UNIVERSITY OF CALGARY

A Sustainable and Multi-Operator Approach to Water Management in Unconventional Oil and Gas Developments

by

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A RESEARCH PROJECT SUBMITTED

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE

DEGREE OF MASTER OF SCIENCE

GRADUATE PROGRAM IN SUSTAINABLE ENERGY DEVELOPMENT

CALGARY, ALBERTA

AUGUST, 2019

ABSTRACT

Unconventional oil and gas developments are causing significant footprints resulting from freshwater use, temporary water infrastructure and the greenhouse gas emissions associated with water hauling truck trips. These status quo industry practices can also prove costly to oil and gas operators. The present study explores the economic and environmental benefits that exist when permanent water infrastructure is planned at scale using entire water life cycle considerations. Focusing on an area of study west of Grand Prairie, AB, the author demonstrates the economy of scale of such a development and proposes that this opportunity is more easily captured when two or more operators collaborate through a multi-operator water management plan (MOWP). This framework prompts regulatory and business model challenges that would need to be addressed but in the light of climate change, increasing water management costs and water security considerations, MOWPs are nothing but an opportunity to be seized.

ACKNOWLEGMENTS

To my supervisor Michael Benson and the entire Integrated Sustainability family, thank you for your time and continued support throughout this study. There were a number of different and important contributors to this project, thank you all very much.

To my family, what I love the most, thank you for your care, patience and love during this time.

Table of Contents

List of Tables

List of Figures

List of Abbreviations

AER	Alberta Energy Regulator
AEP	Alberta Energy Parks
AWSS	Above Ground Synthetically Lined Wall Storage Systems (a.k.a. C-rings)
bbl	Barrel
CAPP	Canadian Association of Petroleum Producers
cf	Cubic feet
CSUR	Canadian Society for Unconventional Resources
CERI	Canadian Energy Research Institute
CWN	Canadian Water Network
d	Day
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPEA	Environmental Protection and Enhancement Act
GHG	Green House Gas
HQNS	High-Quality non-Saline Water
IEA	International Energy Agency
IS	Integrated Sustainability
JV	Joint-Venture
km	Kilometer
LNG	Liquified Natural Gas
m	Meters
m^3	Cubic Meters
MJ	Mega Joule (10^6 Joules)
MOWP	Multi-Operator Water Management Plan

NRC	Natural Resources Canada
NGL	Natural Gas Liquid
POD	Point of Diversion
POU	Point of Use
TDL	Temporary Diversion Licenses
WALIC	Permanent Water Licenses (a.k.a Water Act Licences)
WCS	Western Canadian Sedimentary Basin
WTI	West Texas Intermedium

CHAPTER 1. INTRODUCTION

1.1 Purpose

The purpose of this Research project is to investigate the opportunities that exist for oil and gas companies undertaking hydraulic fracturing operations to cooperate in the reduction of the water infrastructure footprint and the freshwater use in Alberta. It is deemed that achieving these goals requires the successful implementation of a collaborative, infrastructure-sharing based, multi-operator water management framework. The objectives of this framework would be to reduce the use of high-quality non-saline water (HQNS); limit the footprint caused by the water infrastructure needed during well drilling, completion and disposal; and ultimately decrease the participating companies´ water management costs. At the core of the framework is a multi-operator water management plan (MOWP) that would include a centralized intake point, water storage facility, water treatment and conveyance system.

1.2 Methodology

This project was developed in conjunction with the privately-owned, consulting firm Integrated Sustainability (IS). The company is an employee owned water advisory and infrastructure delivery firm with extensive expertise in all aspects of shale-play water management. IS has 100 full-time professionals and operates offices in Calgary, Vancouver, Houston, Barbados and a field office in Grande Prairie. The research will be focused mainly on data and knowledge from the unconventional oil and gas developments concentrated in the Montney play of Alberta and British Columbia. The first component of the study will include placing unconventional oil and gas demand in a global and local context. Secondly, a myriad of data types and volumes will be reviewed within two platforms with spatial capabilities: GeoCata and Power BI. The former is an in-house developed, proprietary tool that pulls, stores and displays publicly available data in a graphical interface. The latter is a business analytics Microsoft product that pulls data from a database and allows users to manipulate it to create charts, statistical analysis and relational plots among others. The goal of this data mining exercise is to quantify the environmental component by identifying trends in water use and water management practices within the current regulatory regime. It is expected that this activity will also lead to the identification of opportunities and/or best practises. This activity will be complimented by an extensive literature review with focus on Government websites and, by specialized conversations with experts on regulatory, business development and environmental assessment matters. Similarly, relevant conversations with some key stakeholders in the Alberta Energy Regulator (AER), Alberta Environment and Parks (AEP), oil and gas producers and service companies will be part of the study. The final two components that will be part of the study are: A Present Value exercise closely related to a Calgary-based oil and gas operator and development plan and, recommendations for a MOWP looking forward.

The project uses an empirical approach to research to diagnose the issues around water management practices in the Unconventional oil and gas industry. These issues reflect a “tragedy of the commons” dilemma, where society thru the private sector benefits from a resource but do very little to conserve it because it is widely perceived as “abundant and cheap”. Additionally, a deductive approach is used to present and test the hypothesis that a MOWP with shared infrastructure development can decrease water management cost to companies and bring about social and environmental benefits. The hypothesis has been examined at a very high, policy level by the Alberta Government to protect society and the environment, but it has not been materialized into a regulatory framework, much less tested in a project development-like scenario. While the present value exercise in Chapter 4 – Economics, is used as a tool to prove the hypothesis, the guidelines presented in Chapter 5 – Proposed Framework Guidelines present an innovate, how-to guide to address the development of a MOWP looking forward. The solution aims to present the most important considerations of what can potentially be a "more sustainable" practice to water management and use, not necessarily a fully sustainable one. Any future steps towards sustainable development within the energy systems can be guided by the ideas of Robert Solow (Solow, 1991), Herman Daly (Daly, 2009) or Amartya Sen (Sen, 2004).

1.3 Interdisciplinary Aspects

This project is anchored in four elements: energy, environment, regulatory and economics behind water management. The energy component lies in the study of the exploitation of unconventional plays such as those in the Duvernay and Montney formations, which is expected to increase as the supply of conventional oil and gas continues to decline and the demand for these commodities increases (ARC, 2019). The environmental component lies primarily in the study of water use, water management practices in hydraulic fracturing operations and, the land footprint associated with it. Climate change, freshwater seasonality and the distribution of natural water sources in the province, where 80% of the water supply lies in the north while 80% of the demand lies in the south (Alberta Water, 2018), are constantly putting the hydrological cycle and its ecosystem under stress. Another component that will be explored is the Green House Gas (GHG) emissions and energy use by water hauling truck trips, a common practice in the industry. It is believed that a centralized, shared water facility represents larger availability for water storage, treatment, recycling and therefore less need for water movement and disposal. Finally, the economic component lies in the investigation of the economy of scale of the shared infrastructure proposed within this report. It is expected that cost advantages can arrive from a few elements: fewer need for disposal wells, reduction of the water transportation costs, and ultimately the economics of scale given by the infrastructure-sharing nature of the MOWP (personal communication, Jeff Coombes, January 29, 2019). Additional economic advantages may arrive from cost certainty and water security considerations. A Joint-Venture (JV) or a pay-per use type of agreement could serve as the backbone for a MOWP. In either case, this legal framework would offer the cost certainty and water security that may be lacking when operators rely on water hauling truck trips and, freshwater sources respectively.

The regulatory component, a key element in the environmental anchor, will be explored within each sub-section as considered relevant.

CHAPTER 2. ENERGY

2.1 Global Context: Increasing Oil and Gas Demand for Years to Come

Faith Birol, executive director of the International Energy Agency (IEA) recently recognized that despite large amounts of investments in renewable energy and growth in adoption of electric vehicles, fossil fuels make up 81% of today's energy mix, just as it was thirty years ago (Bennett, 2019). Even though the statement does not imply any future predictions, it does convey the notion that oil and gas production is an integral part of the energy mix. It is widely believed the statement will continue to be relevant for many years to come. Currently, a key component of the fossil fuel energy share is the U.S. shale boom, which has become the dominant force in the global oil supply and will likely continue to be for the next 5 to 10 years (Bloomberg, 2019). The main driver behind the increasing unconventional oil demand is the conventional oil field decline and the relatively short circle of tight oil resources. It is estimated that 70% of the $54 billion spent in tight oil plays will serve to offset field declines (Cunningham, 2019).

In terms of growth, BP´s latest energy outlook presents a strong demand growth for natural gas at 1.7% per year increasing nearly 50% by 2040 (BP, 2019). The outlook for oil demand, on the other hand, remains more uncertain out to 2040 but it is expected to still play a significant role in the global energy context. In a shorter term, however, the tight oil market production (crude and Natural Gas Liquid, NGL) is to rise to 11,1 million bbl/d out to 2025, with the U.S., Brazil and Canada making up for the non-OPEC supply growth (OPEC, 2017). The International Energy Agency forecasts that around 70% of the world´s oil trade will use a port in Asia (IEA, 2017). This statement also reflects what is arguably one of the main growth drivers for gas demand: Asian markets´ coal switch off. The U.S. and Canada are set to become the most likely sources of the Asian NGL and Liquefied Natural Gas, LNG, demand growth (CERI, 2018a).

In a 2013 report, the McKinsey Global Institute estimates that around $2 trillion in infrastructure spending will be needed to support oil and gas activities to 2030 (MGI, 2013). This figure includes investments in roads, power, water infrastructure, ports, rail facilities and pipelines. The study estimates that nearly 70 percent of infrastructure investment could be multi-user, and the remaining 30 percent could be multi-purpose.

2.2 Canadian Context: New Opportunities

Canada´s full potential in unconventional resources is not yet known or otherwise carries significant uncertainty. In 2013, the Geological Survey of Canada estimated the Country has 4,995 tera cubic feet (cf) of shale gas in place and 623 billion barrels of shale oil in place (Library of Parliament, 2014). The Canadian Society of Unconventional Resources (CSUR) estimates that 343-819 tera cf is marketable gas, while the U.S. Energy Information Administration (EIA) and the World Energy Council place this estimate at 573 tera cf as presented in Table 1 (EIA, 2015 and World Energy Council, 2016).

Table 1. Shale Gas and Oil Resources of Canada

Region	Basin / Formation	Risked Resource In-Place		Risked Technically Recoverable Resource	
		Oil/Condensate (Million bbl)	Natural Gas (Tcf)	Oil/Condensate (Million bbl)	Natural Gas (Tcf)
British Columbia / Northwest Territories	Horn River (Muskwa / Otter Park)	-	375.7	-	93.9
	Horn River (Evie / Klua)	-	154.2	-	38.5
	Cordova (Muskwa / Otter Park)	-	81.0	-	20.3
	Liard (Lower Besa River)	-	526.3	-	157.9
	Deep (Doig Phosphate)	-	100.7	-	25.2
	Sub-Total	**-**	**1,237.8**	**-**	**335.8**
Alberta	Alberta (Banff / Exshaw)	10,500	5.1	320	0.3
	E/W Shale (Duvernay)	66,800	482.6	4,010	113.0
	Deep Basin (Nordegg)	19,800	72.0	790	13.3
	N.W. Alberta (Muskwa)	42,400	141.7	2,120	31.1
	S. Alberta (Colorado)	-	285.6	-	42.8
	Sub-Total	**139,500**	**987.1**	**7,240**	**200.5**
Saskatchewan / Manitoba	Williston (Bakken)	**22,500**	**16.0**	**1,600**	**2.2**
Quebec	App. Fold Belt (Utica)	**-**	**155.3**	**-**	**31.1**
Nova Scotia	Windsor (Horton Bluff)	**-**	**17.0**	**-**	**3.4**
	Total	**162,000**	**2,413.2**	**8,840**	**572.9**

*Less than 0.5 Tcf

Source: (EIA, 2015)

Given the global context, it is of paramount importance Canada finds new mid-stream infrastructure and markets. As of 2018, the midstream industry is planning to invest $39 billion in projects such as facilities and terminals (CERI, 2018a). Three key projects in Western Canada expected to open exporting opportunities are: LNG Canada, Kitimat LNG and Woodfibre LNG, all three projects with project completion dates between 2023 and 2029. The potential added capacity of these three projects alone is 3,3 billion cf/d with an upside of 5,0 billion cf/d (JWN, 2019).

2.3 Unconventional Resources in the Western Sedimentary Basin

Unconventional resources can almost be found across the entire country, but the vast majority are concentrated in the Western Sedimentary Basin. In terms of reserves and production, the Western Canadian Sedimentary Basin (WCS) represents the largest source of unconventional shale and tight resources in the country. For the purpose of this study the prolific Montney and Duvernay plays in will receive a special focus.

Figure 1. Map of Western Canadian Sedimentary Basin and Shale Plays

Source: Adapted from (PacWest Consulting Partners, 2016)

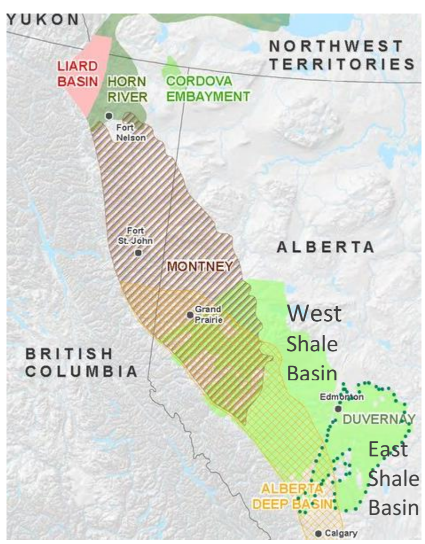
2.3.1 Duvernay

The Duvernay shale formation is in Alberta and present in the “East Shale Basin” (south of Edmonton) and the “West Shale Basin” (east of Fox Creek). It is an oil-rich resource made up of mainly limestone in the East Shale Basin that becomes less calcareous and more shale rich in the West Shale Basin (AER, 2012). The National Energy Board assessed marketable gas reserves at 77 tera cf, oil reserves at 3,4 billion bbl and NGL reserves at 6,3 billion bbl (NEB, 2017). Formation thickness varies between 1000 m at its northeast limit and 5000 m as it moves towards Alberta’s foothills. Much of the play’s development has revolved around the Fox Creek area but in more recent years some operators have turned their interest to the shallower East Shale Basin, where a light 38º API oil has been produced in an area with more competition for water resources. (personal communication, Brad Hydes, October 23, 2018)

2.3.2 Montney

The Montney formation is present along the Alberta-British Columbia border and is characterized as fine siltstone rather than a true shale. Depths increase in the northeast-southwest direction and vary between 500 m and 4500 m (AER, 2012). Thickness increases towards the Alberta-British Columbia border reaching up to 300 m. The Montney can be one of the largest unconventional plays worldwide with marketable gas reserves at 449 tera cf, oil reserves at 1,13 billion bbl and NGL reserves at 14,5 billion bbl (NEB, 2013). The formation is being targeted with stacked completions. The technology, called 'Cube' (covered in more detailed in section 4.5), was introduced to the WCS by Encana in 2017 after it was proven successful in significantly increasing resource potential the U.S. Permian Basin (Jaremko, 2017).

Figure 2. Duvernay and Montney Formations Map



Source: Adapted from (NEB, 2015)

2.4 Incrementalism and Strategic Thinking

Every high-level decision a corporation makes based only on immediate project-by-project basis, has the potential to set the path in an undesirable way in the long-term. Once the path is set, each additional undertaking often perpetuates the status quo. In resource development law, this concept is referred to as incrementalism (Muldoon, 2015) but it can also be applied to resource extraction practices. For example: trying to reduce water management cost by selecting the least expensive available water sourcing option, when what needs to be redefined at a higher level is the strategy to water sourcing itself. Current practices in this regard include short-sighted, siloed visions where logistics, operation optimization, legal, regulatory and engineering efforts among others are not fully integrated. Water sourcing for instance, is often considered of relevance to the drilling and completions team, while water disposal is an “issue to be dealt with” by the surface or production engineering team. This fragmentation usually creates a suboptimal solution that can potentially put the organization at a disadvantage when government policies or market conditions change. For example, siloed operations with independent budgets can both strive for operational cost reduction but, they if cash is limited, they may end up competing for capital investments. Optimization of these internal efforts or capabilities for ultimate cost reduction objectives requires integration (Garcia, 2014).

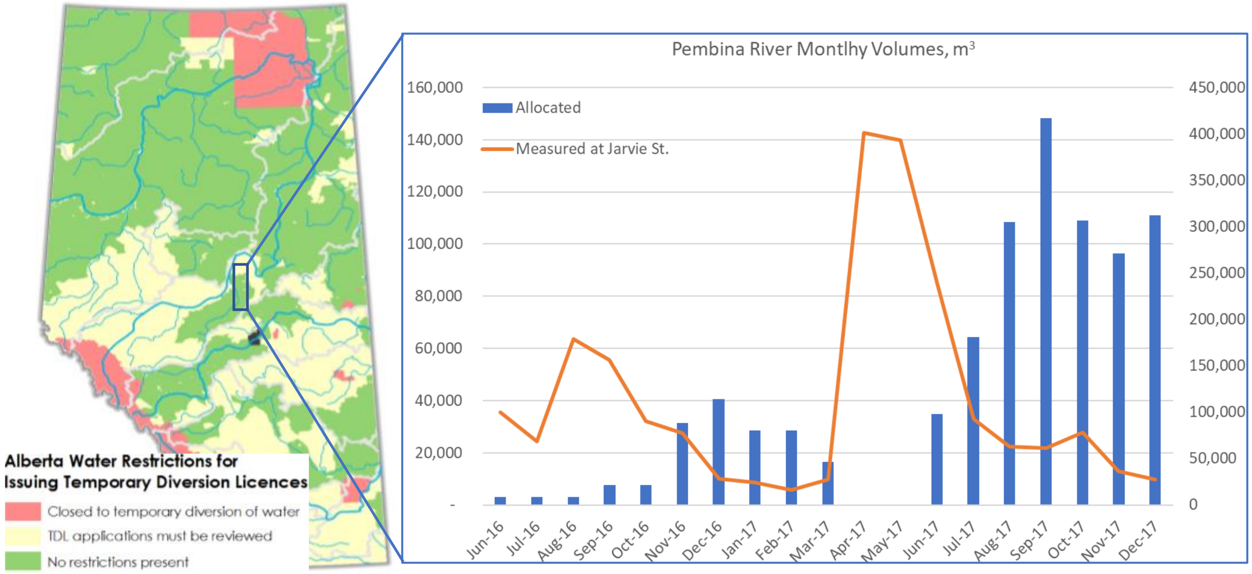
It is widely recognized in Alberta that using freshwater as hydraulic fracturing fluid is cost effective but, in many cases, it can also increase the risk of formation plugging, which can significantly decrease well productivity (Walsh, 2019). Alternatively, using formation water can offer less chances of formation plugging. The reason behind this water type-well productivity link is that produced (and treated) water that is compatible with the fracturing fluid polymer and additives used ensures fluid compatibility with formation water. If not adequately considered, formation plugging can offset the benefits of increased reservoir exposure by longer horizontal sections or increased number of fracturing stages. Another example where strategic thinking can prove beneficial is considering water management cost on a life-cycle and long-term basis as it can be less expensive to treat produced water and use it as hydraulic fracturing water in certain regions of the province where disposal and transportation cost are too high (personal communication, Jeff Coombes, June 10, 2019).

From a regulatory point of view, the 2006 Water Conservation and Allocation Policy for Oilfield Injection along with the Water Conservation and Allocation Guideline for Oilfield Injection have largely laid out the framework for water use in the oil and gas sector. However, both documents fall short now in addressing the current increase in water use in hydraulic fracturing operations. As a result, the Government of Alberta released in 2016 a draft version of the Water Conservation Policy (*the policy*) for Upstream Oil and Gas Operations (Government of Alberta, 2016). The final version of the document is pending approval, but *the policy* will likely result in more stringent regulations that are intended to discourage companies from using freshwater resources. For example, by placing water conservation considerations and adverse environmental net effects ahead of economic evaluations in the approval of water sources. At a general level, *the policy* includes high-level consideration on MOWPs and, a need for a more holistic approach to water management (personal communication, Steve Wallace May 13, 2019). In this context, the scenario where a company is able to create a technically and economically feasible way to increase water recycling in the current regulatory landscape, represents a competitive advantage looking forward.

2.5 Energy-Water Security

Energy security represents more than ensuring permanent supply of the oil and gas required to fulfill the demand part of the local or global energy mix or, to fulfill the fiduciary responsibility oil and gas company´s officials have towards investors. Given the strong water-energy nexus, risking the supply of one commodity can put at risk the supply of the other one. In hydraulic fracturing operations, water is needed in drilling and completion activities while energy is needed to convey it, transport it and treat it. This nexus became evident in Alberta in the winter 2016 – spring 2017 period when below-average moisture conditions brought about by a strong el Niño-Southern Oscillation drew the AER to place a temporary water restriction for the diversion and allocation of water licenses in the Peace River major system (Figure 3). One of the rivers involved in this restriction was the Pembina River where 818,000 m^3 of water had been allocated by the AER (before the low flow levels were measured) to support fracturing operations during the November 2016-December 2017 period. The Figure reveals that the December 2016 - March 2017 and the August 2017 - December 2017 periods, the river experienced its lowest water levels as measured by the Alberta Water Tool (Alberta Water Tool, 2019). These very same periods coincided with increasing drilling activity (water allocations used here as indicative of the potential disruption to drilling and completion operations when restrictions are in place).

Figure 3. 2016/2017 Temporary Water Restriction Areas and Flows at Pembina River



Source: Government of Alberta in (In-Solutions, 2016) - *left*. (Author, 2019) - *right* with Alberta Water Tool and AER water license allocations data

In cases like this, having access to water storage in periods when freshwater sources are at their highest levels (spring thaw out) or, to alternative water sources such as recycled water can represent the difference between being able to complete a drilling plan or not, which eventually results in oil and gas supply and cash flow implications. At the time of writing, the British Columbia Oil and Gas Commission (OGC) suspended all water diversion licenses from the Peace River and Liard river watersheds. As climate change accelerates the glaciers' ice loss rate, the Athabasca, North Saskatchewan and Peace River basins are expected to experience a significant loss in contributions to streamflow from glacier input. This loss will be concentrated in late summer (Alberta Water, n.d.a).

2.6 Ever-Present Risks Around Priority System and Different Mineral Rights

Extractive industries such as the oil and gas rely on obtaining mineral rights under the Mines and Minerals Act to conduct their operations (Government of Alberta, n.d.a). Within certain boundaries, these permits give companies the rights to explore for and develop the resources below the surface but does not give them the rights to the surface itself. If the land is owned by a private party, surface access usually needs to be negotiated with the surface right owner. If, say, operator A seeks to reduce its freshwater use by targeting deep water sources in the same subsurface space where operator B has mineral rights, operator A must have consent from operator B as per AER's Directive 056 (AER, 2017b). Whether it is dealing with mineral or surface leases in areas outside a company's land holdings, these negotiations can turn into a lengthy or/and administrative burden that may represent an operational risk. Similarly, and in Canada, oil and gas companies often rely on temporary water diversion licenses (TDL) or permanent licenses obtained under the Water Act (Government of Alberta, n.d.b) for their freshwater needs. The water licensing mechanism was founded on the first-in-time-first-in-right principle, under which water license applicants are given priority based on the date the application is received. The principle is largely seen as unfavourable to new entrants and can potentially represent a risk as their allocations can be restricted partly or fully at any time, in water short periods before a more senior licence holder is affected (Government of Alberta, n.d.a, Government of Alberta, 2014).

2.7 Innovative Thinking in the Energy Sector

One key takeaway from the 2019 CERAWeek (a widely recognized annual energy conference with discussions around energy trends, outlooks, geopolitics and regulations among others) is that in terms of technology, the hydraulic fracturing industry may have "maxed out" on lateral lengths, proppant and fracturing fluid design and intensity (OGJ, 2019). There are technological gaps that remain to be bridged such as ensuring all number of fracking stages contribute to flow, reducing the interference effects between wells (a.k.a. parent-and-child well issues) and unlocking Enhanced Oil Recovery (EOR) potential of these resources. However, as the industry continues to evolve these technological aspects are likely to become qualifiers rather than differentiators (Garcia, 2014). In this scenario innovative thinking is required to unlock more value out of each resource: water, oil, gas or land or, to position companies at an advantage relative to their peers.

Innovation is about capturing the opportunities that ensure future businesses and investments. The current oil and gas industry in Canada face a scenario that fosters the perfect conditions for innovation to reduce the cost to produce hydrocarbons: low oil prices (or high WTI-WCS oil price differentials) and carbon emission regulations (Stastny, 2017). The concept of innovation needs to coin an idea that goes beyond technology or cost reduction and that looks at different ways of doing things in what is perceived as a highly competitive market. One of these paradigms is strategic partnering. Unlike disruptive technologies such as cloud-based systems, cognitive computing and block chain technology where intellectual property can be sensitive (Deloitte, 2018), strategic partnering to reduce HQNS water use in hydraulic fracturing would rely mostly on matured technologies. The challenge remains in overcoming the paradigm of treating peers as competitors all the time and in all different arenas. COSIA is the perfect, home-made example that proves the latter statement wrong. If an industry-wide alliance with cutting-edge technology has helped in improving heavy oil operations, introducing a much less technologically challenging framework based on shared infrastructure, collaboration and a common agreement is nothing but an opportunity waiting to be seized.

2.8 Wastewater and Infrastructure as a Commodity

Wastewater in oil and gas production operations can be a commodity, or at least it is being perceived as such in the U.S. hydraulic fracturing industry, where supplying, hauling and disposing of water created a $34 billion business in 2018 (Reuters, 2019). Wastewater handling and treatment facilities such as Antero´s Clearwater (Antero Midstream, n.d.) have been built with the specific objective of supporting drilling and completion activities. The mid-stream company reported a net income of $596 million at the end of 2018. Some private equity firms committed $4 billion to buy or start water management companies from 2014 to 2018 (Reuters, 2019). Additionally, they also purchased water infrastructure and handling assets from two different operators for $550 million (Reuters, 2019). Another example of the growing market for wastewater in hydraulic fracturing is the Sourcewater platform (Sourcewater, 2018), an online-booking, U.S.-based interface and open marketplace that connects wastewater buyers and sellers using an interactive map. Sellers such as hydraulic fracturing firms list their wastewater specifications and volumes and buyers such as shippers or treatment facilities bid on transporting it and treating it. Using the system, Shell was able to reduce water hauling distance to 20 miles and eliminate 180+ miles of truck distance (MIT Energy Initiative, 2017).

Even though on paper a system like Sourcewater could be implemented in Canada, a few regulatory hurdles would need to be addressed before it can prove successful in Alberta. The first one is around the definition of produced and flowback water as well as drilling fluid as “oilfield waste” during its entire life cycle. Oilfield waste (also referred to as wastewater) must be disposed of as per AER Directive 058: Oilfield Waste Management Requirements for the Upstream Petroleum Industry (AER, 2013). The Environmental Protection and Enhancement Act

(EPEA) on the other hand, labels wastewater as any substance “deemed to be disposed of…”, e.g. intended for disposal (APEA, RSA 2000). In this context, the handling, storing, conveying and treating of wastewater intended for reuse and recycling purposes could potentially be regulated under an alternative framework that accounts for changes in its intended use and characteristics. This “waste” definition along the entire life cycle deters operators from implementing handling, storing and conveying schemes that could increase the use of alternative water sources such recycled water (AER, 2017b). In the U.S., pickling sludges resulting as by-products of metal treatments are considered hazardous as soon as they are generated, non-hazardous when they are neutralized and feedstock when they are used in the recovery of additional chemicals such as ferric oxide. Waste-to-energy processes are another example where waste streams can be considered of value in other activities.

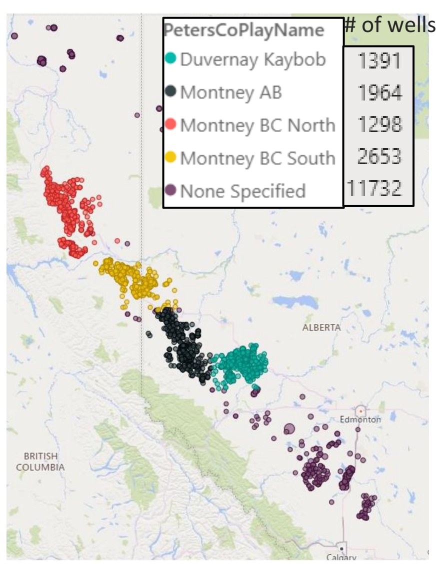
Additional hurdles that are perceived by the industry as “disablers” rather than “enablers” in the reduction of HQNS use include (AER, 2017b): inability to use temporary surface hoses (a.k.a. layflats) for wastewater streams, inability to accommodate for a risk-based, full-lifecycle water management profile and, volume and time limits for aboveground synthetically-lined wall storage systems (AWSS, a.k.a C-rings). Existing wastewater facilities in Alberta are able to take in and treat some of the water generated from hydraulic fracturing activities, however, given the wide and varying-with-time range of contaminants as well as the large volumes generated, they do not provide a long-term solution (CWN, 2015b). Finally, the regulatory system does not allow for the treatment and discharge of produced water, for example for agricultural use.

CHAPTER 3. ENVIRONMENT

3.1 Data Sets and Applications

The spatial web-based application GeoCata and the business analytics platform PowerBI were used to investigate some of hydraulic fracturing indicators in this section. Both tools provide users with access to the industry wide used FracFocus database, AER's Directive 059 on Well Drilling and Completion Data Filings and, IHS well production database among other databases/map layers. Two additional boundaries were used as considered relevant: one within the AER Area-Based pilot project in the municipal district (MD) of Greenview and, another one with the vertical, more rigorous definition of the Montney play (as Peters&Co spatial definition does not necessarily conform to the official formation names). Data cleansing in PowerBI (FracFocus table) included suspicious data points and those with blanks or zero entries. Figure 4 presents the well locations of hydraulic fractured wells as identified within the four spatial widely recognized Peters&Co well clusters.

Figure 4. Hydraulically Fractured Wells registered in FracFocus

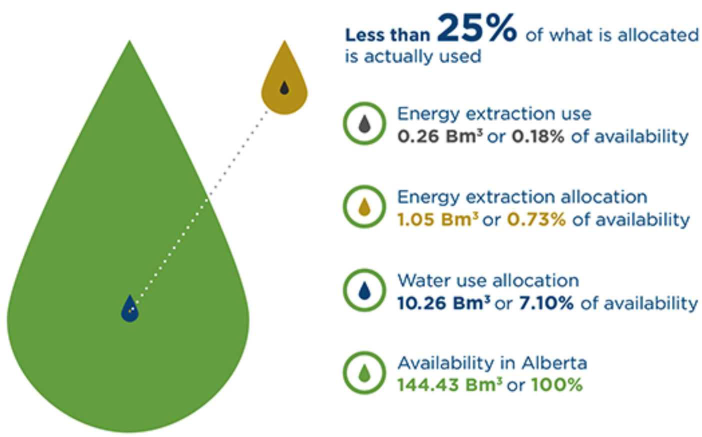


Source: (Author, 2019) from PowerBI (Fracfocus table)

3.2 Water use in Alberta

In 2017, the AER estimated that out of the total 144 billion m^3 of non-saline water available in the province, 10,26 billion m^3 or 7.1% was allocated for use (Figure 5). Energy extraction activities such as SAGD, EOR and hydraulic fracturing were allocated 1 billion m^3 or 0.73% of the total water available in the province.

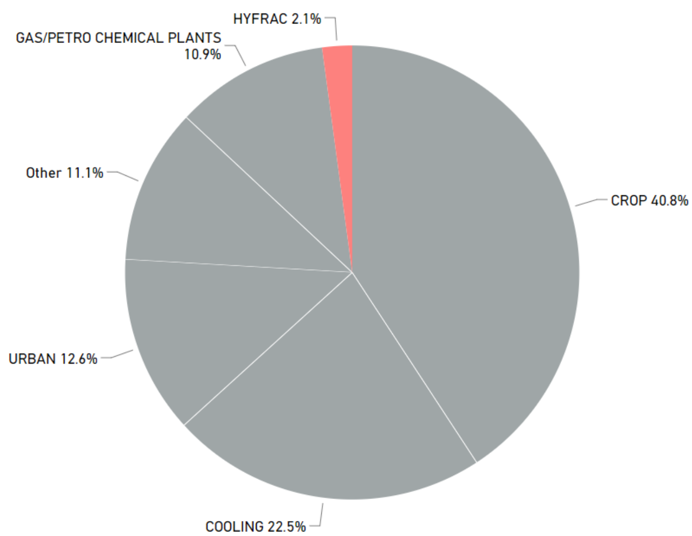
Figure 5. 2017 Overall Non-Saline Water Allocated and Used in Alberta



Source: (AER, 2017)

More recently and relative to the total water allocated, hydraulic fracturing represented only 2.1% of the total allocations in 2019, with the agriculture, commercial and cooling sectors taking more than 62% of this distribution (Figure 6). Given the relatively small percentage of water volumes allocated to hydraulic fracturing operations, it would be fair to think that these activities do not significantly pose a threat to freshwater resources in the province. However, water use in these activities is of consumptive nature, where water is permanently taken out of hydrological cycle. Also, the 2.1% value presented in Figure 6, actually represents a 188% increase relative to the 0.73% value observed in 2017. Another important factor that needs consideration looking forward is that with the increasing demand for energy, larger and larger volumes are expected to be used by these types of activities, which can pose a risk to areas susceptible to drought. Faced with climate change, these events are likely to become more frequent and affect new areas in many parts of the province, thereby reducing water availability (NRC, 2019).

Figure 6. 2018 Water Allocations by Industry

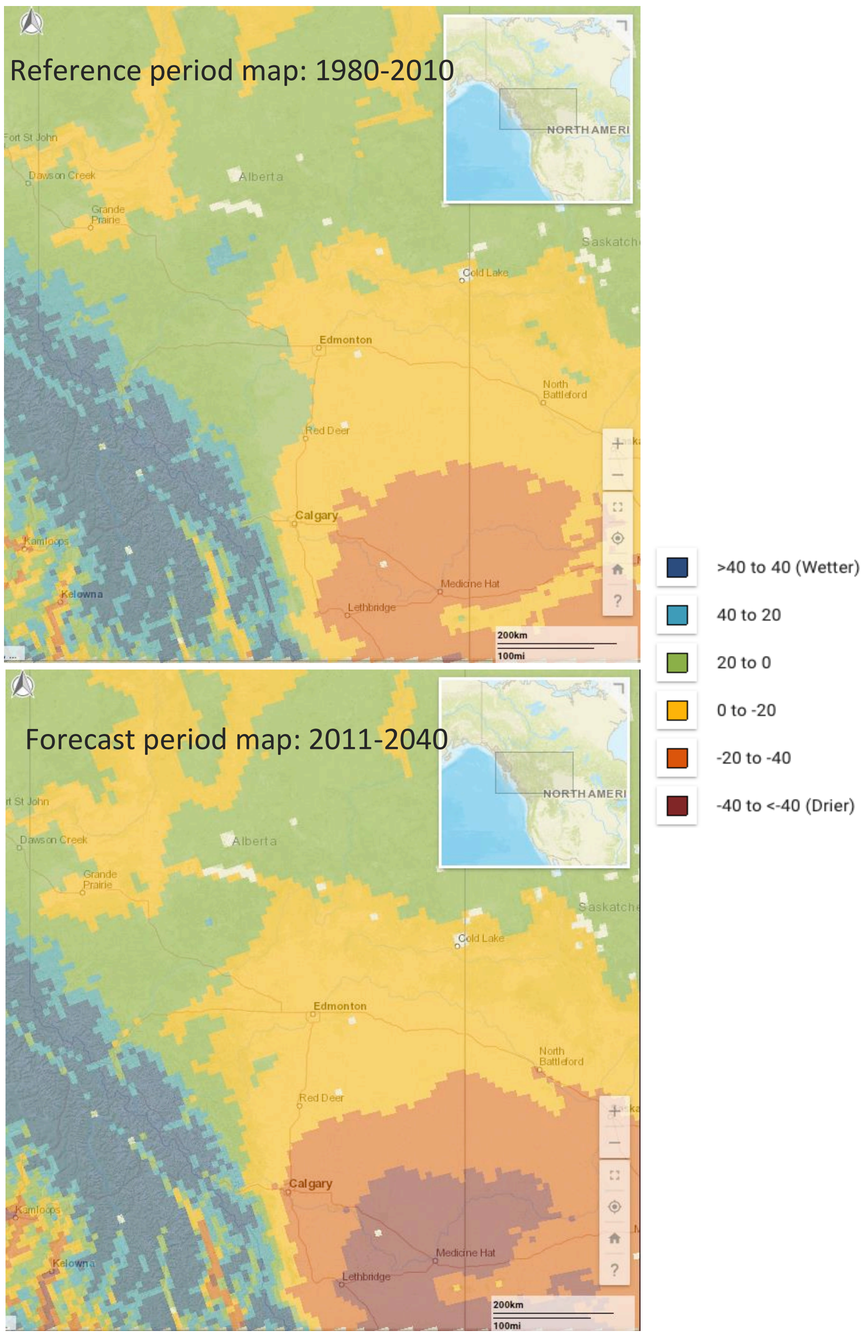


Source: (Author, 2019) from PowerBI (AER table)

One of the main drought indicators used by Natural Resources Canada (NRC) is the Climate Moisture Index. The index is calculated with the difference between annual precipitation and potential evapotranspiration. In a comprehensive study, the NRC agency used data from the 1981 to 2010 period to forecast the Index out to the 2011-2040 and the 2071-2100 periods (Government of Canada, 2018). Figure 7 presents the short-term forecast where positive values indicate moist conditions and negative values indicate dry conditions. It can be noted that the province will observe larger areas covered by the “drier” categories.

Considering the uncertainty brought about by the inherent seasonality and global warming effects on water flows, ensuring water supply for hydraulic fracturing operations when they rely on HQNS water is far from a risk-free activity.

Figure 7. Climate Moisture Index Map: Reference and Forecast



Source: (Government of Canada, 2018)

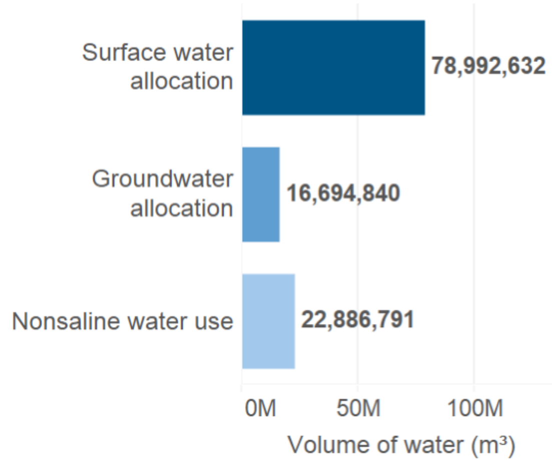
3.3 Licensing and Unused Water Allocations

Water allocations can be granted by the AER through either temporary water diversion licenses (TDL) or permanent water licenses (WALIC). They are awarded in terms of maximum monthly allowances license holders can withdraw from a surface (SW) or a ground (GW) water source. TLD are awarded for one year, while WALIC are can be anywhere between a 1 to 5-year period depending on the license applicant's water needs. At the end of the license period, not all allocated volumes end up being used. A large portion of these unused volumes are the result of overly conservative development projections on the part of oil and gas operators or, permanent license applications that were awarded when the regulatory bodies did not have the tools to properly account for water use in Alberta, particularly in the case of large historic allocations for municipalities or pulp mills (personal communication, Zoë Thomas, June 17, 2019).

Figure 8 indicates that in 2017 as much as 77% of the non-saline water allocations to hydraulic fracturing activities in Alberta was not actually used but physically remained at the source specified in the license, also referred to as the point of diversion (POD) (AER, 2017). In a water license this term specifies the physical location where water is to be withdrawn/pumped from. The reasons for these unused water volumes vary from license holder to license holder but are deemed to be the result of speculative applications aimed at minimizing water sourcing risks, changes in water needs as a result of unrealized development plans or, a combination of both. Even though TDL applications are strict in this regard requiring companies to justify their water volume needs on a yearly basis (as well as effects on the aquatic environment, on nearby license holders and on public safety), WALIC do not necessarily follow suit. WALIC are based on

5- or 10-year projections and therefore, water needs tend to be more inflated (to ensure that the maximum potential needs will be met). On the other hand, transfers of unused water allocations between license holders is not possible without an AER authorization and, an existing water management plan that allows for transfers. Even if water transfers are approved, the government can also withhold a percentage of the water being transferred to meet a water conservation objective (Alberta Government, 2014, Alberta Water, n.d.b). At present and since August 2006, only the Bow, Oldman and South Saskatchewan river basin have a water management plan so the enabling these transfers is limited. The more recent regulatory change in this regard was rolled out in February 2018, with a directive aimed at better addressing the water management practices of hydraulic fracturing projects (Alberta Government, 2018). The directive uses an area of use approach that limits each licence applicant to one and only one POD (a.k.a appurtenant to one POD). This principle allows for better water tracking by the AER but it can also mean PODs need to be more strategically placed based on the license holder's future development. The AER is moving towards a stricter water allocation system where unused volumes by a license holder will be used to suspend existing licenses or restrict future ones. In the meantime, it is clear the framework around these unused allocations does not necessarily foster cooperation among oil and gas operators or across industries (AER, 2017b).

Figure 8. 2017 Hydraulic Fracturing Water Allocation and Use In Alberta

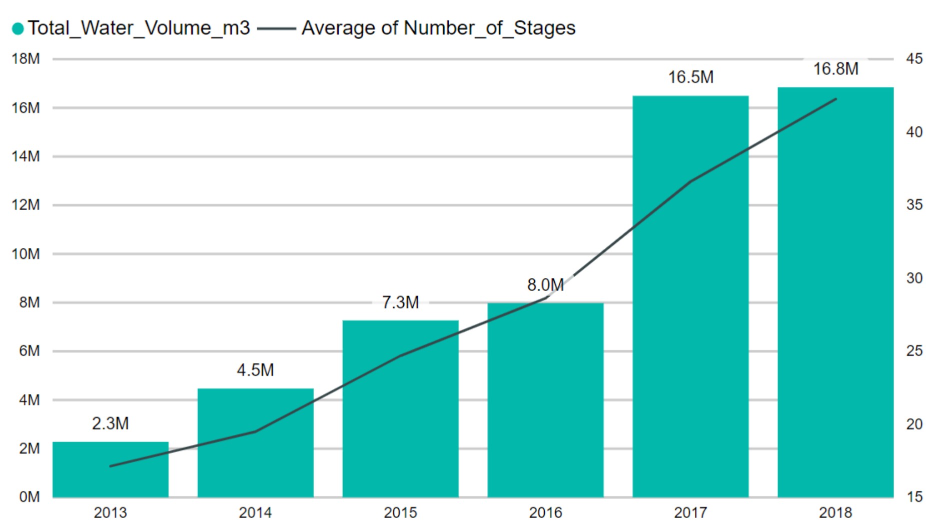


Source: (AER, 2017a)

3.4 Increasing Water use in Hydraulic Fracturing

Since 2014 water used in hydraulic fracturing in Alberta has increased 373%, with the last two years representing a large part of this increase (Figure 9). This trend has been stimulated greatly by technological improvements around multistage horizontal fracturing. In 2015 the average number of stages per well was 25, in 2018 this number grew to 42.

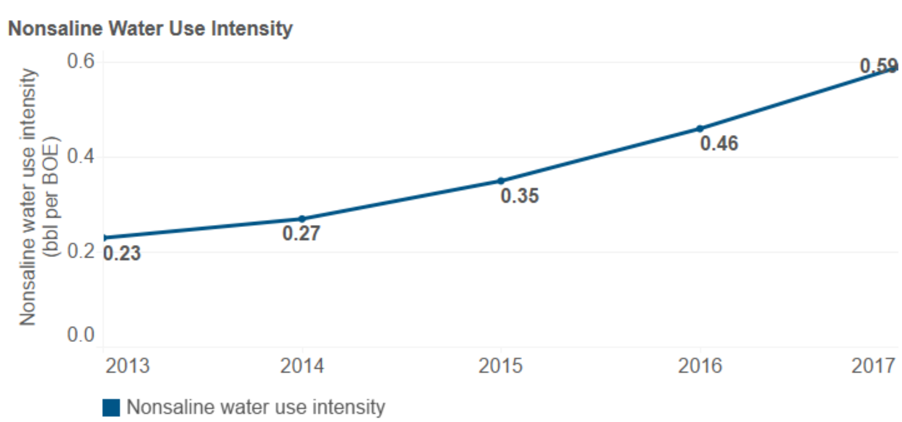
Figure 9. Water Use and Average Number of Stages per Well in Alberta



Source: (Author, 2019) from PowerBI (Fracfocus table)

When analysing the 2013-2017 period presented in Figure 10, it can be noted that, the water volume increment observed in the last few yers has also translated into a water intensity increase, which is problematic looking forward (water intensity refers to the ratio of water use per barrel oil oil equivalent). If the unconvetional plays in Canada are to experience similar exploitation levels than those of the more matured Permian, Eagle Ford and Marcelus plays in U.S., one should expect that the cumulative water use and wastewater volumes can increase by up to 20-fold in unconventional gas plays and up to 13-fold in unconventional oil plays from 2018 to 2030 (Kondsah et al., 2018). In the Duvernay spatial play as defined by Peters&Co, average water volumes per well increased from 23,800 cubic meters (m^3) in 2015 to 36,900 m^3 in 2018. In the Montney play as defined vertically, average water volumes per well increased from 9,300 m^3 in 2015 to 28,000 m^3 in 2018 (Appendix A)

Figure 10. Non-saline Water Use Intensity Trend in Hydraulic Fracturing



Source: (AER, 2019)

3.5 Lack of Water Recycling

Relative to other extraction methods, hydraulic fracturing has been a very poor performer in terms of water recycling. In the 2013-2017 period recycled water averaged only

5% of the total water used (AER, 2017a). Several factors influence an operator´s decision not to recycle produced and flowback water after wells have been fractured. An important factor is associated with the fact that produced and flowback water is usually highly saline (CWN, 2015a). This means that large amounts of fresh water would be needed to dilute it and/or that storage and surface treatment facilities would be required, which would increase water handling costs. On the other hand, the economics of disposal and transportation cost can also compel a company to treat and reuse and recycle water on-site. For example: some operators in the Marcellus play in the U.S. claim they have achieved 100% reusing/recycling rates (CWN, 2015b). This practice is largely driven by the extremely expensive alternative: well disposal and the transportation costs associated with it. Recycling may only be feasible so long the number of wells being drilled outnumbers those being produced or, if wells have high enough water cuts as to support high demand for wastewater in the future. Industry associations such as the Canadian Association of Petroleum Producers (CAPP, 2012) and the Canadian Society for Unconventional Reservoirs Association have guidelines or try to follow principles to encourage operators to reduce the use of HQNS water. However, as recycling is not a regulatory requirement in the province (or any North American jurisdictions with unconventional production), each operator is to find its own mechanisms to try to decrease the reliance on freshwater sources (CWN, 2015b).

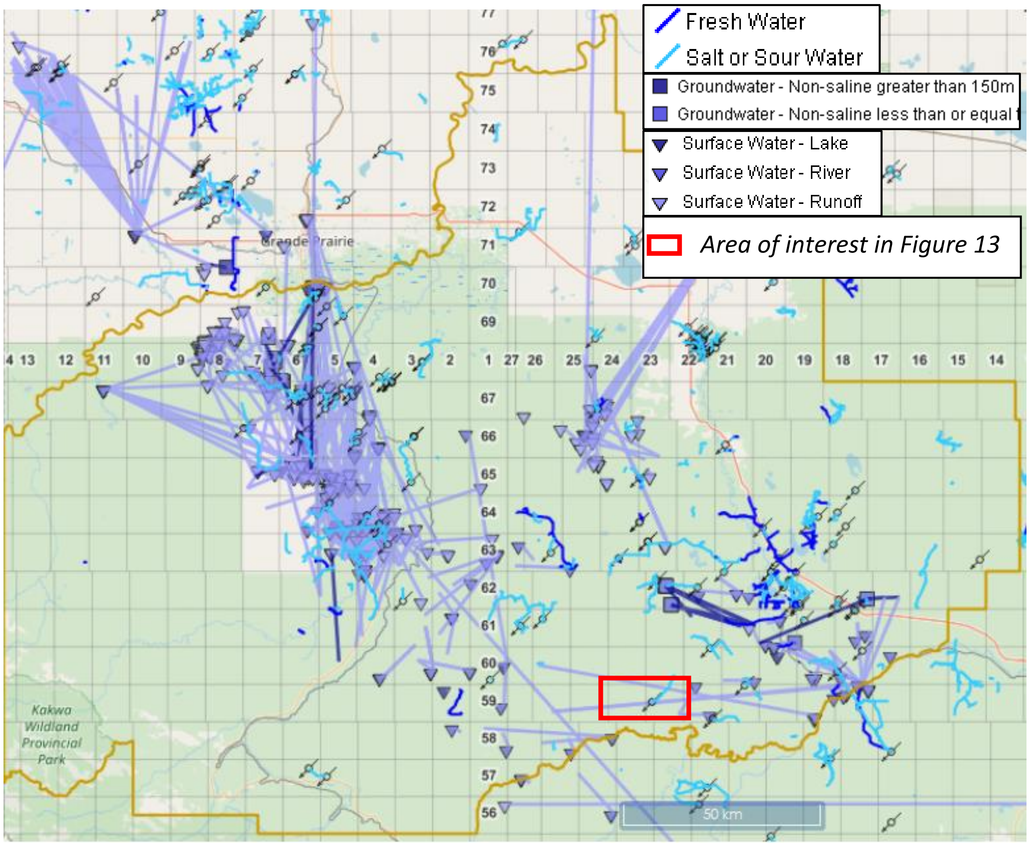
Companies usually have programs in place to find alternative water sources and address contamination matters, but they also report a myriad of issues that do not seem to set the ground for change in the “status quo” or for standardized practices. For example: 1) many technological aspects in the industry in Alberta are new (such as finding the optimal fracturing fluid composition) are thus sensitive to property rights that can represent a competitive advantage (CWN, 2015a), 2) when it comes to water management practices, there is no one-size fits all, from deciding among water sourcing alternatives to finding wastewater disposal solutions, the economics are often dictated by the spatial and vertical location of drilling and disposal sites and the topography along the way, 3) unfavourable benefits of scale for small operations. For example, some companies like Shell Canada (Shell, n.d.) have partnered with municipalities for use of their wastewater or non-potable water supply for hydraulic fracturing operations. Best, long-term practices like this one are tied to a large scope and full development stage where large capital expenditures and distribution can be supported by current oil and gas production. This may not be the case in small operations or an exploration/appraisal stage. Any commitment or long-term solution at any of these two stages represent a capital expenditure risk many companies are not willing to take. 4) regulatory hurdles do not encourage cooperation or collaboration. Hurdles include inability to use risk-based fluid profiles for freshwater transfer and management, time and storage volume limitations on above-ground engineered containment facilities (e.g. C-rings), inability to use temporary surface hoses (e.g. layflats) for produced water and, lengthy approvals for AWSS in Alberta. Even though the AER has an innovation section that is to address some of these issues, the main priority of the organization is to protect the public and the environment, which is not always well suited to manage innovation (personal communication, Gerald Feschuk, June 7, 2019).

3.6 Large Number of Water Displacements

Hydraulic fracturing water is transported from its source (POD) to the point of use (POU) by in-ground pipelines or trucks. Similarly, produced and flowback water usually needs to be transported offsite to a permeant disposal location (e.g. injection well or wastewater treatment plant). As use of in-ground, permanent pipelines can be expensive and not as flexible as water hauling truck trips, many operators often rely on the latter for transportation of wastewater in the short term. In addition, flexible layflats cannot be used for produced water movements so the water transport options that are economical and flexible are limited. In the long term, companies are likely to drill their own disposal well. Transportation of freshwater, on the other hand is more flexible and can rely on layflats, trucks, permanent in-ground pipelines or a combination of both. Considering that trucks (water trailers) used for these purposes usually have a 30 m^3 capacity, that an average well can use as much as 30,000 m^3 of hydraulic fracturing water or more and, that a drilling campaign can have as many as 10 or 20 wells, it can be said that this scenario can swiftly translate into thousands of trips per year, which adds to the noise pollution of these areas, GHG emissions, significant water management cost for companies, traffic disruptions for local residents and, nuisance to animal and human populations.

Figure 11 presents the freshwater displacements for five active companies in and around the Municipal District (MD) of Greenview. The area was used by the 2016 Area-Based Pilot project to assess the cumulative and long-term effects of hydraulically fracturing operations. (AER, 2016a). Freshwater displacements are displayed with a line between a POD (triangle or square) and the POU. Water pipelines are also displayed to convey the idea that most of these displacements are not necessarily associated with permanent pipelines, and thus rely on water hauling truck trips.

Figure 11. Fresh and Ground Water Displacements for five operators in MD of Greenview



Source: (Author, 2019) from Geocata

3.7 Redundancies in Water Infrastructure

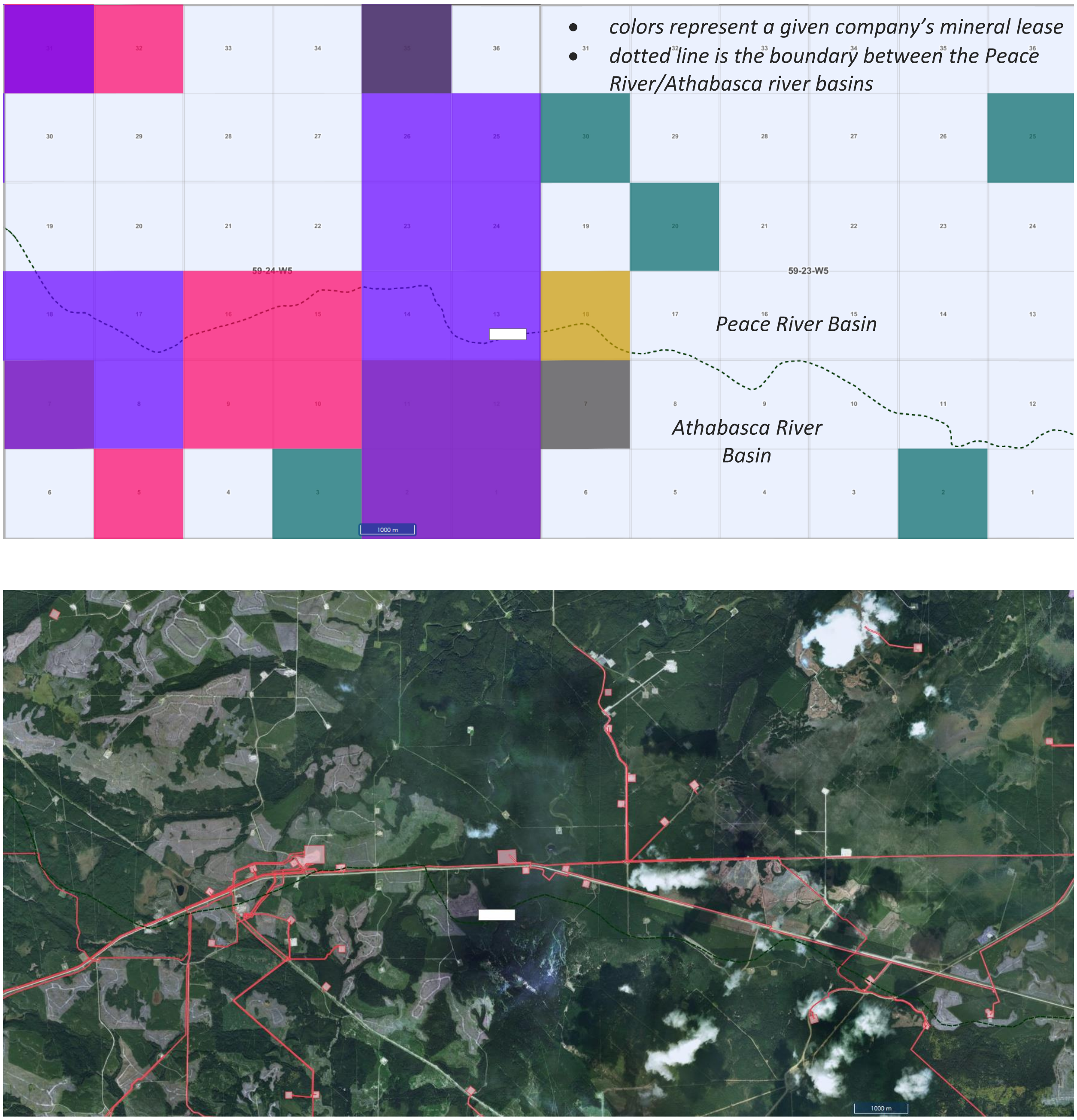
Under the Water Act, inter-basin freshwater and groundwater transfers are not allowed (Government of Alberta, 2017). Though the measure was established to protect the water quality and ecological integrity of each water basin, it also means companies operating on both sides of a water basin boundary need to find separate water sourcing, storage and handling solutions, potentially creating infrastructure redundancies. As many as 60 energy companies have operations along both sides of the Peace and Athabasca river basins in the MD of Greenview (AER, 2017b).

Figure 12. Alberta Major River Basins and the MD of Greenview

Source: (Author, 2019) from Geocata

Figure 13 zooms in on an area of interest displayed on Figure 11. Five active companies are presented with mineral leases on both sides of the river basin boundary. Surface dispositions by the same five companies are also presented as an indicator of the potential land works associated with their operations. Surface dispositions may include rights of way, roadway, pipeline installation and surface material among others. The dotted black line represents the boundary between the Athabasca and the Peace/Slave River basins, between which freshwater transfers are not allowed.

Figure 13. Map and Photo of Mineral Leases and Surface Disposition in Area of Interest

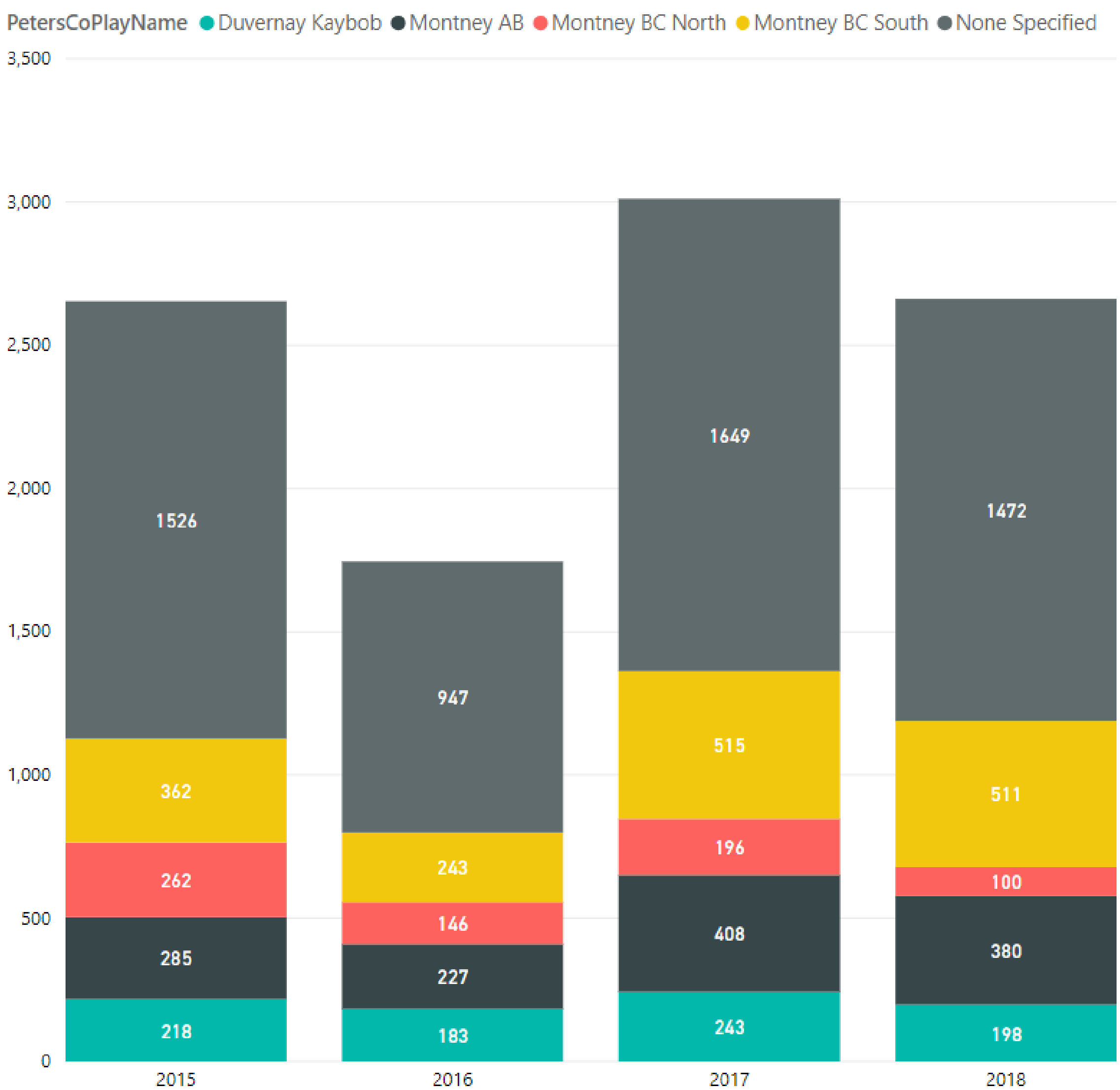


Source: (Author, 2019) from Geocata

3.8 Increasing well density footprint

The total number of hydraulic fractured wells registered in FracFocus in 2018 was 2,661. This number represents a 13% decrease relative to the 3061 wells drilled and completed in 2017 (Figure 14). On a cumulative basis a total of 19,038 wells have been registered in FracFocus since 2012.

Figure 14. Number of Fractured Wells in WCS

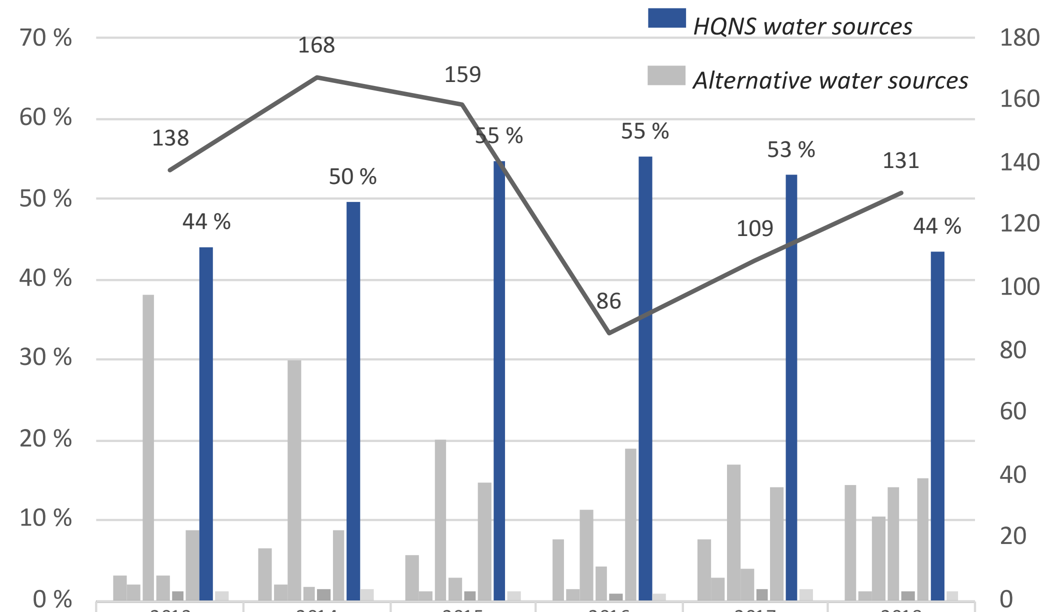


Source: (Author, 2019) from PowerBI (Fracfocus table)

The problem of increasing well density is exacerbated by the drilling of wastewater disposal wells and the induced seismicity risks associated with it. Even though there has been a decrease in the number of disposal wells per year relative to the 2013-2015 period, the upward trend observed in the last three years requires consideration looking forward. Deep well injection is largely seen as the best disposal method to avoid freshwater contamination but has also been linked to increased seismicity in Texas, Colorado and Oklahoma by the U.S. Geological Survey (N.Y. Times, 2015) and, in British Columbia by the BC Oil and Gas Commission.

Figure 15 presents the percentage share of different source types and, the number of disposal wells registered in Geocata. Despite the relatively small decrease in the number of freshwater sources in the last three years, it is evident this category still plays the most significant role in the reliance of water for hydraulic fracturing.

Figure 15. Water Source Types and Number of Disposal Well

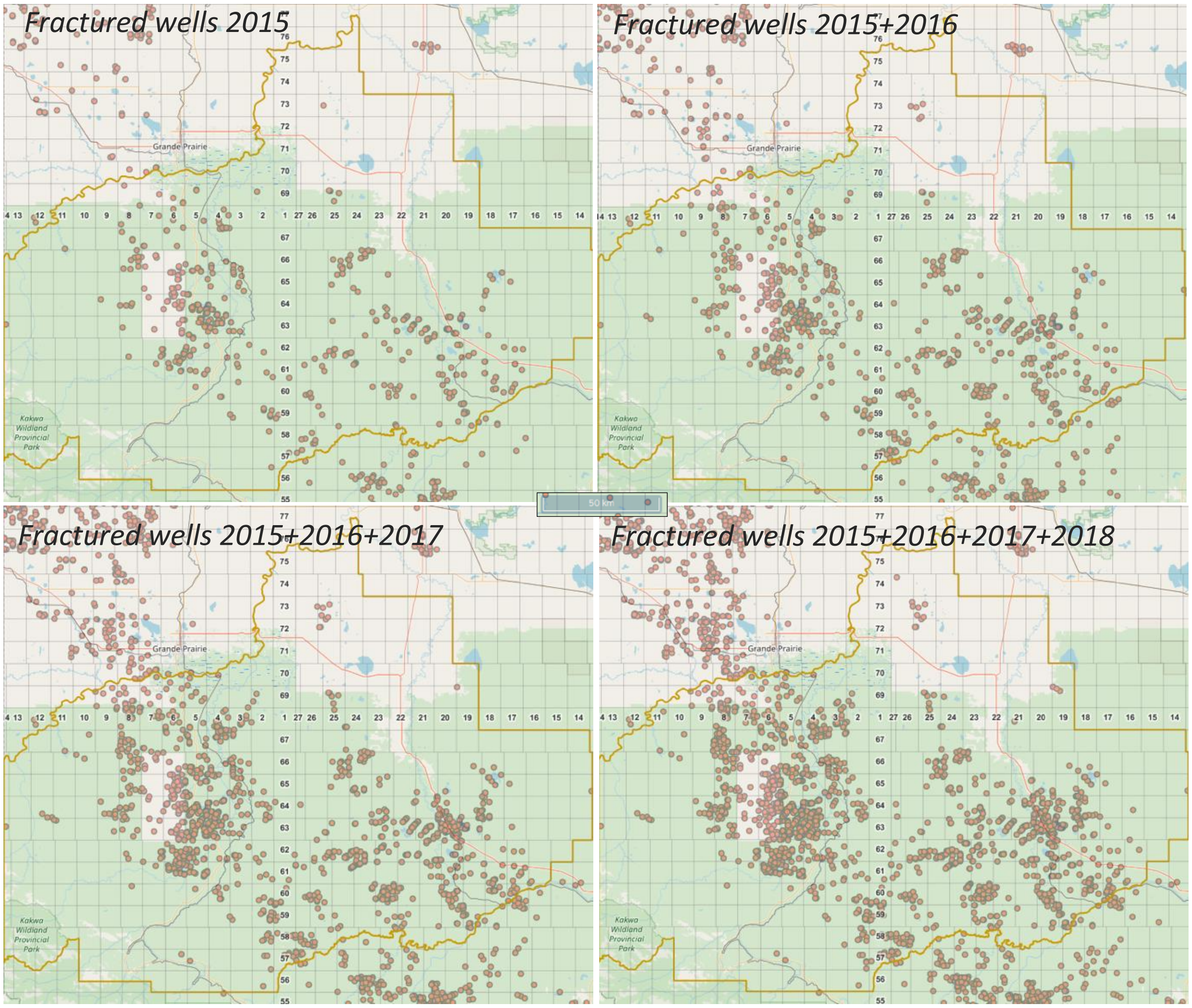


	2013	2014	2015	2016	2017	2018
Central Water Distribution Facility	3 %	7 %	6 %	8 %	8 %	14 %
Groundwater saline	2 %	2 %	1 %	1 %	3 %	1 %
Municipal	38 %	30 %	20 %	11 %	17 %	10 %
Oilfield	3 %	2 %	3 %	4 %	4 %	14 %
Waste	1 %	1 %	1 %	1 %	1 %	1 %
Recycled	9 %	9 %	15 %	19 %	14 %	15 %
Surface and non-saline	44 %	50 %	55 %	55 %	53 %	44 %
Waste	1 %	1 %	1 %	1 %	1 %	1 %
disposal wells	138	168	159	86	109	131

Source: (Author, 2019) from Geocata

Multi-pad well drilling technology has helped the industry to reduce the land footprint by exposing as much of the reservoir as possible using a single surface site. However, some of the highly exploited areas in the MD of Greenview, for example, have 135 and 118 wells per township (63-05-W6 and 63-04-W5 used as reference). This number averages to one well every 0.7 and 0.8 per km^2 respectively (Figure 16).

Figure 16. Well Footprint in the MD of Greenview



Source: (Author, 2019) from Geocata (Fracfocus)

3.9 CO_2 Emissions and Energy Associated with Water Trucking

A single hydraulic fracturing job can use as much as 30,000 m^3 of freshwater or more and depending on the number of stages, it can be completed within less than a week. The CO2 contributions of water hauling truck trips for water sourcing or transportation to a disposal site can be as much as 47,8 metric tons of CO2 per job using the assumptions on Table 2. Figure 17 presents the CO2 emissions associated with an "operations factor", calculated by multiplying round trip distance x water hauling volume (from a carbon footprint standpoint, a 30 000 m^3

job over a 50 km round trip distance is equivalent to a 50 000 m^3 over a 30 km round trip distance).

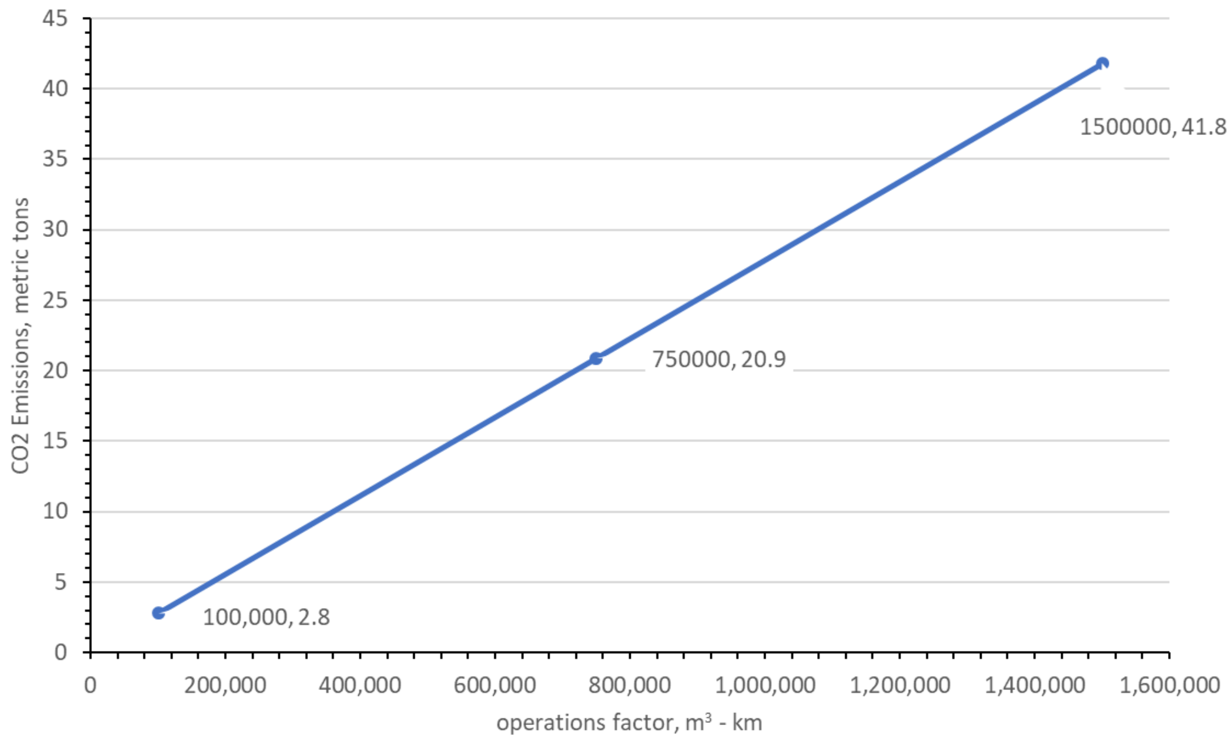
Table 2. CO_2 Emissions and Energy Associated with Water Trucking

Code	***Indicator***	***value***	***unit***	***source***
A	Water volume needs per frac job	30,000	m^3	assumption
B	Truck capacity	30	m^3	(Coombes, 2015)
C	Number of trips per frac job	1,000		A / B
D	Round trip distance to source location	50	km	assumption
E	Fuel Economy (10 mpg)	3.14E-04	m^3 / km	assumption
F	Diesel volume needs per round trip	1.57E-02	m^3	D * E
G	Diesel volume needs per frac job	16	m^3	C * F
H	CO2 tailpipe emissions intensity	2,660	kg /m^3	(NRC, 2014)
I	CO2 tailpipe emissions per frac job	**41,762**	**kg CO_2**	H * G
J	Diesel Heat Value	36,240	MJ / m^3	(Chevron, 2007)
K	Energy used	**568,968**	**MJ**	J * G
F	Operations Factor	1,500,000	m^3 - km	A * D

Source: (Author, 2019)

In perspective 42 metric tons of CO_2 per one single fracturing job is roughly equivalent to 40 Calgary-Toronto round flight trips (myclimate.org, n.d.) or, the carbon footprint of 50 8-ounce sirloin steaks (Live Science, 2011). In contrast, 569 MJ is equivalent to 5 average Alberta household natural gas consumption in a year (Energy Efficiency Alberta, 2018).

Figure 17. CO_2 Emissions Associated with Water Hauling Truck Trips



Source: (Author, 2019)

CHAPTER 4. ECONOMICS

4.1 Global Context

The “shale revolution” behind unconventional developments has disrupted the oil and gas market by opening vast quantities of these resources. However, the profitability of such projects is not that evident. The breakeven prices of new hydraulically fractured wells in the U.S. vary between $49 and $54 per barrel, depending on the basin (Federal Reserve Bank of Dallas, 2019). This interval places these projects at competitive prices relative to SAGD expansions in Canada, where the average breakeven for the same year was ranked at US$51.6 (after adjusting for blending and transportation) (CERI, 2018b). The cost of tight oil and SAGD projects may be similar but the advantage of the latter, is that once wells are put on production, they can have long-term, stable production for two or three decades. Unconventional resources on the other hand need continued drilling to maintain production and this requires significant budget allocations through time.

4.2 Status Quo in Alberta

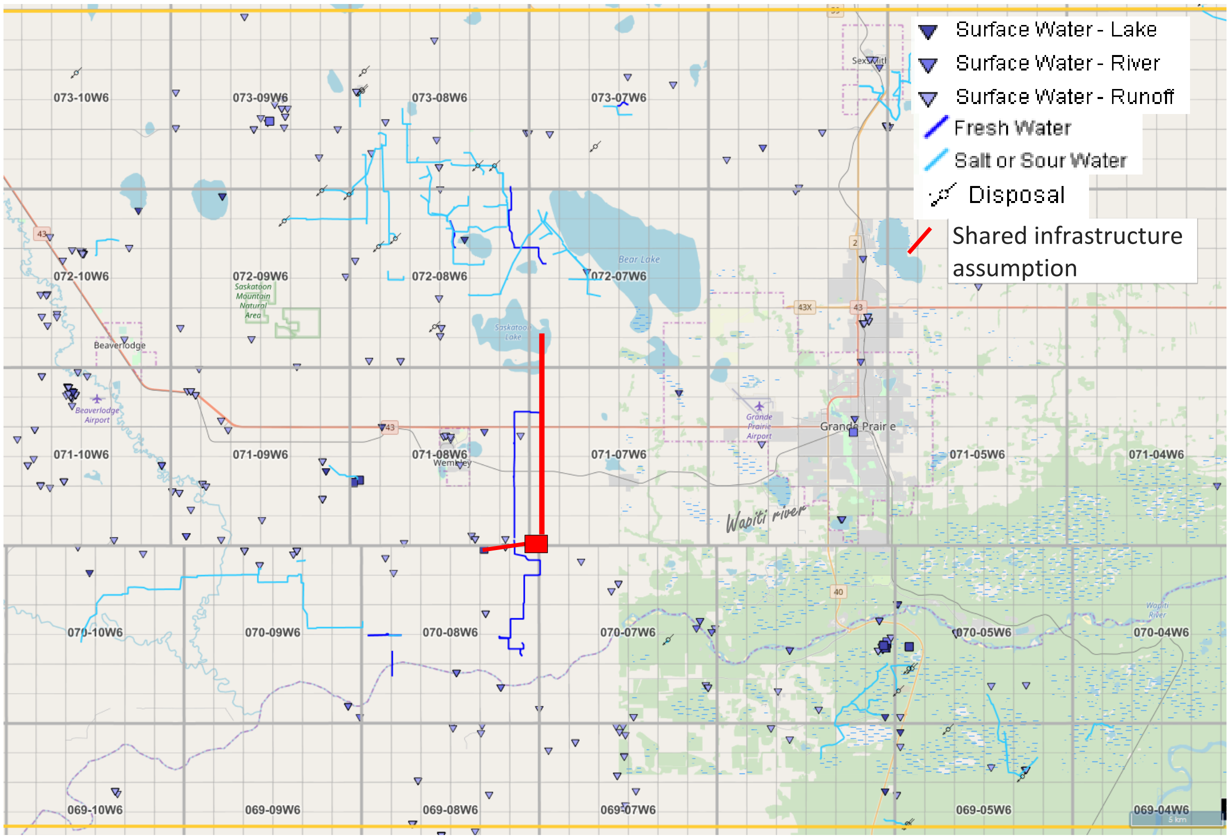
Generally, water management and infrastructure in unconventional developments in the province does not represent a significant portion of the annual Capex of a given oil and gas operator. Operators with limited budgets or strategic, long-term visions often choose not to invest in water reservoirs for storage or treatment units for produced water treatment and recycling. If produced water volumes are not significant, they also choose to dispose of them using third-party vendors, instead of drilling deep well injectors. At small scales (<10 producers per year), in the short term, or with no life cycle considerations, these status-quo practices may pay off. However, in the long term, at large scales or with life cycle considerations it is quite the opposite. To investigate this premise, the remaining sections of the present Chapter elaborate on the assumptions behind a conceptual project where a given operator were to be part of a shared water infrastructure development to support its operations. It is assumed the scale of development of such a project is larger than that of the operator itself and otherwise uneconomical or unpractical to achieve by the operator alone.

4.3 Area of Study

The area of study used to investigate the economy of the shared water infrastructure project is known in the oil and gas industry as Pipestone/Wembley and it covers around thirty townships (approximately 3,700 km^2) west of Grand Prairie, AB (Figure 18). Exploration and production of the Montney play in this area has received interest by various small, mid-size and large oil and gas operators for a number of reasons (Peters & Co, 2018): 1) it is a relatively unexploited area with a total of 298 hydraulically fractured wells drilled and completed to date (178 completed in the Montney formation), this number averages to one well every 9.5 km^2 (almost 1/10th of the well density in the highly exploited area around MD of Greenview presented in section 3.8), 2) at this location, the play has displayed a high and increasing condensate yield, which translates into a higher value per unit of production relative to dry gas alone, 3) some small and medium-size companies are in the appraisal stages and arguably at a disadvantage from a water licensing point of view relative to more senior license holders in the area such as Encana, Canadian Natural Resources and Cenovus, 4) Pipestone Energy, a mid-size operator with vested interest in the area, has secured significant gas production firm capacity on the existing natural gas pipeline system operated by TC Energy. Firm capacity are contracts that include specific gas supply commitments by an operator, which indicates drilling and production activity will be required to fulfil this commitment and, 5) there are at least three key mid-stream, LNG export terminals that will cater to the increasing gas and condensate demand (JWN, 2019).

The map in Figure 18 also presents the location of existing water infrastructure such as disposal wells, freshwater PODs and existing water pipelines. The existing north-south freshwater pipeline observed in blue in the central part of the map was used as the basis for the extent and location of the shared water infrastructure proposed in this Section: a hypothetical north-south, 13 km in-ground pipeline, a water handling facility with storage and pumping capacity and, a 4 km in-ground pipeline and intake facility connecting the water handling facility to the POD in the Wapiti River.

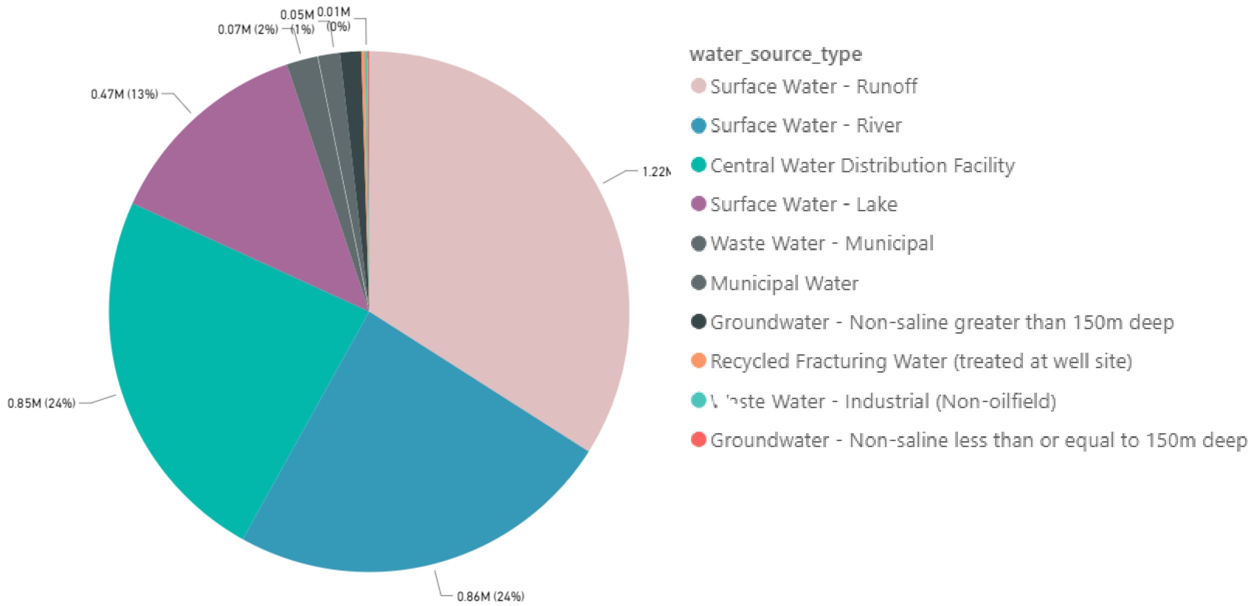
Figure 18. Spatial Area of Study



Source: (Author, 2019) from Geocata

In the last two years, of the total water used in hydraulic fracturing in the area, 71% arrived from freshwater sources (Figure 19). Disposal wells on the other hand are in the north part of the study area and relatively far from the ongoing drilling and completion operations closer to the south of the Wapiti River. This separation indicates that transportation costs associated with wastewater disposal are expensive. The study area has a large concentration of private landowners and six different operators with mineral leases, which can increase the social risks associated by unstainable wastewater management practices looking forward. These characteristics make the area a good candidate for a collaborative, sustainable solution that can reduce water use, land footprint and water management costs for companies.

Figure 19. 2017 - 2018 Water Source Types in the Montney at Pipestone area



Source: (Author, 2019) from PowerBI (Fracfocus table)

4.4 Model Assumptions

The main objective of the economic model is to prove the economy of scale that exists with increasing water handling volumes: the larger the infrastructure, the larger the expenditures but the smaller the cost per unit of production, which in this case is often measured as $/m^3 of water. The reason behind this premise is that pipelines; the largest cost component of permanent installations, are priced linearly ($/m), while the volume for a given meter of pipe increases exponentially (πr^2). As presented in section 4.2, capturing this opportunity assumes a scale of development larger than that a single operator may be able to sustain on its own. When two or more operators benefit from and share the same infrastructure, the capital efficiency of each operator increases. It is assumed that the shared infrastructure proposed in this model is part of a Greenfield development where well pads within a 5 km radius could be drilled and tied in. The highlights of the base assumptions of the model are as follows:

- six drilled and completed wells per year scenarios were assumed from 15 to 65. A constant hydraulic fracturing flow rate of 10,000 m^3/day was assumed so that each well scenario could be completed within a calendar year. In this manner, no one scenario is more/less efficient in terms of fracturing that another,
- a 4 km road would need to be built to access the intake location,
- a water reservoir would provide storage for 90 days,
- the water pipeline would be installed in the trench excavated to place crude oil lines as to reduce installation cost and land footprint,
- a 10-year time frame with 15% capital contingency and 10% cost of capital was assumed for the present value calculation and,
- produced water would be disposed of at first-party disposal well (s) (drilled and completed by parties involved in the agreement).

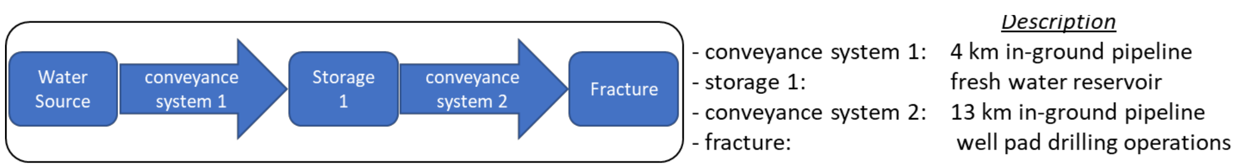
At a high level, the economic model was built around three cases, or systems of interest that a given oil and gas operator in the study area may consider. The first one is a freshwater only system that aims at reducing the associated freshwater truck trips, water sourcing costs and risks if no pipeline was in place. This case is less capital intensive and offers an alternative to operators that may not have the initial budget to invest or commit to the recycled water solution. The second one is a recycling system that aims at reducing freshwater consumption, water hauling truck trips, the entire life cycle water management cost and overall water risks.

For comparative purposes a third case is included assuming status quo practices (introduced in section 4.2) are used to develop the project.

4.4.1 *Freshwater Only System*

As previously mentioned, the system assumes the decision to build and share the water infrastructure is aimed at eliminating the water management risks associated with having no water storage and the water management costs associated with trucking for water hauling (Figure 20). Water disposal is assumed to take place immediately after fracking.

Figure 20. Freshwater Only System



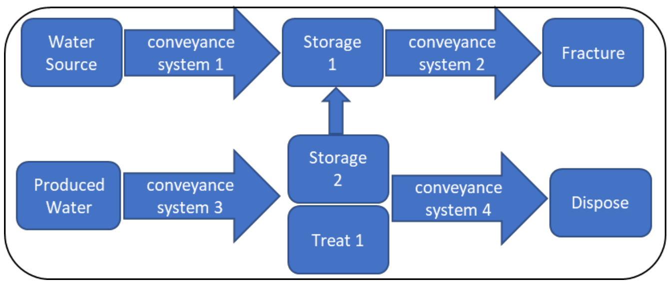
Source: (Author, 2019)

The centralized water handling facility consists of a water storage reservoir located at the end of the 4 km intake branch (Figure 18).

4.4.2 *Water Recycling System*

This is a freshwater system that is converted to a recycling system once wells are put on production and there is sufficient produced water to make-up for all hydraulic fracturing water needs (Figure 21). In other words, the system carries similar assumptions as the freshwater system but additionally, it assumes wastewater (a.k.a. produced water) would be collected, treated and used as make-up water for upcoming hydraulic fracturing activities. The centralized water handling facility in this case includes a treatment unit and a water reservoir, which would need to be re-purposed to treat the wastewater stream once there is no more need for freshwater. This implies the facility would need to be built to wastewater handling specifications (as per AER Directive 058) so a 20% additional cost was assumed relative to the freshwater system (personal communication, Trevor Wall, July 10, 2019).

Figure 21. Recycled Water System



	Description
- conveyance system 1:	4 km in-ground pipeline
- storage 1:	fresh water reservoir
- conveyance system 2:	13 km in-ground pipeline
- fracture:	well pad drilling operations
- conveyance system 3:	conveyance system 2 repurposed
- treat 1:	treatment tank
- storage 2:	storage 1 repurposed

Source: (Author, 2019)

4.4.3 Status Quo Development

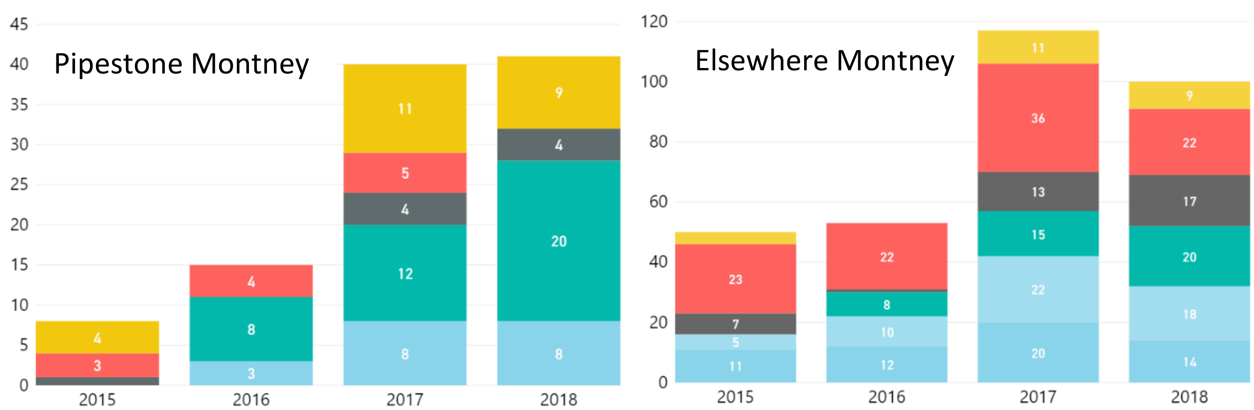
This case assumes the operators develop the project with status quo practices: freshwater sourcing, third party disposal, layflat hosing and no water storage reservoir. The case is presented only for comparison purposes as it is anticipated it would not be economically attractive.

4.5 Development Plan

There are six operators (hereby referred as “group of operators”) with vested interest and mineral holdings in the area. Figure 22 presents the number of hydraulically fractured wells drilled and completed in the Montney formation by the group of operators within the area of study and outside of it. Based on the involved company investors´ presentations on their respective websites and the level of Montney development observed in other areas, it is deemed there may be between 45 to 65 wells per year drilled and completed in the Montney within the next ten years. This estimate represents a 10% to 50% growth relative to the total 41 wells drilled and completed in 2018. The interval is within the 10% to 15% growth NuVista, one of the operators in the area, expects for 2019 (NuVista, 2019). It is assumed the proposed infrastructure would supply the hydraulic fracturing water needs of a portion of the total number of wells expected in the area.

As "Cube" drilling technology is adopted across the industry, well density in the area may average to 4-6 wells per sector. The technology, which exposes different stratigraphic levels of the same formation from the same well pad, has been proven successful in significantly increasing resource potential of the U.S. Permian Basin. Figure 23 illustrates the adoption of the technology using 9 wells in one direction but considering other three azimuth levels, this practice can result in as many as 27 wells drilled and completed from the same pad.

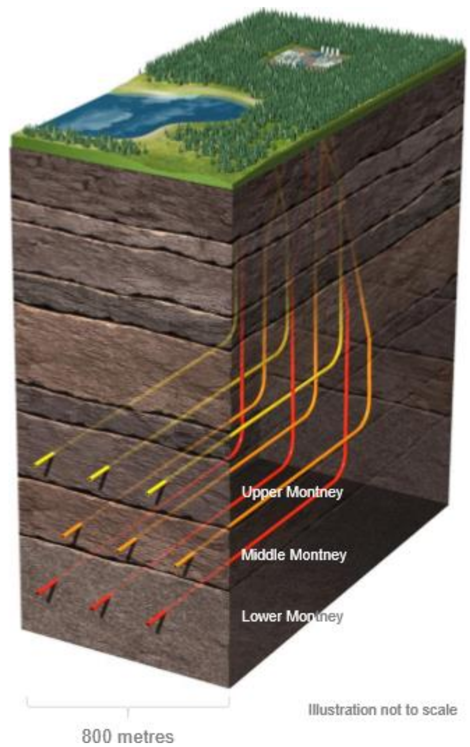
Figure 22. Number of Wells Drilled in Montney Formation by Group of Operators



Source: (Author, 2019) from PowerBI (Fracfocus table with colors representing different operators)

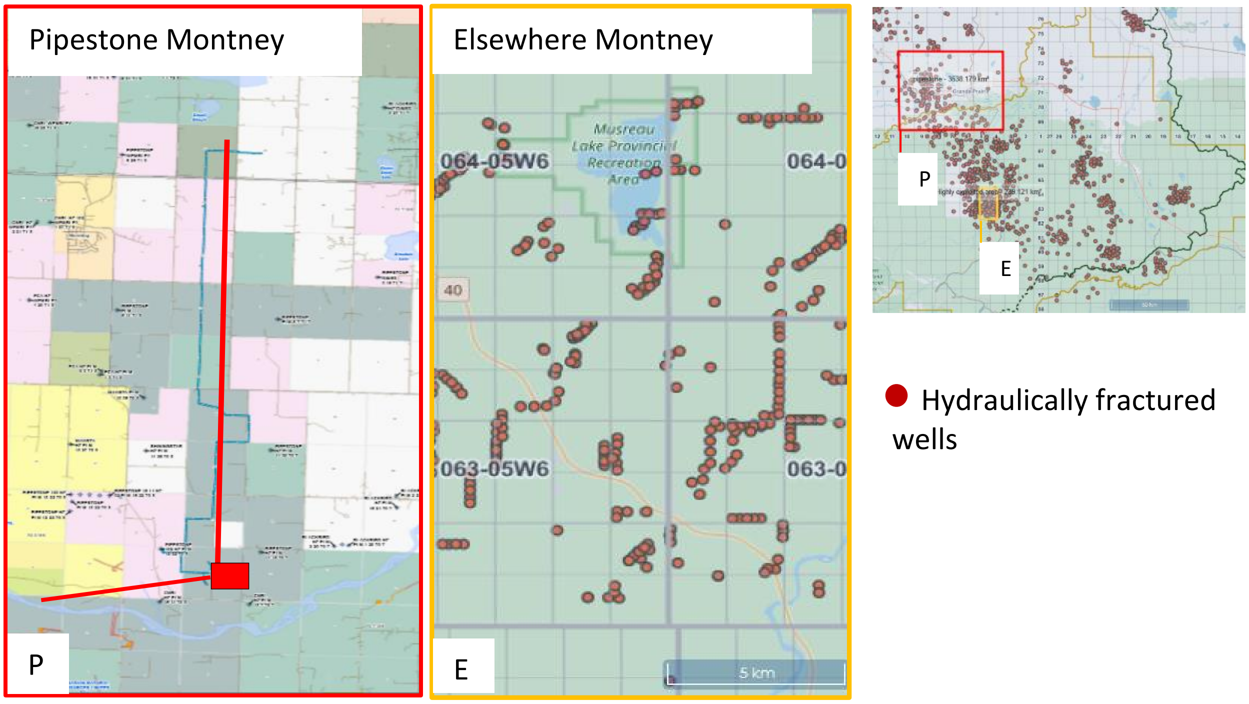
Without additional infrastructure and assuming a relatively flat terrain, the proposed pipeline could convey water to well pads within a 5 km radius as illustrated approximately in Figure 24. Therefore, it is possible an additional conveying method would be required beyond the 5 km radius; especially if a high well count materializes. For the purpose of exploring the economy of scale curve of the shared infrastructure being proposed, this scenario was not included in the economic model.

Figure 23. Seven Generation's Triple Stack Technology



Source: (Seven Generations, 2019)

Figure 24. Main Area Served by Proposed Infrastructure Relative to Highly

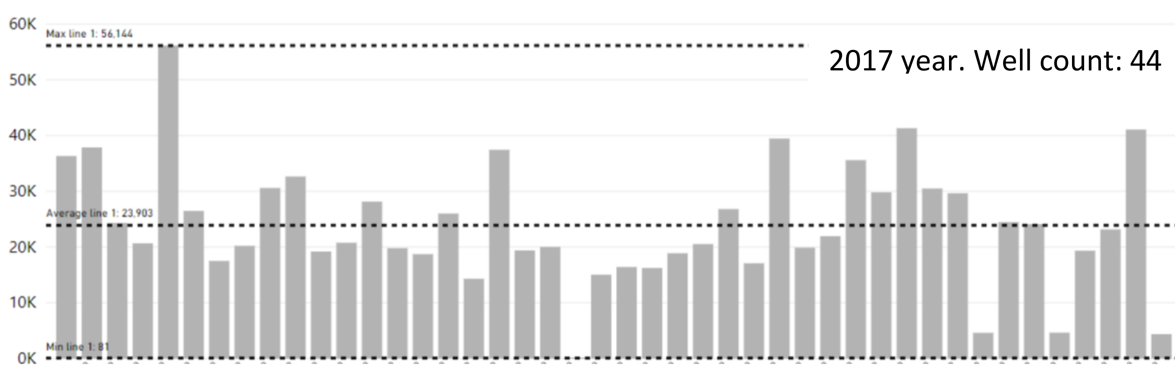


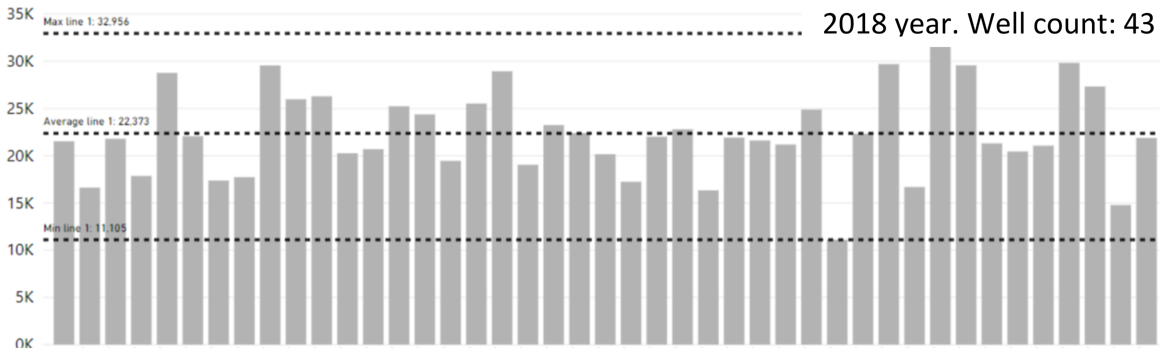
Source: (IS, 2019b) - *left*. (Author, 2019) from Geocata - *right*

4.6 Hydraulic Fracturing Water Demand and Wastewater Supply

Determining fracturing water needs and wastewater supply once wells are on production is of paramount importance in properly sizing the infrastructure needed to handle them. Figure 25 presents the water used for hydraulic fracturing in the last two years. A medium water demand of 30,000 m^3 was assumed for the economic model calculations.

Figure 25. Water used for Hydraulic Fracturing in Montney Formation, m^3

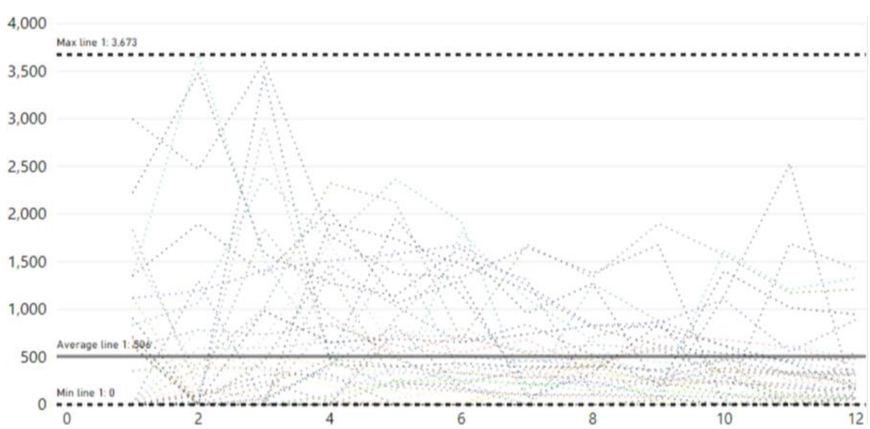




Source: (Author, 2019) from PowerBI (*Fracfocus within Montney Pipestone table*)

Estimation of produced water per well is usually linked to the main flowing phase forecast (e.g. gas or oil) using the empirical watercut ratio. In 2018, observed watercuts for various operators in the area ranged between 100 m^3 and 1,500 m^3 hydrocarbon fluid / m^3 produced water, a 10X factor interval (IS, 2019a). For the purpose of this study and, based on the observed produced water monthly volumes per well in the area (Figure 26) a medium value of 500 m^3 / month per well was assumed. For simplicity purposes, flowback water, usually observed within the first few months of production, was deemed to be part of this interval so no differentiation between formation and flowback water was made.

Figure 26. Produced Water in First Twelve Months, m^3/month. Montney Formation



Source: (Author, 2019) from PowerBI (*Months on Production over Montney Pipestone table*)

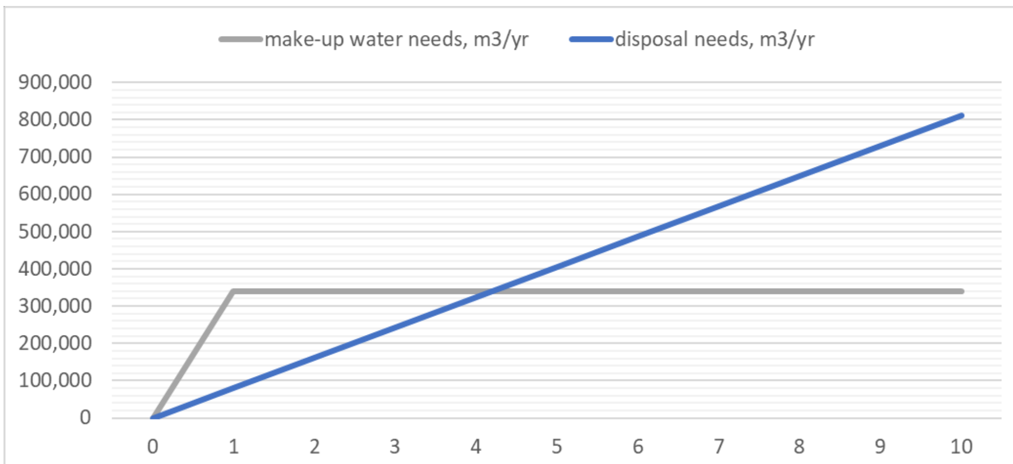
4.7 Water Balance

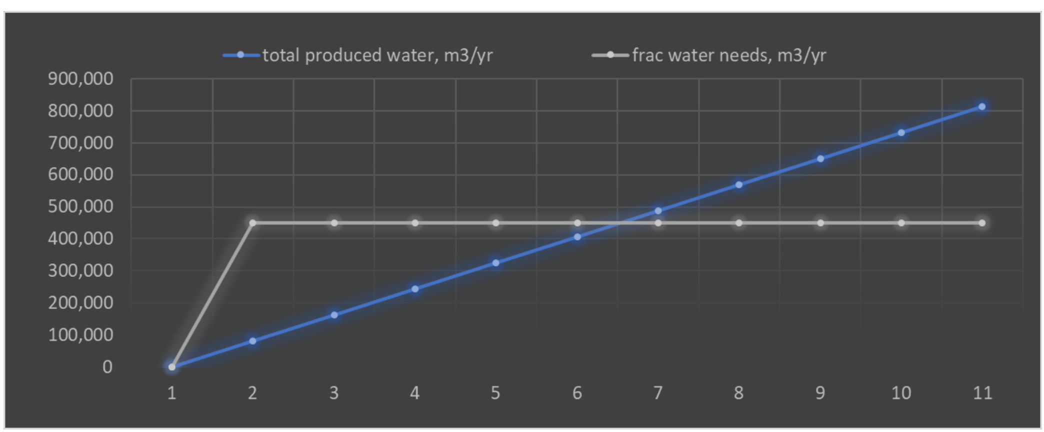
A yearly water balance was built in Excel based on the equation below:

$$water\ balance\ year\ end\ (\frac{m^3}{yr}) = water\ in - water\ out + water\ in\ reservoir$$

Where, $water\ in$ represents produced water, $water\ out$ represents water used for hydraulic fracturing and $water\ in\ reservoir$ represents the water stored. For simplicity, it was assumed storage volumes are available from one year to the next, in other words, the reservoir is filled throughout the year. In the freshwater only system, all produced water was assumed to be disposed of, so no treatment is necessary, while in the recycled water system, an average of 80% of the produced water was assumed to be treated and used for hydraulic fracturing in the consecutive year. In recycling systems, it is a common practice to gradually decrease freshwater volumes as to ensure compatibility with the hydraulic fracturing additives (personal communication, Zeina Baalbaki, July 19, 2019). In this context, the 80% assumption represents a more realistic number between the initial and final stages (years) of a recycling system, which ultimately is targeted at 100%. A negative net water balance means treated water (in the recycled water system) or reservoir water (in the freshwater only system), cannot make up for the yearly hydraulic fracturing water demands so the reservoir needs to be filled more than once during the year. This additional need for water volumes beyond the initial storage reservoir volume is referred to as "make-up water needs" in this model (Figure 27 and Figure 28 are presented as an example for a 15 wells/yr development plan using 30,000 m^3 of hydraulic fracturing water/well and producing 5,700 m^3 of formation and flowback water/well/yr). Disposal water needs were then calculated as the water volumes that remain beyond the storage volume once there is a positive water balance (e.g. produced water volumes are larger than those needed for hydraulic fracturing). Yearly disposal volumes were converted to an equivalent number of water hauling truck trips. However, the base assumption in the model was first party disposal, were such volumes were converted to an equivalent number of disposal wells needed as explained in Section 4.8.

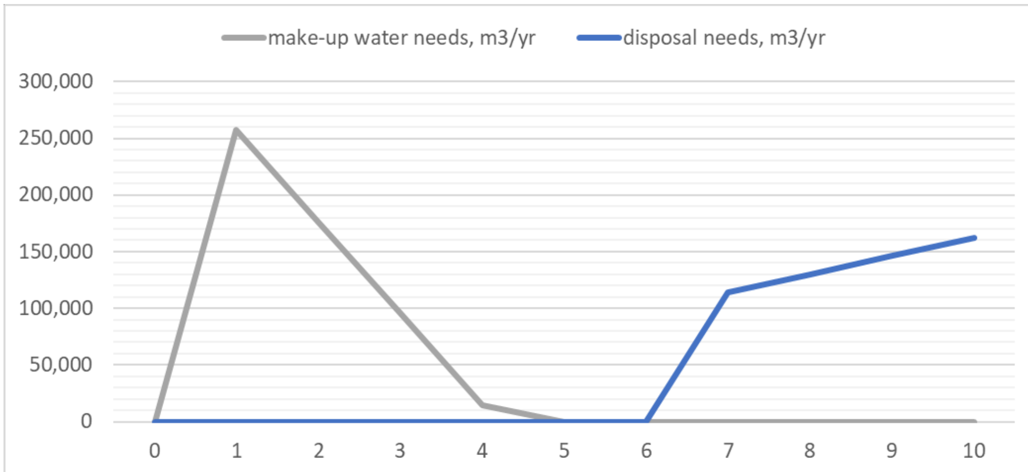
Figure 27. Water Balance Curves Freshwater System: Example for 15 well/yr Development

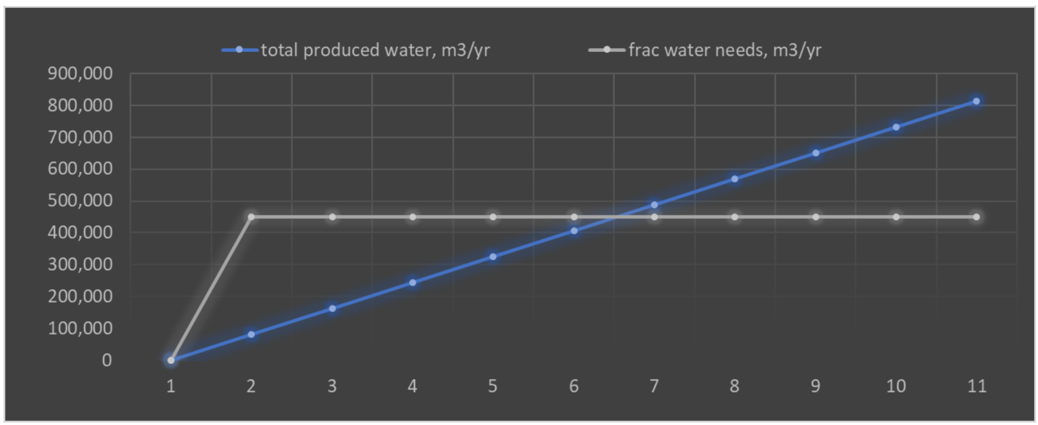




Source: (Author, 2019)

Figure 28. Water Balance Curves Recycling System: Example for 15 well/yr Development





Source: (Author, 2019)

4.8 Disposal Solution

There are around twelve water disposal wells North of Wembley and part of the area of study. They have injection depths varying between 2,000 and 2,500 m approximately, injection volumes between 100 and 20,000 m^3/month and cumulative injection volumes up to 2 million m^3. Given cyclical and complex nature of wastewater injection, it was assumed disposal volumes would be injected in a typical well located 15 km away from the water handling facility at a vertical depth of 2,500 m and a drilling, completion and total installation cost of $ 10 million (personal communication, Trevor Wall, July 10, 2019). The injection rate was assumed as 800 m^3/d with a 10% well downtime during the year. In both, the freshwater and recycling systems the disposal well cost was added as needed based on the disposal volumes at the end of the year. The operational expenditures (Opex) associated with disposal (pumping) were assumed as 3 $\$/m^3$. The third-party disposal solution used in sensitivities assumed a transportation cost of 25 $/km-truck and injection cost of 14 $\$/m^3$ (personal communication, Ingo Gloge, July 10, 2019).

4.9 Present Value Calculation

The model uses a series of *IF* statements and *LOOKUP* functions in excel based on the input items listed in Table 3. Input data was then associated with the corresponding pipeline sizing, pipeline cost, water reservoir volume and cost, chemical treatment cost and rate, pump flow, power and cost for each scenario.

Table 3. Present Value Components

Capex	Annual Opex
• Road construction • Skid system for Chemical treatment • Water reservoir • Pipeline cost and installation • Pump • Disposal well	• Layflat hosing •Energy used by pumps • Equipment maintenance • Cost of chemicals • Staff • Transportation cost of disposal volumes
Total Life Cycle Cost: Annual Capex payment + Annual Opex	

Source: (Author, 2019)

Total lifecycle indicators are presented in the following section to evaluate the economy of scale of volume scenario. Other indicators as well as all input data are presented in Appendix B and Appendix C.

4.9.1 Freshwater Only System

Table 4 presents some of the input data types described earlier and the total Capital Expenditures (Capex) associated with each wells/yr scenario. As this scenario does not include recycling, the water handling facility is made up of synthetically lined storage reservoirs that provide freshwater storage needs for 90 days, in the third quarter of each year where river flows are usually at their lowest. The pipeline cost was assumed constant for each volume scenario as they are commonly scaled as a function of flow rate, which was assumed constant. Maintenance cost and overhead staff were assumed as 5% and 1.5% of the Capex respectively. Based on the water balance scenario and the average injection rate presented earlier, this system would require four disposal wells over the entire 10-year timeframe (Appendix B).

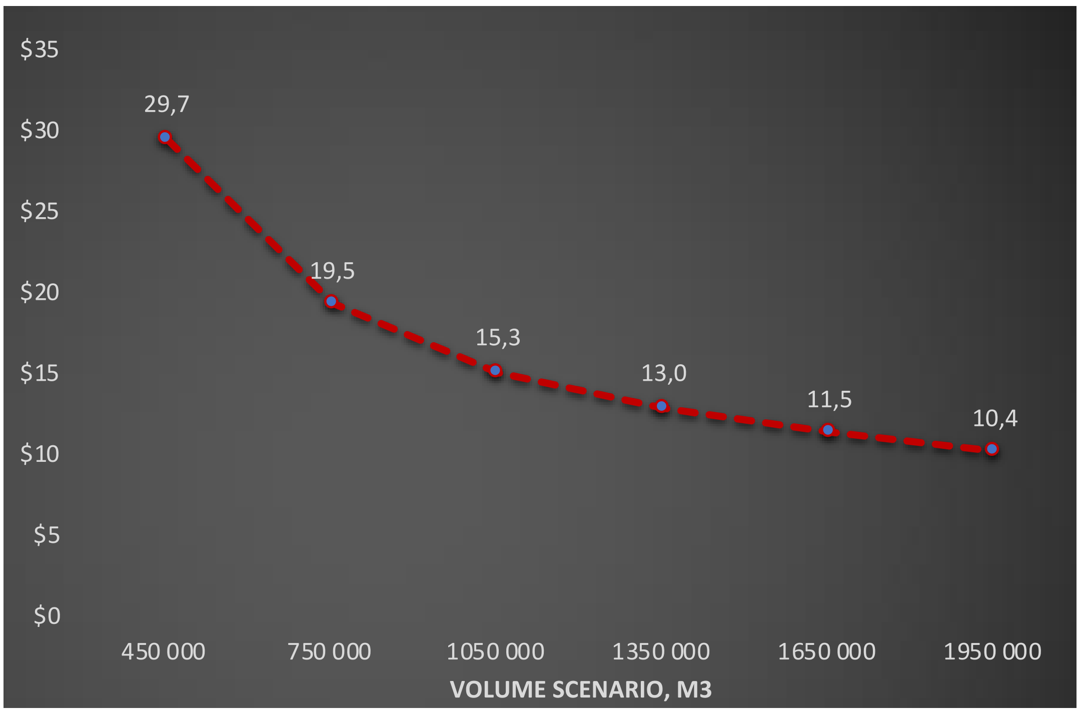
Table 4. Freshwater System Input and Total Capex

Wells /yr	Volume m^3/ well	Vol Scenario m3	Distance (m)	Flow rate m3/day	Days Storage	Storage Volume	Operational Days	# Years	Contingency	Capex including Disposal ($ total)	Capital Charge	Annual Opex including Disposal
		A	B	C	D		E	F	G		I	
15	30,000	450,000	17,000	10,000	90	110,959	45	10	15%	$64,374,148	10%	$2,885,137
25	30,000	750,000	17,000	10,000	90	184,932	75	10	15%	$65,986,324	10%	$3,849,741
35	30,000	1,050,000	17,000	10,000	90	258,904	105	10	15%	$68,808,856	10%	$4,830,133
45	30,000	1,350,000	17,000	10,000	90	332,877	135	10	15%	$72,391,721	10%	$5,820,441
55	30,000	1,650,000	17,000	10,000	90	406,849	165	10	15%	$74,725,478	10%	$6,794,457
65	30,000	1,950,000	17,000	10,000	90	480,822	195	10	15%	$76,337,654	10%	$7,759,061

Source: (Author, 2019)

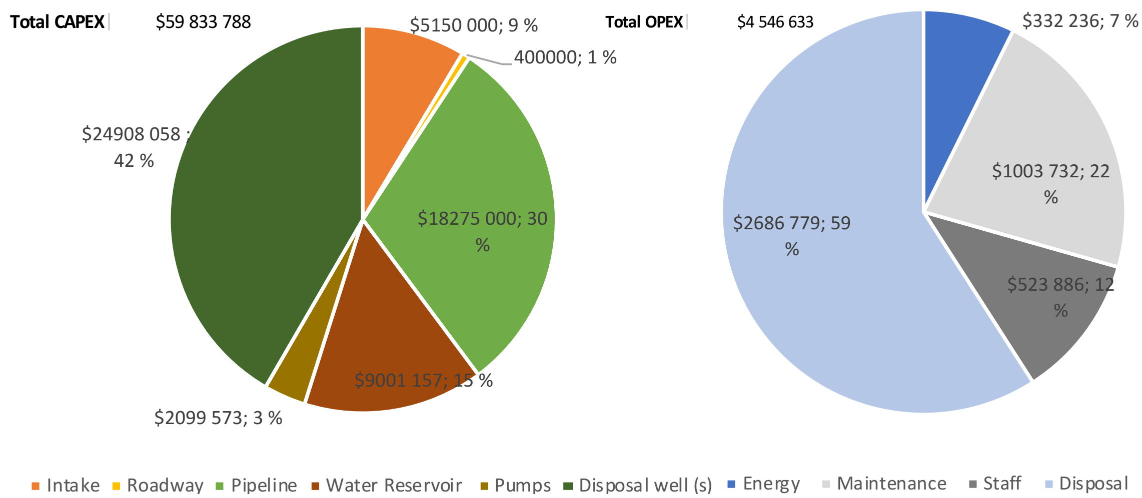
Figure 29 presents the total lifecycle cost per m^3 after including disposal costs. The largest cost associated with capital expenditures is the disposal wells and the pipeline while disposal cost represents by far the largest operational cost. Figure 30 presents the cost breakdown of the 1,050,000 m^3 scenario before accounting for a 15% capital contingency.

Figure 29. Freshwater System: Total Lifecycle Cost per m^3 at Different Volume Scenarios



Source: (Author, 2019)

Figure 30. Freshwater System: Cost Breakdown for 1,050,000 m^3 Volume Scenario



Source: (Author, 2019)

4.9.2 *Recycling System*

Table 5 presents some of the input data types described earlier and the total Capex associated with each wells/yr scenario. Based on the water balance scenario, this system would require one disposal well (Appendix C).

Table 5. Recycling System Input and Total Capex

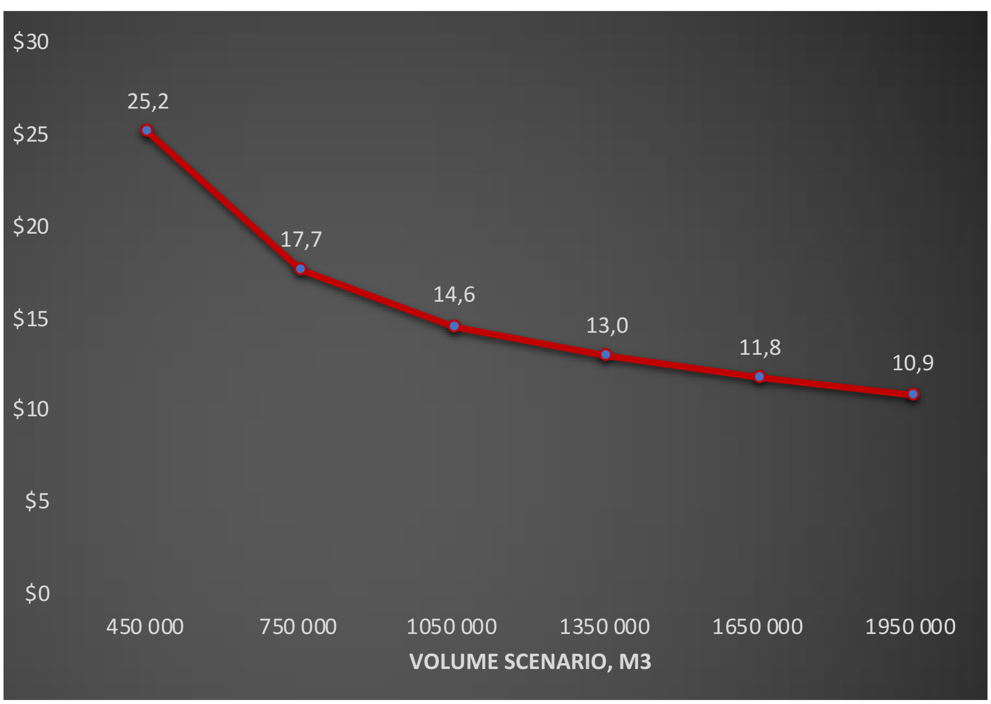
Wells /yr	Volume m^3/ well	Vol Scenario m3	Distance (m)	Flow rate m3/day	Days Storage	Storage Volume	Operational Days	# Years	Contingency	Capex including Disposal ($ total)	Capital Charge	Annual Opex including Disposal
		A	B	C	D		E	F	G		I	
15	30,000	450,000	17,000	10,000	90	110,959	45	10	15%	$48,691,006	10%	$3,431,387
25	30,000	750,000	17,000	10,000	90	184,932	75	10	15%	$52,903,478	10%	$4,661,390
35	30,000	1,050,000	17,000	10,000	90	258,904	105	10	15%	$58,254,319	10%	$5,892,586
45	30,000	1,350,000	17,000	10,000	90	332,877	135	10	15%	$64,323,240	10%	$7,124,700
55	30,000	1,650,000	17,000	10,000	90	406,849	165	10	15%	$68,756,368	10%	$8,329,527
65	30,000	1,950,000	17,000	10,000	90	480,822	195	10	15%	$72,219,862	10%	$9,517,196

Source: (Author, 2019)

Treatment cost in this system included chemical injection skids and chemicals. As presented in Figure 28, it is expected make-up freshwater is needed in the first few years before the system can fully operate with produced and treated water only. The area of study has exhibited wastewater streams with high H_2S content (sour), so a high cost of treatment was assigned in the calculation (4 $/m^3 if sour vs. 2 $/m^3 if sweet). It is also expected that at one point produced water volumes would be larger than those needed in upcoming drilling and completion operations, so disposal volumes were assumed to be pumped out to the disposal well, similarly to the freshwater system.

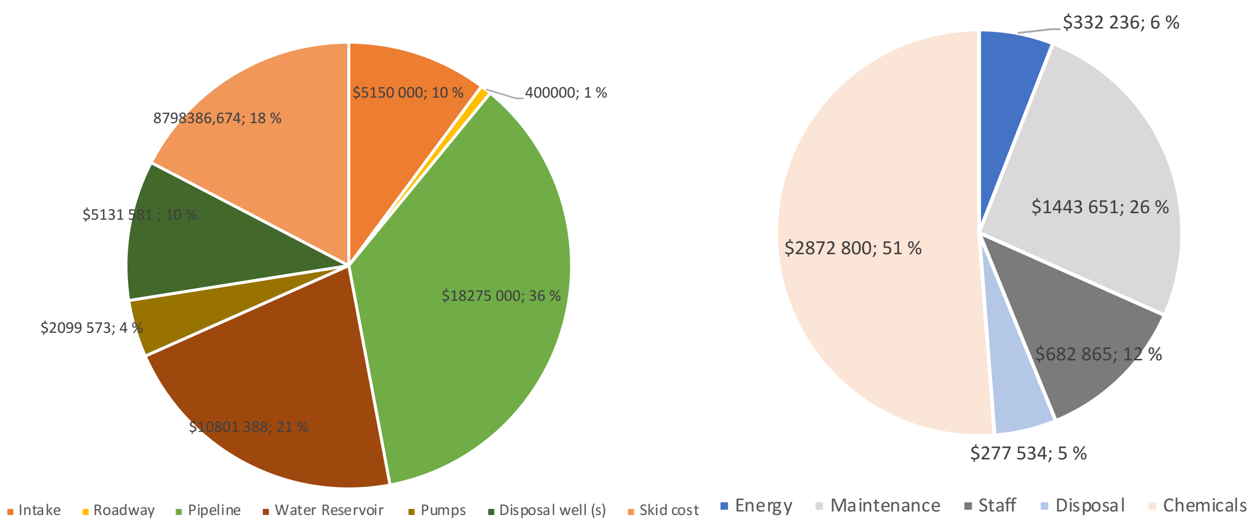
Figure 31 presents the total lifecycle cost per m^3. As with the freshwater system, the pipeline represents one of the largest Capex items while the largest Opex item is the cost of chemicals used in treatment (Figure 32).

Figure 31. Recycling System: Total Lifecycle Cost per m^3 at Different Volume Scenarios



Source: (Author, 2019)

Figure 32. Recycling System: Cost Breakdown for 1,050,000 m^3 Volume Scenario



Source: (Author, 2019)

4.9.3 Status Quo Development

Table 6 presents some of the input data types described earlier and the total Capital Expenditures (Capex) associated with each wells/yr scenario. This scenario is the less initial capital intensive but the most opex-demanding. With no permanent infrastructure, the initial capital is reduced to roadway construction and pump costs.

Table 6. Status Quo Development Input and Total Capex

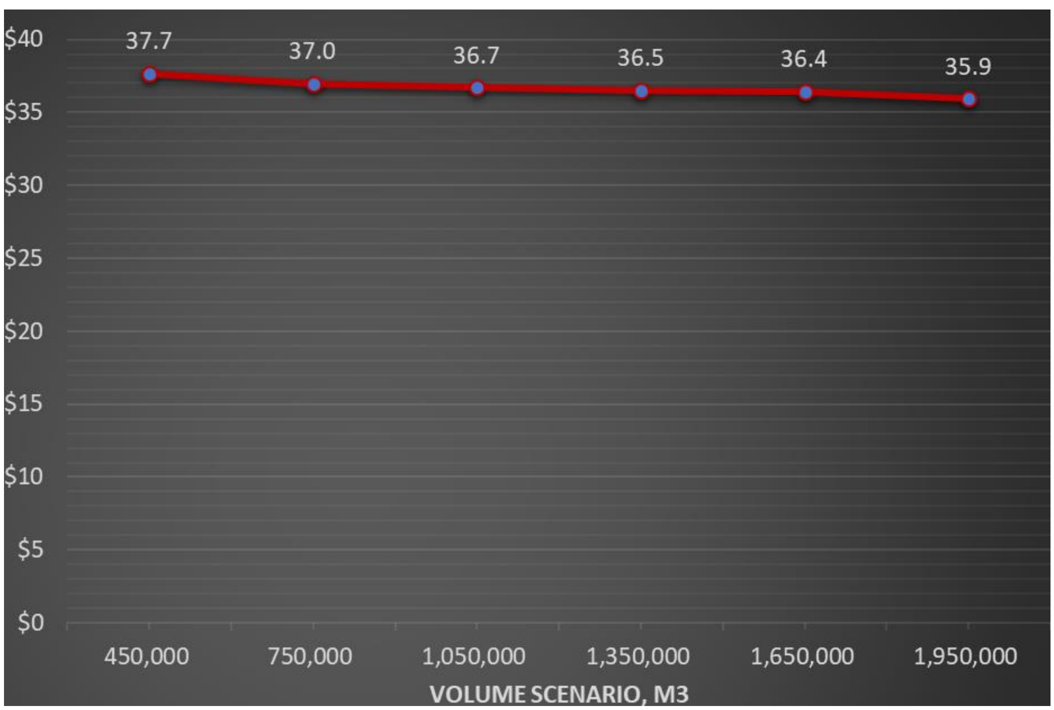
Wells /yr	Volume m^3/ well	Vol Scenario m3	Distance (m)	Flow rate m3/day	Days Storage	Storage Volume	Operational Days	# Years	Contingency	Capex including Disposal ($ total)	Capital Charge	Annual Opex including Disposal
		A	B	C	D		E	F	G		I	
15	30,000	450,000	13,000	10,000	0	0	45	10	15%	$1,895,686	10%	$16,649,916
25	30,000	750,000	13,000	10,000	0	0	75	10	15%	$1,895,686	10%	$27,433,760
35	30,000	1,050,000	13,000	10,000	0	0	105	10	15%	$1,895,686	10%	$38,217,604
45	30,000	1,350,000	13,000	10,000	0	0	135	10	15%	$1,895,686	10%	$49,001,448
55	30,000	1,650,000	13,000	10,000	0	0	165	10	15%	$1,895,686	10%	$59,785,292
65	30,000	1,950,000	13,000	10,000	0	0	195	10	15%	$1,895,686	10%	$69,765,136

Source: (Author, 2019)

As presented in Figure 33 the cost reduction with increasing volumes given by the economy of scale is limited relative that observed in Figure 29 and Figure 31. Over its entire cost cycle, this case is approximately 30% more expensive for the smallest volume scenario and 80% to 120% more expensive for other volume scenarios. Additionally, there are water sourcing risks not reflected in Table 6 that operators would incur into should they select to develop the project under these assumptions. These risks can result in drilling and completion restrictions with cash flow consequences.

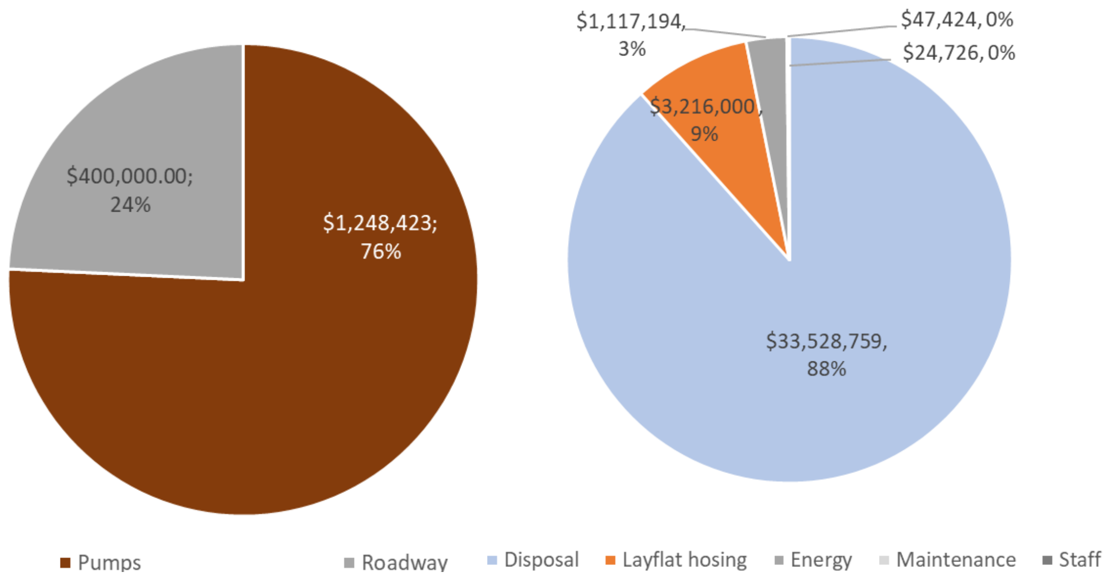
Figure 34 presents the cost breakdown before the 15% capital contingency. As it can be observed, the most significant expense relates to disposal costs.

Figure 33. Status Quo Development: Total Lifecycle Cost per m³



Source: (Author, 2019)

Figure 34. Status Quo Development: Cost Breakdown for 1,050,000 m^3 Volume Scenario



Source: (Author, 2019)

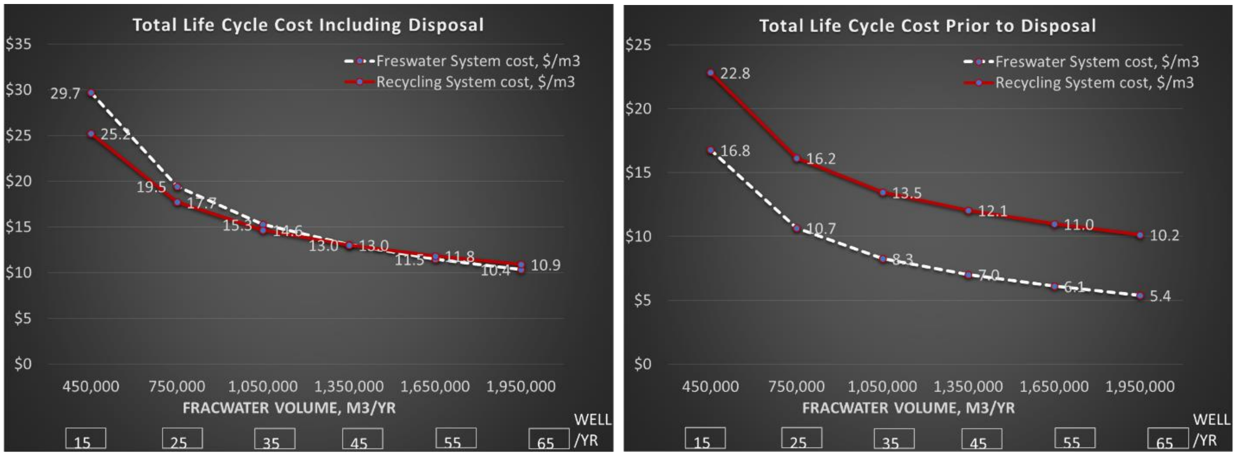
4.10 Analysis and Scenarios

The most obvious observation about the three different systems is that the recycling and freshwater cases have a much lower total lifecycle cost per m^3 than the status quo development. For example, at 450,000 m^3 the total lifecycle cost for the status quo system is $37.7, the freshwater system is $29.7, and the recycling system is $25.2. And at 1,950,000 m^3 the total lifecycle cost for the status quo system is $35.9, the freshwater system is $10.4, and the recycling system is $10.9. In addition, the amount of water that is used by the recycling system is significantly less over the ten-year period. For example, at 450,000 m^3 (15 wells/yr) the total amount of water used by the status quo and freshwater systems is 4,5 million m^3 (Appendix B, Water Balance table) the recycling system on the other hand uses 0,654 million m^3 (Appendix A, Water Balance table).

It can be observed that the Recycling and Freshwater systems display positive economic of scale specially when moving from the 450,000 m^3 to the 1,050,000 m^3 volume mark. This interval reveals a 49% decrease in the total \$/m^3 in the freshwater system and a 42% decrease in the recycling system. However, to capture this opportunity and accounting for capital contingency, an additional 7% to 20% Capex would be required in the freshwater and the recycling systems respectively. This 1,050,000 m^3 "sweet" spot is equivalent to drilling and completing 35 wells /yr, which can arguably be achieved if any two companies in the area of study were to collaborate based on Figure 22. A medium sized company like NuVista is expected to spend \$30 million in water infrastructure and facilities alone in 2019 so the Capex levels are arguably achievable in the area (NuVista, 2019).

When comparing both curves as presented in Figure 35 - *left* and given the assumptions in the base scenario, it is not possible to discern and conclude with full certainty whether the recycling system is more capital efficient than the freshwater system, at least from a \$/m^3 perspective. It is interesting to note that the relative difference between both systems is more evident at the smaller volumes. There is one factor that can help explain this trend: Capex cost associated with disposal wells in the 450,000 m^3 freshwater system make up 44% of the total Capex (4 wells) while in the recycling system this number makes up only 12% of the total capex (1 well). Disposal wells do not share the economy of scale as pipelines, so it is natural to think that at this volume level drilling one disposal well is less efficient than at the next volume level of 750,000 m^3, where the same well can handle more disposal volumes. In fact, when removing disposal cost considerations, the economy of scale indicator is clearer (Figure 35 - *right*).

Figure 35. Freshwater and Recycling Systems Water Management Cost Comparison



Source: (Author, 2019)

An important consideration not reflected in Figure 35 is the risk that operators implicitly accept when having to "deal" with large disposal volumes, which is more evident in the Status Quo development behind Figure 34. A Freshwater system is also exposed to such circumstances. For example, if assuming third-party disposal, the approximately 406,000 m^3 disposal needs observed in year 5 in Figure 27, would translate into 25,383 trucking trips at a total cost of $15,2 million in that one year alone:

$$\frac{406{,}125\ m^3/yr}{(32\ m^3/truck\ /2)} = 25{,}383\ round\ truck\ trips * \$\frac{25}{km - trip} * 15\ km\ + 406{,}125\ m^3/yr * \$14/m^3$$
$$= \$\ 15{,}2\ million$$

When comparing the Freshwater and Recycling systems cost breakdowns, it is interesting to note that the freshwater system appears to be a more CAPEX-intensive solution than the recycling system. This is counter-intuitive at the time of investment as the Recycling system requires the upfront capital of the chemical treatment units. However, over the entire life cycle, the results demonstrate that the discounted cost of the 4 disposal wells required in the Freshwater system is higher than the initial cost of the chemical treatment equipment in the Recycling system. In other words, the treatment equipment pays off over time. As disposal well needs are partly a function of injection rates, it would be of interest to find out how this variable affects the number of wells required, and ultimately CAPEX. Table 7 presents a cost comparison at different injection rates. The results illustrate that an optimistic disposal injection rate of 1000 m^3/d, only three disposal wells would be required. However, the Capex associated would still be higher than that of the chemical treatment system, which can vary between $ 5,7 million and $ 16 million depending on treatment rates.

Table 7. Disposal Injection Rates Sensitivity in Freshwater System

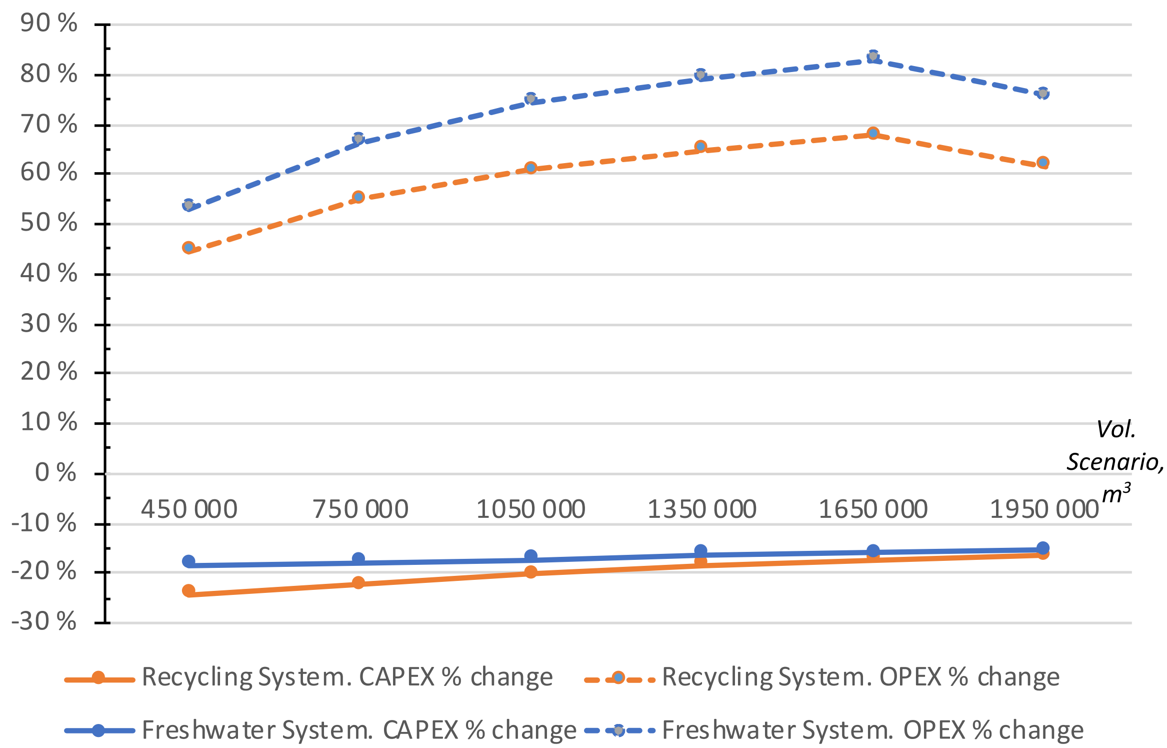
injection rate m3/d	disposal wells required	NPV10 of disposal wells cost
500	5	$ 32,185,828
800	4	$ 24,908,058
1000	3	$ 19,541,099

Source: (Author, 2019)

In summary, a Freshwater system carries cost risks associated with excessive third-party disposal cost and, to large first-party disposal cost brought about by injection rate constrains (usually regulated to avoid seismic events). These characteristics are also present in Status Quo systems. Injection rates at disposal wells can also become an operational risk if such constrains result in an oil and gas production bottleneck. This scenario has been proven to be the case in some jurisdictions in the U.S. and in British Columbia as mentioned in section 3.8. The additional risk of Freshwater and Status Quo systems is the exposure to regulatory withdrawal restrictions, also known as water security risk.

An alternative configuration of the proposed infrastructure was explored assuming the use of layflat hosing instead of a permanent intake in the first 4 km pipe section (this section links the POD to the water facilities as presented in Figure 18). This alternative would represent an 18% to 21% Capex reduction in the Freshwater system and a 17% to 25% Capex reduction in the recycling system (relative to the base scenario). However, layflats would need heating during winter, which would increase Opex significantly in both systems as observed in Figure 36. The ultimate \$/m^3 would also increase with this option (Table 8).

Figure 36. Layflat Hosing / No Intake Sensitivity Relative to Average Case



Source: (Author, 2019)

Table 8. Layflat Hosing / No Intake Sensitivity

Vol. Scenario k m3	Total Lifecycle cost including disposal $/m3	
	Recycling	Freshwater
450	24.4	28.8
750	18.5	20.3
1050	16.2	16.8
1350	15.0	15.0
1650	14.1	13.7
1950	12.9	12.4

Source: (Author, 2019)

Permanent water infrastructure can be capital intensive, but it does not have to be capital inefficient. By splitting the initial costs, the parties involved in a collaborative solution can ultimately benefit from an entire life cycle cost reduction and, from reducing or eliminating the risks associated with water sourcing and disposal.

CHAPTER 5. PROPOSED FRAMEWORK GUIDELINES

5.1 Agreement type

There are three possible agreement types available to oil and gas operators for a collaborative, multi-user framework: Non-Profit, Joint Venture (JV) and For-Profit. For the purpose of this study, we will explore the last two options as it is deemed a Non-Profit framework (such as COSIA) would be too lengthy to create and implement. A JV between two or more companies where the infrastructure is owned by the parties involved and operated by a multi-operator board of directors or one of the parties (usually the one with the largest stake). The Petroleum Joint Venture association (PJVA) created a Co-Own and Operated (CO&O) agreement that is often used in the industry and that can serve as the backbone for this model (PJVA, 2019). This model requires major capital investments from operators but arguably gives them more control over the operations and potential modifications. The second option is a for-profit agreement where one party owns and operates the infrastructure. The party may or may not have commitments of interest in place from other parties ahead of construction. The users and the owner party would negotiate a pay-per-use scheme. This model represents a mid-stream company scenario used in building and operating gas plants. It is arguably the simplest but most expensive option for operators. The highlights of each agreement type are presented in Figure 37.

5.2 Economy of Scale in Full Development Phase

The benefits in the economy of scale curve of a given development can be reached after a certain level of production volumes are expected from a play or area. Long-term plans of this kind are often constructed after exploration and appraisal campaigns, a couple of years after each play or zone has been proven successful with a discovery well. Knowledge of the number of production wells to be drilled per year to meet production targets and the infrastructure required to support them is often an ongoing activity for operators. In the light of an MOWP, the remaining task would be exploring the space of the economy of scale curve to find the "sweet" spot within which the largest cost per unit of production can be realized. If the additional level of investment required is beyond a single company's budget, the opportunity lies in finding similar developments concentrated within the area and initiating peer-to-peer conversations.

Figure 37. Agreement Types Highlights

	For Profit: owned and operated by one party (mid-stream model)	JV: owned by all parties (CO&O model). Operated by equitable body or party
Agreement type	• one-time commitment or on-demand basis at any point in time	• requires one-time alignment and commitment (challenging)
Construction / Operation	• specialized expertise • impartial third party • easier for producer	• potential complex negotiations
Capital / Cost	• access to capital challenging for small mid-stream companies • internal cost control • OPEX driven solution for operators	• CAPEX-driven solution • cost scrutiny • red tape • cut need for third-party margin
Parties Involved / Flexibility	• scaling based on spare capacity	• scaling based on spare capacity
Risk to Operators / Liabilities	• operators not responsible for product handling prior to delivery	• risk shared by operators along value chain

Source: (Author, 2019)

5.3 Play-Based Approach

Area-based analysis and Play-based regulatory frameworks have been implemented by British Columbia and Alberta´s regulatory bodies to reduce the cumulative effects of oil and gas operations. In the context of a MOWP, a play-based approach also aids in maturing the drilling and completion technologies being used and, in gaining enough subsurface knowledge to be able to predict well and/or play performance. Confidence around forecast of produced water volumes and chemistry is of paramount importance in reducing the risk associated with a long-term development that requires major investments. Type curves, already being used to predict oil and gas production performance from these plays can serve as the basis for produced water forecasting when considering a recycled water cycle. Both Freshwater and Recycling systems also require knowledge of hydraulic fracturing water requirements in the long term. Initial water composition and compositional changes with time needs consideration so that initial treatment needs and design remains relevant. For example, it would be not be possible to mix sour and sweet water streams, as they both require very different treatment systems but, given similar H2S compositions, a given treatment facility could be retrofit or adapted to varying chemistries (personal communication, Zeina Baalbaki, July 19, 2019). Large oil content in water streams can also be problematic so in a recycling system it would be desirable to capture water once it has been pre-treated at a battery station.

5.4 Spatial Components of Conveyance System

There are many factors that need examination when evaluating the physical location and extent of the conveyance system, storage and treatment units: point of water separation, distance to batteries, expected well density around conveyance system, lease boundaries and existing trenches excavated for oil and gas lines. It would be desirable to place in-ground water pipelines along the same route of the oil and gas lines connecting well pads to gathering systems as to avoid additional earthworks and installation cost, which otherwise can increase the cost between 3 and 7 times depending on the installation method (plow-in or trench respectively). Finding the "middle ground" between these considerations while remaining fair to the parties involved is likely to be a trade-off deal. In a for-profit option, a $/m^3 pricing scheme can be weighted by distance to delivery point. Keeping fairness in a JV option can be more challenging but can include for example a capital requirement vs. spatial concentration-of-activities scheme that reflects how each party can benefit from being closer to the conveyance system. In other words, if the location of the infrastructure is skewed towards one company's development or interests, the other party's disadvantaged position may be compensated by lesser level of capital commitment. There are existing regulatory barriers that would need to be addressed to facilitate this consideration. For example, by allowing operators to carry out low-risk inter-basin transfers for consumptive use or by allowing the use of layflat hoses for produced water. The former can increase the flexibility around the physical location of the pipeline. The former can reduce the cost associated with wastewater conveyance.

5.5 Licensing Constrains and Opportunities

The current regulatory regime in Alberta does not allow for joint water license applications or storage-only applications that apply across all basins. Similarly, a third party that is not directly involved in the drilling and completion of wells cannot obtain a permanent water license on behalf of other parties, such as oil and gas operators. If an agreement is to be made between one or more parties, the regulatory system in Alberta needs to be challenged in the creation and approval of a joint water license or, in the creation of a priority system that benefits joint solutions. It would be expected that such application be accompanied with a holistic assessment that evaluates the reduction in the land, GHG emissions and overall environmental and social footprints. Total life cycle considerations are indeed what the MOWP proponent, the Government of Alberta, laid out in the Draft Policy (Government of Alberta, 2016). The Government of Alberta refers to water as one of the province's most important resources so there is sufficient common ground to take a closer look at the barriers created by the current regulatory regime.

At present there are three opportunities that are bridging the gap between the licensing of freshwater use and the economics of water recycling in Alberta: in 2018 and for the first time, the AER approved a pilot project that uses engineered containment ponds (ECP) for produced water with a total capacity up to 40 million gal (˜151,000 m^3), which allows for significant storage capacity relative to AWSS, which can be up to 6300 m^3. In a separate project the AER also approved a solution including 8-10 x 6300 m^3 AWSS inside a secondary, synthetically-lined containment unit (though the project did not materialize, it represented the genesis of licensed produced water tanks with capacities greater than 3000 m^3) (personal communication, Greg Smith, June 19, 2019). Finally, the AER is to be evaluating a project that involves the use of flexible pipes for produced water (personal communication, Gerald Feschuk, June 7, 2019), which could significantly reduce cost and increase flexibility around these type of water streams.

In the meantime, a MOWP would need to rely on each company acquiring their own water licenses as to ensure there is enough volumes to support each their own operations.

Unused freshwater allocations could be potentially transferred from one operator to the other one, but this solution may not offer a long-term, uninterrupted level of operations for both operators.

5.6 Oversizing and Undersizing

Sizing the facilities so that the parties involved get to realize their own development plans implies all wells and consequent water needs can be drilled and allocated without interrupting drilling and completion schedules. This means facilities and investments are larger than what they could be should the parties agree to an alternating water allocation scheme, for example on a per-well or per timeframe basis. This scenario offers a less capital-intensive solution but can prove to be challenging as operators would not necessarily want to modify their own plans, especially during the peak of the drilling season. The additional caveat is the diversity in the drilling and completion time across the industry. Some hydraulic fracturing operations may take as much as 15 days while other as little as 3 days, depending on the number of stages and length of horizontal sections in the wellbore. Table 4 and Table 5 demonstrate that for an average 30,000 m^3 fracturing job at a 10,000 m^3/d rate and a 10-month drilling season, up to 65 wells could be drilled within a year. Though the fracturing rate is arguably high, it does demonstrate that it would be possible to agree to alternating water allocation scheme without interrupting a 65 well/yr development plan.

Oversizing facilities is a risk with any major capital project that represents stranded capital but that can be mitigated by de-risking when needed for example by involving a private equity firm, by having a contingency plan that ensures access to an alternative wastewater stream into the facilities or, by using modular treatment units that can be re-used somewhere else. The reasons for an oversized scenario may include lesser than expected produced water volumes or, externalities that may force an operator to reduce the scope of their development plans such as market or regulatory changes. Undersizing on the other hand is also a risk that can be mitigated by retrofitting storage or treatment units whenever possible. The reasons for this scenario may include larger than expected produced water volumes or hydraulic fracturing requirements.

5.7 End-of Life Consideration

Freshwater-only systems can have a 3:5 ratio between reclamation cost and infrastructure investment cost respectively (personal communication, Yves Matson, June 2, 2019). This means $ 0.75 reclamation cost for every dollar spent in Capex. The ratio can be as high as 1:1 in recycled water systems. Some of the end-of life activities in produced water systems include earth works associated with land reclamation, liner removal and disposal of storage systems and, settling of naturally occurring radioactive material (NORM) at the bottom of them. Equipment such as pumps and chemical treatment skids can be repurposed but in-ground pipeline on the other hand are usually left underground. Once the produced water liability has been removed in storage systems, they can potentially be repurposed as dugouts for irrigation (personal communication, Tom Parker, July 2, 2019). The later can also apply to freshwater systems. Decommissioning and reclamation can be cost effective when the land, storage and treatment units, materials and equipment are centralized as opposed to dispersed over large areas.

Given the expected level of development in unconventional resources and, the potential upcoming regulatory changes around freshwater use brought about by the Draft

Policy, a water infrastructure network can be considered an asset. In a recent article published by Reuters, wastewater was labeled as the “private equity’s new black gold”, referring to various U.S. transactions involving private equity firms and water pipeline networks owned by oil and operators and, the creation of water management firms in an industry that in 2018 spawned a $34 billion business (Reuters, 2019).

5.8 A Path Towards a Collaborative Agreement

There is no one-size fits all solution to MOWPs but there are common denominators that can offer a starting point for initiating a shared development conversation among operators. As MOWPs do not currently exist in Alberta, the opportunity needs to be fostered by the operator and industry associations and eventually negotiated among interested parties. Figure 38 presents a high-level outline of the main considerations part of a MOWP as split by the entities involved assuming a JV agreement.

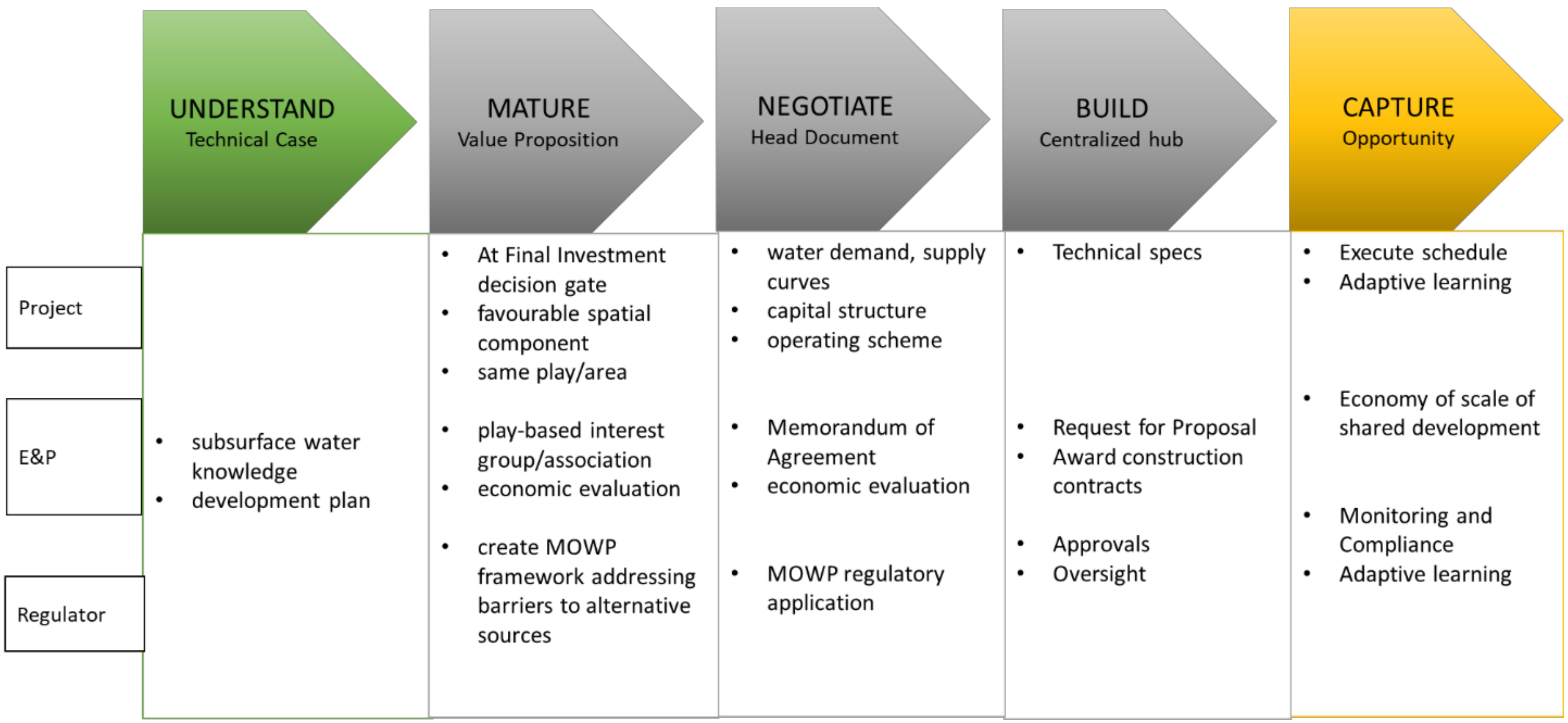
5.9 Agreement in the Light of Sustainable Development Goals

A MOWP based on shared, permanent and recycled water infrastructure can move the Alberta energy system forward towards meeting a few of the 17 United Nations Sustainable Development goals (United Nations, 2016):

- clean water and sanitation (Goal 6): by minimizing impact of unconventional oil and gas developments on freshwater resources that would otherwise be available for consumption,

- affordable and clean energy (Goal 7): by reducing oil and gas production cost that could otherwise discourage companies and investors from expanding their interest in the province,
- industry, innovation and infrastructure (Goal 9): by setting a framework that can be used as an example in implementation of similar solutions in other jurisdictions,
- responsible consumption and production (Goal 12): by reducing the ecological footprint on land and water for a given amount of output and,
- climate action (Goal 13): by reducing the dependence on truck trips that generate GHGs.

Figure 38. Path Towards a Collaborative Agreement under a JV



Source: (Author, 2019)

CHAPTER 6. CLOSING REMARKS

6.1 Conclusions

The increasing HQNS water use and intensity in hydraulic fracturing operations is driving the industry, government and regulator towards trying to find sustainable solutions that reduce reliance on these resources while providing positive economics for the Alberta energy system. A key instrument in the achievement of this goal is the implementation of wastewater recycling systems for produced and flowback water, a practice that has been largely determined by a traditional, single bottom line, business-driven case. With freshwater allocations distributed by the AER at a negligible cost and the rigid regulatory framework around wastewater, such a business case is frequently non-existent in Alberta. As a result, many operators are placed between "a rock and a hard place" when trying to find alternative water sources that are economically viable.

Considering climate change effects, a stricter regulatory regime and a life cycle assessment of water management cost, operators will be faced with more frequent freshwater restrictions, increasing wastewater disposal cost, wastewater injection rate constrains and, the realization water recycling makes economic sense. This scenario requires a paradigm shift that calls for collaboration using a MOWP based on shared infrastructure.

The advantages of a joint development that implements a water treatment and recycling system are social, economical, environmental and ecological. Social because of the all the nuisances that can be avoided when water trucking is reduced or, when seismic activity increases in areas close to disposal wells. Environmental because of the reduced stress that is placed on freshwater resources especially at times of drought. Ecological because the natural habitat and reproduction of animal and plant species are minimized. Economical because of the significant reduction in water management cost brought about by the economy of scale intrinsic to water infrastructure. This research helps to show that this is an opportunity easier to capture when two or more companies collaborate.

6.2 Recommendations

As the study area is at the early stages of development, the implementation of a MOWP is an opportunity that can continued to be pursued. This value proposition can be put forward in front of industry associations such as CAPP or at industry conferences such as the annual SPE Canadian Unconventional Resource Conference.

Awareness around life cycle water management cost is best addressed on operator-by-operator basis. For example, by quantifying a life cycle cost per m^3 indicator based on a given operator´s disposal and sourcing practices. Once operators recognize their own shortcomings in water management, they are more likely to accept the added value that reusing, and recycling brings to their operations. This is perhaps the first step that needs to happen before starting a dialog that involves two or more operators.

As presented in section 5.5, the AER can be persuaded and encouraged to accept an application outside the regulatory status-quo. In this context a value proposition that includes a joint application or a request for approval priority should be accompanied by the additional environmental and social benefits brought about by such a solution: GHG emission, land and environmental footprint reduction as well as reduction in the use of HQNS water. However, this process is likely to take longer than that presented in the previous paragraph, so it is important to give it a swift start.

6.3 Limitations and Future Research

Even though the environmental issues and the water management practices in the Unconventional oil and gas industry in this study were focused on a relatively small area West of Grand Prairie, the principles explored and described in Chapter 4 and Chapter 5 can hold true for similar areas. The pipeline length assumption may fall short in the high well count scenario, where a high well density would be required to capture the economy of scale based on a 17 km pipeline. It is more likely that at one point in the 10-year timeframe, additional layflat hosing or an alternative pipeline branch would be needed to be able to convey water beyond a 5 km radius. Accounting for additional infrastructure or conveyance needs can improve the current model looking forward.

A more discretized water balance analysis as well as a proper water forecast could be developed to more accurately represent a given water supply scenario. In a similar way, proper scaling of water treatment is a task that would require more data points across the industry. Chemical treatment is unique to each water stream so amounts and cost of chemicals would need to be customized for each play.

The disposal solution was based on an average 15 km distance to a first party disposal well. Approximately 90% of all disposal wells are first party owned (personal communication, Trevor Wall, June 10, 2019). Disposal distances in Alberta can be as high as 300 km when using sites in Saskatchewan (personal communication, Ingo Gloge, July 10, 2019). In this context it would be of interest to develop a study evaluating these alternatives and their present value implications.

It would be of interest to explore alternative or mixed water sourcing scenarios. For example: produced water from other oil and gas operations or implementing a mechanical water treatment only.

The economic model did not include a carbon or freshwater price. A cost increase in these variables could represent an additional risk that the Freshwater and Status quo systems would be more exposed to. A separate sensitivity study could cover these aspects and their economic implications.

Apart from the transportation cost associated with disposal volumes, the present value exercise was limited in scope as it did not include yearly cash flows. Oil and gas volumes can be used to construct a Net Present Value and other indicators to better determine the attractiveness of the investment.

The economic model proves the attractiveness of a large investment, where cash is assumed to be available. As this is not necessarily the current case in the province, there is an opportunity to explore alternative ways of financing these types of projects.

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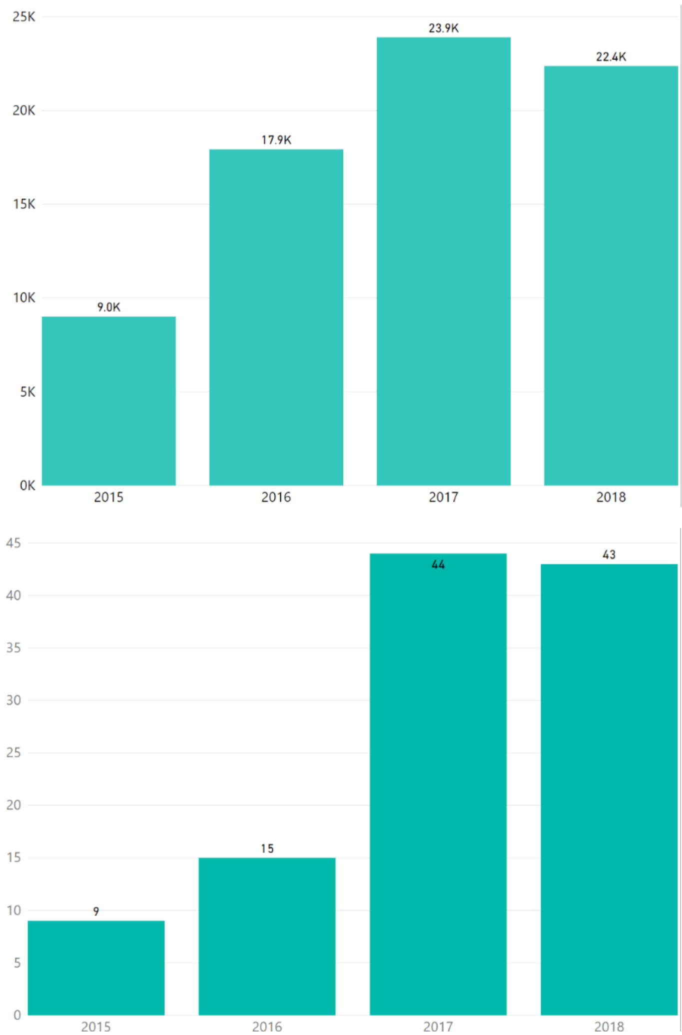
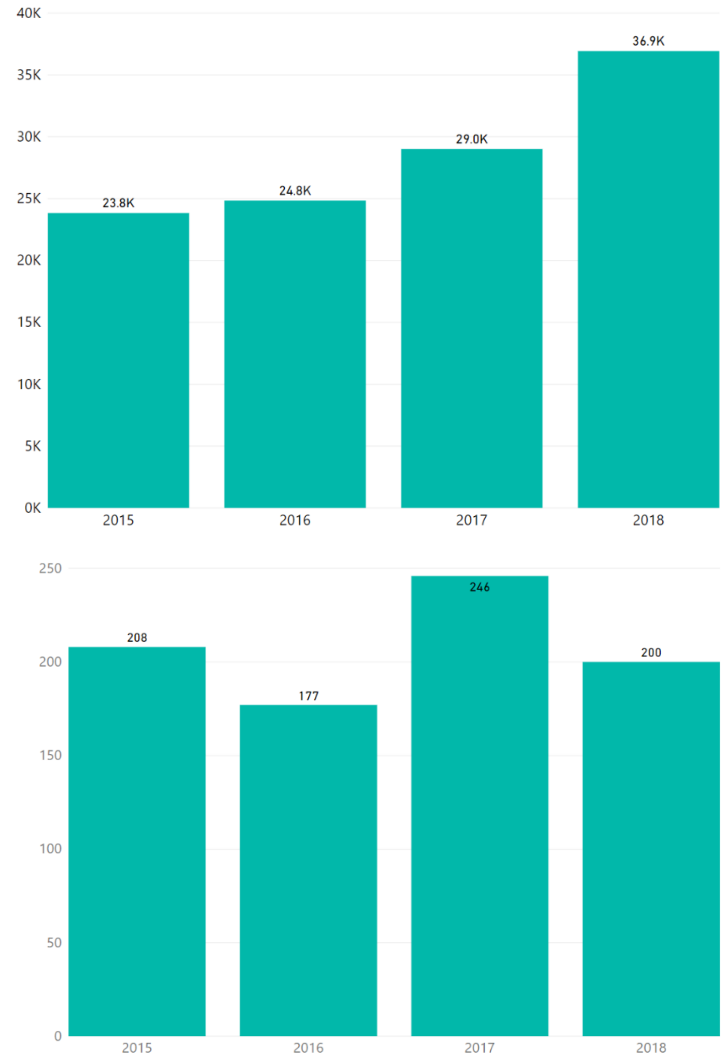
APPENDIX A – FracFocus Average Water Volume and Well Count

Montney Pipestone Boundary (Vertical definition)

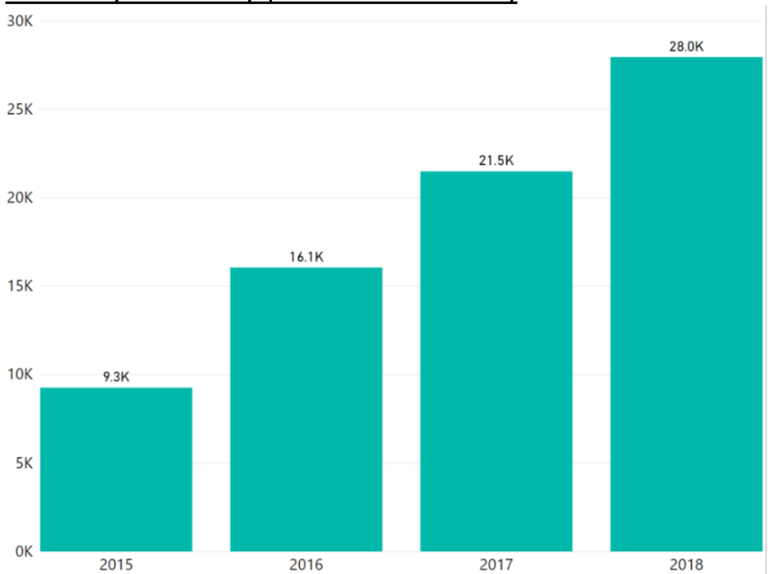


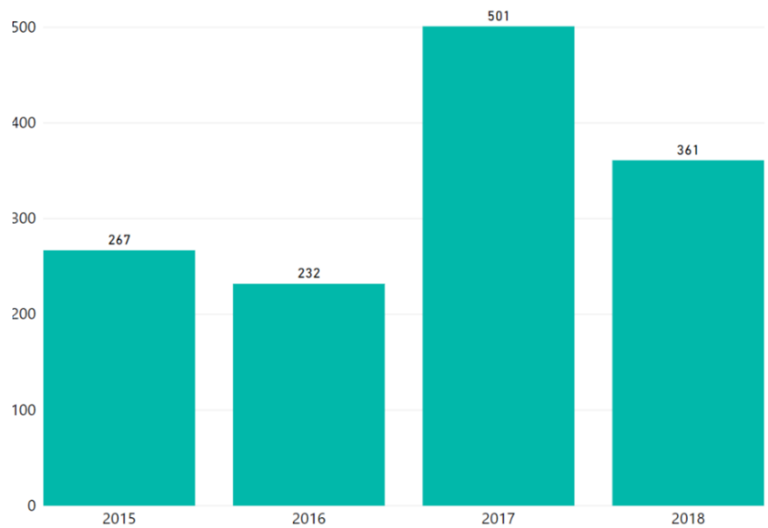
Duvernay Kaybob Boundary (Peters&Co definition)



Source: (Author, 2019) from PowerBI (*Fracfocus within Montney Pipestone -left and Peters&Co -right tables)*

Montney Boundary (Vertical definition)





Source: (Author, 2019) from PowerBI (*Fracfocus within Montney Pipestone table)*

APPENDIX B – Freshwater System Input Data and Economics

Background						Intake			Roadway		
Name	Fluid	Permanent/ Temporary Infrastructure	Vol Scenario m^3	Treatment Type	Disposal Solution	Type	Max Flow Rate	Total	Distance (m)	Cost per m	Total
Freshwater	FW/BW	**P**	450,000	**None Thanks**	**First Party**	**P**	10,000	**$5,150,000**	**4,000**	$100.00	**$400,000.00**
Freshwater	FW/BW	**P**	750,000	**None Thanks**	**First Party**	**P**	10,000	**$5,150,000**	**4,000**	$100.00	**$400,000.00**
Freshwater	FW/BW	**P**	1,050,000	**None Thanks**	**First Party**	**P**	10,000	**$5,150,000**	**4,000**	$100.00	**$400,000.00**
Freshwater	FW/BW	**P**	1,350,000	**None Thanks**	**First Party**	**P**	10,000	**$5,150,000**	**4,000**	$100.00	**$400,000.00**
Freshwater	FW/BW	**P**	1,650,000	**None Thanks**	**First Party**	**P**	10,000	**$5,150,000**	**4,000**	$100.00	**$400,000.00**
Freshwater	FW/BW	**P**	1,950,000	**None Thanks**	**First Party**	**P**	10,000	**$5,150,000**	**4,000**	$100.00	**$400,000.00**

Pipeline				Water Reservoir		
Distance (m)	Units	Cost per unit	Total	# days storage	Capacity	Cost
17,000	m	$1,075.00	**$18,275,000**	90	110,959	**$5,144,889**
17,000	m	$1,075.00	**$18,275,000**	90	184,932	**$6,546,781**
17,000	m	$1,075.00	**$18,275,000**	90	258,904	**$9,001,157**
17,000	m	$1,075.00	**$18,275,000**	90	332,877	**$12,116,692**
17,000	m	$1,075.00	**$18,275,000**	90	406,849	**$14,146,046**
17,000	m	$1,075.00	**$18,275,000**	90	480,822	**$15,547,938**

Pumps									
line size	operational days	m3/day flow	Hp per 1km pipe	Hp req'd for leg <10km	Common header or individual leg	Shared Header Pump Station	Hp req'd for leg >10km	Additional Pump Station	Total
10"	45	10,000	130	1,300	**Individual Leg**	$299,939	910	$1,799,634	**$2,099,573**
10"	75	10,000	130	1,300	**Individual Leg**	$299,939	910	$1,799,634	**$2,099,573**
10"	105	10,000	130	1,300	**Individual Leg**	$299,939	910	$1,799,634	**$2,099,573**
10"	135	10,000	130	1,300	**Individual Leg**	$299,939	910	$1,799,634	**$2,099,573**
10"	165	10,000	130	1,300	**Individual Leg**	$299,939	910	$1,799,634	**$2,099,573**
10"	195	10,000	130	1,300	**Individual Leg**	$299,939	910	$1,799,634	**$2,099,573**

Source: (Author, 2019) from Modified Excel Template provided by Integrated Sustainability

Staff			Maintenance			Energy				
Operator	Head office		% Capex	Total		Heating Diesel Fuel (Ga)	HP	$/Gallon Diesel	$/KWhr	Total
$121,500	$466,042		5%	$1,003,732		56,048	2,210	$6.60	$0.08	$142,387
$202,500	$487,070		5%	$1,003,732		93,413	2,210	$6.60	$0.08	$237,312
$283,500	$523,886		5%	$1,003,732		130,778	2,210	$6.60	$0.08	$332,236
$364,500	$570,619		5%	$1,003,732		168,143	2,210	$6.60	$0.08	$427,161
$445,500	$601,059		5%	$1,003,732		205,508	2,210	$6.60	$0.08	$522,085
$526,500	$622,088		5%	$1,003,732		242,873	2,210	$6.60	$0.08	$617,010

$$Operator\ \$ = 90 * 1 * 24 * \#\ operational\ days, d * 1.25$$

$$Head\ Office\ \$ = Total\ Capex * 0.015$$

rate, m3/d	heating diesel per day, L	heating diesel per day, Ga	Heating fraction per year
6,300	9,430	2491	0.5

$$cost\ of\ energy\ \$ = hp * 24\frac{h}{d} * 0.7457\frac{kW}{hp} * 0.08\frac{\$}{kWh} * \#\ operational\ days, d$$

Source: (Author, 2019) from Modified Excel Template provided by Integrated Sustainability

Code / Function	Item		
A	water reservoir size contigency	**0**	%
B	wells per year	**15**	
C	frac rate, m3/day	**10,000**	
D	avg frac water per well, m3	**30,000**	
E	produced water per well, m3/month	**500**	
F = E*12*(1-J/100)	produced water per well, m3/yr	5,700	
G	mob-demob days per month	5	
H	days of storage	90	
I	percentage of recycled water	80	%
J	downtime per well per year	5	
K	drilling months	10	
L	intake rate from river, m3/day	10,833	
M = D/C	days per well	3.0	
N = (30-G)/M*(K/12)	wells per drilling month	6.9	
O = B*30/N	total drilling time, days	65	
	storage volume, m3	110,959	
	injection rate, m3/day	**800**	
	injection days	**330**	(10% dowtime)
	Disposal opex if first party, $\$/m^3$	**3**	

Source: (Author, 2019)

Water Balance table:

	year	0	1	2	3	4	5	6	7	8	9	10
P	well count		15	30	45	60	75	90	105	120	135	150
D	avg frac water per well, m3		30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
F = E*12*(1-J/100)	produced water per well, m3/yr		5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700
Q = B*D	frac water needs, m3/yr	0	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
R	reservoir size, m3	110,959										
S = P*F*(1-J/100)	total produced water, m3/yr	0	81,225	162,450	243,675	324,900	406,125	487,350	568,575	649,800	731,025	812,250
T	total treated water, m3/yr	0	0	0	0	0	0	0	0	0	0	0
U	**net water balance year end, m3**	110,959	-339,041	-339,041	-339,041	-339,041	-339,041	-339,041	-339,041	-339,041	-339,041	-339,041
V = ABS (U)	make-up water needs, m3/yr	0	339,041	339,041	339,041	339,041	339,041	339,041	339,041	339,041	339,041	339,041
W	**disposal needs, m3/yr**	0	81,225	162,450	243,675	324,900	406,125	487,350	568,575	649,800	731,025	812,250
X	Cumulative injection needs, m3	0	81,225	243,675	487,350	812,250	1,218,375	1,705,725	2,274,300	2,924,100	3,655,125	4,467,375
Y	Number of injection wells needed	0	1	1	1	2	2	2	3	3	3	4
Z	**CAPEX associated with disposal wells**	-	$ 10,000,000	$ -	$ -	$ 10,000,000	$ -	$ -	$ 10,000,000	$ -	$ -	$ 10,000,000
AA = W / (32/2)	disposal round 32 m3 trucking trips	0	5,077	10,153	15,230	20,306	25,383	30,459	35,536	40,613	45,689	50,766
AB	**First Party**	$ -	$ 243,675	$ 487,350	$ 731,025	$ 974,700	$ 1,218,375	$ 1,462,050	$ 1,705,725	$ 1,949,400	$ 2,193,075	$ 2,436,750
NPV10 (AB)	NPV transportation - disposal OPEX	$ 7,075,325										
NPV10 (Z)	NPV injection well CAPEX	$24,908,058										

Total freshwater use, m^3 $= \sum_{year=0}^{year=10} Q$ = 450,000

Source: (Author, 2019)

Name	ATS Route	Fluid	Wells /yr	Volume m^3/ well	Vol Scenario m3	Distance (m)	Flow rate m3/day	Days Storage	Storage Volume	Operational Days	# Years	Contingency	Capex ($ total)	Capex including Disposal ($ total)	Capital Charge
					A	B	C	D		E	F	G	H		I
Freshwater	Main and Intake	FW/BW	15	30,000	450,000	17,000	10,000	90	110,959	45	10	15%	$35,729,881	$64,374,148	10%
Freshwater	Main and Intake	FW/BW	25	30,000	750,000	17,000	10,000	90	184,932	75	10	15%	$37,342,057	$65,986,324	10%
Freshwater	Main and Intake	FW/BW	35	30,000	1,050,000	17,000	10,000	90	258,904	105	10	15%	$40,164,589	$68,808,856	10%
Freshwater	Main and Intake	FW/BW	45	30,000	1,350,000	17,000	10,000	90	332,877	135	10	15%	$43,747,454	$72,391,721	10%
Freshwater	Main and Intake	FW/BW	55	30,000	1,650,000	17,000	10,000	90	406,849	165	10	15%	$46,081,212	$74,725,478	10%
Freshwater	Main and Intake	FW/BW	65	30,000	1,950,000	17,000	10,000	90	480,822	195	10	15%	$47,693,388	$76,337,654	10%

CAPEX Payment ($/yr)	CAPEX Payment including Disposal ($/yr)	Annual CAPEX Payment Including Disposal($/m3)	Annual Opex ($/yr)	Annual Opex including Disposal	Annual Opex including Disposal ($/m3)	Total Lifecycle Cost	Total Lifecycle Cost per m3	Annual DISPOSAL Payment ($/yr)	Total Lifecycle cost including disposal ($)	Total Lifecycle cost including disposal per m3
J=PMT(I,F,H)		K=J/A	L		M=L/A	N=(J+L)*F	O=N/(A*F)	T=PMT(10%,10,NPV)	N=(J+L+T)*F	O=N/(A*F)
$5,814,874	$10,476,596	$23.28	$1,733,661	$2,885,137	$6.41	$75,485,342	$16.77	$1,151,477	$133,617,333	29.7
$6,077,248	$10,738,970	$14.32	$1,930,614	$3,849,741	$5.13	$80,078,614	$10.68	$1,919,128	$145,887,115	19.5
$6,536,602	$11,198,324	$10.67	$2,143,354	$4,830,133	$4.60	$86,799,558	$8.27	$2,686,779	$160,284,570	15.3
$7,119,697	$11,781,419	$8.73	$2,366,011	$5,820,441	$4.31	$94,857,082	$7.03	$3,454,430	$176,018,604	13.0
$7,499,505	$12,161,227	$7.37	$2,572,376	$6,794,457	$4.12	$100,718,815	$6.10	$4,222,081	$189,556,847	11.5
$7,761,879	$12,423,602	$6.37	$2,769,329	$7,759,061	$3.98	$105,312,087	$5.40	$4,989,732	$201,826,630	10.4

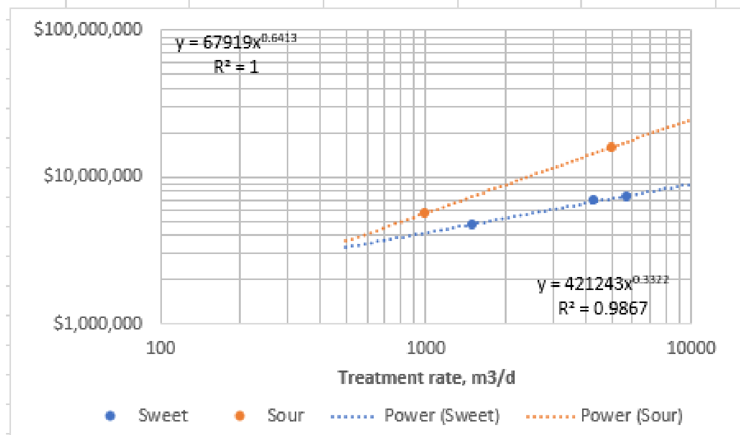
Source: (Author, 2019) from Modified Excel Template provided by Integrated Sustainability

APPENDIX C – Recycling System Input Data and Economics

Water Reservoir		
# days storage	Capacity	Cost
90	110,959	**$6,173,867**
90	184,932	**$7,856,137**
90	258,904	**$10,801,388**
90	332,877	**$14,540,030**
90	406,849	**$16,975,255**
90	480,822	**$18,657,526**
Additional liner cost increase, %		**20**

Chemical Treatment				
m3/day flow	Skid cost	Produed water volume (m3/y)	Chemicals cost (per/m3)	Chemicals total
843	**$5,109,984**	**307,800**	$4.00	**$1,231,200**
1,405	**$7,090,733**	**513,000**	$4.00	**$2,052,000**
1,968	**$8,798,387**	**718,200**	$4.00	**$2,872,800**
2,530	**$10,337,068**	**923,400**	$4.00	**$3,693,600**
3,092	**$11,756,737**	**1,128,600**	$4.00	**$4,514,400**
3,654	**$13,086,200**	**1,333,800**	$4.00	**$5,335,200**

m3/day flow	Skid cost	H2S
1500	**$4,750,000**	<150 ppm H2S
4320	**$7,000,000**	
5760	**$7,300,000**	
1000	**$5,700,000**	> 150 ppm H2S
5000	**$16,000,000**	



Source: (Author, 2019) from Modified Excel Template provided by Integrated Sustainability

Code / Function	Item	
A	water reservoir size contigency	**0**
B	wells per year	**15**
C	frac rate, m3/day	**10,000**
D	avg frac water per well, m3	**30,000**
E	produced water per well, m3/month	**500**
F = E*12*(1-J/100)	produced water per well, m3/yr	5,700
G	mob-demob days per month	5
H	days of storage	90
I	percentage of recycled water	80
J	downtime per well per year	5
K	drilling months	10
L	intake rate from river, m3/day	10,833
M = D/C	days per well	3.0
N = (30-G)/M*(K/12)	wells per drilling month	6.9
O = B*30/N	total drilling time, days	65
	storage volume, m3	110,959
	injection rate, m3/day	**800**
	injection days	**330**
	Disposal opex if first party, $/m^3$	**3**

Source: (Author, 2019). Example for 15 wells/year development

Water Balance table:

	year	0	1	2	3	4	5	6	7	8	9	10
P	well count		15	30	45	60	75	90	105	120	135	150
D	avg frac water per well, m3		30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000	30,000
F = E*12*(1-J/100)	produced water per well, m3/yr		5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700	5,700
Q = B*D	frac water needs, m3/yr	0	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000	450,000
R	reservoir size, m3	110,959										
S = P*F*(1-J/100)	total produced water, m3/yr	0	81,225	162,450	243,675	324,900	406,125	487,350	568,575	649,800	731,025	812,250
T	total treated water, m3/yr	0	64,980	129,960	194,940	259,920	324,900	389,880	454,860	519,840	584,820	0
U	**net water balance year end, m3**	110,959	-257,816	-176,591	-95,366	-14,141	67,084	148,309	229,534	310,759	391,984	473,209
V = ABS (U)	make-up water needs, m3/yr	0	257,816	176,591	95,366	14,141	0	0	0	0	0	0
W	**disposal needs, m3/yr**	0	0	0	0	0	0	0	113,715	129,960	146,205	162,450
X	Cumulative injection needs, m3	0	0	0	0	0	0	0	113,715	243,675	389,880	552,330
Y	Number of injection wells needed	0	0	0	0	0	0	0	1	1	1	1
Z	**CAPEX associated with disposal wells**	-	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,000,000	$ -	$ -	$ -
AA = W / (32/2)	disposal round 32 m3 trucking trips	0	0	0	0	0	0	0	7,107	8,123	9,138	10,153
AB	**First Party**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 341,145	$ 389,880	$ 438,615	$ 487,350
NPV10 (AB)	NPV transportation - disposal OPEX	$ 730,853										
NPV10 (Z)	NPV injection well CAPEX	$ 5,131,581										

Total freshwater use, m$^3 = R + \sum_{year=1}^{year=10} V$ = 654,873

Source: (Author, 2019). Example for 15 wells/year development

Name	Fluid	Wells /yr	Volume m^3/ well	Vol Scenario m3	Distance (m)	Flow rate m3/day	Days Storage	Storage Volume	Operational Days	# Years	Contingency	Capex ($ total)	Capex including Disposal ($ total)	Capital Charge
				A	B	C	D		E	F	G	H		I
Recycling	FW/BW	15	30,000	450,000	17,000	10,000	90	110,959	45	10	15%	$42,789,687	$48,691,006	10%
Recycling	FW/BW	25	30,000	750,000	17,000	10,000	90	184,932	75	10	15%	$47,002,160	$52,903,478	10%
Recycling	FW/BW	35	30,000	1,050,000	17,000	10,000	90	258,904	105	10	15%	$52,353,000	$58,254,319	10%
Recycling	FW/BW	45	30,000	1,350,000	17,000	10,000	90	332,877	135	10	15%	$58,421,922	$64,323,240	10%
Recycling	FW/BW	55	30,000	1,650,000	17,000	10,000	90	406,849	165	10	15%	$62,855,050	$68,756,368	10%
Recycling	FW/BW	65	30,000	1,950,000	17,000	10,000	90	480,822	195	10	15%	$66,318,543	$72,219,862	10%

CAPEX Payment ($/yr)	CAPEX Payment including Disposal ($/yr)	Annual CAPEX Payment Including Disposal($/m3)	Annual Opex ($/yr)	Annual Opex including Disposal	Annual Opex including Disposal ($/m3)	Total Lifecycle Cost	Total Lifecycle Cost per m3	Annual DISPOSAL Payment ($/yr)	Total Lifecycle cost including disposal ($)	Total Lifecycle cost including disposal per m3
J=PMT(I,F,H)		K=J/A	L		M=L/A	N=(J+L)*F	O=N/(A*F)	T=PMT(10%,10,NPV)	N=(J+L+T)*F	O=N/(A*F)
$6,963,825	$7,924,237	$17.61	$3,312,444	$3,431,387	$7.63	$102,762,688	$22.84	$118,943	$113,556,242	25.2
$7,649,385	$8,609,797	$11.48	$4,463,152	$4,661,390	$6.22	$121,125,367	$16.15	$198,238	$132,711,874	17.7
$8,520,210	$9,480,622	$9.03	$5,615,052	$5,892,586	$5.61	$141,352,621	$13.46	$277,534	$153,732,082	14.6
$9,507,899	$10,468,311	$7.75	$6,767,871	$7,124,700	$5.28	$162,757,698	$12.06	$356,829	$175,930,112	13.0
$10,229,370	$11,189,782	$6.78	$7,893,402	$8,329,527	$5.05	$181,227,724	$10.98	$436,124	$195,193,092	11.8
$10,793,037	$11,753,450	$6.03	$9,001,776	$9,517,196	$4.88	$197,948,137	$10.15	$515,420	$212,706,458	10.9

Source: (Author, 2019) from Modified Excel Template provided by Integrated Sustainability

	Cost, million $
Injection well cost around Grande Prairie	2,5 to 3,2
Disposal well cost assumption including piping	$ 10,000,000
Disposal costs	Cost per m3
Water trucking AB - SK truck B	$ 190
Slurry Trucking AB - SK truck B	$ 191
Third party Injection cost per m3	$ 14.0
	Cost per hr
32 m3 truck A in a 32 km trip	$ 175
Cost per km	$ 5.469
AB - SK Distance to disposal location, km	300
truck speed, km/h	60
hrs AB to SK	5
Cost per km per m3	$ 0.63
Cost per km per 32 m3 truck - B	$ 20.3
injection+disposal cost per km per trip truck - B	$ 34.27
Cost per km per 32 m3 truck - A	$ 27.3
Assumption in model (avg mid point)	$ 25.0
Third party Injection cost per m3	$ 14.0
distance to disposal, km	15

Source: (Author, 2019) from Data provided by Integrated Sustainability