casing Gas Recovery (Tie In)	$20	4,390	66,982	$351,031	$5
Instrument air devices for oil battery sites	$22	4,339	71,320	$445,051	$6
Gas Sart to Air start (Gathering)	$24	1,413	72,733	$478,983	$7
Casing Gas Recovery (Tube Truck)	$29	2,926	75,660	$562,969	$7
Plunger Lift	$30	3,615	79,275	$669,909	$8
Pneumatics Pumps to Air (Gathering)	$35	523	79,798	$687,975	$9
Tie-In	$35	6,931	86,729	$932,360	$11
Convert Gas Starter to Air Start (Battery)	$41	306	87,035	$944,930	$11
Tube Truck Tie-In	$47	4,621	91,655	$1,163,331	$13

Appendix B

Summary of Measures

Emissions Sources (kt Methane per year)

Facility Type	Facilities (#)	Wells (#)	Dehydrators (#)	Compressors (#)	Defined Vent Gas (kt/year)	Pneumatics Pumps (kt/year)	Pneumatic instruments (kt/year)	Reciprocating Compressors (kt/year)	Centrifugal Compressors (kt/year)	Glycol Dehydrators (kt/year)	Fugitive Emissions (kt/year)
Gas Battery	14,146	94,565	351	759	147	271	239	15	0	19	125
Gas Plant	835	-	692	1,924	71	5	8	45	3	8	120
Gas Gathering/Compressor Station	10,257	-	519	2,168	41	10	22	51	1	54	82
Crude Bitumen Battery	5,171	5,542	7	54	148	4	2	1	-	-	36
Crude Oil Battery	12,539	38,021	109	643	233	73	83	13	-	2	54

Facility inventories are based on provincial inventories; for Alberta the MERR 2022 dataset was directly applied. For Saskatchewan, Alberta's MERR dataset was prorated based on provincial production levels. British Columbia's total was based on Johnson's 2022 inventory.

Alberta Energy Regulator. (2022). Methane Emissions Management from the Upstream Oil and Gas Sector in Alberta https://open.alberta.ca/dataset/7e41d270-075f-498c-9b3d-7b822c930760/resource/87499438-dacb-4bb6-8d1f-e0f75dc92852/download/aep-methane-emissions-management-upstream-oil-and-gas-sector-2020.pdf

Johnsol et. Al. (2022) Creating Measurement-Based Oil and Gas Sector Methane Inventories using Source-Resolved Aerial Surveys. https://doi.org/10.21203/rs.3.rs-2203868/v1

Assumptions for applying measures to facility types

Defined Vent Gas	Facility Type	Emissions source	Share of targeted emission (%)	Share of emissions source components applicable (%)	Reduction (%)	Justification
Compressor Blow Down	**Gas Battery**	**Compressor**	2%	10%	100%	Very low (2%) share of targeted emission due to low frequency of event. Low applicability due to lack of infrastructure in the field.
	Gas Plant	**Compressor**	33%	50%	90%	High (50%) applicability due to infrastructure being available in plants, relatively important share of emissions due to large population of compressors.
	Gas Gathering/Compressor Station	**Compressor**	33%	50%	90%	High (50%) applicability due to infrastructure being available in plants, relatively important share of emissions due to large population of compressors.
Gas Start to Air start	**Gas Battery**	**Compressor**	4%	50%	100%	Very low (4%) share of targeted emission due to low population in the field. Assume 50% of sites have infrastructure necessary for air start.
	Gas Plant	**Compressor**	66%	50%	100%	Large (66%) share of targeted emission due to high number of compressors in plants. Assume 50% of sites have infrastructure necessary for air start.
	Gas Gathering/Compressor Station	**Compressor**	66%	50%	100%	Large (66%) share of targeted emission due to high number of compressors in plants. Assume 50% of sites have infrastructure necessary for air start.
Reduce Emission Completion	**Gas Battery**	**Well**	29%	2%	90%	Medium share of targeted emissions (29%) due to intense but infrequent instances of methane release. Low applicability because RECs only apply to new or renovated well installations. Many wells also already subject to regs (BC).
Plunger lift	**Gas Battery**	**Well**	63%	30%	75%	Environmental Protection Agency. (2016). Options for Removing Accumulated Fluid and Improving Flow in Gas Wells. https://www.epa.gov/sites/default/files/2016-06/documents/ll_options.pdf
Casing Gas Recovery (Tie In)	**Crude Bitumen Battery**	**Well**	60%	60%	95%	Assume a large portion of casing gas recovered can be tied into existing collection infrastructure.
Casing Gas Recovery (Tube Truck)	**Crude Bitumen Battery**	**Well**	40%	40%	95%	Assume remaining proportion of casing gas recovered can be collected through tube trucks.
Tie-In	**Crude Oil Battery**	**Well**	60%	60%	95%	Assume a large portion of gas recovered on oil sites (including currently flared gases) can be tied into existing gas collection infrastructure.
Tube Truck Tie-In	**Crude Oil Battery**	**Well**	40%	40%	95%	Assume remaining proportion of oil site gas recovered can be collected through tube trucks.

Pneumatics Pumps & Pneumatics Instrument	Facility Type	Emissions source	Share of targeted emission (%)	Share of emissions source components applicable (%)	Reduction (%)	Justification
Pneumatics pumps to air	**Gas Battery**	**Pumps**	100%	90%	100%	Aggressive transformation of pneumatic pumps to compressed air. Assume only 10% already use compressed air due to complications in the field.
	Gas Plant	**Pumps**	100%	50%	100%	Aggressive transformation of REMAINING pneumatic pumps to compressed air. Assume 50% already use compressed air.
	Gas Gathering/Compressor Station	**Pumps**	100%	50%	100%	Aggressive transformation of REMAINING pneumatic pumps to compressed air. Assume 50% already use compressed air.
	Crude Oil Battery	**Pumps**	100%	90%	100%	Aggressive transformation of pneumatic pumps to compressed air. Assume only 10% already use compressed air due to complications in the field.
Pneumatics instrument to air	**Gas Battery**	**Instruments**	100%	90%	100%	Aggressive transformation of pneumatic instruments to compressed air. Assume only 10% already use compressed air due to complications in the field.
	Gas Plant	**Instruments**	100%	50%	100%	Aggressive transformation of REMAINING pneumatic instruments to compressed air. Assume 50% already use compressed air.
	Gas Gathering/Compressor Station	**Instruments**	100%	50%	100%	Aggressive transformation of REMAINING pneumatic instruments to compressed air. Assume 50% already use compressed air.
	Crude Oil Battery	**Instruments**	100%	90%	100%	Aggressive transformation of pneumatic instruments to compressed air. Assume only 10% already use compressed air due to complications in the field.

Compressors	Facility Type	Emissions source	Share of targeted emission (%)	Share of compressors applicable	Reduction (%)	Justification
Rod Packing System Upgrade or Capture gas from wet seal	**Gas Battery**	**Compressor**	100%	70%	50%	Adapted from EDF2015 assuming only 70% of target compressors remain to be upgraded - ICF. (2015). Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries.
	Gas Plant	**Compressor**	100%	25%	50%	Adapted from EDF2015 assuming only 25% of target compressors remain to be upgraded - ICF. (2015). Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries.
	Gas Gathering/Compressor Station	**Compressor**	100%	25%	30%	Adapted from EDF2015 assuming only 25% of target compressors remain to be upgraded - ICF. (2015). Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries.
	Crude Oil Battery	**Compressor**	100%	70%	50%	Adapted from EDF2015 assuming only 70% of target compressors remain to be upgraded - ICF. (2015). Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries.

Glycol Dehydrators	Facility Type	Emissions source	Share of targeted emission (%)	Share of compressors applicable	Reduction (%)	Justification
Flash Tank Separators	**Gas Battery**	**Dehydrator**	49%	50%	90%	We assume roughly half of dehydrator emissions are due to flashing, and that 50% of active units have flash tanks.
	Gas Gathering/Compressor Station	**Dehydrator**	49%	50%	90%	We assume roughly half of dehydrator emissions are due to flashing, and that 50% of active units have flash tanks.
Kimray to Electrical Pumps	**Gas Battery**	**Dehydrator**	39%	70%	100%	We assume 39% of emissions from dehydrators are released to power the pump, that that electric pumps have grown to 20%, and 10% are non convertible for technical reasons.
	Gas Gathering/Compressor Station	**Dehydrator**	39%	70%	100%	We assume 39% of emissions from dehydrators are released to power the pump, that that electric pumps have grown to 20%, and 10% are non convertible for technical reasons.
Optimize flowrates	**Gas Battery**	**Dehydrator**	6%	100%	100%	We assume that a small part (6%) of dehydrator emissions can be avoided via optimisation, based on EPA. (2016). Optimize Glycol Circulation And Install Flash Tank Separators In Glycol Dehydrators https://www.epa.gov/sites/default/files/2016-06/documents/ll_flashtanks3.pdf
	Gas Gathering/Compressor Station	**Dehydrator**	6%	100%	100%	We assume that a small part (6%) of dehydrator emissions can be avoided via optimisation, based on EPA. (2016). Optimize Glycol Circulation And Install Flash Tank Separators In Glycol Dehydrators https://www.epa.gov/sites/default/files/2016-06/documents/ll_flashtanks3.pdf

Fugitive Emissions	Oil and Gas Well Sites	Gathering	Processing	Justification
Emissions % Reduction	90%	90%	90%	The hours listed here are based on previous analysis by ICF. (2015). Economic Analysis of Methane Emission Reduction Opportunities in the Canadian Oil and Natural Gas Industries Prices have been updated using local Alberta vendors prices for 2023, see Appendix C.
Hours per LDAR inspection	0.4	10.7	16	
Frequency of LDAR per year	9	9	9	
Annual inspection cost	$769.56	$20,585.61	$30,782.23	

Appendix C

Cost of Measures

Measure	Emission Source	Sector	Reference		Measure Description	Capex (2022 $)	Maintenance (2022 $)
Compressor Blow Down	**Compressor**	**Gas**	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Recover some of the otherwise vented gas during blowdowns by connecting blowdown vents to the inlet.	$ 13,794	$ -
Gas Start to Air start	**Compressor**	Gas	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Replace pressurized gas use to start internal combustion engines for compressors with compressed air.	$ 335,064	$ 5,700
Rod Packing System Upgrade or Capture gas from wet seal	**Compressor**	Gas or Oil	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Upgrade the rod packing to a low bleed packing rings packing system.	$ 28,500	$ 7,125
Flash Tank Separators	**Dehydrators**	Gas	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Install a flash tank separator to recover gas during glycol regeneration process.	$ 14,978	$ -
Kimray to Electrical Pumps	**Dehydrators**	Gas	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Replace gas-assisted glycol pumps with electric pumps.	$ 40,389	$ -
Optimize flowrates	**Dehydrators**	Gas	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Monitor and maintain thermoelectric generator circulation at optimal, reduced rate to avoid unnecessary venting.	$ -	$ 616
Pneumatics pumps to air	**Pneumatics Pumps**	Gas	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Retrofit pneumatic components to run on compressed air instead of gas. Solar panels and batteries provide 10 days of power for the system.	$ 39,900	$ 133
Pneumatics instrument to air	**Pneumatics Instruments**	Gas	**Delphi (2017) - Adjusted with oil and gas PPI**	Delphi Group. (2017). Methane Abatement Costs: Alberta. https://static.aer.ca/prd/documents/DelphiAlbertaMethaneAbatementCostStudy.pdf	Retrofit pneumatic components to run on compressed air instead of gas. Solar panels and batteries provide 10 days of power for the system.	$ 39,900	$ 133
Reduce Emission Completion	**Wells**	Gas	**Natural Gas Star**	Environmental Protection Agency. (2016). Reduced Emissions Completions for Hydraulically Fractured Natural Gas Wells. https://www.epa.gov/sites/default/files/2016-06/documents/reduced_emissions_completions.pdf#:~:text=RECs%20help%20to%20reduce%20methane%2C%20VOC%2C%20and%20HAP,reported%20performing%20reduced%20emissions%20completions%20in%20their%20operations.	Capture gas that would otherwise be vented or flared during well completion.	$ 39,136	$ -
Plunger lift	**Wells**	Gas	**Kaizen Well, value is mid point between High and Low range**	Quote obtained from Kaizen well solutions, 2023	Equipment installation that allows operators to remove accumulated fluids in the well without incurring significant gas losses.	$ 44,500	$ -
Casing Gas Recovery (Tie In)	**Wells**	Bitumen	**Gas Pro: Booster Compressor ($359 000)**	Quote obtained from Gas Pro Compression Corp., 2023	If gathering infrastructure is available, bring casing gas to sale by increasing well pressure and feed into sales line.	$ 359,000	$ 7,296
Casing Gas Recovery (Tube Truck)	**Wells**	Bitumen	**Gas Pro: Booster Compressor ($359 000) + Tube Truck Removal ($128 000)**	Quote obtained from Gas Pro Compression Corp., 2023	If gathering infrastructure is not available, bring casing gas to sale by increasing well pressure and transporting gas in tube trucks.	$ 487,000	$ 7,296
Tie-In	**Wells**	Oil	**Gas Pro**	Quote obtained from Gas Pro Compression Corp., 2023	If gathering infrastructure is available, bring associated gas to sale by increasing well pressure and feed into sales line.	$ 359,000	$ 7,296
Tube Truck Tie-In	**Wells**	Oil	**Gas Pro**	Quote obtained from Gas Pro Compression Corp., 2023	If gathering infrastructure is not available, bring associated gas to sale by increasing well pressure and transporting gas in tube trucks.	$ 487,000	$ 7,296
LDAR Wells	**Fugitives**	All	**Described Below**				
LDAR Gathering	**Fugitives**	Gas					
LDAR Processing	**Fugitives**	Gas					

Leak Detection and Repair (LDAR) Cost Parameters	
Labour Rate	$ 177.38
Hours/yr	1,880.00
Infrared Camera	$ 222,000
Photo Ionization Detector	$ 9,000
Truck (GMC Sierra)	$ 72,000
Record Keeping	$ 24,795
Training (80 hours)	$ 14,191
Amortized Capital + Training	$ 68,397
Annual Labour	$ 333,482
Annual Total Cost	$ 401,879
Total Cost as Hourly Rate	$ 213.77

Quotes obtained from various Alberta equipment suppliers, 2023
Pricing structure based on EDF2015 report

Leak detection and repair (LDAR) measure is based on the increase in average intervention frequency from once every four months to once per month. Costs and reduction potential were calculated using the updated cost parameters (see table at left) for each case. The marginal increase in total annual cost was divided by the marginal increase in annual methane reductions to determine the cost effectiveness of increasing the frequency of inspection and repair.

Potential emissions reduction numbers were taken from simulations in Fugitive Emissions Abatement Simulation Toolkit (FEAST) conducted by Kemp et al. (2021), and we did not remodel specific parameters.

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This report was prepared by Dunsky Energy + Climate Advisors, an independent firm focused on the clean energy transition and committed to quality, integrity and unbiased analysis and counsel. Our findings and recommendations are based on the best information available at the time the work was conducted as well as our experts' professional judgment. **Dunsky is proud to stand by our work.**