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ALBERTA'S LOW-CARBON HYDROGEN PRODUCTION:

HOW LOW CAN IT GO?

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1.

EXECUTIVE SUMMARY

Alberta is a major low-cost producer and leader in hydrogen technology, and now finds itself on the path to becoming a mature low carbon hydrogen economy. When it comes to hydrogen production in the province, most new investment has focused on making hydrogen from natural gas with carbon capture and geological storage (CCS), with at least eight major facilities under development. This method of hydrogen production is often referred to by industry as "blue" hydrogen. The resulting hydrogen product from these potential facilities may be used within the province to decarbonize industry, transportation, heat and power applications, or converted to ammonia for export.

Worldwide, there is increasing emphasis on developing standards for hydrogen as a low carbon fuel based on lifecycle carbon intensity. While Alberta and Canada do not currently have such standards in place, this will become increasingly relevant to Alberta, especially if the province aims to export its hydrogen products on an international stage. The most advanced of these standards is CertifHy in Europe at 4.4 kg CO_2/kg H_2, but others are emerging as well. This raises the question of how "low"can the carbon intensity of Alberta's produced hydrogen production go, assuming it continues to be made predominantly from natural gas – and will it be sufficiently low enough to meet emerging emissions standards?

Lifecycle emissions for Alberta blue hydrogen production arise from three main sources: (1) CO_2 produced during hydrogen production; (2) CO_2 released during combustion activities that take place during natural gas production, processing, and transportation, upstream of the hydrogen production facility; and (3) methane released during these same upstream activities. For (1), high capture rates are possible with natural gas autothermal reforming (ATR) technology that enables very high levels of CO_2 emissions reduction during production. Production emissions can be further reduced by sourcing electricity for the ATR facility from the low-carbon hydrogen itself, rather than the provincial grid, or from other low-carbon power sources.

For (2) and (3), the picture is more nuanced. When it comes to CO_2 and methane emissions upstream of the actual hydrogen production facility, there is significant variability among producers in their reported emissions. For example, the provincial average is reported as 3.2 kg CO_2e/GJ natural gas produced, but individual sustainability reports from some of Alberta's top natural gas producers with activities in the Montney field show them beating this average by a factor of seven, with intensities as low as <0.5 kg CO_2e/GJ. This variability is to some extent attributable to the natural gas fields themselves, based on factors like gas composition, produced water, field maturity, and distances from wells to delivery point – but is also related to the degree to which best available technologies have been implemented, including both emissions reduction as well as measurement and monitoring technologies.

To date, operators in the province have made significant investments to reduce emissions along the upstream natural gas value chain, including reducing emissions from pneumatics, engines, and compressors. Many of these technologies are now in the implementation phase by the most advanced natural gas producers but have yet to reach full-scale implementation across the province – hence the wide variance between the provincial average and the best performers.

There are also significant uncertainties around emissions calculation methodologies that impact all producers, especially when it comes to methane reporting. Methane is a far more potent greenhouse gas than CO_2, but unlike CO_2, which is a direct product of combustion activities, methane occurs naturally. Leakages and fugitive emissions occur all along the natural gas value chain. For this reason, in addition to deploying technologies to reduce methane, technologies to improve measurement and monitoring of methane are equally important to minimize the lifecycle emissions of blue hydrogen.

In our analysis, we concluded that if an ATR+CCS hydrogen production facility uses natural gas that has the average footprint of Alberta upstream production and Alberta grid electricity, then the lifecycle GHG emissions are in the range of 3.7 kg CO_2e/kg of hydrogen. By contrast, best practices for equipment selection and GHG leak detection and repair can bring this value down to 2.7 kg CO_2e/kg of hydrogen. Further reduction to below 1 kg CO_2e/kg hydrogen can be achieved by using electricity generated by the low carbon hydrogen itself or other low-carbon sources. These values are well below existing or projected international standards, even when uncertainties around methane reporting are taken into account.

It does not take many natural gas producers to fulfill the demand for the number of hydrogen facilities being proposed in Alberta. For example, a small handful of high-performing Montney fields is sufficient for a major hydrogen production facility. Therefore, meeting international low carbon hydrogen standards is possible with technology already being implemented at the level of production required, provided there are contractual mechanisms and drivers in place to do so. Going forward, it will be critical to expand use of best available technology and ensure appropriate measurement verification mechanisms are in place so that Alberta's natural gas-based hydrogen can continue to meet clean fuel standards and establish credibility as a zero-emissions pathway on an international scale.

2.

INTRODUCTION

2.1 Alberta's Low-Carbon Hydrogen Opportunity

Alberta is currently the largest hydrogen producer in Canada, producing 2.4 MT H_2/year for traditional industrial uses at some of the lowest costs in the world (Alberta Energy, 2021). To date, hydrogen in Alberta has mainly been produced using steam methane reforming (SMR) without CCS, also known as "gray" hydrogen. This has a relatively high GHG intensity of 10-14 kg CO_2e/kg H_2, of which 1-5 kg CO_2e/kg H_2 arises from upstream natural gas production. Therefore, in the gray hydrogen case, the majority of lifecycle emissions arise from CO_2 released during hydrogen production, rather than the production of the upstream natural gas (International Energy Agency, 2024).

While current hydrogen production in Alberta is relatively high-emitting, this is expected to change in the near future. Low-carbon hydrogen production and export of hydrogen carriers, like ammonia, are core pillars of *Alberta's Emissions Reduction and Development Plan* and its provincial *Hydrogen Roadmap*. Because of Alberta's existing, deep expertise in hydrogen, access to abundant, low-cost natural gas, as well as ample geological pore space infrastructure for permanent storage of CO_2, Alberta has become a target for global investment in low-carbon hydrogen projects – ranging from businesses specializing in industrial chemicals to international trading houses in Asia.

Most recent investment in the province has focused on hydrogen produced from natural gas via SMR or ATR combined with CCS, which drastically reduces the carbon footprint compared to current practices, while also taking advantage of Alberta's economic advantages. This is referred to by industry as "blue" hydrogen. This hydrogen will be produced at large central facilities to be used locally in a variety of applications, or else converted to blue ammonia and methanol for export as a low-carbon fuel overseas, most to likely Korea and Japan. As of March 2024, at least eight large-scale hydrogen facilities were under development in Alberta to produce hydrogen and/or ammonia and methanol from SMR or ATR of natural gas (Government of Alberta, 2024).

LOCALLY IN ALBERTA, LOW-CARBON HYDROGEN CAN DISPLACE:

- Existing industrial demand in oil and gas refining and fertilizer production that is currently being served by "gray" hydrogen, made from natural gas without carbon capture
- Fossil fuels used in transportation, for fuel cell electric vehicles, dual fuel, and H_2 combustion
- Fossil fuels used for electricity and home heating

INTERNATIONALLY, BLUE HYDROGEN CAN BE CONVERTED TO AMMONIA AND EXPORTED, WHERE IT CAN DISPLACE:

- Power, such as blending ammonia with coal
- Or could be converted back to hydrogen for other end uses.

2.2 Other types of low carbon hydrogen production

Apart from SMR and ATR, other methods of hydrogen production are also being explored in Alberta. For example, there has been significant investment in distributed hydrogen production from methane pyrolysis (also called natural gas decomposition, or NGD) with carbon black as a byproduct, known as "turquoise" hydrogen. To date, investment here has mainly focused on distributed hydrogen production for domestic use, rather than large central facilities and/or for export – although these opportunities may emerge in the future. There is also at least one company exploring production of very low carbon hydrogen from biomass. While these both offer promising avenues for emissions reduction, they largely out of scope for this paper as they are not currently the major focus of international investment.

Of note, elsewhere in the world, including Eastern Canada and the Middle East, investment has focused on developing large projects to produce hydrogen from zero-emissions electricity via electrolysis. This is commonly known as “green” hydrogen, and may be produced from wind, solar, or nuclear power. In Alberta, there has been more limited focus on this type of hydrogen production due to the need for enormous quantities of low-carbon electricity and freshwater, as well as the technology’s current lack of scalability that would erode Alberta’s economic advantage (The Transition Accelerator, 2020).

2.3 Emerging GHG standards for hydrogen & its carriers

Given these various production methods, and the potential role of hydrogen as a global zero-emissions pathway, there is active discussion worldwide on how to understand and consistently measure the emissions profile of a given low-carbon hydrogen value chain. This discussion becomes even more critical when hydrogen and its carriers, such as ammonia, are the focus for international trade as low carbon fuel commodities, since these fuels must ultimately demonstrate they are helping to achieve emissions reduction in the countries where they are imported. Even domestically, there may be end-users of hydrogen with corporate sustainability targets that require them to validate their use of low carbon fuels.

It is increasingly accepted that color by itself is used inconsistently and does not indicate exactly how the hydrogen was produced, nor does it provide sufficient information as to the lifecycle emissions of the resultant hydrogen product. For this reason, governments and stakeholders worldwide are moving towards lifecycle carbon intensity as a quantitative basis for comparison between projects and for setting a benchmark as to what qualifies as “low carbon”, often agnostic to the actual method of production.

Europe is the most advanced jurisdiction in this regard with its “CertifHy EU Low-H_2 Standard” of 4.37 kg CO_2/kg H_2, which is referenced in Alberta’s Hydrogen Roadmap (Alberta Energy, 2021). As shown below in Fig. 1, over its lifecycle, blue hydrogen using ATR with a high capture rate likely meets this standard, whereas blue hydrogen produced from SMR with a lower rate of capture likely does not.

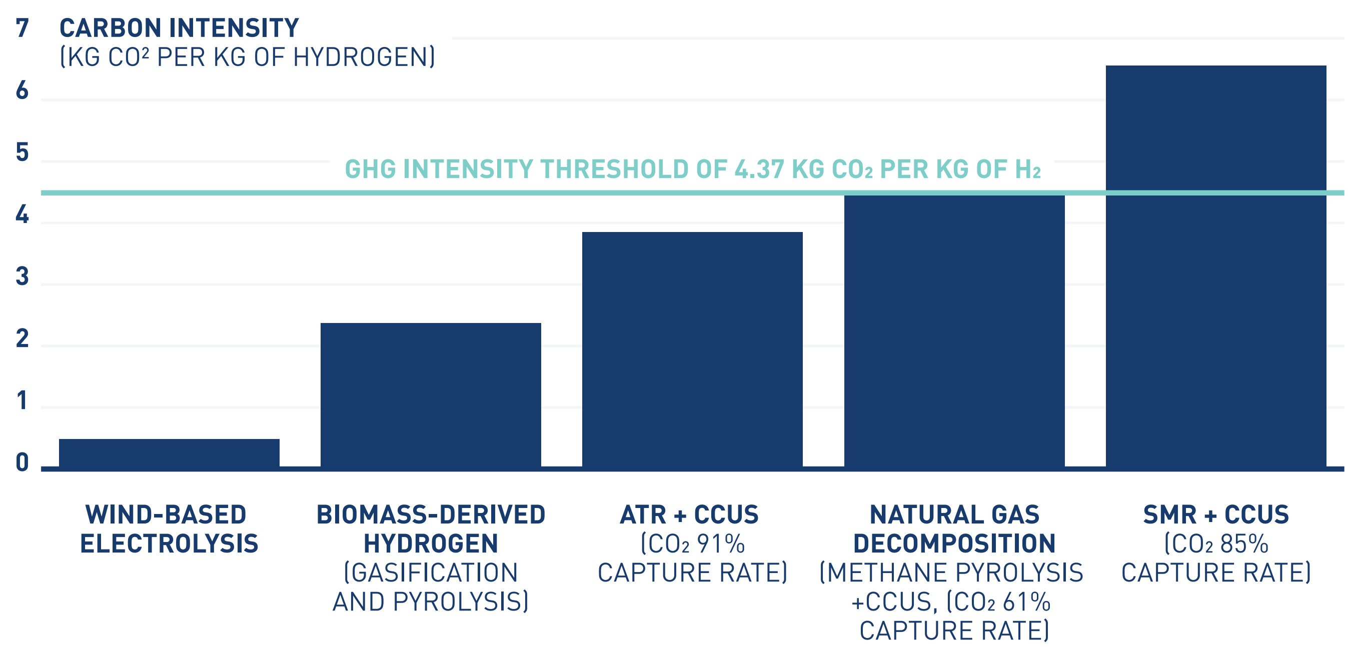


Figure 1. GHG footprint of hydrogen derived from different production technologies in Alberta (Alberta Energy, 2021).

For Alberta to supply hydrogen products overseas, additional steps are required for conversion and transportation. This typically involves conversion to ammonia, which can be much more readily transported over long distances than pure hydrogen itself (Meikle et al, 2023). On an energy content basis, the CertifHy standard translates to 36 kg CO_2e/GJ of energy delivered by a low-carbon fuel, therefore, the standard would translate to 9.75 kg CO_2e/t of ammonia fuel.

Apart from CertifHy, other emerging standards for low-carbon hydrogen range from 3.4 to 14.5 kg CO_2e/kg H_2 (Table 2). It is likely that these and other standards will decrease over time. Some standards prescribe that hydrogen must be produced from renewables, which range 2.4-3.4 kg CO_2e/kg H_2 (Table 2). Other jurisdictions, such as Asia and the US, the most likely targets for Alberta exports, do not currently have such carbon intensity standards – but they may follow Europe's lead and develop them in the future.

This raises the question, will Alberta's low carbon hydrogen and ammonia produced from natural gas continue to meet these standards in the future? And more importantly, what technologies are needed to achieve these standards? What does a best-in-class natural gas-based hydrogen value chain look like – and when it comes to emissions, **how low can it go?**

TABLE 1. EMERGING HYDROGEN STANDARDS

STANDARD OR TARGET	COMPARATORS AND LEVELS SET	GHG LIMIT, G CO_2E/MJ	KG CO_2E/KG H_2
TUV Rhineland H2.21	Comparator - SMR of methane	94	11.3
	Renewable H_2 - electrolysis	28.2	3.4
	Low-C H_2 - any process path	28.2	3.4
CertifHy (EU)	Comparator - SMR of methane	91	10.9
	Renewable H_2 - electrolysis	36.4	4.4
	Low-C H_2 - any process path	36.4	
4.4UK Low Carbon Hydrogen Standard		20	2.4
China Standard and Assessment for Low-Carbon Hydrogen, Clean Hydrogen and Renewable Hydrogen Energy	Comparator - Coal gasification	242	29
	Low-C H_2 - 50% below comparitor	120.9	14.5
	Comparator - Coal gasification w CCS	117	14.0
	Clean H_2 65% reduction from comparitor	40.8	4.9
USDOE Clean Hydrogen Production Standard		33.3	4
Japan Hydrogen Strategy			3.4

3.

LOW CARBON HYDROGEN PRODUCTION IN ALBERTA

Below we discuss (1) the steps along the value chain for making hydrogen from natural gas, (2) the emissions that result from these activities, and (3) potential sources of variability, to provide context around low-emissions cases of large-scale hydrogen production in Alberta.

3.1 A natural gas-based value chain for low carbon hydrogen

What does a natural gas-based value chain for hydrogen look like – what are the steps along the way? What are the sources of emissions and how much can the emissions profile vary within the broad category of "blue"? In a typical large-scale blue hydrogen production facility, emissions can be divided into three main source categories:

1. **Emissions from hydrogen production plants with carbon capture and storage (CCS)**
   a. Any CO_2 that is not captured and stored, as capture rates are not 100%
   b. Emissions associated with electric power consumption for the hydrogen plant
2. **CO_2 emissions from upstream natural gas processing, and transportation**
   c. CO_2 emissions from combustion of fuels in gas plants, compressors, and flares
   d. Venting of carbon dioxide separated from the raw natural gas
3. **Methane emissions from upstream natural gas production and processing**
   a. Methane emissions from incomplete combustion, venting, and fugitive emissions

Source: Meikle et al., 2023

Based on the hydrogen export gap analysis from Meikle et al. (2023), which assumed hydrogen was produced using ATR+CCS and relied on publicly available data for upstream processing, the respective contribution between these three areas to lifecycle emissions is as follows:

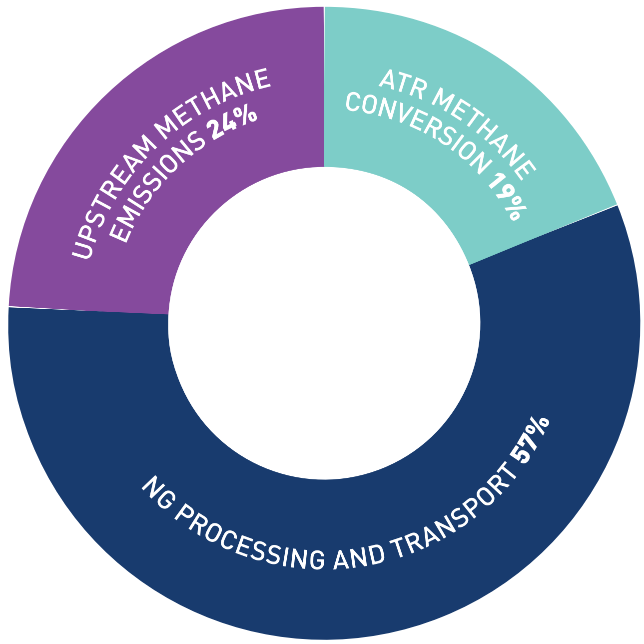
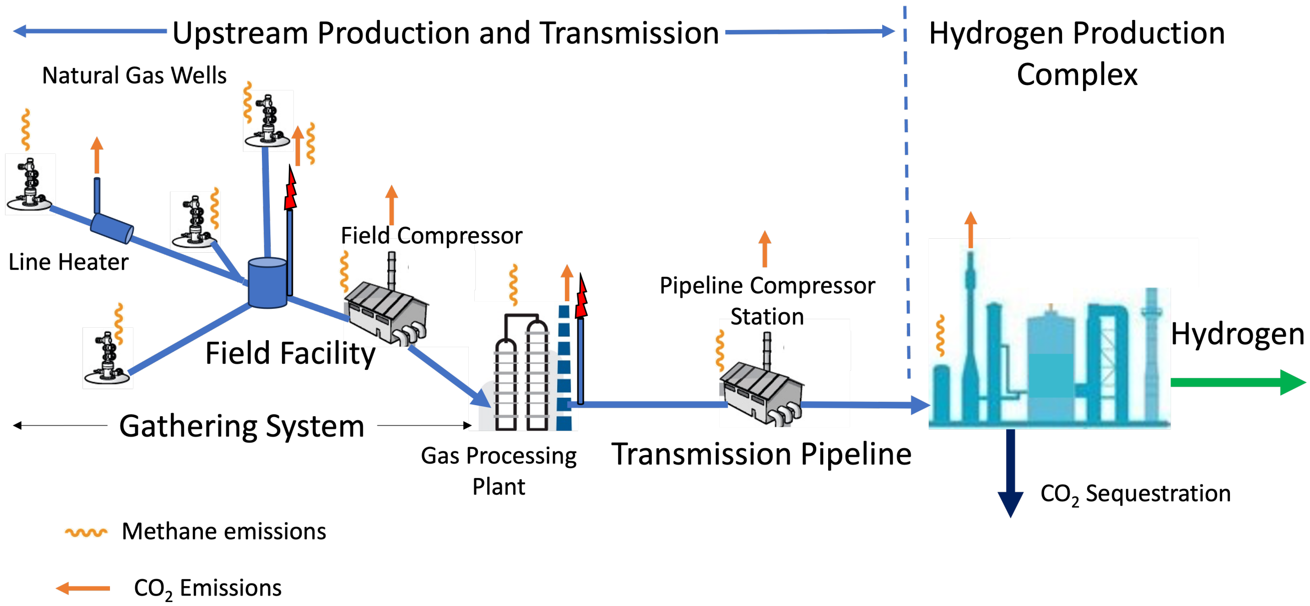


Figure 2. Sources of GHG emissions for blue hydrogen in Alberta. Total upstream emissions are from Oni et al., 2022, with fraction of methane emitted from ECCC, 2022. Contribution from hydrogen production is for an ATR plant with 95% CCS and electric power from produced hydrogen.

This shows that unlike in the "gray" hydrogen case, where the majority of emissions arise from hydrogen production itself (International Energy Agency 2022), when CCS is applied, the majority of lifecycle emissions occur upstream of the actual hydrogen facility. Therefore, lifecycle GHG intensity becomes largely dependent on natural gas production practices.

Figure 3 shows a schematic diagram of the typical steps for production, transport and conversion of hydrogen at a central hydrogen facility in Alberta, indicating the sources and types of emissions. Note: emissions associated with electric power from the



grid are not shown.

Figure 3. Schematic diagram of natural gas production and processing to hydrogen in a central facility, indicating4 sources of methane and carbon dioxide emissions.

This shows that CO_2 emissions arise primarily from combustion activities at compressor stations and natural gas processing plants, and that methane arises from many sources, ranging from the wellhead itself to venting and leakage at all steps of the value chain. NO_x, not shown here, occurs in smaller amounts as a byproduct of fossil fuel combustion. It is important to the discussion because some emerging technologies to eliminate NO_x from combustion engines have had the unintended side effect of increasing methane emissions, in an effect known as "methane slip".

Evidence of the difficulty of quantifying emissions upstream of the hydrogen production facility is exemplified by the difference between the provincial average and what large-scale natural gas producers provide in their sustainability reporting. The data of **Figure 4** compares the five-year average of Alberta's total upstream emissions (Oni et al., 2022) with data from three large-scale producers' 2022 sustainability reports. The producers that were chosen have activities in the Montney field and are considered leaders in terms of their environmental performance. This demonstrates the potential for great variability, even within the same province.

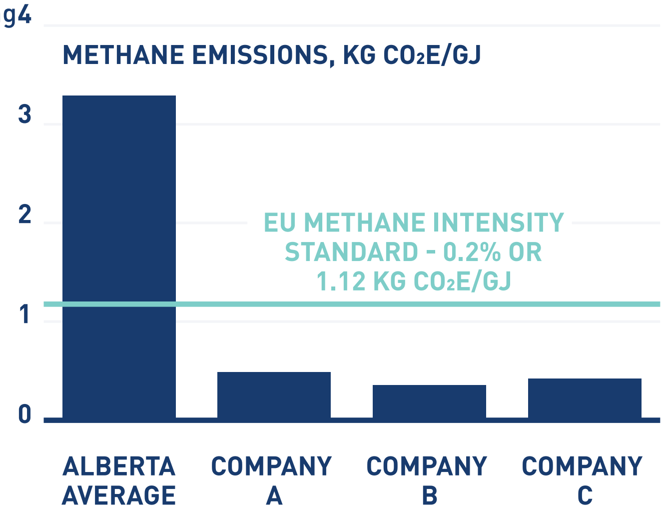


Figure 4. Alberta's total 'upstream' methane emissions for natural gas production, processing, and transport by pipeline from Modern West (2023), compared to methane emissions reported by example large natural gas producers. Company data are examples from three 2022 sustainability reports.

3.2 Sources of variability

One of the main reasons for variability arises from the characteristics of the natural gas field itself. Emissions data reported to the AER has shown that upstream operations are highly variable from field to field. Some fields, like the Montney, possess characteristics that make them inherently lower emitting. Some examples of variables that determine these variations in emissions profile include:

- **Gas composition** – sweet versus sour. Sour gas can contain from 2% to over 10% carbon dioxide, even within a single formation like the Montney (Raj et al., 2016).

- **Produced water** – may require gas field facilities to handle water production, which requires energy, and may result in additional emissions.

- **Field maturity and reservoir characterization** – older and shallower operations need more compression, which requires energy, and may result in additional emissions.

- **Distances from wells to final delivery point** – impact transportation emissions profile.

Beyond this inherent variability, there is also uncertainty in upstream emissions arising from the current calculation requirements for reporting emissions. The three main GHGs released during natural gas production include CO_2, methane, and NO_x. CO_2 is relatively straightforward to track and measure because it generally involves combustion, but naturally occurring methane is more challenging, and there are limits to the methodology and accuracy of the current reporting approach. For example, average emissions factors are used for calculating the methane slip in flares to approximate their contribution to the carbon footprint. Similarly, fugitive and venting emissions are often based on calculated amounts rather than actual field measurements. This contrasts with independent studies of actual methane emissions based on airborne sensing or satellite measurements, which can give approximately 1.5x higher emission estimates than regulatory emissions calculations (Conrad et al., 2023). These discrepancies are exacerbated when including comparisons with fixed sensor or ground-level measurements.

Figure 5 shows the magnitude of various source categories of methane emissions in natural gas upstream production and processing, based on current reporting methodologies in Alberta. The largest source is pneumatic equipment, which includes pumps and control systems that use compressed natural gas to drive their operations, with low-pressure gas vented as a result. Compressors and flares burn natural gas as a fuel, but the combustion efficiency is less than 100%, so these sources "slip" methane gas to the environment in addition to releasing CO_2. Venting includes regular ongoing releases of methane from dehydration units and venting of equipment, such as tanks, as routine operations as well as for maintenance and repair. Fugitive emissions are defined as unintentional releases of gas to the atmosphere from leaking equipment such as valves, connectors, and meters.

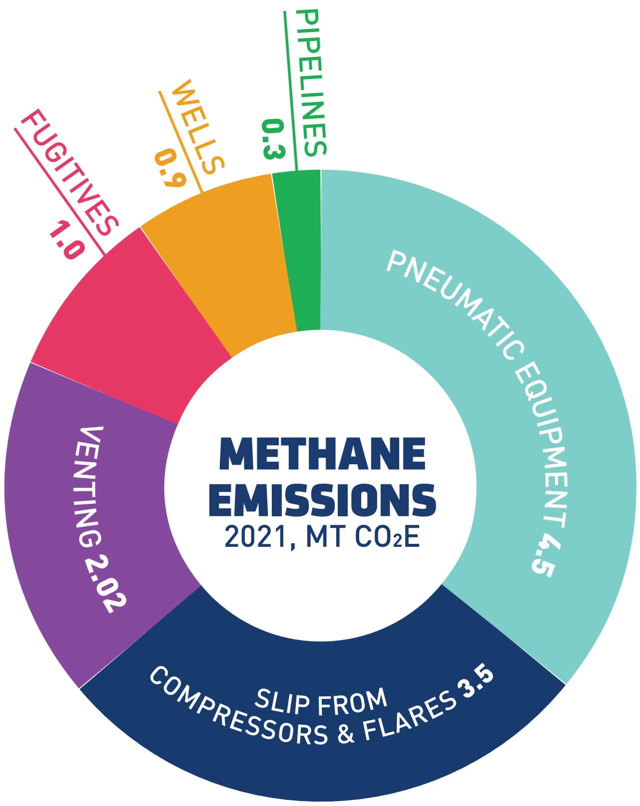


Figure 5. Sources of methane emissions from natural gas production and processing (Modern West, 2023).

Given this context – the variability, and major sources of emissions, as well as the inherent uncertainty in quantifying those emissions – we now turn to analyzing the potential "floor" lifecycle GHG intensity for low carbon, natural gas-based hydrogen in Alberta, and the associated technology solutions.

4.

ANALYSIS

In this section, we assess opportunities for reducing emissions across the hydrogen value chain and highlight some examples of best available technology being implemented in Alberta.

4.1 Opportunities for reducing emissions

To produce world-class low-carbon hydrogen and ammonia for export from natural gas, technology solutions must be implemented in the following three areas:

1. Minimizing emissions from **hydrogen production plants**
2. Minimizing emissions from **upstream natural gas production**
3. **Improved GHG measurement and monitoring** during upstream natural gas production

Next we discuss the recommended best available technologies in each area and their level of technology readiness, including examples of technology implementation.

4.1.1 Minimizing Emissions at Hydrogen Production Plants

The analysis of Oni et al. (2022) provides an excellent comparison of the main commercial technologies (SMR and ATR+CCS).

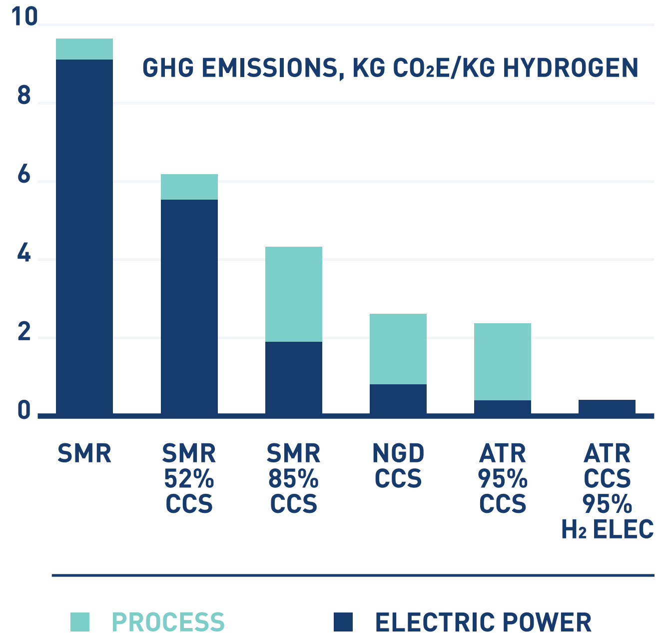


Figure 6. GHG emissions from different hydrogen production technologies, from Oni et al. (2022) with carbon capture estimated at 95% for Autothermal Reforming (Air Products, 2024) and for ATR with 95% CCS and site power generation from Meikle et al. (2023). Process emissions are direct emissions from the hydrogen plant, while the electric power emissions are indirect from the use of Alberta grid electricity.

The data emphasizes that two main technologies are critical to achieving low-carbon hydrogen production:

1. **Capture of a high fraction of the carbon from the methane, either by CCS or by conversion to elemental carbon via natural gas decomposition (NGD, also known as methane pyrolysis)**

   In an SMR hydrogen plant, the carbon dioxide from catalytic conversion of methane with steam is already happening at a commercial scale via the Shell Quest project in Edmonton, Alberta. Carbon capture from the high-temperature process furnaces is more difficult, therefore, the range of feasible CCS is considered to be 52-85% for this process (Oni et al., 2022). ATR, used less frequently today, involves conversion of methane by direct reaction with oxygen. This technology enables CCS up to 95% (Air Products, 2024 – refer to Air Products web information on Edmonton facility) but requires additional investment in air separation, therefore, ATR has higher electrical consumption than SMR.

   The data also shows that NGD (methane pyrolysis) also has the potential to sequester high portions of CO_2. Currently, this technology is being pursued at smaller, distributed scales, due in part to challenges in scaling storage and/or end use of the standard byproduct, solid carbon black. Therefore, for the time being, ATR+CCS is likely the best approach to very large-scale hydrogen production from natural gas, but NGD remains a compelling alternative at smaller scales.

2. **Use of low-carbon electric power to minimize the indirect emissions from the hydrogen complex**

   ATR facilities are better suited than SMR for high capture rates, but they come with the cost of having a very high electrical load. In Alberta, use of fossil-fuel based grid electricity to provide this power would add significantly to the lifecycle carbon footprint. To avoid use of fossil fuel electricity from the Alberta grid, a zero-emissions facility may power itself using the hydrogen it produces. This has the downside of reducing the amount of hydrogen that may be sold to market, but will result in a zero or very near-zero emissions hydrogen production facility.

   Other methods to reduce the emissions intensity of electricity use can include decarbonizing the Alberta grid. Alberta has already taken great strides in eliminating the use of coal for power production within the province (Government of Alberta, 2024k). Addressing remaining carbon sources is in active development via the province's *Emissions Reduction and Energy Development Plan*.

   Beyond these, at the production facility, there may be other, niche opportunities to reduce emissions, such as the potential for use of biogenic feedstock (i.e. renewable natural gas) – but the availability of these feedstocks is currently limited and/or the supply chains for this are not yet fully developed. Otherwise, to further reduce emissions at the hydrogen plant, alternative methods of producing hydrogen must be used that do not release CO_2.

4.1.2 Minimizing emissions from upstream natural gas production, processing, and transportation

In a blue hydrogen scenario where ATR+CCS is used, the majority of lifecycle emissions occur upstream of actual hydrogen production, during natural gas production, processing, and transportation. CO_2 and methane are produced in significant amounts during these upstream activities, and NO_x to a lesser extent. Based on source categories of upstream emissions, the following technology approaches may be implemented to achieve actual reductions in CO_2 and methane along the natural gas value chain, upstream of hydrogen production:

1. **Elimination of pneumatic emissions**

   Based on Modern West's 2023 report, pneumatic equipment is the largest source of methane emissions during natural gas production. This includes pumps and control systems that use compressed natural gas to drive their operations with low-pressure gas vented as a result. The main alternatives include electrification, zero-bleed pneumatics, or the use of inert gas as a replacement to methane.

2. **Elimination of vented methane from compressors**

   Compressor stations that assist with natural gas transportation along pipelines are another major source of methane leakage. These are often self-powered by natural gas flowing through the compressor station. Most are powered by combustion engines, and vent both CO_2 and methane during operations. To mitigate this, technologies are needed to improve efficiency and control, capture and recirculate vented methane, and electrify or fuel-switch these compressor stations to low carbon alternatives.

3. **Reduction in CO_2 emissions from combustion**

   There are many sources of CO_2 emissions along the upstream natural gas value chain arising from combustion of fossil fuels, ranging from vehicle engines, to compressors, to heat and power at gas processing plants. Similar to the above, these emissions could be eliminated by solutions such as electrification or switching to zero emission fuels. Due to their smaller, more dispersed nature, carbon capture and management from these sources will likely be more difficult and expensive than for large, centralized point sources (Zhou et al., 2022).

4.1.3 Opportunities for improved measurement & monitoring

Even after emissions reduction opportunities are taken into account, there remains uncertainty around the reported values for methane because of current reporting calculation requirements that rely on estimates rather than actual field measurements. International standards are emerging for monitoring, reporting, and validation of methane emissions (Stern, 2022). Three major requirements for future reporting of emissions will be:

1. **Changing measurement and reporting of methane emissions from standard factors to actual field measurements with reconciliation of bottom-up (ground level) and top-down (remote) observations.**

   Currently, methane emissions are empirically calculated to develop an estimated value based on emissions factors, which lacks precision and fails to show the nuances between individual producers and assets. The industry is moving towards actual field-based detection and measurement technology, with many efforts underway via the Alberta Energy Regulator's (AER's) Alternative Fugitive Emissions Management Program (alt-FEMP). Through this program, mechanisms are evolving to validate these uncertainties. New methods are posted on the AER website that use novel combinations of measurement and monitoring technologies, such as combining aerial with fixed/on the ground measurement to improve detection sensitivity and accuracy. Improved measurement and reporting could also help bridge the gap in the wide variability we see between the provincial average and the best performing producers.

2. **Ensuring data measurement and reporting has been verified and certified by accredited bodies.**

   Any new measurement and monitoring methodologies deployed by operators will need to be verified and certified by the AER, or other relevant regulatory body.

3. **Making asset-level emissions data transparent and publicly available, to ensure credibility.**

   Currently, provincial data and some corporate-level data is available in the public domain, but this fails to differentiate between the performance of individual assets, which may vary widely. Whether reporting requirements are at the corporate or asset level will make a significant impact on the drivers to implement best available technologies at individual sites.

4.1.4 Technology investment and scale-up

Many of the technologies discussed above have received development support from the Government of Alberta, industry, and innovation funding organizations such as Emissions Reduction Alberta and Alberta Innovates over the past decade and are now at or near commercial implementation. Below is a brief summary of recent funding programs dedicated to achieving emissions reduction in upstream natural gas production:

- Emissions Reduction Alberta investments in methane reduction, measurement, and monitoring: $35M
- Methane Emissions Reduction Network (MERN): $2M
- Methane Technology Implementation Program (MTIP): $25M
- Baseline and Reduction Opportunity (BRO) Assessment Program: $15M
- Canadian Emissions Reduction Innovation Network (CERIN): $17.4M
- Alberta Methane Emissions Program (AMEP): $17.6M – ongoing

In addition, Alberta Innovates and Emissions Reduction Alberta have invested a combined more than $50M in low carbon hydrogen production technologies.

In *Appendix A*, we highlight ten key examples of technologies to reduce or eliminate emissions from hydrogen facilities and upstream natural gas production, as well as to improve measurement and monitoring of methane, that can help fulfill many of the emissions reduction opportunities identified above.

5.

RESULTS: HOW LOW CAN IT GO?

Using a combination of best available technologies, such as those described in the previous section, hydrogen production with high levels of carbon capture can result in low GHG emissions, as illustrated in **Figure 6.**

If a hydrogen production facility uses natural gas that has the average footprint of Alberta upstream production, and Alberta grid electricity, then the lifecycle GHG emissions for the resulting hydrogen are in the range of 3.7 kg CO_2e/kg of hydrogen, as illustrated in Figure 7. By contrast, best practices for equipment selection and leak detection and repair can bring this value down to 2.7 kg CO_2e/kg of hydrogen. This shows the extent of the range that is possible in a single jurisdiction (Alberta) all under the same "color" umbrella.

Further reduction to below 1 kg CO_2e/kg hydrogen can be achieved by using electricity generated by hydrogen produced with CCS. The Air Products Canadian Net-Zero Hydrogen Energy Complex illustrates how low the emissions from the hydrogen production steps can be, by combining high rates of carbon capture with electric power generation from hydrogen.

Assuming that a given hydrogen production company is able to contract natural gas producers that implement advanced procedures for monitoring, reporting, and validation along the entire value chain, an Alberta hydrogen producer would be able to meet even the most stringent international standards for hydrogen supply across its value chain, as illustrated in **Figure 7.** Even if methane emissions are off by a factor of two as some evidence suggests, the "best practice" scenario is still well below these standards.

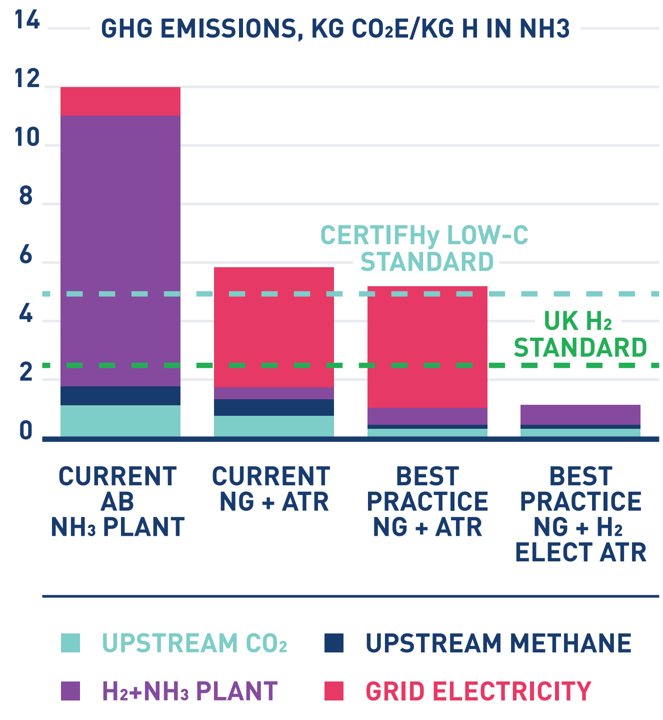


Figure 7. Total life cycle GHG emissions for hydrogen produced from Alberta natural gas (NG) using best available technologies. The upstream emissions from **Figure 4** are combined with the hydrogen plant and electricity emissions from **Figure 6** to give life cycle estimates for carbon dioxide and methane.

Note that the data in **Figure 7** also consider the GHG footprint for delivery of hydrogen outside of Alberta. The GHG footprint will be higher if the hydrogen is converted to ammonia for transport. Conversion of hydrogen from an ATR plant using electrically powered equipment requires 0.72 MWh/t ammonia (Grundt and Christiansen, 1982). Sourced from the Alberta grid, this power would add 2.2 kg CO_2e/kg of hydrogen, even without allowing for additional emissions for transport from Alberta, based on a grid factor of 544 CO_2e/kWh, which is consistent with Oni et al. (2022). If low-carbon hydrogen is used to meet these energy needs, then the incremental footprint could be near-zero, but this further erodes the delivered energy efficiency of the clean fuel at the point of end use (Meikle et al., 2023). Therefore, while domestic uses of hydrogen easily meet international standards, conversion to ammonia for export opens up additional sources of emissions that are likely to greatly increase lifecycle emissions.

6.

CONCLUSION

Alberta blue hydrogen can meet an array of international emissions standards, provided that the best available technology is deployed, low carbon electricity is available during hydrogen production, and contractual mechanisms are in place to select natural gas feedstock based in part on carbon intensity. When CCS is deployed and low carbon electricity is used during hydrogen production, the majority of emissions occur upstream, during production, processing, and transportation of natural gas feedstock. Upstream, reported CO_2 is well understood, but there is uncertainty within the actual and reported emissions when it comes to methane. Based on what aerial data has shown, these seem to be within a factor of approximately 1.5x in Alberta. Even when this uncertainty is taken into account, low carbon hydrogen production that deploys best practices across its value chain can still meet current international standards. There are additional emissions and energy impacts introduced, however, when the low carbon hydrogen product is converted to ammonia and subsequently transported over long distances before being used.

It does not take many natural gas producers to fulfill the demand for the number of hydrogen production facilities being proposed in Alberta. For example, a small handful of producing Montney fields is sufficient for a major hydrogen production facility. In other words, there is significant low-emitting, high performing natural gas production taking place today to meet the potential feedstock demand for blue hydrogen production that may take place in the future.

The ability to validate product lifecycle emissions to a prospective blue hydrogen customer will depend on how emissions reporting is managed on a go-forward basis, for example either at the corporate or asset level, and whether the contractual mechanisms are in place to do this. From a technological perspective, however, it is possible and being implemented today.

Expanding the use of best available technology, especially for upstream natural gas production, continues to be critical to establish and maintain the credibility of low carbon blue hydrogen production on a global scale. The province has made significant investments in technologies to reduce emissions from hydrogen production, upstream natural gas production, as well as improved measurement and monitoring of those emissions. Many of these investments have since become household names and are in commercial deployment today. There will be further opportunities to expand implementation and/or combine existing technology in novel ways that will enable expanded access to low carbon hydrogen production in Alberta.

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APENDEX A:
CASE STUDIES

CASE STUDY #1: AIR PRODUCTS
CANADIAN NET ZERO
HYDROGEN COMPLEX

ERA FUNDING:	**$15M**
TOTAL VALUE:	**$1.6M**
LOCATION:	**ALBERTA INDUSTRIAL HEARTLAND**
STATUS:	**UNDER CONSTRUCTION, TRL 8-9**

Overview: Air Products is constructing a first-of-kind-technology for Alberta: a world-scale net-zero ATR hydrogen production plant in Edmonton using locally-sourced natural gas. The plant will include carbon capture and integrated 100% hydrogen fuel-cell power production to further reduce its carbon footprint. Once operational, it will help decarbonize industrial hydrogen in local refineries, as well as domestic transportation, heat, and power. It is currently under construction, due to become operational in 2025.

Source: Air Products, 2024

CASE STUDY #2: CALSCAN
NEAR-ZERO EMISSIONS
WELL CONTROL SYSTEM

ERA FUNDING:	**$1M**
TOTAL VALUE:	**$4.5M**
LOCATION:	**CANADA-WIDE**
STATUS:	**COMMERCIALLY ESTABLISHED, TRL 9**

Overview Alberta- based Calscan Energy developed and scaled up their Near Zero Emission Well Control System. The solar-electric system eliminates all pneumatic equipment and is designed for reliable winter operations at remote off-grid well sites and incorporates a solid acid fuel cell that is powered by industrial grade on-site methanol. The solar-fuel cell hybrid power system can also eliminate the need for expensive small-scale propane or natural gas generators commonly used to power communication systems and auxiliary equipment at remote sites. Since being funded, the solar-electric technology has been deployed and proven at hundreds of well sites across Canada and established partnerships with major producers, helping to reduce costs and eliminate their methane emissions from pneumatic devices.

Source: Calscan, 2024

CASE STUDY #3: CONVRG INNOVATIONS
ENGINEERED POWER ON DEMAND (EPOD)

ERA FUNDING:	**$1.3M**
TOTAL VALUE:	**$4.3M**
LOCATION:	**CANADA-WIDE**
STATUS:	**ENTERING COMMERCIALIZATION, TRL 9**

Overview: Convrg Inovations's Engineered Power on Demand (EPOD) technology provides reliable power and compressed air for remote wellsites. The EPOD is a hybrid design powered primarily by solar energy. It includes a gas generator and an advanced battery system that provides reliable power to a wellsite with up to four days of backup power. The EPOD provides ample instrument air to run a pneumatic control system, which offsets methane emissions that would otherwise be generated by traditional gas-driven systems. The EPOD is safe, operator friendly, and can generate carbon credits or offset carbon tax, and will help to further eliminate pneumatic emissions.

Source: Global Methane, 2024

CASE STUDY #4:
INSTALLATION OF AIR/FUEL RATIO CONTROLLERS AND VENT GAS CAPTURE ON ENGINES

ERA FUNDING:	**$2.7M**
TOTAL VALUE:	**$7.7M**
LOCATION:	**CANADA-WIDE**
STATUS:	**COMMERCIALLY ESTABLISHED, TRL 9**

Overview: From 2011-2015, ERA supported Cenovus Energy to install REMVue computerized air/fuel ratio controllers across engines and Slipstream ® vent gas capture controllers to tie vent sources into engines and offset fuel across their site, offsetting an estimated 175,000 tCO2e to date at this site alone. This helped to commercially de-risk the technology for deployment at a wider scale. This technology was then incentivized via ERA's Small Producers Energy Efficiency Deployment (SPEED) program. Since then, the technology been deployed at hundreds of sites across Canada.

Source: Spartan Controls, 2024

CASE STUDY #5: QUBE
INTERNET OF THINGS CONTINUOUS MONITORING DEVICE

ERA FUNDING:	**$4M**
TOTAL VALUE:	**$10.6M**
LOCATION:	**NORTH AMERICA-WIDE**
STATUS:	**COMMERCIALLY ESTABLISHED, TRL 9**

Overview: Qube is a Calgary based technology company which provides low-cost continuous emission monitoring solutions for high emitting industries. With over 5,000 devices deployed globally, Qube works with leading operators in oil & gas, mining, landfills and agriculture to cost-effectively detect, quantify and reduce emissions. There are three components to Qube's solution: 1) a solar powered Industrial Internet of Things (IoT) device that continuously measures ambient gas concentrations and local meteorological conditions, 2) physics-based models that convert device data into emission sources and volumetric rates using machine learning and 3) a web-app that operators can use to manage emissions across multiple assets. These components can be incorporated into operational decision-making systems by a wide range of industrial users to improve their environmental performance.

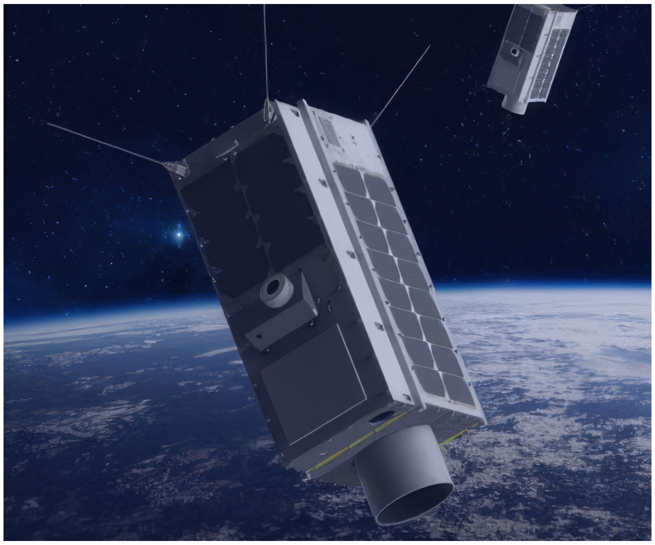
Source: Qube, 2024

CASE STUDY #6: KUVA
METHANE IMAGING SOLUTION FOR CONTINUOUS LEAK DETECTION AND QUANTIFICATION FOR TANK EMISSIONS AND FACILITY MONITORING

ERA FUNDING:	**$1.6M**
TOTAL VALUE:	**$3.2M**
LOCATION:	**CANADA-WIDE**
STATUS:	**ENTERING COMMERCIALIZATION, TRL 8**

Overview: Tank emissions are a focus area for upstream E&P operators in Alberta, as they are widely fluctuating and have been challenging to measure so far. Kuva Systems together with site hosts Cenovus Energy, NAL Resources and CMC Research Institutes is commercially demonstrating its ground-breaking IoT solution to detect, visualize and quantify methane and other hydrocarbon emissions, affordably making the invisible measurable. The technology includes two solutions: (1) a relocatable camera site assessment system for quantifying tank emissions over a period of days and weeks, and (2) permanently installed, cloud connected cameras with automatic leak detection and alarming. Installed cameras at larger sites can enable operators to automatically detect malfunctions if they occur, repair them quickly, demonstrate regulatory compliance and replace manual leak detection, reducing costs and accelerating emissions reductions.

Source: Kuva Systems, 2024



CASE STUDY #7: GHGSAT
SATELLITE-AIRCRAFT HYBRID DETECTION AND QUANTIFICATION OF METHANE EMISSIONS

ERA FUNDING:	**$3.7M**
TOTAL VALUE:	**$9.6M**
LOCATION:	**WORLDWIDE**
STATUS:	**ENTERING COMMERCIALIZATION, TRL 9**

Overview: GHGSat has developed and demonstrated a Calgary-based aircraft-satellite hybrid methane detection and quantification system. The two-tiered satellite/aircraft approach enables screening and detection of large methane leaks from diffuse or point sources from orbit, followed by more detailed imaging and quantification by aircraft surveys. The technology can help to document previously undetected methane leaks and improve the accuracy of methane measurements. Since its launch in 2016, the company has enabled mitigation of 5.6 million tons of carbon dioxide equivalent emissions from industrial facilities around the world, which is equivalent to over 1.2 million gasoline-powered passenger vehicles driven for one year.

Source: GHGSat, 2024

CASE STUDY #8: KAIROS AEROSPACE
DEMONSTRATION OF AERIAL METHANE IMAGING FOR WIDE-AREA METHANE DETECTION

ERA FUNDING:	**$0.2M**
TOTAL VALUE:	**$0.5M**
LOCATION:	**NORTH AMERICA-WIDE**
STATUS:	**ENTERING COMMERCIALIZATION, TRL 9**

Overview: Kairos Aerospace has developed a technology to locate and quantify methane releases over large areas by plane, rapidly and cost-effectively. Kairos' technology can survey up to 100 square miles per day, drastically reducing inspection and compliance costs and time. Kairos is commercially ready and expects its Leak Surveyor technology can reduce upstream oil and gas methane emissions by up to 80 per cent by 2025, with potential applications in midstream and other industries.

Source: Kairos Aerospace, 2024.

CASE STUDY #9: UNIVERSITY OF CALGARY-CANADIAN NATURAL FUGITIVE EMISSIONS PILOT STUDY: FIELD-SCALE DEPLOYMENT OF POMELO LEAK DETECTION

ERA FUNDING:	**$1.6M**
TOTAL VALUE:	**$3.2M**
LOCATION:	**MULTIPLE ALBERTA OILSANDS SITES**
STATUS:	**ENTERING COMMERCIALIZATION, TRL 9**

Overview: This project involves execution of the first full-scale field pilot of a new vehicle-based technology for regulatory leak detection and repair (LDAR) in North America, while simultaneously accelerating development of the world's first mobile methane sensor web for monitoring and reducing methane emissions from the upstream oil and gas supply chain. The technology, called PoMELO, is an advanced mobile emissions screening technology that incorporates multi-sensor hardware, proprietary software infused with artificial intelligence, and a 'one-visit' work practice to reduce cost and enable equivalent emissions reductions to regulations. At full commercial deployment, PoMELO can enable reduction of >60% of fugitives targeted by LDAR in Alberta under regulations. Further reductions will be achieved from early detection of vented emissions exceedances. Overall, this project will create a blueprint of PoMELO's commercial implementation for reducing upstream methane emissions in Alberta and other jurisdictions.

Source: PoMELO, 2024.

CASE STUDY #10: CANADIAN NATURAL RESOURCES LIMITED FUGITIVE EMISSIONS STUDY USING AERIAL DETECTION TECHNOLOGY

ERA FUNDING:	**$0.9M**
TOTAL VALUE:	**$1.9M**
LOCATION:	**MULTIPLE ALBERTA OILSANDS SITES**
STATUS:	**ENTERING COMMERCIALIZATION, TRL 9**

Overview: Canadian Natural is piloting an Alternative Fugitive Emissions Management (alt-FEMP) aerial screening technology coupled with ground-based detection. This entails de-risking the Bridger drone-based area detection technology for leaks and imaging. A key lesson learned was that the Bridger aerial method is best used when in combination with PoMELO (ground-based detection, described above). This increases cost, but greatly improves the effectiveness of the technology at accurately detecting and measuring methane emissions. This project is part of Canadian Natural's larger overall Alt-FEMP program, which will cover their conventional oil and gas facilities, province-wide, across a diverse set of operational conditions. With Canadian Natural's scale (almost 20% of Alberta's total facilities), they are championing the commercial deployment of these technologies throughout their operational areas.

Source: CNRL, 2024

EMISSIONS REDUCTION ALBERTA

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