Determination of the Most Effective Technologies in Methane Emissions Reduction for Oil Sands Operations in Alberta, Canada

by

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Abstract

Several regulatory policies have been implemented in the past five years on methane mitigation and oil sands industry emission in Alberta, Canada; however, most effective technologies in methane reduction remain to be explored in the context of these new policies in the Alberta oil sands industry. The purpose of this research was to determine the most effective technologies, based on economic and environmental criteria, to mitigate methane emissions from Alberta's upstream oil sands processes. This was achieved through qualitative analysis of current technologies, and the development and application of a qualitative risk analysis and quantitative cost-benefit analysis considering economic and environmental factors. I concluded that high risk technologies have the lowest ratio of cost to environmental benefit and suggest that more effective technologies incur a greater risk to the industry; conversely, precise emission inventories need to be completed in order to identify areas of high emissions in individual cases.

Keywords: methane, GHG emissions, mitigation technologies, oil sands, Alberta

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Chapter 1: Introduction

As of 2018, the primary sources of the world's anthropogenic energy consumption consisted of petroleum, coal, and natural gas; thus, fossil fuels make up 85% of the primary energy consumption worldwide (British Petroleum PLC, 2019). Alberta Canada is an important producer of conventional and synthetic crude oil from its large deposit of oil sands, which make up >95% of North America's bitumen deposits (Hein & Cotterill, 2006). In general, oil sands are a mixture of bitumen (a complex of heavy hydrocarbons), coarse sand, clay, and water. The Alberta oil sands (also referred to as tar sands) originate from a large deposit of heavy bitumen that is primarily located in the Athabasca region in the northeast of the province. The oil sands extraction process emits a significant volume of methane (CH_4) gas, along with carbon dioxide (CO_2) and other potent greenhouse gases (GHGs). Currently, methane accounts for 70% of the provincial Greenhouse Gas (GHG) emissions and 25% of provincial oil and gas emissions (Alberta Government, 2019b). Although methane is emitted from several human and natural sources (e.g., garbage dumps, agricultural operations), the energy sector remains one of the leading contributors to methane emissions in Alberta. Concern exists regarding the emission of methane and increased production in the energy sector in Alberta, which has led to increasing regulation and legislation to mitigate these emissions in recent years (Natural Resources Canada, 2017).

Alberta produces 38% of Canada's total GHG emissions and is the highest of any province or territory (Alberta Government, 2017). This is in large part due to oil sands production in northern Alberta, which emits close to 12% more GHGs overall than conventional extraction of oil based on a wheel-to-well analysis of carbon intensity (Alberta Department of

Energy, 2012). In addition to contributing to local and global environmental concerns, such as tailings ponds leaking toxic substances into surrounding waterbodies (Commission of the Environmental Cooperative [CEC], 2020), Alberta's role in exacerbating climate change has created a negative reputation for the Province's oil and gas industry that can harm future business in the energy sector. According to studies (e.g., Gasser et al., 2017), methane is estimated to have a global warming potential 34 times greater than carbon dioxide over a 100-year period. As a result, CH_4 should be reduced from emissions to protect the environment and to stimulate the economic sector by modernizing the energy market and producing a respectable and responsible product on the global market.

The oil sands extraction process is more environmentally intensive than conventional oil extraction processes due to the additional step of having to remove sand and water in order to recover the bitumen (Alberta Government, 2019a). Bitumen can be extracted via conventional processes, such as drilling from wells, or through the process of extraction from oil sands (Oil Sands Magazine, 2016b). Extraction of bitumen from oil sands can be achieved using truck and shovel mining of ores, which are then further refined to remove sand, water, and other impurities from the bitumen. Bitumen can also be obtained through in-situ extraction, which relies on steam and well systems to extract products from depths greater than 75 meters (Oil Sands Magazine, 2016a).

Figure 1.

Oil sands well-to-wheel process overview.

The Government of Alberta released the *Climate Leadership Plan* (CLP) in 2015, which outlined a number of emission reduction goals to reduce the Province's industrial contribution to climate change (Alberta Government, 2015) and highlighted methane as a key molecule for mitigation. In 2018, the Government of Canada mandated that carbon pricing be implemented on all GHG emissions on a provincial level (Government of Canada, 2018a). After a provincial election in 2019, the CLP was eliminated by the newly formed government, and replaced with a technology-focused approach to regulation, which correspondingly aligned with the federally mandated carbon pricing policies (Alberta Government, 2019b). Both federal and provincial governments are actively looking at reducing methane emissions through implementation of technology, legislation, and market-based strategies. Thus, it is important for recommendations on the most effective methane mitigation technologies to be available for decision-making.

Research Question & Objectives

Although the CLP is no longer used in practice by government to meet emission reduction targets, I consider that the goals and recommendations put forth by this document are realistic and suitable. My research objectives will rely on the CLP as its foundation because it sets measurable emission reduction goals for the industry in the Province and suggests avenues (i.e. technology, legislation) for reducing GHG emissions. My research is justified by the lack of literature in domains where the Province and industry need to make crucial decisions on greenhouse gas emission technologies. My research will use the guidelines and goals set out by the Province in both the CLP and the *Technology Innovation Emissions Reduction* (TIER) regulation (Alberta Government, 2019b) to determine the best technologies to mitigate methane emissions from oil sands industries.

Due to the limited scope of my thesis, I will only examine two of the three aspects of the triple bottom line philosophy (Poveda & Lipsett, 2013): environmental and financial considerations for decision-making. Under the triple bottom line philosophy for better business practices, every decision is made with thorough and informed consideration of economic, environmental, and social aspects (i.e. cost, mitigation efficiency, and risk to life). For business purposes, many oil sands companies (such as Suncor Energy) have adopted the triple bottom line philosophy for development in the industry (Suncor Energy Inc., n.d.). The criteria chosen for analysis of each technology was chosen based on their representation of the first two principles; that is, environmental and financial attributes are represented in the assessments.

Based on the goals set out by the CLP (Alberta Government, 2015) and recommendations from the TIER regulations, methane mitigation technologies currently available and in the research stage are analyzed quantitatively and qualitatively to determine the best practice for methane emission reduction in the context of the oil and gas industry in Alberta. Reducing methane emissions will address the GHG-reduction goals outlined by Alberta's Climate Leadership Report to Minister (Alberta Government, 2015), and technology developments have been identified as having the most significant impact on GHG emissions reductions (Bohm et al., 2012).

My research question was:

> Which methane mitigation technologies will best align with goals of reducing methane emissions from upstream oil sands productions?

As such, the objectives of this research are as follows:

1. To determine which technologies are available and applicable to reduce methane emissions from upstream oil sands operations in Alberta.
2. To highlight the benefits and consequences of each technology based on emission reduction capacity, applicability, risk, and financial benefits.
3. To identify the limitations of each technology along the criteria highlighted.
4. To recommend the most effective technology based on the requirements of different industrial activities and applications.

Significance of Research

This study establishes an important direction for industry decision-makers to move forward with the best mitigation technologies to reduce methane emission in different upstream oil sands production areas. There is currently an increased interest, from industry and government, to examine methane mitigation technologies in the context of oil sands production in Alberta. This project applied qualitative and quantitative analyses to gain a thorough understanding of the current best technologies. Potential significance of this study includes a better understanding of available technologies previously unexplored in the context of oil sands production, developing recommendations for future implementation of methane reduction technologies in the Province, and serving as a foundation for other industries seeking to reduce carbon emissions from production.

Background

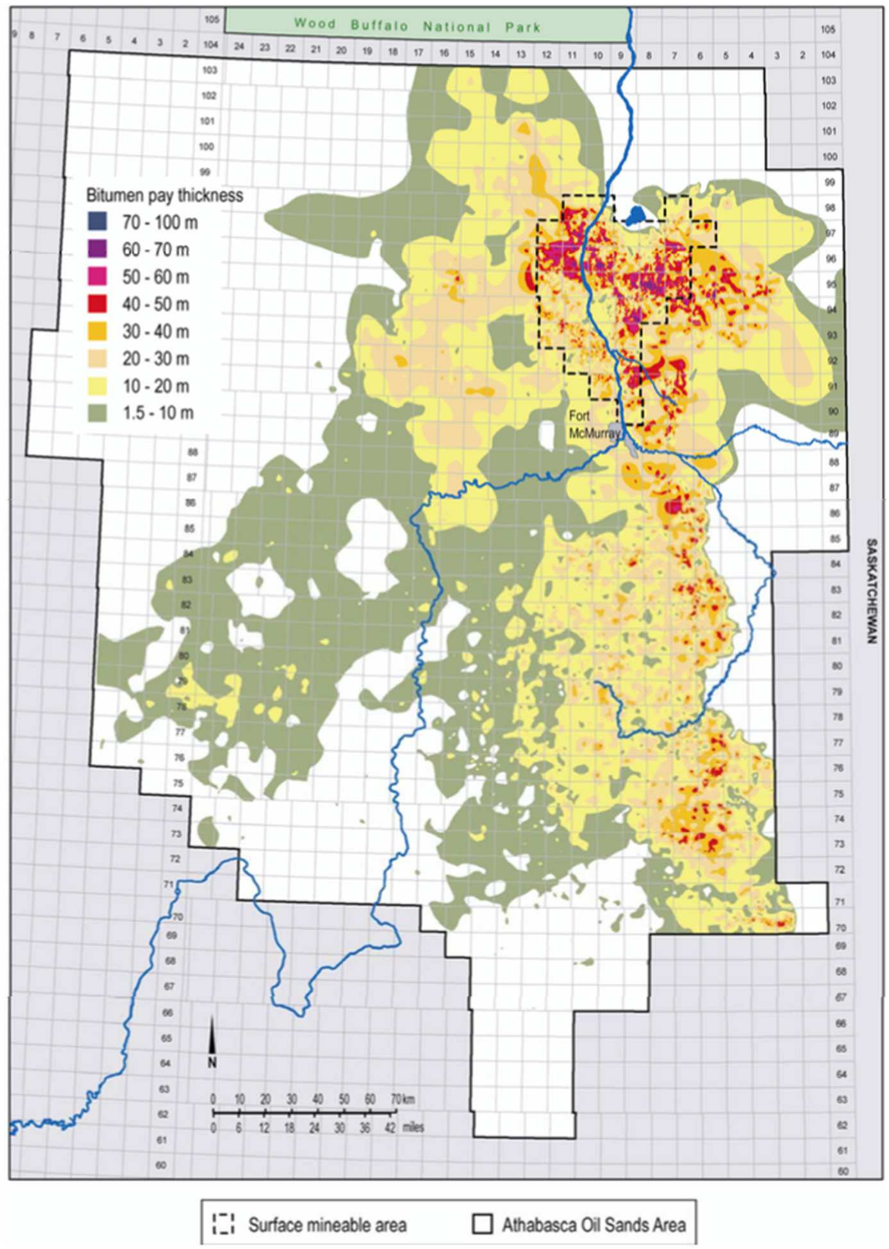
Alberta Oil Sands

The Athabasca oil deposit is the largest crude oil deposit in the world, and the largest of three in Alberta along with the Cold Lake and Peace River deposits (Hein & Cotterill, 2006). As noted already, there are two methods of extracting oil from the oil sands: in-situ extraction and surface mining. In-situ extraction is obtained through processes such as steam-assisted gravity drainage (SAGD), where high pressure steam is pumped into the bitumen deposits which changes the viscosity of the desired product. The bitumen can then flow into wellbores and be extracted from the ground (Oil Sands Magazine, 2016b). Roughly 80% of the available oil sands deposits are inaccessible by traditional mining and are recovered using in-situ (or SAGD) extraction technology (Oil Sands Magazine, n.d.). Due to the large volume of steam required to use this method of extraction, steam generation burns natural gas and has greater GHG emissions than traditional mining. Currently, in-situ extraction from oil sands has surpassed mining as the preferred method of bitumen recovery at roughly 52% of operation capacity (Oil Sands Magazine, 2016a). A smaller fraction (roughly 20%) of oil sands extraction is obtained through traditional open-pit mining (Oil Sands Magazine, 2016a).

The bitumen extracted from oil sand deposits must be refined further to eliminate water, sand, and clay. Bitumen ores from mining are added to hot water in large separation vessels to allow the components to separate. During this process, bitumen froth rises to the surface, where it is removed and refined further (Oil Sands Magazine, 2016b). The bitumen extraction process from oil sands produces a large amount of GHGs (i.e. from natural gas-powered pumps and tailings ponds) along with wastewater, and other toxic emissions such as NO_x, SO_x, and volatile organic compounds (VOCs). The additional extraction processes coupled with by-products of production contribute to the substantial environmental footprint of the Alberta oil sands (Charpentier et al., 2009).

Figure 2.

Bitumen pay thickness (a portion of a reservoir that contains economically recoverable hydrocarbons) *map of the Athabasca Wabiskaw-McMurray deposit*



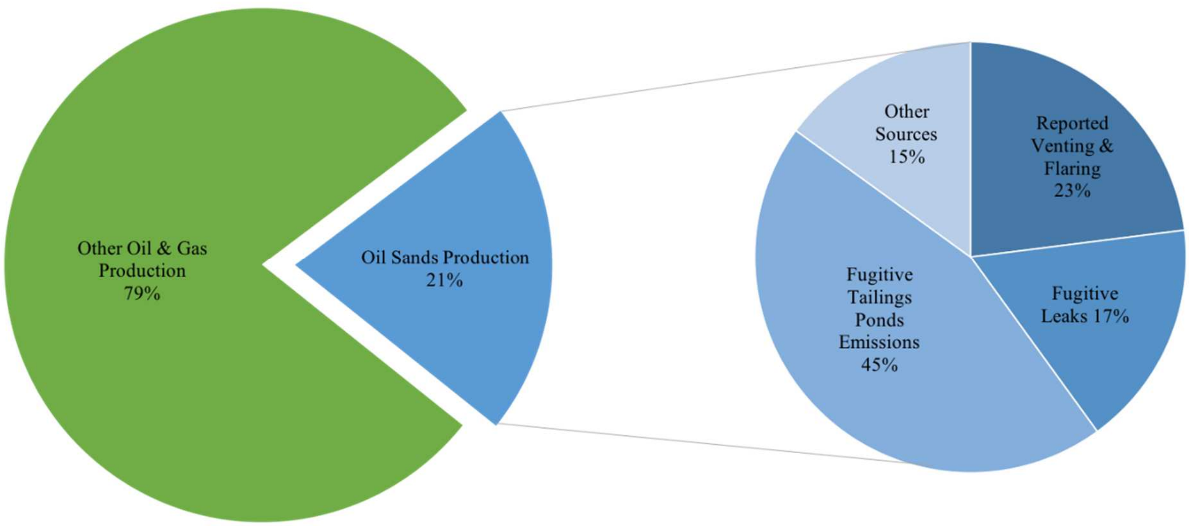
Note. Reprinted with permission from *Alberta's Reserves 2004 and Supply/Demand Outlook 2005-2014* (p. 32), by Alberta Energy and Utilities Board, 2005. Copyright 2005 by the Alberta Energy Regulators.

Oil Sands Emission of Methane

While some methane emissions are naturally occurring, there are many opportunities to reduce or eliminate anthropogenic sources of methane to combat global warming trends. Oil sands production accounts for 21% of all oil and gas emission of methane (Johnson, 2020). In the oil and gas industry, methane is emitted through intentional venting and unintentional releases. Unintentional CH_4 emissions from the oil sands industry occur from leaks, known as fugitive leaks, in equipment and valves used in extraction and production processes. Intentional controlled release of methane occurs during venting and incomplete flaring practices, where gaseous by-products of bitumen production are either released directly or burned into the atmosphere. This practice is regulated by government and monitored by industry who report to government officials; however, recent studies have shown that emissions from industry may be far higher than reported due to fugitive leaks from equipment and tailings ponds (Baray et al., 2018). Other sources of methane come from the production of electricity to power equipment used in upstream oil and gas production and incomplete fuel combustion from transportation vehicles (Charpentier et al., 2009). Although not every source of methane can be managed, recent efforts have been made to better monitor the level of methane emitted from industry in order to determine the best course of action for mitigation (Ravikumar et al., 2020).

Figure 3.

Methane emission sources and distribution in the Alberta oil sands industry.



Note. Data for overall methane emission in the oil sands industry from Johnson, et al., (2020); for venting & flaring from ECCC (2017); for tailings ponds emissions from Baray et al., (2018); for other emissions, from Fernandez, et al., (2005); and for fugitive leaks, from Yusuf, et al., (2012).

Emission Reduction Regulations

The now-repealed CLP outlined four policy measures to attain several goals to reduce climate change contribution by the Province of Alberta and its industries: (1) implement carbon pricing to drive down emissions, (2) phase out coal powered energy by 2030 and triple renewable energy so that 30% of electricity is generated by renewable sources, (3) cap oil sands emissions at 100 megatonnes (Mt) per year, and (4) reduce methane emissions from upstream oil and gas production by 45% below 2014 levels by 2030 (Alberta Government, 2015).

The CLP led to the creation of the Alberta Climate Leadership Panel (referred hereafter as 'the Panel'), where climate and industry experts developed steps through which the Province could reach its outlined goals. Among the suggestions made by the Panel, capping emissions from the oil sands industry and reducing methane emissions from upstream oil and gas production were outlined as critical steps to reducing the Province's overall emissions. The Panel also identified technology and innovation as an important strategy to accelerate emissions reduction (Alberta Government, 2015).

In 2018, the federal government implemented the Greenhouse Gas Pollution Act, which mandated carbon pricing on GHG emissions to be implemented on a provincial level (Government of Canada, 2018a). This federal law was established to set a national standard for carbon pollution pricing to meet the emission reduction targets outlined under the Paris Agreement (United Nations, 2016): (1) reduce global carbon dioxide (CO_2) emissions by 20%; (2) increase the percentage of global energy derived from renewables by 20%; and, (3) increase the efficiency of global energy sources by 20% by 2030.

With the inauguration of the new provincial government in 2019, the United Conservative Party (UCP) repealed the carbon pricing strategy put in place by the previous provincial party and instead replaced it with a technology-focused approach outlined in the TIER regulation, which aligned with federally mandated carbon pricing policies (Alberta Government, 2019b). The new emission reduction strategy focused on industry heavy-emitters and priced emissions based on individual producer's historical emissions data, rather than a province-wide average (Alberta Government, 2019b). This includes any oil and gas producer, as well as other industrial producers such as petrochemical and mining. Carbon pricing was subsequently implemented on January 1, 2020, charging $30/tonne of GHGs on facilities emitting greater than 100,000 T of total GHG emissions annually, with projected increases to $50/tonne by 2022 to stimulate a facility-specific reduction of 15% below individual producer's historical benchmarks by 2025 (Alberta Government, 2019b). This new method of pricing emissions allows individual facilities to reduce their emissions based on reported data, rather than using an industry average that must be met by all producers. Oil sands facilities operating in Alberta emitting more than 100,000 T of GHG per year are automatically enrolled under these new guidelines, and any additional facilities may opt-in to avoid federal carbon pricing on fuel usage (Alberta Government, 2019b).

Provincial and federal governing bodies have initiated legislation to regulate the amount of GHG emissions through policy-based approaches. These policies can act as a driver for change, where costly implementations become cost-effective down the line as industry is taxed for excess emissions. Provincial regulations such as the CLP and the new TIER set, I believe, realistic restrictions on current industry in order to reach the goals of the provincial and federal governments. These regulations set guidelines to industry decision-makers on which directions to follow to reach GHG reduction goals; they also set carbon pricing to try and drive emission reductions across the province. I do note that the CLP is not in force in Alberta at the time of the writing of this thesis and has been replaced by the TIER regulation guidelines; however, I consider it an important document due to its explicit recommendations to the oil sands industry.

The following table (Table 1) summarizes policies set by provincial and federal governments to reduce methane emissions from the oil and gas industry. The policies outlined in were obtained from *Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and*

Venting (Alberta Government, 2018b) and *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (Government of Canada, 2018b).

Table 1

Methane Emission Reduction Regulations from the Federal and Provincial Governments.

Target Areas of Concern	Government of Alberta	Government of Canada
Venting & Flaring	Vent gas limit (2020)	No venting Conservation of methane for re-use on site or for sale, or flaring / clean incineration of methane (2020)
	Overall vent gas limit exemptions for pneumatic devices, compressor seals, and glycol dehydrators expire (2023)	Venting limit to 1,250 m^3 per month Conservation of methane for re-use on site or for sale, or flaring / clean incineration of methane (2023)
Fugitive Emissions / Leak Detection & Repair	Fugitive emissions management program (2020) Fugitive emissions surveys & screening (2020)	Implementation of LDAR programs Inspection of leaks 3x/year Corrective action when leaks found (2020)
Pneumatic Pumps	Vent gas limits for pneumatic devices installed on or after January 1, 2022 (2022) Vent gas limits for pneumatic devices installed before January 1, 2022 (2023)	Venting limit of 0.17 m^3 of natural gas per hour for pneumatic controllers Conservation of methane for reuse on site or for resale, or replacement with non-emitting or low-bleed pneumatic devices (2023)

Chapter 2: Literature Review

This chapter explores the role of methane in climate science and oil and gas industries, and the review of the literature on methane-mitigation technologies from government agencies, academia, and other literary sources. This literature review will highlight current and emerging technologies and recommended practices needed for the foundation of the research.

Methane as a key molecule

Methane is a naturally occurring molecule in the atmosphere and contributes to the natural greenhouse-effect of the planet. Natural gas is primarily composed of methane and is the cleanest burning hydrocarbon when used to produce electricity. It is also a by-product of oil sands production, contributing to the total GHG emissions of industry. In 2010, the levels of atmospheric methane measured in the Arctic was over twice as high as it had been in the previous 400,000 years (NASA, 2012). Although it is a much smaller component of GHG emissions globally than carbon dioxide, methane has a greater ability to trap heat in the atmosphere making it an important molecule to mitigate for climate science (Jain et al., 2000). The difficulty for researchers is in identifying and quantifying industrial sources of methane and differentiating them from naturally occurring emissions (Johnson et al., 2017).

Johnson et al., (2017) have done extensive work on methane emissions from natural gas and heavy oil production in south-central Alberta including inventories of greenhouse gas emissions, and listed their components including carbon dioxide, methane, hydrogen sulfide, and other volatile organic compounds. The conclusions of their airborne measurements estimate that methane emissions from the upstream oil and gas sector (excluding mined oil sands) are 25-50% greater than current estimates, which indicates that methane has an even greater impact on global warming than previously considered. All these constituents may be naturally occurring in the area, although in much lower concentrations. Saunois et al. (2020), summarized a report on natural sources of methane from the environment and methods in determining methane concentrations. Based on bottom-up and top-down measurements of methane, roughly 60% of emissions are attributed to anthropogenic sources and their analyses follow the Intergovernmental Panel on Climate Change (IPCC)'s trends for warmest global scenarios and atmospheric methane concentrations (Saunois et al., 2020). Although this study demonstrates that methane is emitted from natural source (e.g. melting permafrost), these sources can be minimized by reversing positive feedback loops by controlling anthropogenic emissions. Simply, mitigating industrial sources of methane can also decrease natural emissions by decreasing global warming, which in turn leaves methane trapped in the permafrost. These studies by Johnson et al. (2017) and Saunois et al. (2020) are highly valuable since accurate emission inventories have been identified to be an important first step in mitigating emissions of concern such as methane.

Why is methane a problem?

Methane is a potent greenhouse gas, and as such an important molecule to mitigate to reduce the impact of climate change. To further understand the effect of methane on global temperatures, Gasser et al's., (2017) analysis of non-CO_2 molecules and their relative global warming potential (GWP) and global temperature-change potential (GTP) highlights methane as an important greenhouse gas. Their modeling on climate-carbon feedback determined that methane has a GWP 34 times greater than carbon dioxide over a 100-year time horizon and found that methane was one of the most persistent and potent molecules occurring from anthropogenic sources. In terms of quantity, GWP, and difficulty mitigating sources, methane, they determined, is a key molecule to be understood by climate science and mitigated by industry.

The fifth assessment of the IPCC estimates that methane has increased by nearly 20% since 1970 due to anthropogenic sources, particularly fossil fuels, and industrial sources (IPCC, 2014). According to the IPCC report, roughly half of anthropogenic carbon emissions have occurred in the years between 1970 to 2011 and has only been increasing (p. 4). Further research on the global methane budget by Saunois et al., (2020) determined that approximately 60% of methane emissions can be attributed to anthropogenic sources between 2008 to 2017. These documents illustrate the increased divergence between oil sands development and global climate concerns and demonstrate the urgency of methane in this crisis.

Oil sands sources of methane

Methane emissions continue to increase as the oil sands industry expands, despite the recent implementation of erratic policies from federal and provincial governments to try and control emissions. The current challenges facing regulators, industry decision-makers, and policymakers are 1) the difficulty in estimating the amount and source of methane emissions in various upstream oil sands processes to 2) determine which technologies or policies will best mitigate the problem. In most cases, methane emission inventories are calculated based on flaring and venting data and known sources of emissions (such as pneumatic pumps) and fails to accurately capture emission from fugitive sources (Pandey et al., 2019). Variation in GHG emissions has also been observed between ground-level monitoring and aircraft monitoring, which adds to the difficulty in determining accurate GHG emission inventories (Liggio et al., 2019).

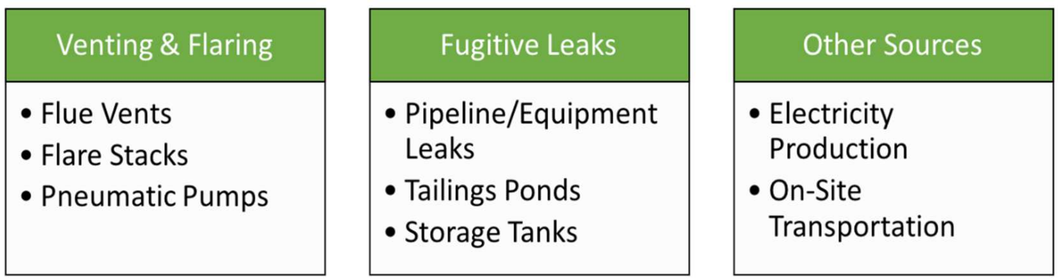
The Alberta oil sands made national headlines in 2019 when a paper by Environment Canada scientists concluded that the GHG emissions of the oil sands industry were up to 30% higher than initially reported (Liggio et al., 2019). Given that GHGs were primarily measured from the ground, this study determined that aircraft monitoring gave much more accurate assessments, particularly of fugitive emissions that may be coming from the extensive tailing ponds, and that current fugitive emission volumes were more uncertain and greater than previously estimated.

Attempts have been made to quantify methane sources and volumes, such as by Charpentier et al., (2009) who explored the different levels of GHGs emitted by various oil and gas processes, and which described the need to consider methane emissions related to the each of the various methods of production and for each step of the process (e.g. refineries, mining, in-situ extraction). Charpentier et al., (2009) identified the critical sources of methane as (1) electricity production, (2) natural gas production, (3) venting & flaring, (4) fugitive leaks, and (5) fugitive tailings pond emissions. Methane emissions occur from electricity production due to incomplete combustion if fossil fuels are used to run generators, or from fugitive leaks in the electricity generation system (e.g. steam generation). All these sources contributed to methane emissions from industry and need to be considered when developing mitigation measures.

Additionally, Yusuf et al., (2012) published a detailed study of methane sources for key sectors and included policy and technological mitigation methods for each identified source. They determined that fugitive methane emissions make up 17% of emissions from the energy sector, making it one of the largest contributors for the industry. Considering the difficulty in accurately measuring and mitigating fugitive emissions, their inventory analysis of fugitive methane emissions is valuable in determining methane reduction best practices.

Figure 4.

Intentional and unintentional methane emission sources and industrial origin in the oil sands industry.



Upstream oil sands production of methane

Alberta oil sands production emits a higher level of GHG emissions compared to conventional oil and gas production due to the additional extraction process needed to obtain bitumen. According to Charpentier et al., (2009), surface mining of oil sands produces two times the methane emission of conventional crude oil; in-situ extraction emits four times the amount of methane of conventional extraction processes due to the energy requirements of the method. Upstream production, which includes recovery and extraction processes, emits the largest portion of methane during production (Charpentier et al., 2009).

Pneumatic emissions result from the normal operation of pneumatic devices in the oil sands industry; these devices use natural gas pressure from the production process to move a piston or rotating parts (US EPA Office of Air Quality Planning & Standards [OAQPS], 2014). Environment and Climate Change Canada [ECCC] (2017) estimates attribute pneumatic emissions to be as high as 20% of overall oil sands industry methane emissions. For the purposes of my research, pneumatic emissions will be included in general flaring and venting emissions (see Figure 4).

Flaring is the controlled incineration of waste gas from petroleum production which breaks down methane and H_2S into less harmful products such as CO_2 and elemental sulphur. Flaring is a less harmful option than venting (controlled release of waste gases) into the atmosphere due to the destruction of GHGs into less potent ones based on GWP and toxicity (ECCC, 2017). Environment and Climate Change Canada (2017) estimate that general venting and flaring account for 23% of methane emissions from the oil and gas sector. Although flaring can be a useful strategy for reducing methane emissions, it still produces CO_2, which is an important source of greenhouse gases (Tyner & Johnson, 2018).

Fugitive leaks are uncontrolled and unintentional methane emissions that usually occur from valves and other equipment used in the oil sands extraction process such as seals, relief valves, and other control valves (Payner & Johnston, 2019a). Recent research has shown that tailings ponds release a large volume of methane and contributes to overall fugitive emissions of the industry (Baray et al., 2018).

Considering the above methane sources from the oil sands industry provides an indication to producers and regulator as to where targeted technologies need to be implemented to mitigate a large portion of the methane produced.

In-situ operations must report natural gas combustion in the extraction process as flared gas and must report to the Alberta Energy Regulators (AER) any emissions exceeding 500 m^3/day per site. The purpose of this monitoring program is to address the primary sources (fugitive and venting) of methane emissions and includes methane reduction requirements (AER, 2018a). Individual operations are required to monitor and report emissions and develop a Methane Reduction Retrofit Compliance Plan (MRRCP) as part of the new provincial legislation which came into effect on January 1, 2020, thus establishing concrete milestones for methane reduction targets for the oil and gas industry (AER, 2018b).

Chapter 3: Analysis of Methane Mitigation Technologies

Methane mitigation technologies are an important element to the responsible development and production of the oil sands industry. An assessment of available technologies and processes is key in taking the initial steps in achieving emission reduction objectives. Su et al., (2005) introduced an assessment of mitigation technologies and alternative uses for methane emissions in coal mines. Their findings showed the different technologies applicable to mining and their reduction in methane emissions along with an assessment of real mine emissions data, which allowed them to make recommendations on most effective technologies to mitigate methane in this context. Su et al.'s (2005) research on how to mitigate various sources of methane in a coal mine influenced the design of my thesis and the application of such a study on methane mitigation in the context of the Alberta oil sands industry.

Along with technology assessments, industry decision-makers will need to understand what technology can be used to deliver the best results to meet emission reduction targets. One way this has been presented was by Lee et al's., (2017) decision-making algorithm that incorporates the risk of different carbon capture and storage (CCS) technologies, while also minimizing cost and environmental impact, to be used by industry decision-makers. Their algorithm provides an optimal plan for infrastructure and technology by assigning quantitative values to economic and environmental impacts and suggest most effective technologies based on risk and benefits. This algorithm is unique in its presentation of most effective technologies based on risk from differing variables and conclusions to allow decision-makers to decide their own risk tolerance. Mitigation technologies I have reviewed follow a similar design to best represent the most effective technologies for methane mitigation based on risk, cost, mitigation potential, applicability, and novelty to the oil sands industry.

Methane mitigation technologies can be placed into two categories: conservation or conversion. Technologies that use *conservation* systems recover methane for sale or on-site uses, whereas *conversion* will convert methane to different molecules (Clearstone Engineering Ltd., 2017). The methane mitigation technologies reviewed are a mix of both conservation and conversion technologies. The technologies discussed in my review target venting and flaring emissions, and some fugitive emissions from tailings ponds.

Vapour Recovery Units

Vapour recovery units (VRU) are a conservation technology primarily installed on product storage tanks, which are an important source of fugitive emissions on oil sands sites. AER (2017) highlight the use of VRUs to compress hydrocarbon vapours from crude oil storage tanks, to separate the gas components for reuse or sale, and to reduce the amount sent to flaring. The AER report describes the sources of methane emissions for reported countries, emissions per industry sectors, and applicable reduction technologies based on economic and mitigation factors but is not specific to Alberta oil sands applications. The use of VRUs has been well researched and documented for GHG emission mitigation in the Alberta oil sands industry and is required by the Alberta Energy Regulators (AER) under Directive 60: Upstream Petroleum Industry Flaring, Incinerating, and Venting (AER, 2018b).

The US Environmental Protection Agency (EPA, 2006a) has investigated the use of VRUs for capturing methane emissions from crude oil storage tanks and when and where this technology should be implemented. They note that vapour recovery from storage tanks not only reduces venting emissions by 95-100%, it can also provide revenue due to the moderate initial cost of the technology and economic value of recovered gases (e.g. natural gas, fuel) (EPA, 2006a). The EPA's Installing Vapor Recovery Units on Storage Tanks (2006a) and AER's Methane Abatement Costs: Alberta (2017) were the primary literature sources of information for the mitigation of methane emissions from storage tanks.

The Alberta oil sands industry has been using VRU systems with high mitigation successes for many years. Benefits of this system include moderate implementation costs, a reduction in GHG emissions, and recovery of useful by-products for on-site fuel or resale (EPA, 2006a). VRU systems must be coupled with a rotary compressor (electrical) or a high-pressure compressor with spare capacity (non-electrical) to function; therefore, this technology is applicable in any location on a site regardless of proximity to a powerline. The economic recovery benefits of VRU systems is dependent on the market price of natural gas, its practicality as on-site fuel, and efficiency of the unit itself to reduce venting emissions from storage tanks.

Table 2

Vapour Recovery Unit Summary

Cost	Moderate implementation cost and can recover vapour for sale or site uses.
Efficiency	High efficiency, with a mitigation of 95-100% of vapours.
Application	Hydrocarbon storage tanks - can be applied to new or existing infrastructure.
Novelty	Historical use demonstrated in the oil and gas industry.

Note. Economic benefits vary based on natural gas market price and recovered amounts.

Replace High Bleed Pneumatics with Instrument Air Systems

Pneumatic pumps are devices which use gas pressure to force a fluid by increasing or decreasing the pressure of the liquid through displacement, piston, or rotating impellers. These pumps are generally used in oil and gas sites where electricity is not readily available. Compressed air can be used to power these instruments; however, methane is most often used from the production stream and can vary between high bleed (venting) or low bleed emissions (GRI, 1996).

Natural gas-powered pneumatic control systems vent methane as part of their normal operations and replacing these systems with compressed instrument air system removes 100% of methane emissions from the process by replacing the methane used to power the machinery with compressed air. Other positive effects of instrument air systems are the conservation of methane for sale or other on-site purposes that would otherwise be vented to the atmosphere (Petroleum Technology Alliance Canada [PTAC], 2017).

The limitations of using instrument air systems are the availability of on-site power, although electrical and infrastructure upgrades are relatively low in cost for sites with proximity to a power source (Fernandez et al., 2005). The elimination of methane in pneumatic systems has the added benefit of eliminating GHG emissions from pneumatic pumps and compressor-engine pneumatic starters. Instrument air systems need to be combined with three-phase power to run an air compressor, therefore smaller sites with single-phase power likely will need electrical upgrades to accommodate air compressor, desiccant dryers, communication equipment, and any added infrastructure or equipment. Specific limitations on methane venting from pneumatic equipment and requirements for new and existing infrastructure will be implemented by the

Government of Alberta by 2022 and will require all pneumatic systems to reduce or eliminate methane emissions from its normal operation (AER, 2018b).

Table 3

Replace High Bleed Pneumatics with Instrument Air Systems Summary

Cost	Moderate implementation cost but reduces cost of natural gas.
Efficiency	High efficiency, with a mitigation of 100% of emissions.
Application	Pneumatic control systems with proximity to electrical input.
Novelty	Historical use demonstrated in the oil and gas industry.

Note. Application is limited by proximity to power source and available infrastructure.

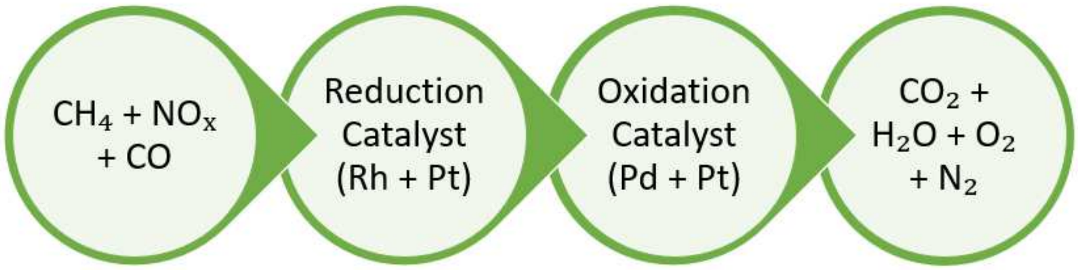
Catalytic Conversion

Catalytic conversion is a process that uses metallic catalysts to generate a reaction that would normally occur at a higher temperature (e.g. combustion of methane). For methane mitigation catalysts, CH_4 is converted to CO_2 and H_2O without a combustion reaction. This technology is advantageous where ignition in the environment would be hazardous (Centi et al., 2003).

Catalytic conversion for the abatement of GHGs is known for its ability to mitigate low concentrations of methane in vented gas streams (Tyner & Johnson, 2018). Other positive effects of this technology are its capacity to target multiple GHGs, its ability to oxidize methane to completion (See Figure 5) within its load capacity, and some studies show promising results for low concentration conversion of methane emissions to potential uses as clean energy (Wang et al., 2020). The major downside of palladium (Pd) catalysts, the more popular catalyst for methane mitigation, is its inhibition by water vapour and sensitivity to sulphur poisoning (Majewski & Jääskeläinen, n.d.).

Figure 5.

Flow diagram of 3-way catalytic converter application to industrial emissions.



Catalytic conversion of methane should be coupled with other technologies to increase its oxidation potential due to its relatively low mitigation capacity and susceptibility to contamination from other compounds; however, its ability to abate low concentrations of methane and unique application makes it an effective technology for this analysis. Wang et al., (2020) used electrical catalysis processes that showed high catalytic activity and increased stability without solid carbon deposition on the catalyst surface. A nickel-based anode was used to demonstrate applicability at various CH_4:O_2 ratios and relative low concentration of CH_4 in the flue emissions. After the pre-treatment of the Ni-anode supported catalytic cell, energy production showed promising results as a potential source of power; the resistance to deactivation of Ni oxidation and carbon deposits also increased such that the catalyst showed more robustness to environmental conditions than in the commercial Pd catalyst (Wang et al., 2020). Although energy production from CH_4 conversion was demonstrated, long-term industrial applications still need to be investigated. AER (2017) identified the cost and application of methane catalytic conversion as moderate, although its limitations could increase the capital cost.

Current research on catalytic conversion is promising to increase the mitigation potential of the technology and increase the robustness of catalytic converters to varying scenarios. Petrov et al., (2018) examined the effect of different catalysts on methane conversion, including various Pd oxides, reactant mixtures, reaction temperature ranges, preparation methods, reactor types, as well as the effects of various rate-limiting factors (i.e. water inhibition) and proposed a mechanism of reaction for the catalytic combustion of methane. The results of Petrov et al.'s (2018) study shows that several oxides can be used to support the reaction rate of Pd catalysts by increasing the reoxidation of metallic Pd and accelerating the desorption of hydroxyl, both of which increase the rate of reaction. Their results provide promising conclusions on the increased mitigation potential of catalytic conversion of methane for GHG mitigation in industrial applications

While the research on catalytic conversion is promising for increased methane mitigation, some limitations currently exist in the implementation of this technology. Tyner & Johnson (2018)'s analysis of methane mitigation technologies indicated a limitation of using catalytic conversion; the throughput is limited to 55 m^3 per day based on manufacturer's data. Karakurt et al. (2012) suggest that catalytic conversion of methane to carbon dioxide is best applied when the vented gas has a methane concentration lower than 30% v/v, which limits the application of this technology to low methane gas emissions. Although the production of CO_2 still creates a problem with global warming, recent studies have shown promise in converting carbon dioxide to be used as fuel by further catalytic conversion (Keith et al., 2018). Spent (or waste) catalyst may be repurposed for other industrial uses; however, increased research into the resilience and mitigation abilities of catalytic converters could reduce the amount of spent catalyst to be replaced and discarded.

Although this technology has high potential for mitigating GHGs, it should be considered in conjunction with other methane mitigation technologies to get the emissions reduction required to meet provincial targets. Catalytic conversion of methane should be considered as a supplementary technology to minimize GWP at the current stage of the technology's development.

Table 4

Catalytic Conversion Summary

Cost	Moderate implementation cost: additional upgrades turn effluent into fuel.
Efficiency	Moderate to high efficiency, depends on reaction parameters and deactivation.
Application	Low methane concentration ventilation air (i.e. combustor exhaust).
Novelty	Historical use in the oil and gas industry; research needed on catalyst variations.

Note. Catalytic conversion has limited capacity and must be used with other technologies.

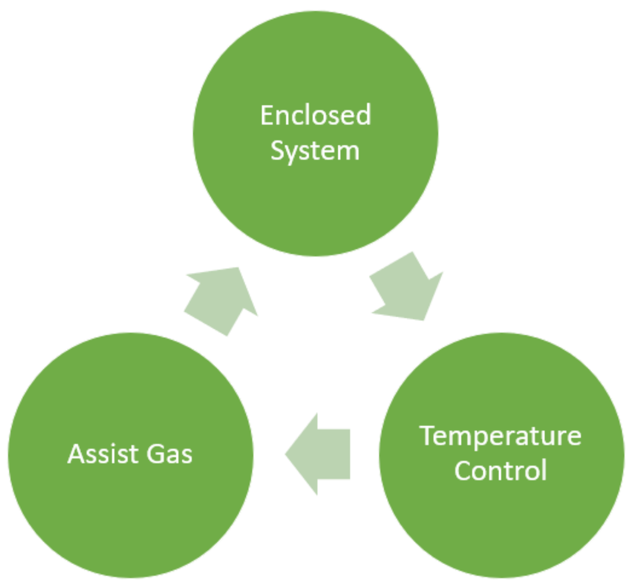
Enclosed Vapour Combustion

Enclosed vapour combustion is a method of burning excess gas where vapours are pressurized inside a confined structure, which ensures more complete combustion of the flue gas than directly flaring to the atmosphere (Tyner & Johnson, 2018).

A technical report on cost analysis of methane mitigation technologies highlights enclosed vapour combustion as a more efficient alternative than flaring waste natural gas due to its ability to provide 99.9% combustion (or conversion) capacity without additional fuel gas or air intake (Clearstone Engineering Ltd., 2017). One of the qualifying criteria of this technology is its ability to completely convert waste methane to carbon dioxide, thus decreasing the GWP of the effluent gas by 34 times (Gasser et al., 2017) and suggesting that enclosed vapour combustion should be considered ahead of flaring, which has an average combustion capacity of 80%, to meet emission reduction demands. Provincial regulations implemented by AER restrict the allowable venting and flaring volumes, therefore complete combustion is favourable when limitations are placed on emissions (AER, 2018b).

Figure 6.

Components of enclosed vapour combustion that increase destruction efficiency.



Enclosed vapour combustion of methane emissions is the most effective conversion technology reviewed in this thesis. Since this method involves destruction of waste methane, this method is not as cost-effective as conservation-based technologies that can reuse the captured methane as on-site fuel. Enclosed vapour combustion technology will increase in value for industry once a GHG emission reduction valuation system is implemented (Clearstone Engineering Ltd., 2017). Emissions produced in the SAGD process are also higher in methane and H_2S (Pembina Institute, 2009), which are better mitigated by vapour combustion than conventional flaring and venting methods.

AER released a directive for the oil and gas industry operations in the province, *Upstream Petroleum Industry Flaring, Incinerating and Venting*, in December 2018. The objective of this document was to reduce incomplete combustion from flaring, venting, and incinerating, and to document all activities related to the above practices. Carbon conversion efficiency (CCE) is used to determine the percentage of carbon in the fuel that is converted to CO_2, and thus determines the combustion efficiency of GHG mitigation technologies. The formula for calculating CCE (AER, 2018b) is as follows:

$$CCE = \frac{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel}{Mass\ Rate\ of\ Carbon\ in\ the\ Fuel\ Converted\ to\ CO_2}$$

Although enclosed vapour combustion is costly based on capital cost of installation, it is important to consider due to its high methane mitigation efficiency, low maintenance upkeep and cost, and potential low number of years to see the return on the initial investment cost when considering carbon tax avoided on sites where excess gas flow meet or exceed 252 m^3 per day (PTAC, 2017). The largest cost for such projects for the initial capital and installation of the technology, depending on the volume of vented gas.

Potential disadvantages of this technology include the maximum throughput emissions of 1,500 m^3 per day, and it is more sensitive to a narrow flow rate. Vapour combustion incinerators can also be affected by varying fluctuation in flow rates and can therefore inadequately disperse emissions containing higher concentrations of uncombusted molecules (such as H_2S) in the vented gas.

Effluent gas pipeline tie-ins should be investigated in conjunction with this technology to maximize mitigation capacities and minimize cost when considering multiple sites within a geographical area (Tyner & Johnson, 2018). Although enclosed vapour combustion is a relatively costly technology in terms of capital costs, the implementation carbon emissions pricing should be considered in the decision-making process and regarded as a cost-effective solution in the long term.

Table 5

Enclosed Vapour Combustion Summary

Cost	High implementation cost: investment return depends on carbon pricing.
Efficiency	High efficiency in all emission GHGs.
Application	Combustion vented gas - particularly for SAGD steam generation batteries.
Novelty	Historical use demonstrated in the oil and gas industry.

Note. Carbon pricing and investments may counterbalance the high capital cost.

Biofiltration of Methane

Biofilters are made up of packed and porous materials (e.g. biochar) with methane-metabolizing bacteria called methanotrophs; contaminant emission gas is passed through the reacting surface in combination with humid air by forced convection. The biological treatment occurs when oxygen and methane streams diffuse into the biofilter and develop on the surface of the material. There, aerobic methanotroph microorganisms use the CH_4 as a source of energy and convert it to CO_2 in oxygen-rich environments (La et al., 2018).

Low concentrations of methane in GHG emissions (less than 5% v/v) are difficult to mitigate using traditional methods but contribute to a large portion of the overall methane emissions of the oil sands industry. Recent studies have estimated that low concentration methane emissions from tailings ponds, due to their large area, contribute 45% of the total methane emissions measured from the oil sands industry (Baray et al., 2018). In this regard, biotechnologies using methane-oxidizing bacteria with biochar are an efficient way to mitigate diffuse methane emissions via conversion (La, et al, 2018). Although La et al., (2018) found that biofiltration is successful in mitigating low concentrations of methane, the rate limiting factors of the technology include increased flow rates and methane ratio in flue emissions.

La et al., (2018) determined that under diffuse methane environments, biofilters can mitigate roughly 90% of methane emissions, given adequate reaction time and oxygen concentrations. This indicates a potential additional cost of operation, depending on whether oxygen is required to obtain optimal flue gas ratios. Adsorption materials, such as biochar, have also been studied to increase the retention time of methane to the material and thus, increasing the methanotroph mitigation capacities of the system (La et al., 2018).

The mitigation potential of biofiltration of methane is reduced when the methane concentrations increase above a 2.5:1 ratio of O_2 to CH_4. When there is insufficient oxygen or a large concentration of methane in the emission gas, methanotrophs cannot function optimally to oxidize methane, therefore aerated biofilters are necessary to maintain the optimal oxygen concentration (up to 1.2% v/v) (Brandt et al, 2016). The cost of biofiltration of methane emissions from tailings ponds has not yet been cost-evaluated; however, for its application in hydrocarbon remediation in soil, the cost is estimated to be between $30 and $100 per cubic meter of contaminated material (Van Deuren, et al., 2002).

Biofiltration has established proof of concept in industries such as landfills, agricultural soils, and compost and is used on commercial scales all over the world and within Canada (La et al., 2018). Successful biofiltration projects include a case study on soil remediation on a decommissioned oil field site, which resulted in a significantly reduced cost in remediation with this implementation (Federal Remediation Technologies Roundtable [FRTR], n.d.). Biofiltration has not been used on a large-scale tailings pond at oil sands operations yet; however, interest and funding has been contributed by Emissions Reduction Alberta to this technology in recent years (CCME, 2015).

Table 6

Biofiltration Summary

Cost	High implementation cost - dependent on area of tailings pond.
Efficiency	High efficiency in emission GHGs - dependent on oxygen concentration.
Application	Tailing pond emissions; can remediate up to 90% of emissions.
Novelty	In the research and development stage - high interest from industry.

Note. Requires large areas of land and additional research and development for application.

Summary of the Analysis of Technologies

The following table (Table 7) summarizes the technologies chosen for this analysis and discussed in the above sections, with a brief description and respective advantages and disadvantages based on analysis of available scientific literature of cost, efficiency, application, and novelty. The information summarized in this section will be used in the risk assessment and cost-benefit analysis of this thesis.

Table 7

Summary of Proposed Technologies for Methane Reduction in Upstream Oil Sands Industry

Technology	Description	Advantage	Disadvantage
Vapour recovery unit	Compress the collected hydrocarbon vapours to separate the streams components for reuse, and to reduce the amount vented.	Applicable to crude oil storage tanks with a mitigation efficiency of 95%.	Requires conventional rotary compressor (electrical) or high-pressure compressor (non-electrical).
Instrument air systems for pneumatics	Natural gas-powered pneumatic devices can be replaced with compressed, dried air systems, eliminating methane emissions.	Applicable to valve controllers, pneumatic pumps, and engine pneumatic starters, with a 100% mitigation efficiency.	Applications are limited to field sites with available electrical power.
Catalytic conversion	Palladium (or other metals) active surface used to oxidize methane from ventilation air sources.	Applicable to ventilation air with 10-30% methane concentration and a mitigation efficiency of 100%.	Methane is converted to CO_2 (diminishes GWP by 34x) up to 110 m^3 and the rest is vented (or flared).
Enclosed vapour combustion	Pressure vapour combustors to combust natural gas from well casing, produced oil storage tanks and dehydrators with reduced emissions.	Applicable to well casing emissions with GHG emissions reduction of 81% and an efficiency of 100%.	Methane is converted to CO_2 (diminished GWP by 34x) up to 1500 m^3 per day and the rest is vented.
Biofiltration	Biochar with specific bacteria that oxidize methane emissions from tailings ponds.	Applicable to low methane concentration (1-3%) emissions from tailing ponds with an efficiency of 100%.	Different methods involve the conversion of CH_4. More research needed in using this methane mitigation technology in practice.

Chapter 4: Methodology

The purpose of my research was to determine the most effective technologies, based on economic and environmental criteria, to mitigate methane emissions from upstream oil sands processes in Alberta, Canada. The aim of this study was to characterize each technology based on perceived risk, cost-effectiveness, and methane mitigation efficiency. Primary qualitative data was collected from academic literature, government regulations, and other publicly available sources and reviewed in the literature review section of this thesis. A risk assessment of a potential failure was completed using likelihood and severity values assigned for large scale applicability, cost, methane mitigation efficiency, and novelty to the oil sands industry based on a review of literature. A cost-benefit analysis based on capital cost and mitigation efficiency was accomplished using carbon pricing values and return on investment (ROI) calculations. The results of the risk assessment and the cost-benefit analyses were then compared to identify conclusions and recommendations about the most effective methane mitigation technologies for Alberta oil sands applications.

Research Design

I utilized a combination of qualitative and quantitative analyses to gain a thorough understanding of the available methane mitigation technologies. This research method, known as mixed-methods research, is a type of research in which qualitative and quantitative approaches are used in combination to expand and strengthen the conclusions of a study (Johnson et al., 2007). The type of mixed-methods design used in this research was triangulation design, where quantitative and qualitative methods are implemented during the same timeframe with equal weight. This involved the concurrent analysis of quantitative and qualitative data, and both results are merged in the interpretation or by transforming the data to ease the integration of the two data sets (Creswell & Clark, 2017). In my research, the risk assessment and values assigned represented the qualitative research component, and the cost-benefit analysis represented the quantitative research component of the mixed method approach. The interpretation of both data sets provided a better understanding of the available technologies, their effectiveness based on cost, risk, and mitigation efficiency, and increased the reliability of results based on internal consistency.

Risk Assessment Model

As previously mentioned, Su et al's (2005) research design influenced the design of this thesis, and I used a similar risk assessment approach they used in the coal industry to evaluate methane mitigation technologies in the context of the Alberta oil sands industry. A risk assessment is used to identify potential future events that may negatively affect or harm assets, individuals, and/or the environment. It can determine *possible incidents*, their *likelihood* to occur and *severity*, and can be expressed qualitatively or quantitatively (Popov et al., 2016). Risk assessments are an important part of risk management and help mitigate potential risk-related incidents in decision-making.

Likelihood is defined as the chance of an event happening expressed qualitatively, whereas *probability* is generally the quantitative measure of chance expressed as a percentage (Popov et al., 2016). In the context of this assessment, likelihood is defined as the chances of a failure to cause significant financial and/or environmental impacts and severity is defined as the financial and environmental impacts caused by the potential failure of the technologies.

Table 8

Likelihood Rating

5	an incident related to the failure of the technology is at a high risk to occur,
4	an incident is at a moderate-high risk to occur
3	a moderate risk to occur
2	a moderate-low risk of an incident to occur
1	a low risk to occur

Table 9

Severity Rating

5	failure of the technology will be catastrophic and cause severe loss of production, detrimental environmental impact, and personal injury/death
4	a critical impact such as a temporary loss of production or long-term environmental impacts
3	a significant effect such as short-term production loss and environmental impacts
2	minor impact
1	minimal impacts on environment, production, and personnel

A qualitative risk assessment is determined by applying a risk matrix using the following formula:

Risk = Severity (S) * Likelihood (L) (Popov et al., 2016)

The risk formula yields a value that can be used in my research to qualitatively rank technologies based on equal consideration for severity and likelihood. For the purposes of my analysis, risk is defined as the possibility of financial and environmental consequences that an industry encounters when adopting a technology, and risk assessment uses the severity and likelihood variables from one to five, described by Popov et al., (2016).

Table 10

Risk Assessment Matrix

Likelihood (L)	Severity (S)				
	Insignificant (1)	Negligible (2)	Marginal (3)	Critical (4)	Catastrophic (5)
Frequent (5)	5	10	15	20	25
Likely (4)	4	8	12	16	20
Occasional (3)	3	6	9	12	15
Seldom (2)	2	4	6	8	10
Unlikely (1)	1	2	3	4	5

From Popov et al., (2016).

Likelihood Assessment

In the context of my analysis, likelihood is defined as *the chances of a failure to cause significant financial and/or environmental impacts*, with a value of 5 being frequent and a value of 1 being unlikely to occur. *Large-scale applicability* of a technology increases likelihood of a technology failure due to increased reliance on the technology for mitigation. *Mitigation efficiency* increases the likelihood of significant environmental impacts in the event of a technology failure, as the amount of methane mitigated relies on the proper operation of the technology. Similarly, increase in *cost* also increases the likelihood of significant financial impacts in the event of technology failure due to loss of capital investment and the penalty of carbon pricing on emissions. *Novelty* of the technology relates to the likelihood of a significant impact based on the research and proven applicability of the technology and the possibility of failure from lack of proof of concept in the oil sands industry.

Severity Assessment

A specific technology may produce several consequences with various magnitudes (i.e. level of severity) should the technology fail and could affect different aspects of the industry and stakeholders. The context of the assessment is necessary to determine the types of consequences and the level of severity assigned for each scenario (Popov et al., 2016). In this analysis, the scenario used is the upstream oil sands industry in Alberta, where environmental and economic consequences are considered.

In the context of this assessment, *severity is defined as the financial and environmental impacts caused by the potential failure of the technologies*. A severity value of 1 indicates minor environmental and/or financial consequences to a failure and a severity value of 5 indicates a large repercussion to technology failure. In terms of *large-scale applicability,* wide-spread adoption of the technology increases the severity of financial loss and environmental damage. *Mitigation* also increases severity of environmental impact as efficiency increases, therefore the failure of the technology increase severity in this variable. The *cost* of implementation increases the severity of technology failure based on the loss of capital cost to the industry and a potential for increase carbon pricing due to the loss of emission mitigation capacity. Lastly, *novelty* of the technology affects severity of potential technology failure due to lack of real-world applicability and require greater risk tolerance by the industry decision-maker on adopting novel technologies.

Cost Benefit Analysis

Considering the CLP (Alberta Government, 2015) recommendations for methane mitigation and the new Alberta TIER guidelines for heavy emitters (Alberta Government, 2019b), the technologies investigated in my research are compared using a cost-benefit analysis using the number of years to observe a return on the initial investment cost. Using the application of a $30/tonne carbon pricing to calculate return on investment, mitigation efficiency can be directly compared to the capital cost of each technology (Alberta Government, 2019b). The number of years to observe a return on the initial investment cost was calculated using the following formula and each technology was ranked from lowest to highest based on the results:

$$Return\ on\ Investment\ Cost\ = (Capital\ Cost/(\$30\ \times\ Mitigation\ Potential)$$

When ranking the methane mitigation technologies to determine most effective technologies, I targeted the reported vented and flared emissions and preliminary airborne tailings ponds emissions for mitigation. Variables considered for each technology for the cost-benefit analysis were capital costs, methane mitigation potential, and provincially mandated carbon pricing. Capital costs were obtained from a primary peer-reviewed source for each technology, and figures were in alignment with secondary sources examined. An average of cost ranges listed for each technology in primary literature sources were used to represent capital cost in this analysis, and the values reflect cost per unit for initial installation.

Methane mitigation efficiency was further demonstrated using estimated proportional methane emission sources and each technology that works to mitigate the sources identified. Using a fictional producer emitting 100,000 T of GHG per year and assuming that 25% of those emissions are measured as methane, this analysis illustrates which technologies were most effective in mitigating methane emissions from target sources outlined in Figure 3. Carbon pricing was applied to the volume of methane emissions to demonstrate the annual cost of the outputs currently being measured and reported. Capital cost and mitigation efficiency was applied to determine the cost of mitigation per tonne of methane emissions using the following formula:

$$Cost\ per\ tonne\ of\ CH_4\ mitigated = \frac{Capital\ Cost\ (per\ unit)}{Mitigation\ efficiency\ (per\ unit)}$$

The results of the cost-benefit analysis were compared to the results of the risk assessment and conclusions were given on which technologies were deemed most effective in mitigating methane in upstream oil sands production.

Data Collection

Using the Panel's (Alberta Government, 2015) recommendations on methane reduction and aspects of the triple bottom line philosophy, most effective methane mitigation technologies for oil sands production were investigated. For the purposes of my analysis, "most effective" is operationalized as "cost-effectiveness", "methane mitigation efficiency", and "low risk". Data on existing publications were gathered and selected based on applicability in upstream oil sands production in the context of Alberta, Canada.

The material used in this research were sources from peer-reviewed academic articles, with secondary supporting sources collected from government publications and industry journals. The original data was produced from real-world industrial applications of the technology or research trials on a smaller scale. Specific criteria used for data collection of primary sources were:

- for primary source publications to have been issued within the past 5 years

- for applicability in the context of Alberta upstream oil sands production
- technologies that can be retrofitted onto existing infrastructure
- technologies had to align with target emission sources outlined in the previous section.

Target methane emission sources considered in this thesis were pneumatic emissions, general venting and flaring, and fugitive leaks (adapted from sources identified by Charpentier et al., (2009)). The following technologies were selected based on their applicability to upstream oil sands production in the above-mentioned target areas:

- Vapour recover units (VRU);
- Replacing high bleed pneumatic with air instrument systems;
- Catalytic conversion;
- Enclosed vapour combustion; and,
- Biofiltration.

These technologies also had to be viable for long-term methane mitigation to meet or exceed their return on investment periods and reach the emission reduction goals set out by the Province in the former CLP , the new TIER regulations, and the continued prosperity of the oil sands industry in Northern Alberta.

Data Analysis

Before the technologies could be compared, risk assessment values were assigned based on four key criteria:

1) *large-scale applicability* refers to the ease with which a technology can be implemented within an industry.

2) *mitigation efficiency* refers to the ability of each technology to maximize mitigation efficiency per unit installed

3) *cost* refers to the average capital cost required per unit of the technology

4) *novelty* refers to the amount (or lack thereof) of research available on the technology and its real-world application to mitigate methane in the upstream oil sands industry.

Each criterion was ranked on a scale of one to five for both severity and likelihood. A high likelihood value suggests that a failure of the technology is highly probable to occur, and high severity of such an event will have great financial and environmental consequences for the company. A low likelihood value indicates that a failure of the technology is unlikely to occur, and a low severity value suggests that such a failure occurring will have minor financial and environmental consequences. The risk value associated with each technology is equally weighted to the results of the cost-benefit analysis when determining which technology is most effective in reducing methane emissions in upstream oil sands production.

These four criteria were selected based on environmental and financial considerations of the triple bottom line philosophy for better business practices.

The data was then analyzed using Popov et al., (2016)'s risk assessment matrix for decision-making (Table 10). The following section explains the rationale for values assigned for each technology for likelihood and severity criteria. Risk assessments were completed to determine risk associated with each technology and compared to a cost-benefit analysis of technology implementation in oil sands production to determine the most effective methane mitigation technology.

Reliability & Validity

Reliability was established by using a combination of quantitative and qualitative analyses to develop internal consistency in the conclusions. In theory, finding consistent results over time between the two types of assessments increases the reliability of the results. Inter-rater consistency and test-retest consistency was not established due to limited scope and resources and is a limitation of the conclusions. Validity was demonstrated by using existing theory and knowledge of methane mitigation technologies from peer-reviewed literature, cost-benefit assessments adapted from Su et al., (2005), and risk assessment matrix by Popov et al., (2016). Additionally, the variables measured to determine most effective technologies are quantified prior to data collection.

Deficiencies exist on the external validity of my ability to generalize from the research results based on the limited sample size (primary and secondary sources for each technology) and external validity in practice. The limited scope of this research introduces these limitations to the generalizability of the results; however, I consider that a mixed method research design and my analysis of similar studies increases my confidence in the results presented here.

Assumptions, Limitations and Delimitations

As previously mentioned, the scope of my thesis limits the analysis of methane-mitigation technologies to environmental and financial criteria for decision-making. Creating this tool for industry decision-makers and policymakers to come to their own conclusions about the most effective technologies allows for some social consideration in practice. The social aspect was not implicitly assessed in my thesis, and industry decision-makers are encouraged to seek social considerations alongside their economic and environmental assessments.

Based on my initial analysis, some technologies were excluded from this study based on applicability, cost, novelty, or methane mitigation capacity. Some previously researched methane-mitigation technologies were found unsuitable for upstream oil sands applications in Alberta due to geographical constraints or inadequate volume of available gas. For example, electricity generation from methane waste gas is unsuitable or costly in some cases due to the low availability of methane emissions and distance from the electrical grid. Some other large engineered projects, such as carbon capture and sequestering, are also ineffective because they often require planning into the initial design of the production operations to capture, transport, and store carbon dioxide emissions. (Tyner & Johnson, 2018). The technologies selected for my analysis had to be applicable to existing infrastructure to allow for retrofitting to align with methane reduction goals outlined by the province and the federal government.

An important assumption made in the application of each technology is that a thorough and accurate inventory of the site's methane emission volume and sources, including any possible areas of leaks as well as intentional venting practices, is, or can be, completed. Each technology will need to be selected in practice following a baseline analysis of methane emission involving unoccupied aerial vehicles (UAV or drones) or direct reporting of venting and flaring of process-related emissions (Payner & Johnston, 2019b). This process can be conducted by third-party companies that specialize in greenhouse gas emission detection and quantification. It must be understood that each technology needs to be considered based on accurate knowledge of baseline emission sources and amount when ranking each technology. The findings of my assessment assume that an accurate emission analysis was conducted prior to choosing each technology, and the best mitigation technology was chosen for its application.

Some considerations were used to determine target areas associated with GHG reduction in upstream oil sands industries. For instance, fugitive leaks are hard to mitigate and make up 17% of total methane emissions; therefore, leak detection and repair (LDAR) can be used to assess and control these emissions occurring outside of tailing ponds (Poveda & Lipsett, 2013). Additionally, up to 15% of methane emissions occur from other sources that may or may not be reported by the producer and are not targeted in this analysis (Fernandez et al., 2005); therefore, other sources included in this portion were not targeted by the technologies in this analysis.

Costs vary greatly depending on the proposed technology. My cost-benefit analysis was conducted using present-day capital cost values due to the fluctuation in costs associated with technology implementations on various applications within the industry. Based on the area of the site and number of infrastructures needed to be upgraded, costs beyond capital investments may vary extensively. Estimates were used, where appropriate, to rank the economic benefit of each analyzed technology in this study. In many cases, economic cost was determined from a primary source and was included in the cost-benefit analysis of the methane mitigation treatment for consideration.

The results and conclusions are delimited to oil sands extraction in Northern Alberta and the processes associated with upstream bitumen production used there. Due to the amount of GHG emissions and variability of emissions sources in the Athabasca region, my thesis will only analyze technologies that could be applied to existing oil sands operations in Northern Alberta, with generalization of the results to all oil sands facilities, where applicable.

Chapter 5: Results

The results of the risk assessment and cost-benefit analyses are summarized in the below sections. Likelihood and severity values are assigned based on the analysis of technologies from literature in Chapter 3. Table 11 summarizes the results of the likelihood assessment; Appendix A illustrates the analysis of the value assignment for each technology and risk criteria.

Table 11

Likelihood Assessment Summary

Technology	Large-Scale Applicability	Methane-Mitigation Efficiency	Cost of Implementation	Novelty of Technology	Sum of Likelihood
Biofiltration	2	3	4	5	14
Enclosed vapour combustion	4	3	4	2	13
Vapour recovery unit	5	4	3	1	13
Instrument air systems for pneumatics	3	4	3	2	12
Catalytic conversion	2	3	2	1	8

Table 12 summarizes the results of the severity assessment; Appendix B illustrates the analysis of the value assignment for each technology and risk criteria:

Table 12

Severity Assessment Summary

Technology	Large-Scale Applicability	Methane-Mitigation Efficiency	Cost of Implementation	Novelty of Technology	Sum of Severity
Biofiltration	4	5	4	3	16
Enclosed vapour combustion	3	3	4	1	11
Instrument air systems for pneumatics	3	3	3	2	11
Catalytic conversion	4	2	2	2	10
Vapour recovery unit	1	4	3	1	9

Table 13 summarizes the calculated risk from highest to lowest for each technology using Popov et al., (2016)'s risk assessment matrix and risk equation:

Table 13

Risk Assessment Summary

Technology	Likelihood	Severity	Risk
Biofiltration	14	16	224 (highest risk)
Enclosed vapour combustion	13	11	143
Instrument air systems for pneumatics	12	11	132
Vapour recovery unit	13	9	117
Catalytic conversion	8	10	80 (lowest risk)

A comparison of cost to mitigation efficiency is presented in the following graph and represent the initial results of the cost-benefit analysis.

Figure 7.

Capital Cost and Mitigation Potential of Technologies Analyzed in the Cost-Benefit Analysis.

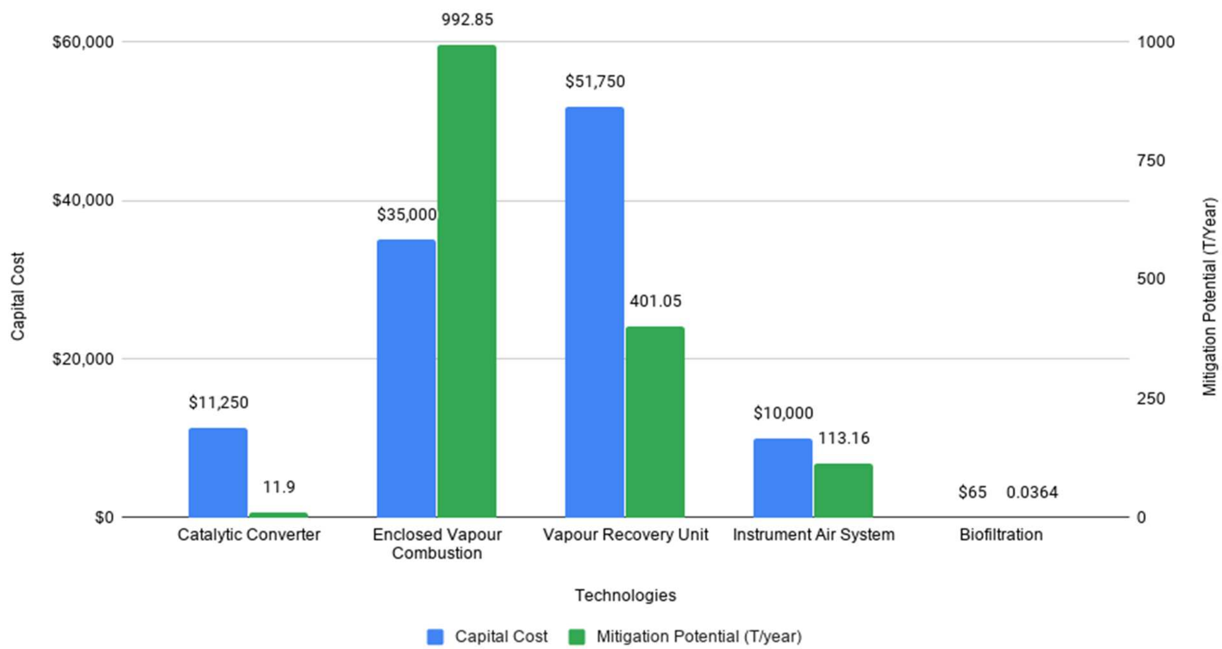


Table 14

Primary and Secondary Sources for Capital Cost and Mitigation Potential.

Technology	Capital Cost		Mitigation Potential	
	Primary	Secondary	Primary	Secondary
Catalytic Converter	Tyner & Johnson (2018)	Petroleum Technology Alliance Canada [PTAC], 2017.	Tyner & Johnson (2018)	Petroleum Technology Alliance Canada [PTAC], 2017.
Enclosed Vapour Combustion	Tyner & Johnson (2018)	Clearstone Engineering Ltd. (2017).	Tyner & Johnson (2018)	Petroleum Technology Alliance Canada [PTAC], 2017.
Vapour Recovery Unit	Alberta Energy Regulator (AER). (2017).	Petroleum Technology Alliance Canada [PTAC], 2017.	Alberta Energy Regulator (AER). (2017).	Environmental Protection Agency (EPA). (2006a).
Instrument Air System	Fernandez, et al., 2005.	Petroleum Technology Alliance Canada [PTAC], 2017.	Fernandez et al., n.d.	Environmental Protection Agency (EPA). (2006b).
Biofiltration	La, et al., 2018	Brandt et al., 2016.	Federal Remediation Technologies Roundtable [FRTR]. (n.d.).	Van Deuren et al., 2002

Cost Analysis

When carbon pricing is factored in using the return on investment cost equation, the results show that biofiltration, of all the technologies considered, is the least cost-effective and results in the highest number of years for a return on the initial investment. Catalytic conversion of methane proved to be an inexpensive technology but yields a high cost per tonne of methane mitigated. Enclosed vapour combustion had the shortest return on initial investment, followed by instrument air systems, and vapour recovery units.

Table 15

Cost-Benefit Analysis Results for Implementing Methane Mitigation Technologies.

Technologies	Capital Cost	Mitigation Potential (tonnes/year)	Carbon Pricing ($30/tonne $50/tonne)	Return on Investment (Years)
Enclosed Vapour Combustion	$ 35,000	992.8	$ 29,785 $ 49,640	1.2 ($30/t) 0.7 ($50/t)
Instrument Air System	$ 8,500	113.1	$ 3,394 $ 5,655	2.5 ($30/t) 1.5 ($50/t)
Vapour Recovery Unit	$ 51,750	401.0	$ 12,031 $ 20,050	4.3 ($30/t) 2.6 ($50/t)
Catalytic Converter	$ 11,250	11.9	$ 357 $ 595	31.5 ($30/t) 18.9 ($50/t)
Biofiltration (per m^2)	$ 65	0.03	$ 1.00 $ 1.50	65.0 ($30/t) 43.3 ($50/t)

Mitigation Efficiency

The following table shows the estimated proportional methane emission sources and technologies that best work to mitigate each source. The results summarized in Table 16 assume a producer that emits 100,000 tonnes of GHGs per year and is required to follow provincial carbon pricing of $30/tonne, and that 25% of oil sands GHG emissions are methane gas (Alberta Government, 2019b). The emissions contribution percentages are obtained from literature and summarized in Figure 3, and capital costs per tonne mitigated are calculated using capital cost and mitigation potential in Table 14. These results were analyzed to further illustrate which technologies were most effective in mitigating the target sources of methane emissions outlined in Figure 3. Although some technologies are more cost-effective in mitigating methane emissions than others, it is important to consider the source of emissions to better reduce the overall emissions of the industry.

Table 16

Summary of Methane Emission Sources and Most Effective Methane Reduction Technologies

Emission Sources	Emission Contribution	CH_4 (in tonnes)	Carbon Pricing ($30/tonne)	Technology	Capital Cost ($) per Tonne Mitigated
Fugitive Tailings Emissions	45%	11,250	$337,500	Biofiltration	$1,785
Venting & Flaring	23%	5,750	$172,500	Catalytic Converter	$945
				Enclosed Vapour Combustion	$35
Fugitive Leaks	17%	4,250	$127,500	Vapour Recovery Unit	$129
				Instrument Air System	$75
Others (i.e. on-site transportation)	15%	3,750	$112,500	-	-
Annual total	100%	25,000	$750,000	-	-

Analysis of Results

Based on the risk assessment calculation, biofiltration of methane coming from tailings pond emissions appears to have the highest risk, highest ROI, and is the most expensive technology per ton of methane mitigated; catalytic conversion of methane appears to have the lowest risk to mitigate methane based on economic and environmental criteria. Results showed that enclosed vapour combustion had the lowest number of years for a return on the initial investment, making it the most cost-effective and efficient technology discussed (see Table 17). This was followed by the replacement of pneumatic devices with instrument air systems, vapour recovery units on storage tanks, catalytic conversion, and lastly biofiltration of methane from tailings ponds. Excluding biofiltration, the technologies were inversely ranked based on risk; high risk technologies were determined to have the lowest ratio of cost to environmental benefit (in number of years for a return on initial investment).

Table 17

Ranking of Technology Based on Cost-Benefit Analysis and Risk Assessment Results

Rank	Cost-Benefit Analysis	Risk Assessment
1	Enclosed Vapour Combustion	Catalytic Converter
2	Instrument Air System	Vapour Recovery Unit
3	Vapour Recovery Unit	Instrument Air System
4	Catalytic Converter	Enclosed Vapour Combustion
5	Biofiltration	Biofiltration

Chapter 6: Discussion

The results of the risk assessment and cost-benefit analysis sought to determine the most effective methane mitigation technologies based on criteria set out by government regulations through the Alberta CLP (Alberta Government, 2015), the TIER Regulations (Alberta Government, 2019b) and specific needs of the oil sands industry in Northern Alberta.

Based on the results of the cost-benefit analysis, enclosed vapour combustion is the most cost-effective and efficient technology based on mitigation potential, followed by vapour recovery units, instrument air systems, catalytic converters, and biofiltration. The limitations of biofiltration are due to the low mitigation potential per unit considered, technical limitations such as the O_2 requirements, and lack of proof of concept in the oil sands industry. These results were the opposite to the risk assessment results except for biofiltration, which had the worst score for both risk and cost to mitigation efficiency. The ranking of technologies based on risk showed an inverse relationship to the cost-benefit analysis (see Table 17); that is, *the more cost-effective and efficient the technology, the more risk is incurred by the producer in implementing the technology*. This information is important for industry decision-makers as they consider their risk tolerance and willingness to pay to meet their target emissions for the implementation methane mitigation technologies.

Findings & Implications

Enclosed vapour combustion had the lowest return-on-investment, and the second highest risk based on capital cost and consequence of failure to mitigate methane. Seemingly, enclosed vapour combustion is the best choice for investment in technology considering the new enforcement of methane reduction regulations by the Alberta Energy Regulators (AER, 2018a).

Pneumatic devices using instrument air systems were determined to have the second lowest return-on-investment, and the third highest risk among the methods considered. This technology should be considered where in-situ operations are the major constituent of the site's extraction process and align with plans to regulate pneumatic emissions from high-bleed controllers (Alberta Government, 2015).

Vapour recovery units had the third lowest return-on-investment and was considered to have the second highest risk based on assessment. This mitigation option is best used for oil sands sites that have a large number of on-site storage tanks and have potential benefits in methane capture for resale or internal usage and is required to manage the gas by regulations on venting and flaring by the Alberta Energy Regulators (2018b).

Catalytic converters had the fourth lowest return-on-investment and had the lowest risk of all the technologies. This is a favourable starting point for industry decision-makers looking to reduce methane emissions but have a low risk tolerance; however, it could be implemented in conjunction with other methane mitigation technologies to achieve regulatory targets, which is similarly concluded by Tyner & Johnson (2018) in their analysis for conventional oil and gas extraction in Alberta.

Biofiltration had the highest ratio of return-on-investment, and the highest risk among these technologies. This technology is currently the least preferred due to its high cost and novelty in its application on an industrial scale in the oil sands industry. Based largely on lack of proof of concept on a large scale and cost, biofiltration using methanotrophs should be considered as a promising technology and future development could change the risk and cost-benefit of the mitigation method, consistent with the research funded by the Climate Change and

Emissions Management Corporation (CCEMC, 2015) into biofiltration for tailings pond emissions. However, it should not be considered a primary mitigation method based on my findings.

Although catalytic conversion of methane is considered the lowest risk technology based on the risk analysis, this is likely due to the low cost and low mitigation efficiency of the technology, thereby minimizing financial risk and environmental impact from failure of the technology. It should not be considered the most preferred technology based on the risk analysis alone, which is consistent with findings by Tyner & Johnson (2018).

Discussion of Findings

In general, the results of both assessments showed an inverse relationship; that is, the higher (riskier) the risk, the lower the technology ranked based on the cost-benefit analysts. The inverse relationship between risk and return has been previously identified in financial investments (Chen, 2020), and has also been recognized in climate science research (Laurikka & Springer, 2003). The recommendations based on risk-return relationships is to diversify investments into several low-risk technologies to maximize returns and minimize risks.

An unanticipated exception to this pattern was biofiltration; due to the lack of field application and high cost per tonne of methane mitigated, my findings are consistent with a technology in the research stage of development. Due to the novel nature of biofiltration as a method of reducing methane emissions in the oil sands industry, the price of the technology remains high for industrial applications. Although the number of years for a return on the initial investment is still large, increased carbon taxes will drive down the time to achieve return on investment, and application on an industrial scale is necessary to mitigate the large contribution of fugitive methane emissions from tailings ponds.

In accordance with industry business practices, the technology that produces the best overall methane mitigation capacity is not ultimately the technology that will be chosen by each company or should be applied industry-wide as the most effective technology. Evidently, the triple bottom line philosophy for business practice will guide decision-making for individual cases and circumstantial needs based on a thorough and informed analysis of environmental, economic, and social risks and benefits.

The extensibility of the results to the larger oil and gas industry in Alberta may be broadened to the Cold lake and Peace River oil sands deposits, which require in-situ extraction to recover bitumen. In-situ extraction employs many of the technologies discussed in this research including: pneumatic pumps, storage tanks, flare stacks, and other similar infrastructure. In terms of mid-stream upgrading refining of crude bitumen to final products, these results may be used when overlapping technologies exist on the site; however, specific areas of target were not identified in this research. Accordingly, the results and conclusions of this research may be used as a starting-point for industry decision-makers in the oil and gas industry to determine most effective technologies to mitigate methane emissions from the production process.

Based on the results of the risks, environmental, and financial feasibility for methane mitigation, it is apparent that technologies must be adopted on a case-by-case analysis of the methane sources following leak detection programs, which is consistent with directives by provincial regulators, and not all technologies will be applicable to every site looking to implement such mitigation strategies.

Undoubtedly, no particular technology can be singled out as the most effective technology for the oil sands industry overall; however, based on individual industry requirements and a thorough inventory of methane emissions, the most effective technology can be chosen based on the above analyses. Table 16 highlights the most effective technologies in targeting the major emissions sources in upstream oil sands production, and how capital cost for mitigation compares to annual carbon pricing. Targeting methane emissions in these key areas not only reduces carbon pricing for the producer but also aligns with federal and provincial emission reduction targets.

Chapter 7: Conclusions and Recommendations

I sought to determine the most effective methane reduction technologies to reduce GHG emissions from oil sands operations in order to adhere to emissions guidelines and used the research literature to develop a risk assessment and cost-benefit analysis. Enclosed vapour combustion was found to be the most cost-effective in methane mitigation based on cost-benefit analysis results. The following most cost-effective technologies were: replacing high-bleed pneumatics with instrument air systems, installing vapour recovery units, and catalytic converters, respectively. The least effective technology was found to be biofiltration, though future research into the application of this technology may change this result. Inversely, the most cost-effective technologies were found to possess the greatest risk for the producer based on the risk assessment apart from biofiltration, which showed the greatest overall risk due largely to a lack of proof of concept.

Regardless of the chosen technologies, the implementation of methane reduction technologies should ideally be considered during the planning stages of an oil sands project. Additionally, flaring and venting data should be reported to officials and leak detection and repair programs should be implemented to reflect the accurate volume of GHG emissions being emitted by the site during production. The rift between increased carbon emissions in the oil sands sector and national climate commitments are becoming increasingly evident. According to a recent report published by the Pembina Institute (Israel et al., 2020), improving emissions measurements and enhancing transparency in reporting is one of the key recommendations in achieving a decarbonized industry. As such, once baseline emissions data is accurately measured and quantified by source, methane mitigation technologies can be accurately chosen based on each individual site requirements.

My assessments indicated that higher mitigation potential is more cost-effective than less expensive technologies when carbon pricing is considered (Table 12), which is consistent with previous conclusions by Tyner & Johnson (2018) and their analysis of methane mitigation of venting data. Contrarily, higher mitigation potential resulted in higher risk due to the fiscal and environmental consequences of technology failure, which was observed by Lee et al., (2017) when they compared carbon capture and storage technologies on cost and mitigation efficiency.

Implication of the Research

Collecting emissions data should remain an important component of meeting methane emission regulation objectives. Site operations should conduct regular air quality and emissions monitoring programs to detect fugitive emissions and ensure triple bottom line objectives are met. Although emissions testing is currently being implemented at oil sands sites, new monitoring technologies, such as air-borne measurements using drones (Liggio et al., 2019), will give additional insight towards more reliable emission evaluation.

My general conclusion is that industry decision-makers should contextually consider a combination of several technologies to best mitigate their methane emissions and comply with targets put forward by the provincial and federal governments. As research into novel technologies continues and carbon prices increase, the risk and the number of years for a return on the initial investment cost for these technologies will change. This thesis serves as a reference document in the preliminary implementation of methane mitigation technologies; however, baseline methane emission measurements, social consideration, and other technologies should be included in the decision-making process.

The results of my research assume that the most effective technology is applied following a thorough and accurate methane emission inventory is completed on the site's sources and volume of emitted greenhouse gases, including any possible leaks and all vented emissions. The most effective technology cannot be implemented without a baseline knowledge of methane emissions, and results will vary in practice if emission sources are not known. My conclusions cannot be applied without an accurate knowledge of methane release; therefore the findings of this assessment assume that a baseline emission assessment was completed prior to choosing and implementing the most effective methane mitigation technology, and that the best technology was selected based on the specific target sources of the producer.

Prior to the implementation of methane mitigation technologies, industry decision-makers should review conclusions with local communities and regional industries to obtain feedback and discuss the process of technology implementation and methane mitigation. Ensuring proper and informed consent of all involved groups in the decision-making process is an important step in proper business practices and fulfills part of the social criteria requirements of the triple bottom line philosophy to business development (Poveda & Lipsett, 2013).

Recommendations

My recommendations for Alberta oil sands industry decision-makers, government regulators and site operators, are:

1) **Encourage investment and research in technology through market-based policies and economic incentives, such as research grants and carbon credits.**

Economic incentives are a powerful tool for regulators to influence the industry to move to a less environmentally damaging production process. Producers should continue to receive carbon credits, which have been shown to incentivize research and development and investment into methane mitigation technologies (Mathews, 2008), as implemented by the TIER regulations when targets are met.

Strict guidelines and policies should encourage research, development, and implementation of methane mitigation technologies instead of venting or flaring waste gas to the atmosphere. I believe that regardless of party position, emission reduction guidelines must be implemented in some manner to continue driving GHG emissions down and reduce climate impact from the industry. GHG emissions aggravate the climate crisis while also containing other compounds that are hazardous to the environment; reducing emissions reduces these consequences to both the environment, industry, and quality of all life.

2) **Establish a thorough and comprehensive methane source inventory of individual sites to better target sources and select mitigation technologies.**

Most effective methane mitigation technologies cannot be accurately selected if a thorough and comprehensive methane inventory is not completed prior to decision-making. Understanding the sources and volumes of GHG emissions will help target the biggest emitters and reduce methane at the lowest cost and risk to the producer. It is important for policy-makers to understand sources of methane from industry to better implement regulations on emissions to drive down the overall environmental footprint of the oil and gas industry.

3) Address known sources of fugitive emissions, such as orphaned or abandoned wells, to tackle the large proportion of industry methane emissions from fugitive sources.

The continued increase in methane emissions from industry is no longer accepted by global standards and challenges the target of the Paris Agreement, which is committed to limiting global warming to below 2°C (Nisbet et al., 2019). The burden of repairing the damage of increasing global temperatures should not be allotted to future generations and stakeholders should have to take accountability for their part in the climate crisis. Liability for emissions falls on the producer, and I believe that GHG reduction goals should be based on targets that will reflect the largest reduction in methane, specifically, mitigating fugitive emissions.

4) Increase regulatory guidelines on methane emissions to continue stimulating the reduction of methane emissions, while maintaining productivity of oil and gas facilities.

Industry producers should examine their GHG emission processes as production increases and mitigate fugitive emissions by incorporating the most ecologically and financially beneficial equipment. Since 2018, new regulations have been implemented on methane emissions in the upstream oil and gas industry, and these rules are only expected to get stricter as the province moves toward a more environmentally friendly energy product (AER, 2018b). The economic benefit of these technologies may not be currently apparent; however, considering the triple bottom line philosophy, investing in methane mitigation technologies can potentially be beneficial in avoiding carbon levy costs, and in maintaining a social license by reducing emissions and creating a respectable product on a global market.

With the collaboration of government and industry decision-makers, Alberta can successfully reduce its carbon emissions and become an industry leader in environmentally conscious energy production.

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Appendix A

Likelihood Assessment of Methane Mitigation Technologies

Table 18

Vapour Recovery Units Likelihood Assessment

	Score	Comments
Large-scale applicability	5	…based on its popular application in the industry and the high market value of recovered vapours. Methane and other gas streams can be isolated and used as on-site fuel or sold on the market, which is an additional benefit of implementing this technology
Mitigation efficiency	4	…based on their conservation mechanics; all emission GHGs are mitigated and no gas is vented or flared in the process.
Cost	3	…based on cost of implementation due to the high capital cost of the technology.
Novelty	1	…due to their well-researched and present implementation in the oil sands industry

Table 19

Instrument Air Systems Likelihood Assessment

	Score	Comments
Large-scale applicability	3	…based on the number of retrofits and capital cost required on existing infrastructure.
Mitigation efficiency	4	…based on their conservation mechanics; that is, all emission GHGs are mitigated and no gas is vented or flared in the process.
Cost	3	…based on the number of retrofit installations required for replacing high bleed pneumatic systems.
Novelty	2	…due to their well-researched applications in the oil sands industry; however, some older sites

		have yet to retrofit old technologies and continue using high bleed pneumatic and venting systems.

Table 20

Catalytic Conversion Likelihood Assessment

	Score	Comments
Large-scale applicability	2	…based on the low daily mitigation volume.
Mitigation efficiency	3	…based on their conversion mechanism. In other words, methane is converted to carbon dioxide through an oxidation process and reduces the GWP of emissions by 34 times but does not completely mitigate all GHG emissions (such as carbon dioxide).
Cost	2	…based on the low capital cost of the technology.
Novelty	1	…due to their well-researched and current implementation in the oil sands industry.

Table 21

Enclosed Vapour Combustion Likelihood Assessment

	Score	Comments
Large-scale applicability	4	…based on the current popular application of this technology across the industry.
Mitigation efficiency	3	…based on their conversion mechanism. In other words, methane is converted to carbon dioxide through an oxidation process and reduces the GWP of emissions by 34 times but does not completely mitigate all GHG emissions (such as carbon dioxide).
Cost	4	…based on the high capital cost of enclosed vapour combustors.
Novelty	2	… due to their well-researched applications in the oil sands industry; however, some older sites have yet to retrofit old technologies.

Table 22

Biofiltration Likelihood Assessment

	Score	Comments
Large-scale applicability	2	…based on the low mitigation volume of catalytic conversion and the novelty of biofiltration, although the latter has potential in the coming years.
Mitigation efficiency	3	…based on their conversion mechanism. In other words, methane is converted to carbon dioxide through an oxidation process and reduces the GWP of emissions by 34 times but does not completely mitigate all GHG emissions (such as carbon dioxide).
Cost	4	…based on the large surface area of tailings ponds that would require biofiltration.
Novelty	2	… due to its lack of practical, large-scale applications in the oil sands industry.

Appendix B

Severity Assessment of Methane Mitigation Technologies

Table 23

Vapour Recovery Unit Severity Assessment

	Score	Comments
Large-scale applicability	1	…based on the low capital cost of the technology and its widespread application.
Mitigation efficiency	4	…based on the high volume of methane that this technology removes from emissions and cost of the methane lost if technology fails.
Cost	3	…based on the moderate cost of implementation of the technology and economic loss from the investment to the stakeholder.
Novelty	1	… since they are well researched and understood in the industry.

Table 24

Instrument Air Systems Severity Assessment

	Score	Comments
Large-scale applicability	3	…based on the high cost of replacing existing infrastructure and that they are less frequently used in the industry
Mitigation efficiency	3	…based on their moderate methane mitigation capacities, however older technologies that may already exist on site such as low bleed pneumatic systems also function to reduce GHG emissions.
Cost	3	…based on the moderate cost of implementation of the technology, and economic loss from the investment would be significant to the stakeholder.
Novelty	2	…since they have historical evidence of use in the industry.

Table 25

Catalytic Conversion Severity Assessment

	Score	Comments
Large-scale applicability	4	…based on a relatively high cost of implementation compared to its maximum mitigation potential.
Mitigation efficiency	2	…based on the low daily mitigation volume of the technology. A failure of the catalytic conversion would not significantly increase GHG emissions of the site.
Cost	2	…based on the low maintenance and capital cost of the technology.
Novelty	2	…since they have historical evidence of use in the industry and has been used on a large scale but is more popular in different industries.

Table 26

Enclosed Vapour Combustion Severity Assessment

	Score	Comments
Large-scale applicability	3	…based on to the high cost of combustors and that they are less frequently used in the industry than flaring and venting.
Mitigation efficiency	3	…based on their moderate methane mitigation capacities, however older technologies that may already exist on site such as flaring also function to reduce GHG emissions.
Cost	4	…based on the high cost of implementation for the technology. In the chance of a failure of the technology, targeted emissions would increase significantly and contribute to higher carbon pricing for the stakeholder.
Novelty	1	…since it is well researched and understood in the industry.

Table 27

Biofiltration Severity Assessment

	Score	Comments
Large-scale applicability	4	…since it is unproven on a large scale, and large investments into this technology could result in financial loss and environmental impact through continued GHG emissions.
Mitigation efficiency	5	…since the technology has yet to be tested on a large scale, and the science has not yet been optimized for methane capture. The volume of released methane from tailings ponds due to the failure of the technology would be a significant contribution to the industry's overall GHG emissions.
Cost	4	…based on the high cost of implementation for the technology. In the chance of a failure of the technology, targeted emissions would increase significantly and contribute to higher carbon pricing for the stakeholder.
Novelty	3	…due to the novelty of the technology. This method needs to be applied to a larger scale before it can be considered as a mitigation method.