HYDROGEOLOGY OF THE INTERMEDIATE ZONE BETWEEN DEEPER ANTHROPOGENIC ACTIVITIES AND SHALLOW AQUIFERS IN SASKATCHEWAN

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Abstract

Large volumes of often saline formation water are both produced from and injected into sedimentary basins as a by-product of oil and gas production. In Saskatchewan the prominent disposal zone is the Mannville Group and despite this, the distribution and interactions of these waters have not been studied in detail, and the effects of long-term water injection on reservoir pressures and groundwater quality remain uncertain. Even where injection and production volumes are equal at the basin scale, local changes in hydraulic head can occur due to the distribution of production and injection wells.

The changes in hydraulic head caused by this injection of fluids are important in understanding the potential to act as a driver of saline fluid flow, possibly leading to contamination of overlying potable groundwater resources where high permeability pathways or leaky abandoned wells are present. Across the Western Canada Sedimentary Basin's (WCSBs) Mannville Group, approximately 250,000,000 m^3 of excess water has been injected into the Group. This study evaluates the effects of injection wells on deep groundwater resources by examining wells within the Intermediate Zone of the WCSB. Hydraulic head maps were created for each aquifer within the Intermediate Zone, as well as maps of the difference between aquifer hydraulic heads. By comparing maps detailing the difference in hydraulic head, it was possible to locate areas where there is the potential for waters to migrate upwards through natural pathways or leaky wells. The potential for significant upward migration through natural pathways was deemed low due to the presence of low permeability shales in the Intermediate Zone of the study area, but leaky wells pose a bigger problem. As the leaky well becomes further away from the injection well this problem is not as severe but still poses a problem for freshwater aquifers.

Acknowledgements

I would like to thank my supervisors Dr. Grant Ferguson and Dr. Jennifer McIntosh for their amazing support and guidance throughout my thesis. They both provided me with invaluable guidance and support on the technical attributes of this project as well as the continuous assistance with the editing of the thesis. I would like to thank David Phillips for his detailed teaching on how to analyze Drill Stem Tests back in 2017, it was very valuable for this project. I would also like to thank the rest of the University of Saskatchewan-University of Arizona research group for all the great conversations and helpful feedback over zoom; hopefully we will all meet in person one day.

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1.0 Introduction

Protecting the quality of groundwater resources and reducing depletion is a global concern (Famiglietti, 2014). Shallow freshwater aquifers are an important water source for domestic water supplies, but domestic well owners often compete with larger agricultural and industrial water users (McIntosh and Ferguson, 2019; Perrone and Jasechko, 2019). In some areas around the world the amount of groundwater withdrawal is unsustainable, and wells are being drilled deeper and deeper to reach fresh and brackish water resources (Jasechko and Perrone, 2021). As the depth of water wells increases, these wells may approach existing oil and gas activities (DiGiulio and Jackson, 2016; Ferguson et al., 2018). The zone or interface between oil and gas activities and overlying potable groundwater resources is known as the intermediate zone (Dusseault and Jackson, 2014). The thickness and permeability of the Intermediate Zone along with natural and induced hydraulic gradients can influence the potential transport of deeper fluids, such as fluids injected for oil and gas activities, mining activities or natural saline formation waters, into freshwater aquifers possibly affecting drinking water sources (Cherry et al., 2014; Ferguson et al., 2018; Perrone and Jasechko, 2019). Yet, the Intermediate Zone is rarely characterized because it is often beyond the depth of fresh to brackish water resources and shallower than hydrocarbon reservoirs. Characterizing the Intermediate Zone is critical to ensuring water security in regions with oil and gas activities (Dusseault and Jackson, 2014) and protecting freshwater aquifers for future water security (Perrone and Jasechko, 2019).

The lack of adequate data for the Intermediate Zone leads to uncertainty regarding the groundwater flow direction along with the potential for deeper fluids to migrate across this interface to shallower aquifers (Dusseault & Jackson, 2014). There are many pathways for fluids to migrate throughout the Intermediate Zone such as naturally occurring geological features (Baytok, 2010). In areas of lower permeability, faults and fractures can help fast track fluid migration (Baytok, 2010; Gassiat et al., 2013; Bense et al., 2016), while in areas of higher permeability the fluids can move through that unit at a faster rate than areas with lower permeabilities, they also do not need the aid of faults and fractures (Horner and Hasegawa, 1978; Baytok, 2010). While there are many different natural geological pathways, there are also anthropogenic pathways such as leaky wellbores which can include poor cement jobs, leaky annuluses, and poor abandonment jobs (Rivard et al, 2019).

Even with the presence of high permeability pathways, fluids need to have a "driving force" (i.e., upward hydraulic gradients) for fluid migration from deeper units, through the Intermediate Zone into shallower formations (Freeze and Cherry, 1979). Injection of unwanted or waste fluids into a high permeability reservoir is a common way to dispose of these fluids (Patton, 2018) and this action could cause upward fluid migration because of an upward hydraulic gradient sustained by increased pressures that are larger than natural hydraulic gradients caused from the recharge of confined aquifers at higher elevations (Irwin and Morton, 1969). When pressure is increased the hydraulic gradient is increased along with the hydraulic heads, causing fluids within the formation to flow out of the area of increased or high hydraulic head to areas of decreased or low hydraulic head which could be upwards in this case (Flewelling and Sharma, 2014). Pressure induced upward migration is often overlooked by many when considering the protection of shallower freshwater aquifers (Irwin and Morton, 1969; Rivard et al, 2019) and with possible pathways for migration this is a process that should be investigated. It is possible that the sustained injection of wastewaters into high permeability disposal formations could cause contamination of freshwater aquifers over time through upward migration in the presence of permeable pathways, such as missing cap rocks and leaky wellbores (McIntosh and Ferguson, 2019).

The Intermediate Zone in the study area in Saskatchewan (Figure 1-1) is not well characterized and we lack important data to facilitate freshwater protection (McIntosh and Ferguson, 2019). In Saskatchewan, the Mannville Group lies beneath the Intermediate Zone in most areas and is found between depths of roughly 600m to 1200m in the study area. The Mannville Group is mainly made up of sandstones and in western Saskatchewan it contains members that have oil and gas present (Mossop and Shetsen, 1994). As of late, the Mannville Group has commonly been used as a disposal formation for produced fluids (Jellicoe et al, 2021). Above the Mannville Group lies the Intermediate Zone which is made of interbedded shales and sandstones with shales of the Milk River/Lea Park Formation and the Colorado Group with shales being the more dominate lithology along with the Viking Formation which is an oil and gas producing formation in small areas in Saskatchewan (Leckie et al., 1994). Areas of higher permeability may be associated with large faults in the Williston Basin, most of which are associated with dissolution of the Prairie Evaporite and these faults can form anywhere in the sediments above (Horner and Hasegawa, 1978). Abandoned and leaky wellbores may also provide a pathway for leakage from the Intermediate Zone to the shallower freshwater aquifers because wellbores can corrode, and cements can degrade over time (Adelman and Duncan, 2011) (Figure 1-2). Perra (2020) noted that in the Southeast Saskatchewan region alone there are 297 abandoned wells within two kilometers of 476 wells which are either used for enhanced oil recovery or disposal of saline fluids.

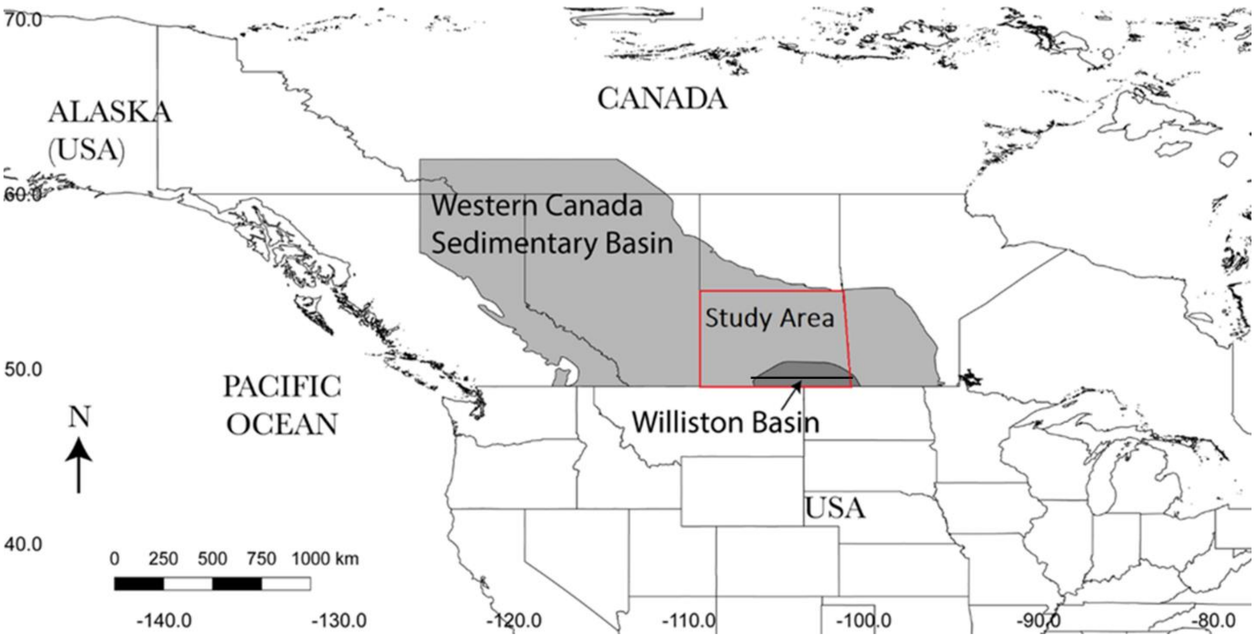

Figure 1-1: Location of the study area in North America along with extent of the Western Canada Sedimentary Basin and the Canadian portion of the Williston Basin (Wright et al. 1994)

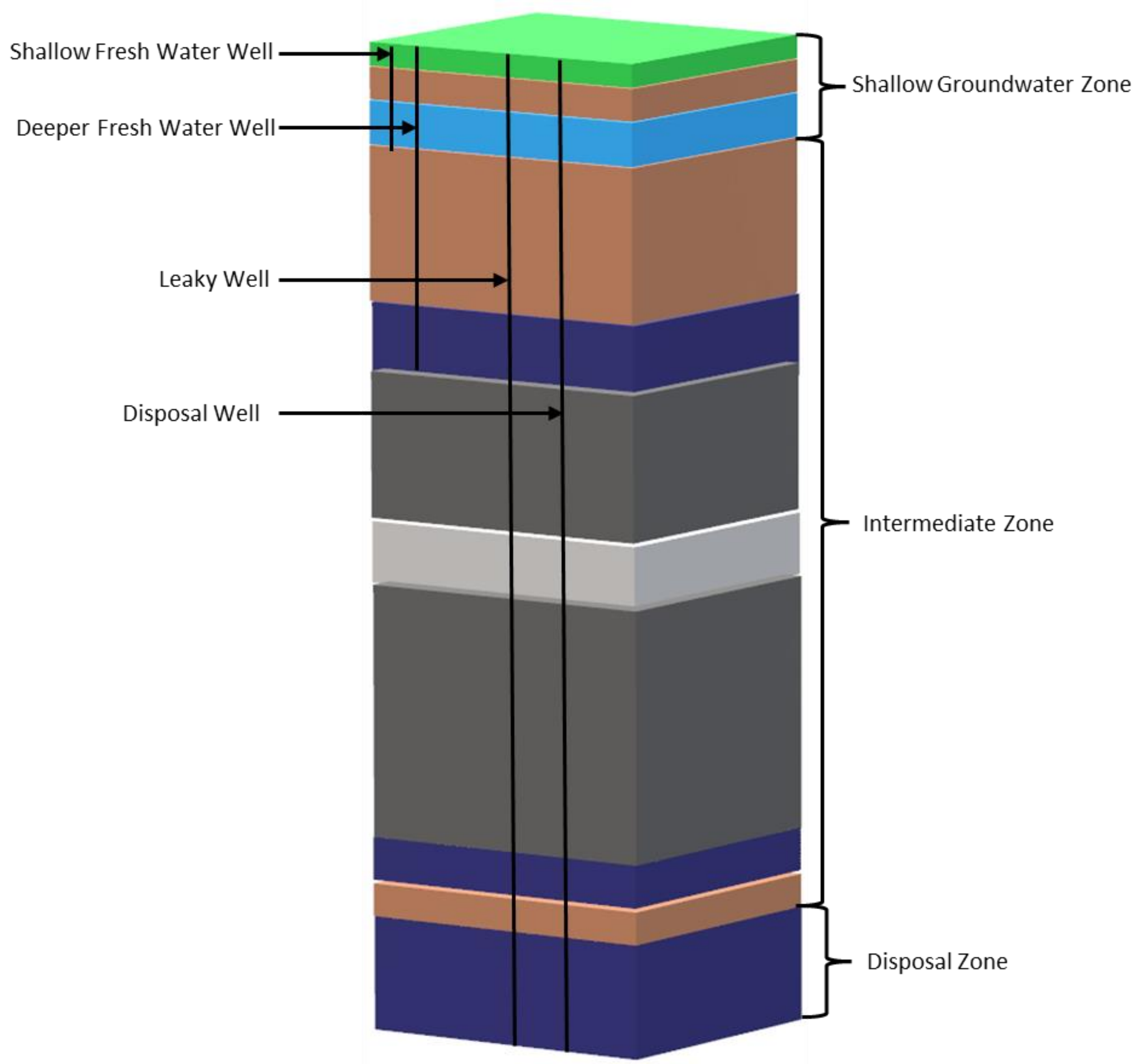

Figure 2-2: Intermediate Zone conceptualized with disposal zone, fresh waters wells and the leaky well pathway for contamination/fluid movement.

1.1 Research Objectives

This study examines the Intermediate Zone in Saskatchewan's portion of the Western Canada Sedimentary Basin along with the Mannville Group, which is often one of the uppermost units exploited by the oil and gas industry, to assess the level of protection the Intermediate Zone provides for the overlying freshwater aquifers. The specific objectives of this study is to assess whether injection into underlying disposal zones can cause upward formational fluid migration thru the Intermediate Zone and into the freshwater aquifers above. The following tasks were completed to determine this:

- Characterize and define available porosity, permeability, and chemistry data of the Intermediate Zone.
- Determine the hydraulic heads and hydraulic gradients within the Intermediate Zone to examine possible over pressuring and flow patterns.
- Review/synthesize how to represent leaky wells in a numerical model to determine their role in fluid movement.
- Model the role of the horizontal distance between the injection well and leaky well to determine how this distance afects water movement.
- Determine the protection provided from the Intermediate Zone shales and the Viking Formation.

Hydrogeological properties were collected from available core measurements and drill stem tests (DSTs). DSTs were analyzed to estimate hydraulic head values, which were then compared to hydraulic heads present in shallower formations, including aquifers containing potable groundwater supplies to determine where the Intermediate Zone is a sink or source area for waters.

1.2 Thesis Structure

Chapter 2 provides an overview of the study area and summarizes the relevant geology, geochemistry, and hydrogeology. Chapter 3 describe the data analyses including the data sources and the procedures for assessing the DSTs. It also details what information the data can provide about the study area. Chapter 4 covers the modeling done to predict the changes in hydraulic heads and the role the leaky well plays in fluid migration between aquifers and contains the results of the modeling, and Chapter 5 draws out interpretations from the empirical data and the model’s predictions. A summary, main conclusions and recommendations from the study can be found in Chapter 6.

2.0 Geology, Geochemistry, Hydrogeology and History of the Study Area

2.1 Geology

The Western Canada Sedimentary Basin (WCSB) covers portions of British Columbia, Alberta, Saskatchewan, and Manitoba (Mossop and Shetsen, 1994). The basin is divided into distinct parts that represent the two different tectonic phases within the basin, one on the plate margin dominated by carbonate rocks and the other being the foreland basin dominated by clastic rocks (Mossop and Shetsen, 1994). The Paleozoic to Jurassic platform succession is mainly dominated by carbonate rocks and was deposited on the stable craton next to the margin of North America (Mossop and Shetsen, 1994). The mid-Jurassic to Paleocene sediments of the foreland basin are mainly dominated by clastic rocks (Mossop and Shetsen, 1994).

The important geological strata in the Saskatchewan stratigraphic column (Figure 2-1 & Figure 2-2) for this investigation extends from Devonian-age groups upwards to the top of the Cretaceous Period. The Devonian Elk Point Group is the source of extensive economically important potash deposits in Saskatchewan (Meijer Drees, 1994). Moving upwards in the stratigraphic column in Saskatchewan there are Devonian carbonates overlying the potash deposits that have the potential for oil and gas development along with the clastic Bakken Formation which is a major oil and gas formation in Saskatchewan (Meijer Drees, 1994). Carbonate-dominated strata of Mississippian age overly the Devonian-age strata, but are absent in some areas of Saskatchewan, mainly in the central parts of the province. Above these lie the Jurassic strata which also follow the same pattern as the Mississippian strata (i.e., they are mostly missing in the central areas). Both units have the potential for oil and gas activities (Richards et al., 1994). Next are the sandstones of the Lower Cretaceous Mannville Group and above those is a mixture of Lower Cretaceous shales and less common sandstones followed by the Upper Cretaceous(Hayes et al., 1994; Reinson, 1994). There are formations or units within both the Lower Cretaceous and the Upper Cretaceous that can be oil and gas producers with the latter being the more dominant in the shale zones (Hayes et al., 1994; Reinson, 1994).

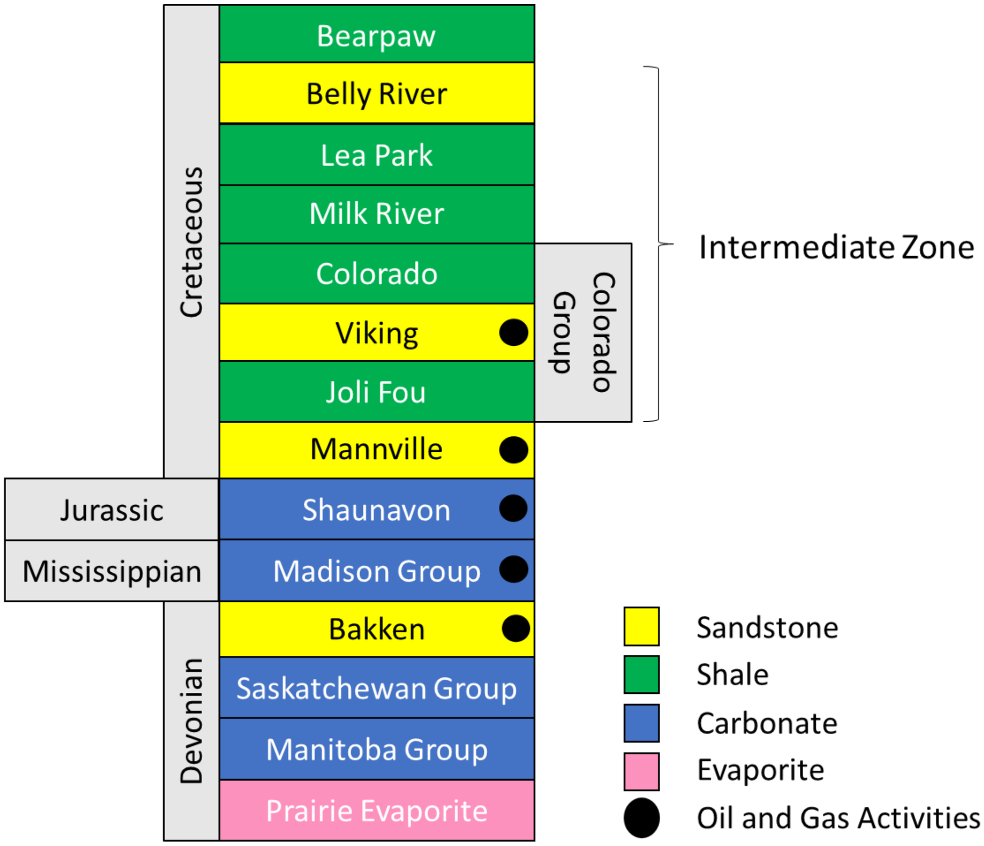

Figure 3-1: Saskatchewan Stratigraphic Chart detailing the Intermediate Zone and its proximity to key Saskatchewan Formations and Groups.

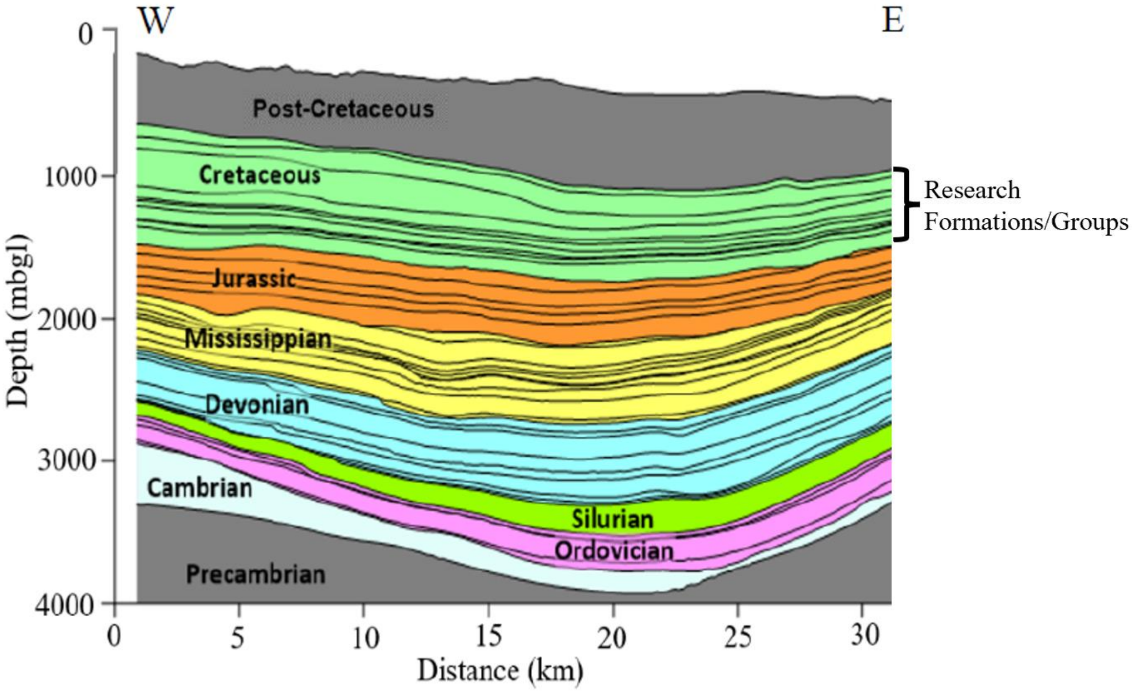

Figure 4-2: Cross Section of Western Canadian Sedimentary Basin and the Research Formations/Groups across the study area with approximate depths (after Jellicoe, 2021). The black line on Figure 1-1 represents the location of the cross section.

2.2 Geochemistry

2.2.1 Sources of Salinity

Understanding the distribution of saline waters and the source of salinity within a sedimentary basin are both important for constraining fluid and solute transport (McIntosh and Walter, 2005) (Figure 2-3). Total dissolved solids (TDS) is the measure of the dissolved combined content of all inorganic and organic substances present in a liquid and is commonly measured in parts per million (ppm) whereas salinity is just the measure of dissolved salt. The USGS (2020) categorizes water into four groups based on their salinity concentrations measured in ppm. The categories are fresh water, which contains less than 1000 ppm; slightly saline water, which contains 1000 ppm to 3000 ppm; moderately saline water, which contains 3000 ppm to 10000 ppm; highly saline water, which contains more than 10000 ppm to 100000 ppm. Brines are also noted to have concentrations greater than 100000 ppm (USGS, 2020). Seawater salinity tends to fall around the 35000 ppm mark and is classified but the USGS (2020) in the highly saline waters category.

In addition to TDS there are several geochemical tracers that are helpful in examining and analyzing sources of salinity. Walter et al. (1990) and Carpenter (1978) notes that Cl/Br and Na/Br molar ratios are widely used in many hydrogeological studies to trace sources of salinity. For example, seawater has a Cl/Br molar ratio of 655, while groundwater affected by halite dissolution has a Cl/Br ratio greater than 1000. Formation waters affected by dissolution of halite (NaCl) will have equal concentrations of Na and Cl with a molar ratio of 1:1 (Hanor, 1994; Abdalla, 2015).

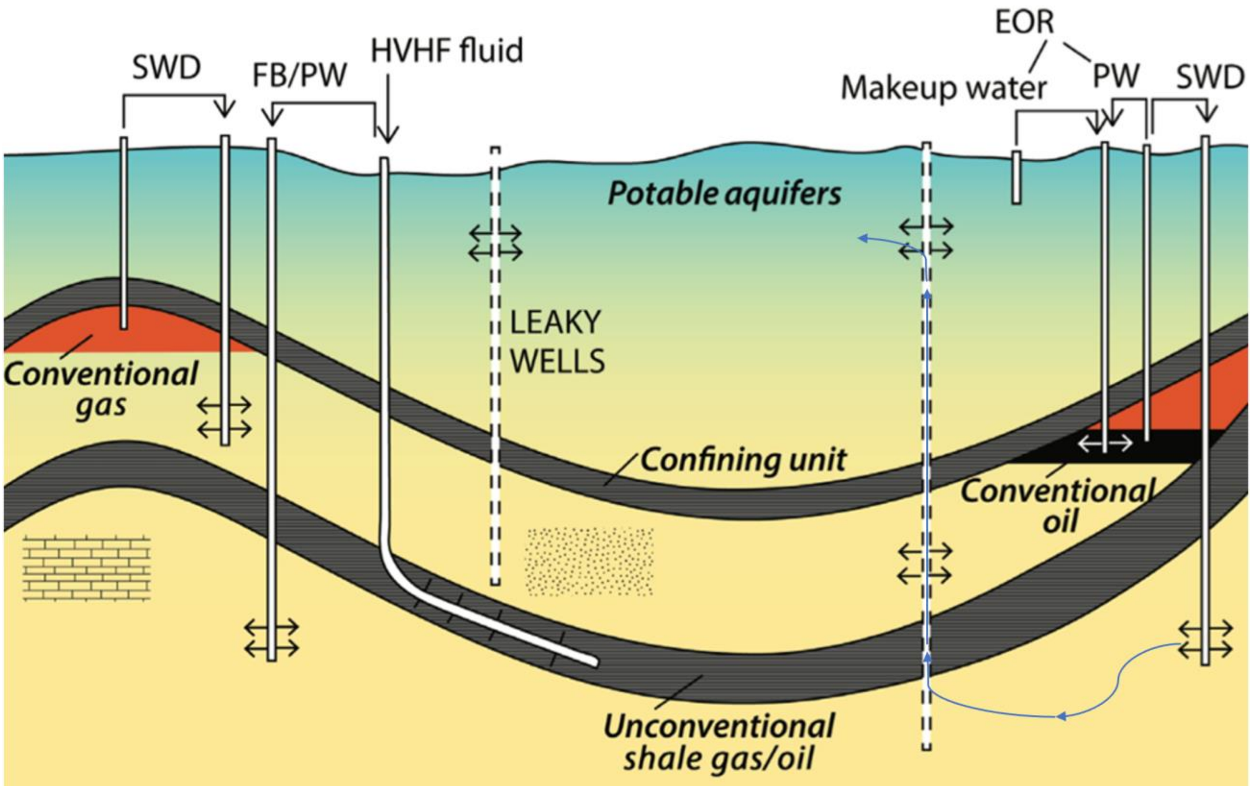

Figure 5-3: Possible contamination sources and pathways from oil and gas activities (after McIntosh and Ferguson, 2019) with the blue arrows showing a possible pathway of water movement from a disposal well to a leaky well and into possible freshwater aquifers above.

2.2.2 Salinity Sources in the Western Canadian Sedimentary Basin

There are two main sources of salinity within the WCSB: paleo evaporated seawater (Richard et al., 2011) and dissolution of evaporites (Chien and Lautz, 2018). Some of the formations within the Intermediate Zone were deposited in marine environments (Alberta Energy Regulator, 2020). During sediment deposition, evaporated sea water was entrapped within the formations and has been diagenetically altered through water-rock reactions over geologic time (Alberta Energy Regulator, 2020). The evaporated seawater was enriched in Na, Cl, and Br (Richard et al., 2011).

The second main source of salinity within Saskatchewan's portion of the WCSB is the dissolution of halite (Wittrup and Kyser, 1990; Grasby and Chen, 2005: Grasby et al, 2012; Chien and Lautz, 2018). Large-scale salt dissolution has been invoked to explain brine chemistry in a variety of settings in sedimentary basins (McIntosh et al., 2011). Connolly et al (1989) suggests that halite dissolution can account for the high salinity of formational fluids in other parts of the WCSB.

The TDS of formation waters in the WCSB mainly increases with depth and towards the center of deposition of each formation (Palombi, 2008). TDS values in lower aquifers can be higher than 300,000 ppm but as the formations get closer to surface this value decreases greatly. The Mannville Group has an average pore water TDS of 65,000 ppm and the Viking Formation has an average TDS of approximately 15,000 ppm (Bachu and Hitchon, 1996). The waters containing higher TDS (300,000 ppm and greater) have sometimes been injected into the Mannville Group for disposal.

2.2.3 Mechanisms for Salinity Migration in the Western Canadian Sedimentary Basin

A mechanism for saline fluids to migrate within the basin, especially the Intermediate Zone, is related to oil and gas activities (Lautz et al, 2020). McIntosh and Ferguson (2019) note that sources of contamination from oil and gas activity can come from high volume hydraulic fracturing, surface spills and leaky wellbore casings. Leaky wellbore casings are likely a widespread problem in the oil and gas industry, and these can be a pathway for fluid migration if there is a high permeability and upward gradient (McIntosh and Ferguson, 2019). The injection of fluids for enhanced recovery and disposal purposes may lead to contamination of groundwaters (McIntosh and Ferguson, 2019). McIntosh and Ferguson (2019) explain that many oil and gas wells were drilled before proper well-integrity regulations. While most of these wells have now been abandoned, they may provide potential leakage pathways into shallow potable aquifers (McIntosh and Ferguson, 2019). Perra et al. (2020) provide a more detailed analysis on well integrity and plug placement after abandonment. The continued injection of disposal fluids can cause over pressuring, which may force fluids upwards through leakage pathways and into the Intermediate Zone and possibly overlying shallow aquifers.

2.3 Hydrogeology

The regional scale flow of formation waters within the WCSB in Saskatchewan is a key element to better understanding the Intermediate Zone. Most regional scale flow mapping in the WCSB has been done using DSTs and geochemical analyses (Bachu and Hitchon, 1996; Palombi, 2008; Melnik, 2012). Regional recharge to the WCSB occurs in the west to southwest regions at relatively high altitudes with discharge in the eastern and northeastern regions in low lying areas of Manitoba and along outcrops near the edge of the Precambrian Canadian Shield (Bachu and Hitchon, 1996).

Above the Precambrian shield-type rocks, lie basal sandstone aquifers overlain by a series of Paleozoic carbonates that are generally considered an aquifer system with the Prairie Evaporite (confining unit) interbedded in parts (Bachu and Hitchon, 1996). Above this aquifer system is another series of Mesozoic and Cenozoic sandstone aquifers and shale aquitards (Bachu and Hitchon, 1996).

Within the Mesozoic and Cenozoic part of the sequence, the Mannville Group is an aquifer system that has a southwest to north-easterly regional groundwater flow (Figure 2-4), with hydraulic head values ranging from 1000 m in the southwest to 400 m in the northeast by the Manitoba escarpment (Bachu and Hitchon, 1996). The Mannville Group has been extensively developed by the oil and industry and a large amount of excess water has been injected into the formation (Jellicoe et al., 2021; Figure 2-5). The Joli Fou Formation acts as an aquitard between the Mannville Group and the Viking Formation which is also an aquifer (Bachu and Hitchon, 1996). The Viking Formation (Figure 2-6) is the shallowest aquifer that is not considered a freshwater aquifer anywhere in Saskatchewan; there is oil and gas activity in the Viking Formation and groundwater flow is more eastward trending (Bachu and Hitchon, 1996). Above the Viking Formation, is the Colorado Group and the Lea Park/Milk River Formation which are mainly comprised of shales and some sandstones (Leckie et al., 1994). These shaly-units act as aquitards and may impede the upward migration of formation waters (Leckie et al., 1994). Within the Upper Cretaceous lies the Belly River (Judith River) Formation, which is the deepest potable freshwater aquifer in some areas of the province (Dawson et al., 1994; Ferris et al., 2017). Above the Belly River Formation, the Bearpaw Formation is the youngest Cretaceous aquitard in the Province of Saskatchewan (Dawson et al., 1994).

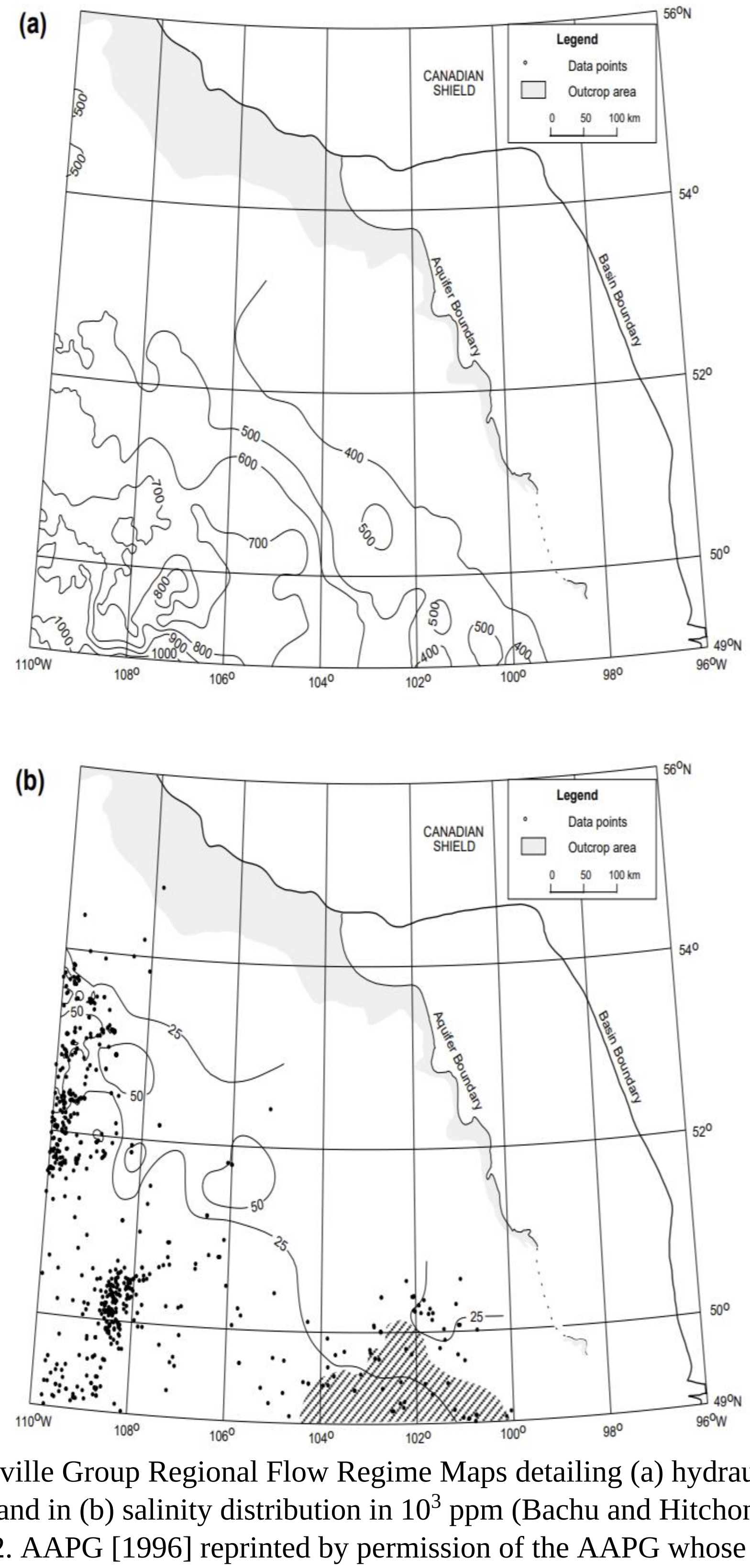

Figure 6-4: Mannville Group Regional Flow Regime Maps detailing (a) hydraulic head distribution in m and in (b) salinity distribution in 10^3 ppm (Bachu and Hitchon, 1996, AAPG Bulletin v.80 no.2. AAPG [1996] reprinted by permission of the AAPG whose permission is required for further use)

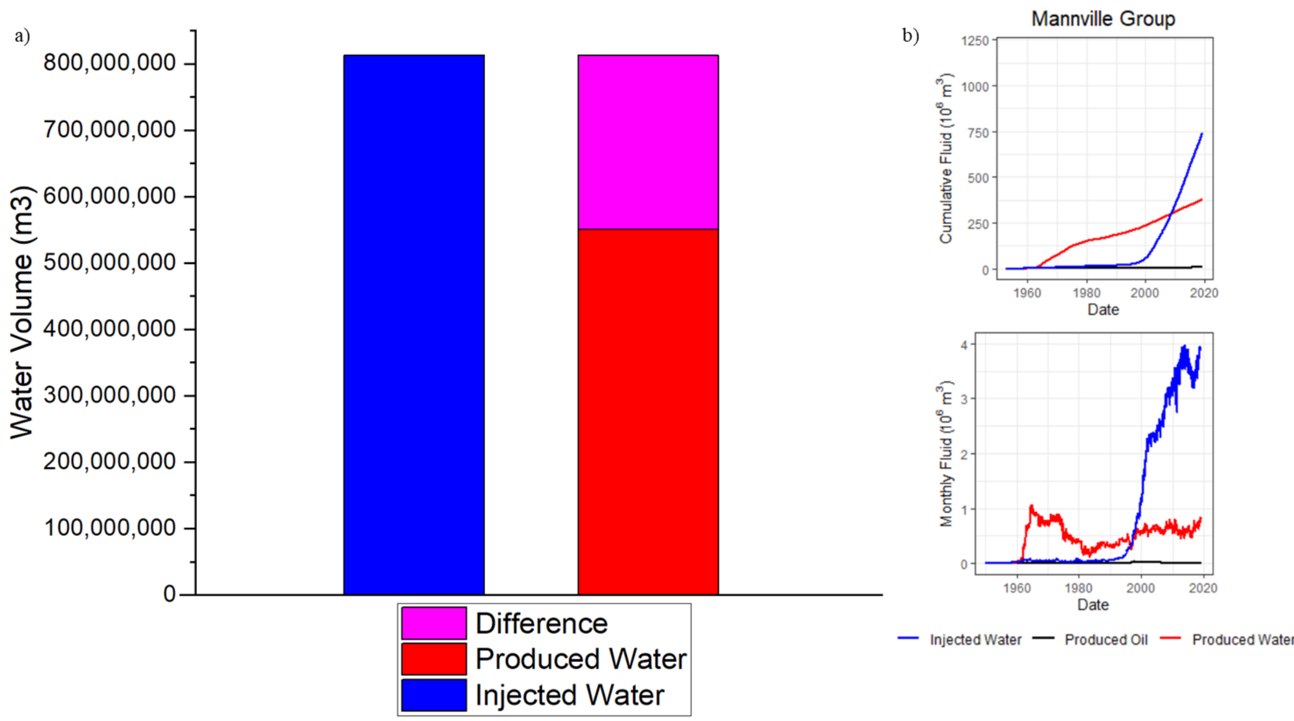

Figure 7-5: Mannville Group Water Volumes a) detailing the amount of water that has been injected and produced and b) detailing the timeframe over which this water has been injected and produced (after Jellicoe, 2021)

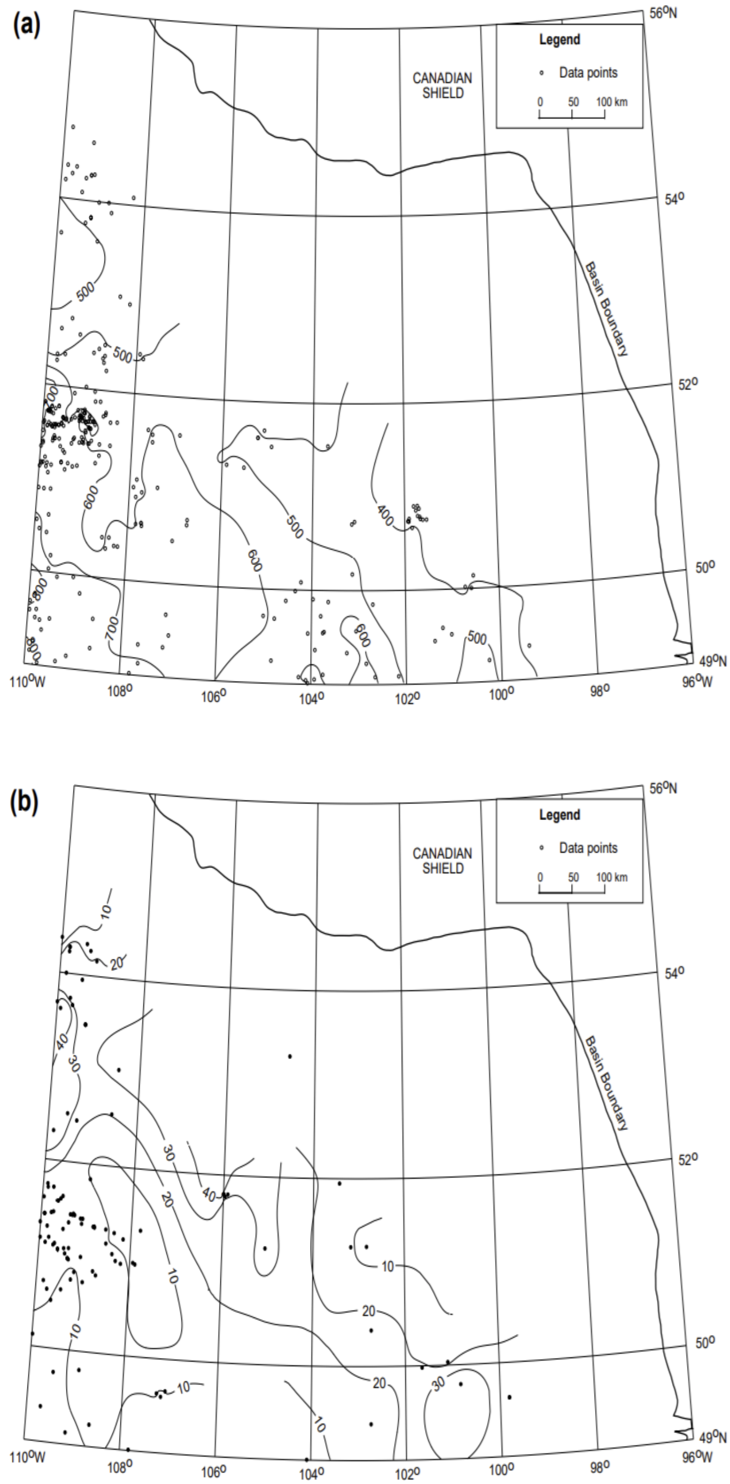

Figure 8-6: Viking Formation Regional Flow Regime Maps detailing (a) hydraulic heads distribution in m and in (b) salinity distribution in 10^3 ppm ((Bachu and Hitchon, 1996, AAPG Bulletin v.80 no.2. AAPG [1996] reprinted by permission of the AAPG whose permission is required for further use)

2.4 Saskatchewan Oil and Gas History

Oil and gas history in Saskatchewan can be traced back to the 1880s with the first, unsuccessful drilling of a vertical natural gas well in the Regina area. Exploration for oil and gas continued sporadically throughout the years until the discovery of oil in 1943 in the Lloydminster area. However, most of the major pools were discovered after extensive exploration in the 1950s to the 1960s (Government of Saskatchewan, 2008). In Saskatchewan, there are four main areas where oil production is significant, as follows: Lloydminster, Kindersley-Kerrobert, Swift Current, and Weyburn-Estevan (Hanly, 2006). The oil in the Lloydminster area is heavy oil and has mainly comes from the Viking Formation and the Mannville Group (Government of Saskatchewan, 2008). Other hydrocarbon-producing areas of the province produce mainly light and medium oil (Government of Saskatchewan, 2008) and/or natural gas, mostly from formations which underlie the Mannville Group, with the notable exception of the Viking Formation.

The use of horizontal well technology was first considered in Saskatchewan in the early 1980s for a laterally extensive pool of oil in the Lloydminster area (Saskatchewan Research Council, 2019). In 1987 the first horizontal well was drilled in the Lloydminster area to extract heavy oil and this well was a success. After that, the use of horizontal wells spread across the province and enabled producers to reach previously untapped reservoirs (Saskatchewan Research Council, 2019). Even before the time that horizontal wells were being developed, new enhanced oil recovery methods (i.e., waterflooding and gas-flooding) were also being introduced in Saskatchewan (Saskatchewan Research Council, 2019). These technologies have increased production anywhere from 20-40% depending on the field (Howes, 1988). The Government of Saskatchewan offers incentives to producers that use enhanced oil recovery methods (Government of Saskatchewan, 2005), as this allows for the use of previously drilled wells to be utilized instead of drilling new wells. Additionally, incentives for waterflooding were introduced in 2019 which allows producers to save money for drilling wells specifically designed for waterflooding or the conversion of an older producing wells to waterflooding injection well (Government of Saskatchewan, 2019).

3.0 Data Collection & Synthesis

3.1 Data Collection

To evaluate whether fluid injection into the Mannville Group could cause fluids to migrate upwards through the Intermediate Zone and into overlying shallow aquifers, data from the Intermediate Zone was compiled and analyzed. Well data was acquired through AccuMap (2020), which is a data management software created by IHS Markit. The Integrated Resource Information System (IRIS) (www.saskatchewan.ca/iris), an online database managed by the Government of Saskatchewan's Ministry of Energy and Resources was used to acquire additional data. AccuMap collects and digitizes oil and gas data from across the WCSB into one integrated database. Querying this dataset by formation, area, well type, and other options allowed for the creation of a collection of data specific to this study. AccuMap was used to collect data regarding DSTs, producing zones, well modes (which include operating, suspended, abandoned, proposed, drill & cased and injection), permeability, porosity, injection and production data, and fluid chemistry. The AccuMap data was taken from across Saskatchewan’s oil and gas region for strata from the Mannville Group upwards to the Belly/Judith River Formation. Data available for core porosity and permeability across the entire study area were analyzed; however, data collected for the DSTs were only be analyzed if the test was completed in the 1990’s or later, to allow for the most recent values in the study area. Further, only tests of good quality, with no failures or errors, were selected. IRIS is an integrated, simple portal for industry members to submit applications, permits, and required data applying to oil and gas wells and processes. It enables access to all submitted data, documents, and reports. IRIS was used in this study for obtaining well specific data, which included DST reports. Shallow fresh groundwater data including water levels/water table were retrieved from the Saskatchewan Water Security Agency (SWSA).

3.2 Drill Stem Test Analysis

The magnitude and direction of fluid fluxes within the Intermediate Zone were estimated using data compiled from AccuMap and IRIS. After extracting permeability and porosity data from AccuMap the data was organized by formation and equivalent formation, to account for differences in naming conventions in the database. Next, the data was spatially and statistically analyzed for trends which could include areas of outlying values (high or low), areas of missing data, and general formational trends.

3.2.1 Pressure and Hydraulic Head from DSTs

DSTs were used to estimate the permeability and pressure. Directional flows were determined by analyzing DSTs and comparing them to known hydraulic head values in shallower known aquifers. Pressure data were compiled for the Mannville Group and the Viking Formation from the IRIS database. Following an initial check for data completeness, criteria outlined by Melnik (2012) were used to eliminate unsuitable DSTs. This culling process requires the following: a test interval of less than 50 m; shut in times long enough to allow for stabilization, as the longer the shut-in time the better data representation; proper recovery with no leaks or failures; suitable water recovery (mud and oil recoveries will not be used).

The DST Horner analysis (Bredehoeft, 1965) was undertaken on the useable DSTs and aquifer pressure (P) was estimated. Aquifer pressure (P) was estimated using a Horner semi-log plot (Figure 3-1) by plotting $\Delta t/(t_o + \Delta t)$ vs. P where t_o is the shut-in time and Δt is the time since the last shut in period. To properly estimate the value the line of best fit must be matched up to the late-time data, as the effect of reduced permeability (skin effect) is diminished (Bredehoeft, 1965). To properly estimate this the late time data is best suited for the line as skin effects, which are effects from the well sides itself, are least problematic here (Borah, 1992). The DST test assumes radial flow and therefore produces a value for permeability in the horizontal direction and not the vertical (Bredehoeft, 1965). To convert the aquifer pressure into a hydraulic head the pressure after the second shut in period that value was converted back into a pressure head value by dividing it by fresh water density and gravity. Finally, that value was added to the subsea level recorder depth to get a hydraulic head value for that formation. Comparing these hydraulic head values to known hydraulic head values of shallower aquifers above was undertaken to identify areas where the Intermediate Zone formations are sinks or sources of water.

Hydraulic gradients were determined from the difference in hydraulic head values at given points and the distance between those formations in the stratigraphic sequence. From these gradients, directions of groundwater flow were determined within and below the Intermediate Zone. The magnitude of the groundwater flow was determined using Darcy's Law and the permeability and porosity data that will be extracted from core and DSTs.

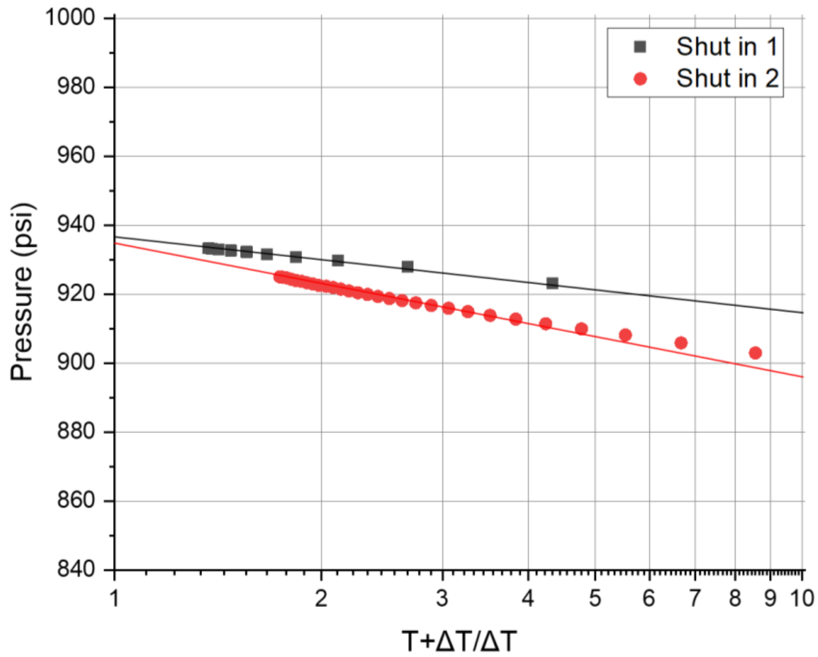

Figure 9-1: Horner Semi-Log Plot used in the Analysis of DSTs to determine pressures in pounds per square inch (psi) with High Data Quality.

3.2.2 Permeability from DSTs

The DST Horner analysis (Bredehoeft, 1965) was undertaken on the useable DSTs and permeability (k) was estimated. Permeability (k) was calculated using the following equation:

$$k = (T \times \mu)/B \qquad (3.1)$$

Where:

- μ is the fluids viscosity (Pa s).
- T is the transmissibility (m^2s/kg).
- B is the formation thickness (m).

3.2.3 Chemistry Analysis

Chemistry data available includes resistivity, density, pH and concentrations of major cations and anions. To analyze the geochemistry data from the Intermediate Zone the first step is to perform a charge balance on the cation and anion data to ensure the data is of good quality (Fritz, 1994). The charge balance is the summation of the cations subtracted by the summation of the anions divided by the summation of the cations added to the summation of the anions. The value is then multiped by 100 and anything under 5% is considered to be acceptable (Fritz, 1994).

After that is complete, any wells with errors marked in them by the testing company on or off site will also be removed from the chemistry dataset as the values may not be accurate.

3.3 Data Availability

Within the Intermediate Zone there were a total of 3,782 permeability/porosity analyses, with 7 from the Belly River Formation, 86 from the Milk River Formation, 114 from the Colorado Group, 1103 from the Viking Formation, 311 from the Joli Fou Formation and 2161 analyses from the Mannville Group. From these queries it was clear that the Intermediate Zone had data availability issues.

The Mannville Group and below the Intermediate Zone and the Viking Formation which is within the Intermediate Zone have abundant data across the study area because of their exploitation by many oil and gas companies as well as mining companies. However, formations and/or groups that are not production or injection targets have not been sampled or tested extensively (Figure 3-2). Besides the Mannville Group and the Viking Formation, the Joli Fou Formation (which is predominantly shale) has the most abundant data were most likely due to the fact it lies between formations that play a role in oil and gas activities. Higher up in the stratigraphic column less data is present; e.g., the Bearpaw Formation has no queried data available in the study area.

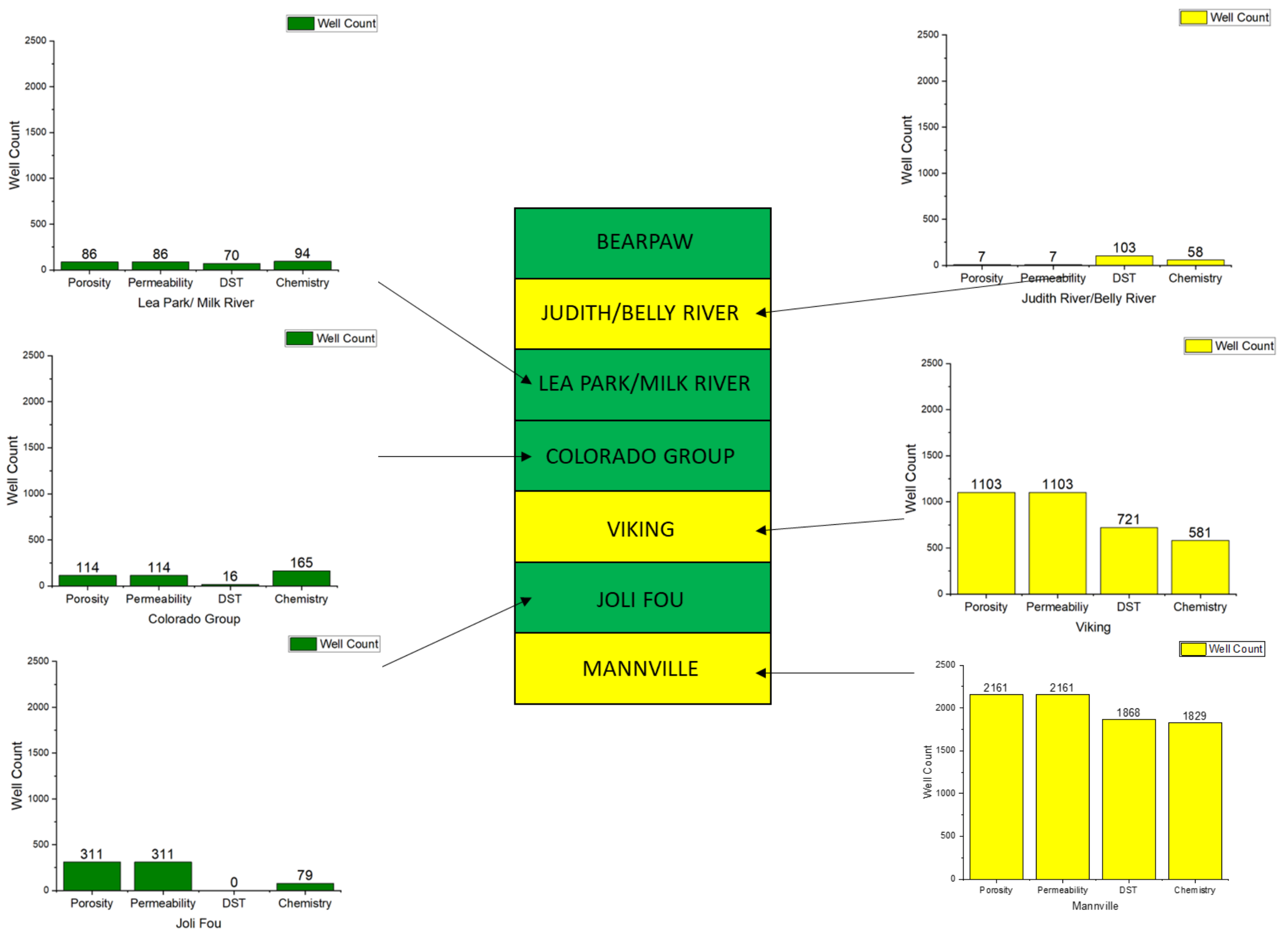

Figure 10-2: Intermediate Zone data well counts for porosity, permeability, DST, and chemistry detailing the lack of data outside of economically exploited formations/groups.

3.4 Geochemistry

3.4.1 Data Overview

Water chemistry data was queried from IHS AccuMap from the Mannville Group and the overlying Intermediate Zone for analysis. The data was then culled based on charge balance; if the charge balance error was greater than 5% the data was excluded. Within the Intermediate Zone there were a total of 263 chemistry analyses, with 3 from the Belly River Formation, 23 from the Milk River Formation, 85 from the Colorado Group, 90 from the Viking Formation, 18 from the Joli Fou Formation and 44 analyses from the Mannville Group. Figure 3-3 shows the distribution of water chemistry samples across the study area.

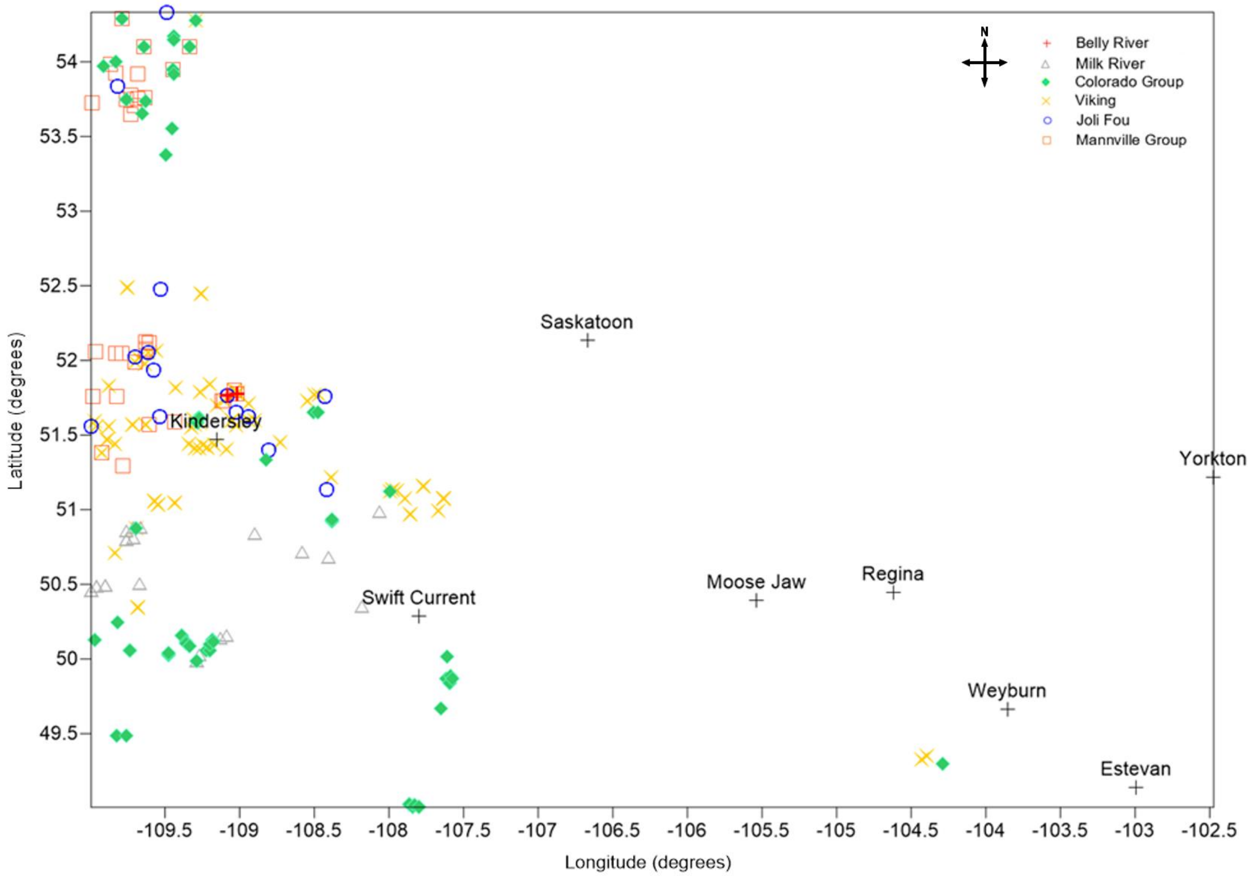

Figure 11-3: Spatial Distribution of Intermediate Zone Water Sample Data across the study area, detailing lack of data distribution in the central and eastern portions of the study area.

3.4.2 Water Quality

All salinity values of groundwater within the Intermediate Zone fall above what the USGS (2020) classifies as fresh water (< 1,000 ppm TDS) and are mostly brackish to saline (>1,000-100,000 ppm TDS; Figure 3-4). There are slightly higher salinity values in the western portion of the study area compared to the middle, but most of the data is concentrated in the western part of the study area (Figure 3-5). In the brackish (>1,000 ppmTDS) to seawater salinity (~35,000 ppm TDS) category there are waters mainly from the Viking, Belly/Judith River, and Milk River formations, along with the Colorado Group. The few samples that are classified as brines (>100,000 ppm TDS) are from the Mannville Group, Viking Formation, Milk River Formation, Joil Fou Formation and Colorado Group. Overall, the Intermediate Zone waters are generally brackish to near seawater salinity with a few samples with higher salinity values.

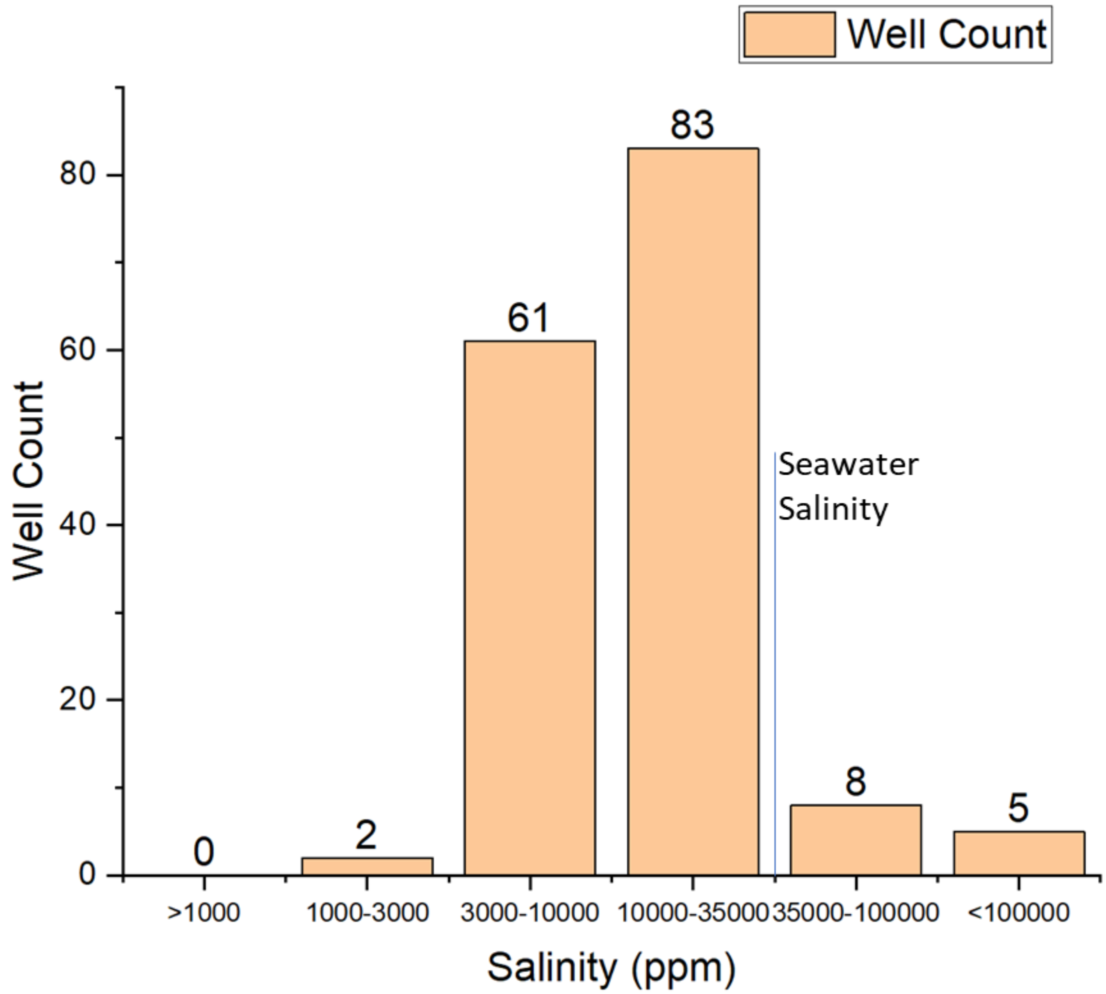

Figure 12-4: Intermediate Zone Well Water Salinity Counts separated into USGS (2020) classification ranges for salinity.

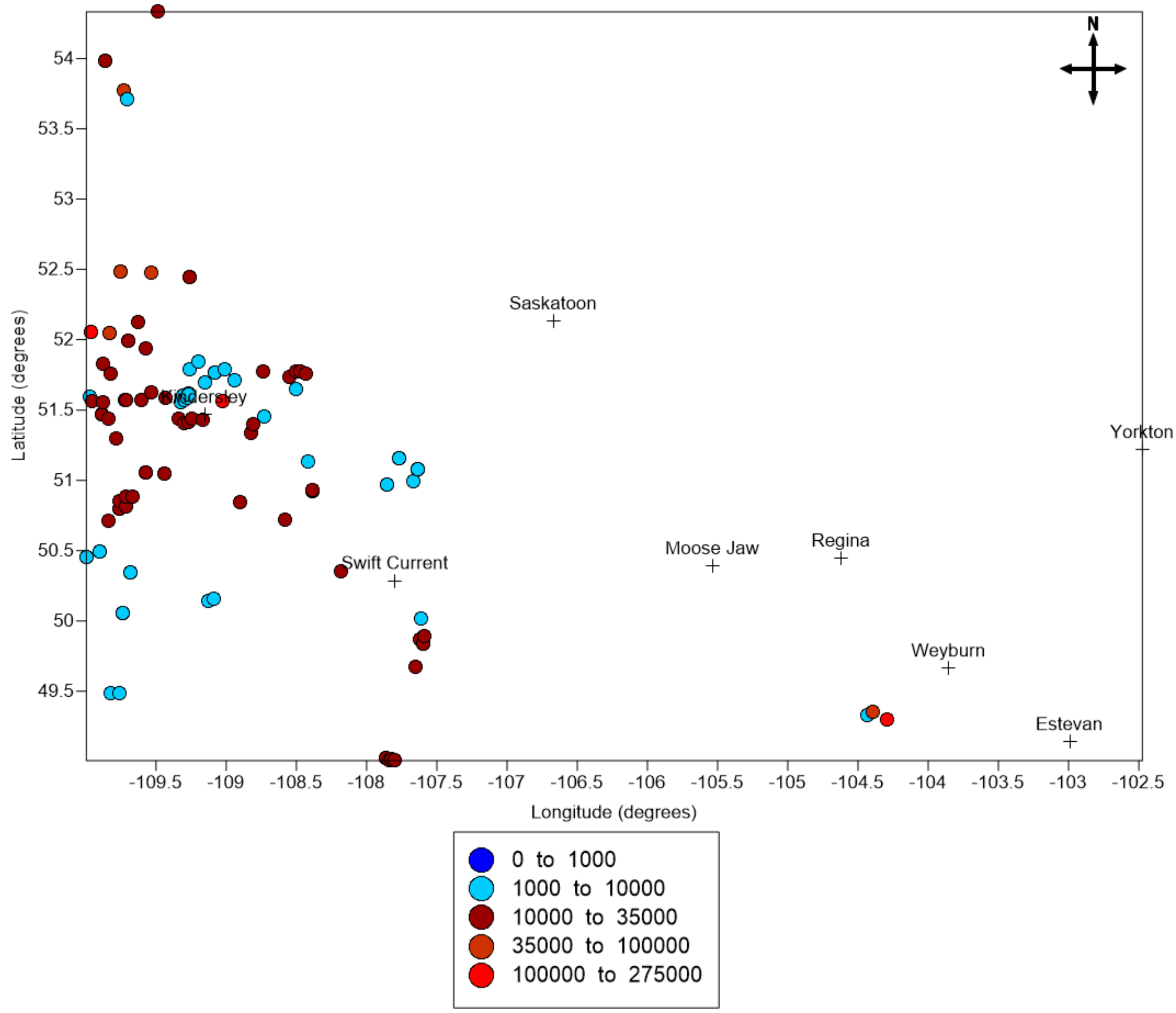

Figure 13-5: Spatial Distribution of Groundwater Salinity Values (ppm) broken down into USGS (2020) classification ranges for Salinity in the Intermediate Zone Waters across the Study Area.

Intermediate Zone waters are dominated by sodium and potassium with a few samples from the Colorado Group that are calcium type waters (Figure 3-6). The waters within the Groups/Formations within the Intermediate Zone are mainly of the sodium chloride type with some sodium bicarbonate type waters or a mix of the two types.

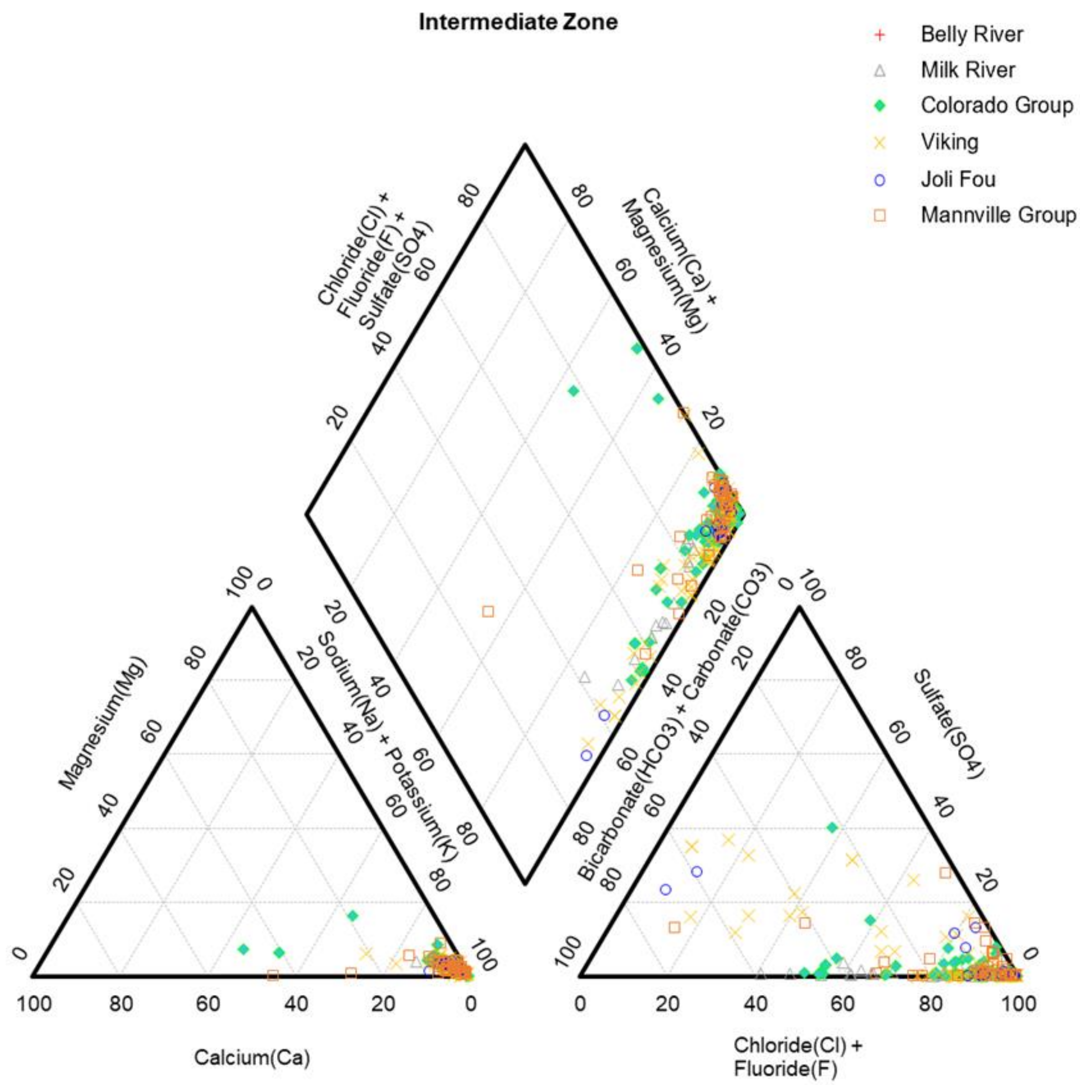

Figure 14-6: Intermediate Zone Piper Plot

Most of the data from the Intermediate Zone have a molar Na:Cl ratio ~ 1:1 with Na and Cl concentrations that fall between freshwater, from a monitoring well in the Mannville Group (Saskatchewan Water Security Agency, 2020), and seawater (Figure 3-7). A few of the Intermediate Zone samples, with salinities above seawater, also have Na:Cl ratios ~ 1:1 and similar Na and Cl concentrations as groundwater that dissolved halite in the Prairie Evaporite Formation (Woroniuk et al., 2019; Wittrup and Kyser, 1990). The most dilute samples, with Cl concentrations less than 0.1 mol/L tend to have Na:Cl ratios > 1.

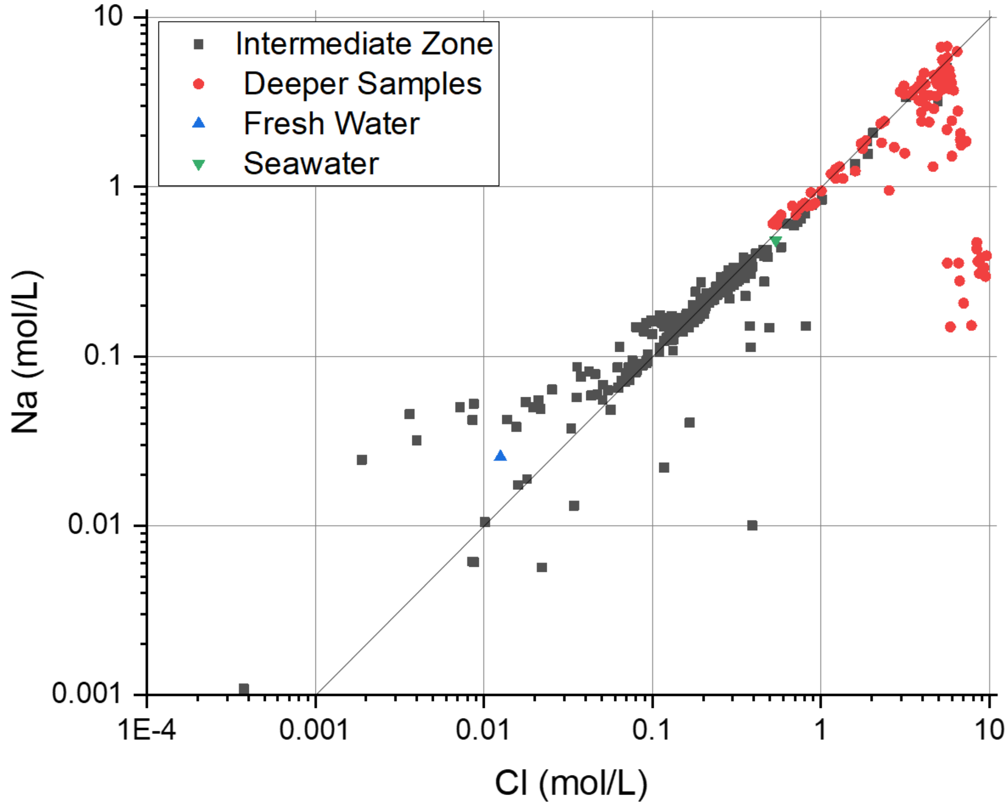

Figure 15-7: Intermediate Zone Na Vs. Cl (1:1 Trend Line) Water Data detailing that most water falls between fresh water and seawater on the trend line. Deeper Samples of Water affected by dissolution (Woroniuk et al., 2019)

The presence of brines that result from halite dissolution can have substantial impacts on regional groundwater flow regimes (Bachu, 1995). The water samples in the Intermediate Zone plot between fresh water and seawater and near the 1:1 line of Na:Cl (Figure 3-7). The Mannville Group was mostly deposited in continental and coastal settings (Alberta Energy Regulator, 2020) and water deposited with those sediments would more likely be fresh or slightly brackish. A component of freshwater may also be present from circulation of meteoric water in some areas, notably from Pleistocene subglacial recharge (Hendry et al., 2013). Salinity may come from paleo seawater that was entrapped in the formations surrounding the Mannville Group when they were deposited and has since migrated into the Mannville Group. The overlying shales in the Intermediate Zone were mainly deposited in Cretaceous seawater (Alberta Energy Regulator,

2020) and Schmeling (2014) notes that Cretaceous seawater may have been less saline than modern seawater and this is mainly what is seen from the water samples.

Cozzarelli et al. (2020) suggest that some of the salinity of produced waters near the subcrops of deeper formations, like the Bakken Formation, is caused by halite dissolution, thus making halite dissolution a possible source of salinity to overlying formations. A few water samples with higher salinity values overlap with groundwaters known to have been influenced by halite dissolution. Without sufficient Cl/Br ratio data and/or δ^{18}O values it is difficult to delineate between seawater and/or halite dissolution as the source of salinity in the Intermediate Zone. The δ^{18}O modeling undertaken by Hendry et al. (2013) and evolution of pore water chemistry indicates that a major salinity source for Cretaceous shales and the Intermediate Zone is paleo seawater from the time of deposition however this study was only conducted in the Williston Basin, which does not encompass the entire study area.

The few samples in the Intermediate Zone with salinity values greater than seawater could possibly be influenced by injection of produced fluids from other formations with higher salinity values or leakage along wellbores that have communication with formations with higher salinity values and the Mannville Group.

3.5 Hydraulic Head Distribution

The following figures show fresh water hydraulic head estimates from DSTs measured at different points in time. Using the pressures determined from the DST Horner analysis (Bredehoeft, 1965), the freshwater hydraulic head (h) in meters was calculated using the following equation:

$$h = \frac{P}{(9.81\times \rho)} + RD \tag{3.2}$$

Where:

- P is the pressure determined through the DST analysis (Pa).
- ρ is the freshwater density (1000 kg/m^3).
- RD is the subsea depth of the recorder used during the DST (m).

Pervious study’s such as Palombi (2008) and Melnik (2012) had removed DSTs affected by production and injection. In this study, those were not removed in order to give a complete picture of the present-day hydraulic head distribution. These maps provide an idea of how production and injection activities have affected the natural hydraulic head distributions.

The Mannville Group has regions with elevated hydraulic head values around the Weyburn/Estevan area, and some regions in southwestern Saskatchewan which are elevated to a lesser extent, when compared to the freshwater hydraulic head maps of Palombi (2008) (Figure 3-8). This outcome is not completely unexpected as both these regions have higher oil and gas activity and possess the infrastructure for injection of disposal fluids. However, it does show that the background formational flow within the Mannville Group has been disturbed and altered.

The Viking Formation hydraulic head distribution is close to background conditions, with no regions with major elevated hydraulic heads. Even though the Viking Formation has been exploited for oil and gas extraction it has not seemed to affect the natural formational flow patterns in a noticeable way at the regional scale. However, it is important to understand that these maps were not developed to interpret flow directions or absolute head changes. Rather, they are only meant to give an idea of the amount of disturbance caused by the oil and gas industry.

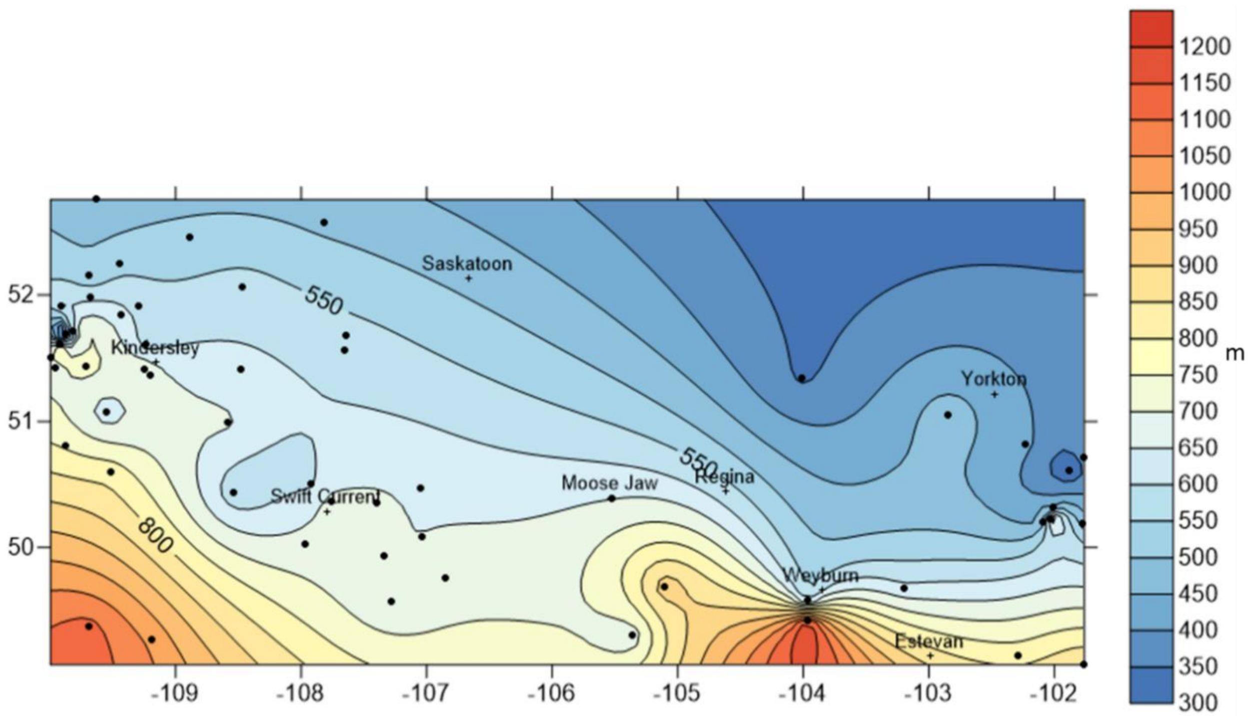

Figure 16-8: Mannville Group Fresh Water Hydraulic Head Map in meters (m) determined from DST Analysis. The black dots represent locations where hydraulic head values were determined.

The difference between the Mannville Group hydraulic head in meters and the water table (Fan et.al, 2013) in meters (Figure 3-9) allows for estimation of the direction of the vertical hydraulic gradient. The water table from Fan et.al (2013) uses the Saskatchewan Water Security Authority's (SWSA) water well database for Saskatchewan and uses spot measurements from different timeframes but provides far better spatial coverage than the few shallow wells in the SWSA observation well network. This map again shows that in the Mannville Group waters in the Weyburn/Estevan area and the southwest Saskatchewan region have the possibility to migrate upwards towards the shallower groundwaters. The Viking Formation waters are only able to migrate upwards towards the water table in the western portion of the study area. In the eastern portion of the province, water would be expected to flow downwards to the Viking Formation (Figure 3-10).

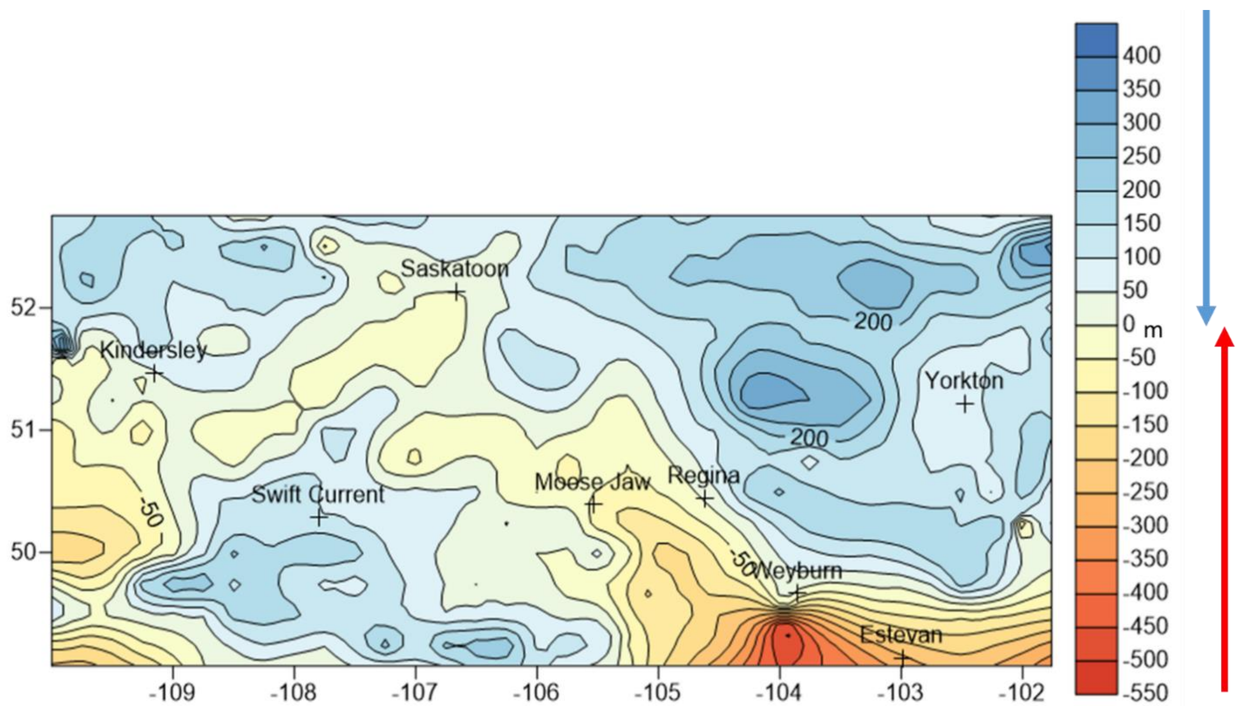

Figure 17-9: Difference in Freshwater Hydraulic Head between Mannville Group determined through DST Analysis and the Saskatchewan water table (Fan et.al, 2013) (m).

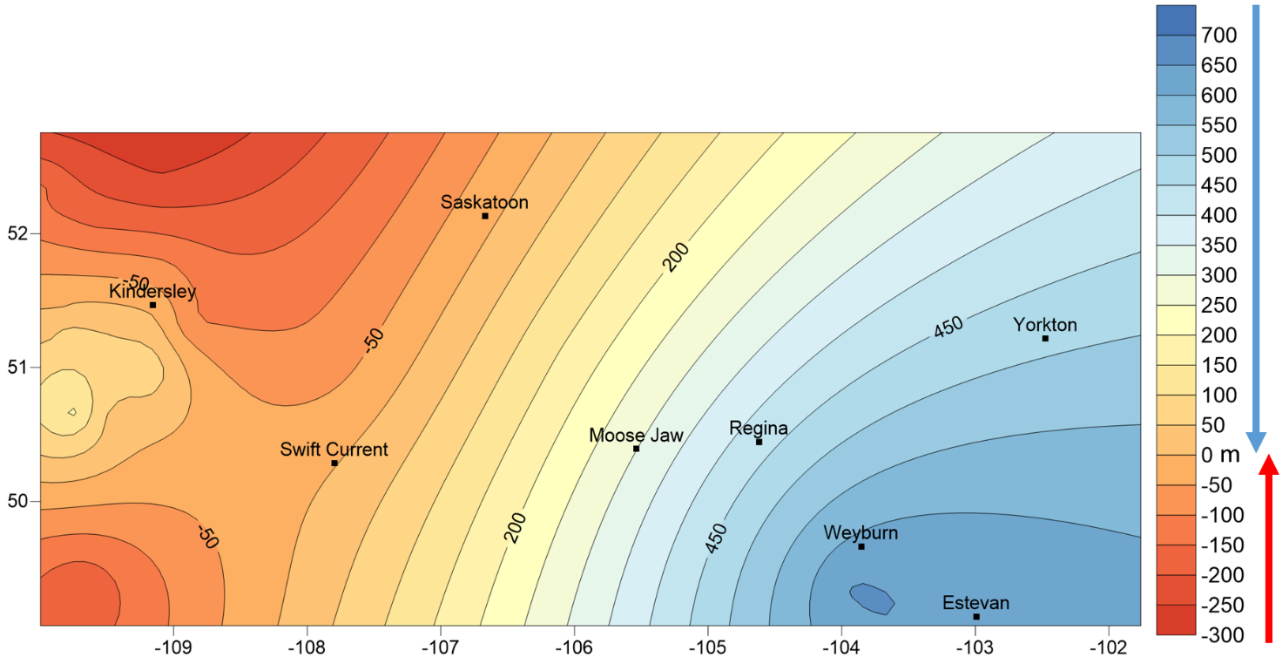

Figure 18-10: Difference in Freshwater Hydraulic Head between the Viking Formation determined through DST Analysis and the Saskatchewan water table (Fan et.al, 2013) (m).

In most places across the Saskatchewan study area the Viking Formation within the Intermediate Zone can act as a sink for the migration of waters from the Mannville Group (Figure 3-11). Besides some of the western portion of the study area, head differences indicate that water will flow from the Mannville Group into the Viking Formation. The hydraulic trap resulting from low hydraulic heads in the Viking Formation could be vital in protection of freshwater aquifers above the Intermediate Zone.

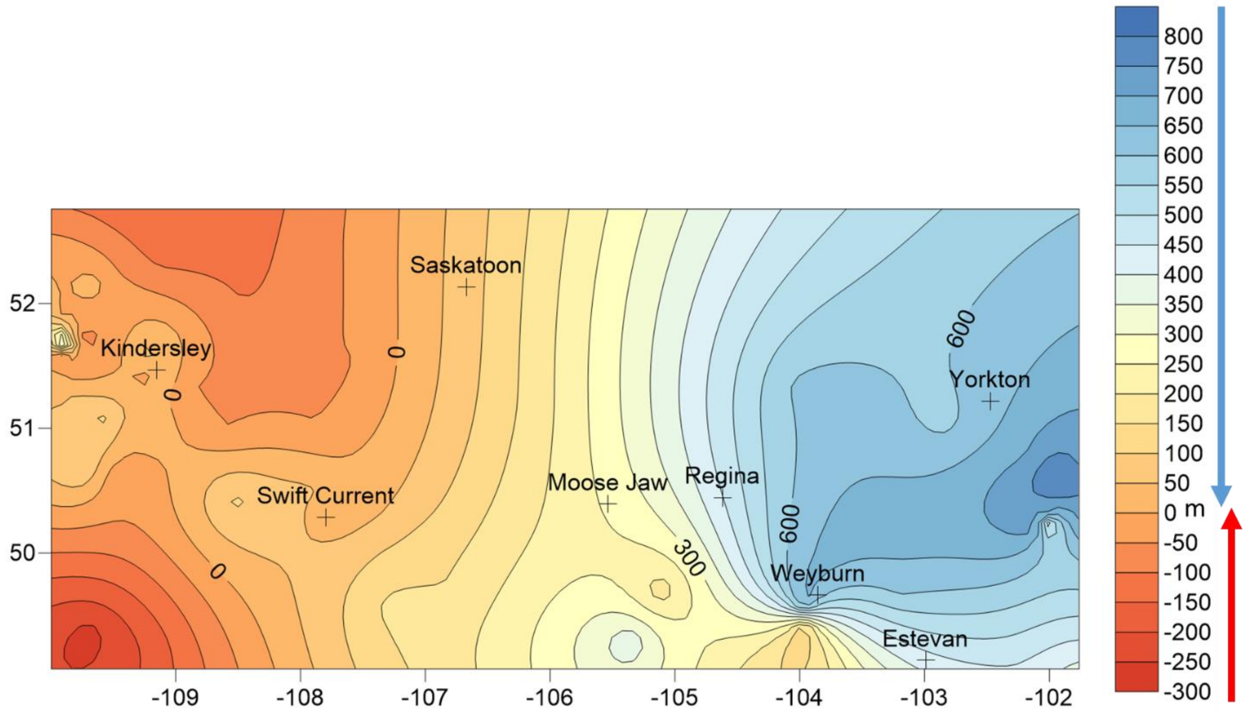

Figure 19-11: Differences in Freshwater Hydraulic Head between the Mannville Group and Viking Formation determined through DST Analysis (m).

4.0 Modeling

4.1 Modflow

Modflow 6 is an object-oriented program developed to model groundwater flow or groundwater transport problems using the control-volume finite-difference (CVFD) method (Langevin et al., 2017). Modflow can support ether two-dimensionally or three-dimensionally models and has many add-ins that can calculate outputs like water volumes in and out of formation (Langevin et al., 2017).

4.2 Modeling and Methods

Modflow 6 was used to create a three-dimensional model fluid flow involving an injection well in the Mannville Group and overlying the Intermediate Zone. The model (Figure 4-1) is built from the base of the Mannville Group to the top of the Belly/Judith River Formation. The model forms a 10,000 meter by 10,000-meter square with a grid block size of 100 meters by 100 meters. The model dimensions and grid block sizes were determined after a sensitivity analysis on model results. The model size was increased until outputs from the model stabilized and showed no more change. Once this was determined the model boundaries were set. The same approach was used for the grid block size. The grid block size was increased and decreased, while this did not change the data outputs, it did change the model run time. The grid block size was determined to allow for model run times of around an hour while still producing accurate outputs.

Formation depth and thickness was based off averages from IHS AccuMap in wells that go into or deeper than the Mannville Group within the Saskatchewan study area and the injection rate was based off representative disposal wells. The exact thicknesses are 58m for the Mannville Group, 40m for the Joli Fou Formation, 18m for the Viking Formation, 203m for the Colorado Group, 265m for the Lee Park/Milk River Formation and 125m for the Belly/Judith River Formation.

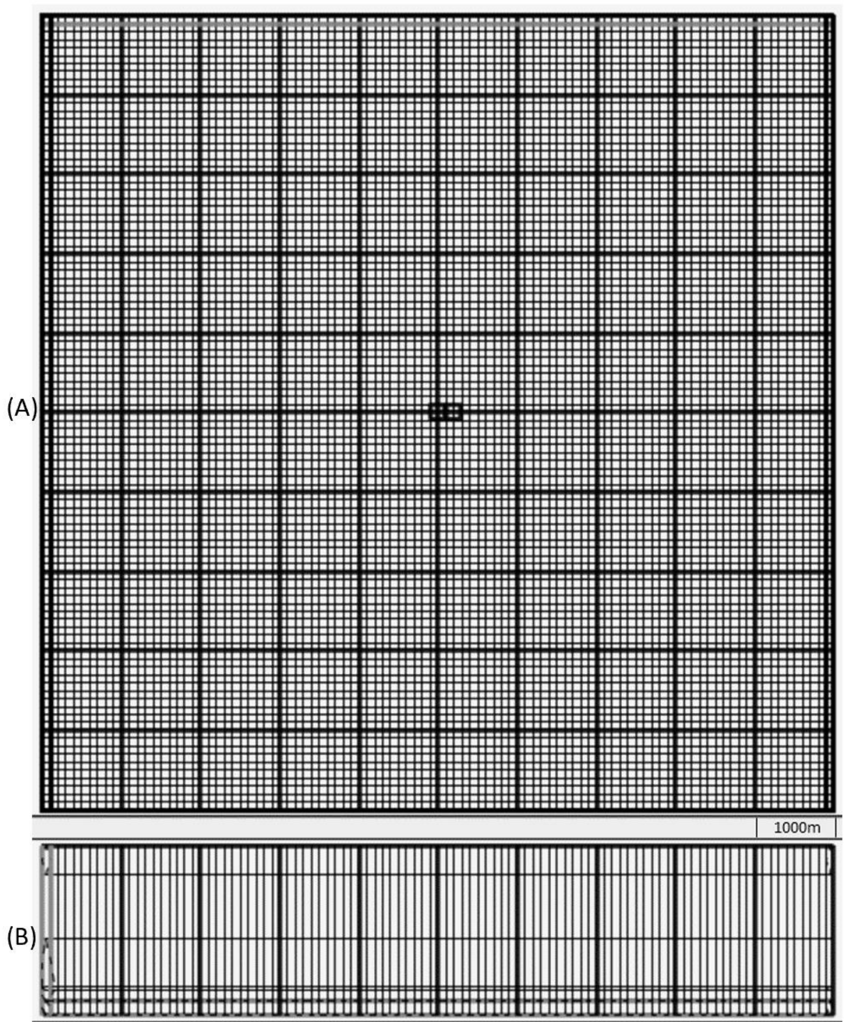

Figure 20-1: Model domain with grid blocks size constructed using Modflow 6 (A) Top View and (B) Side View. Vertical Exaggeration of 0.335.

The disposal well was placed right at the center of the model to ensure the model boundaries do not affect the formational head values and using the Modflow well package. The well package allows for a well to be open in one unit or formation (Langevin et al., 2017) which would be a conservative worst-case scenario of an uncased open hole abandoned well and is noted in Perra (2021) as a possibility in uncased wells. This approach for using an open hole abandoned well allows the greatest effective permeability possible. Perra (2021) determined that leaky open wellbores could increase the effective permeability of a formation by two orders of magnitude. In other situations where the leak is due to poor cementing, damaged/degraded casing, the effective permeability of the leaky well would be less (Perra, 2021). Other key inputs such as hydraulic conductivity, porosity, and injection rate were built into the model and can be found in Table 4-1.

Table 4-1: Inputted Model Parameters

Parameter	Input Value	Reference
Hydraulic Conductivity – Sandstone (m/s)	6×10^{-6}	Freeze and Cherry, 1979
Hydraulic Conductivity – Shale (m/s)	1×10^{-11}	Freeze and Cherry, 1979
Porosity – Sandstone (%)	30	Freeze and Cherry, 1979
Porosity – Shale (%)	20	Freeze and Cherry, 1979
Injection Rate (m^3/s)	0.08	AccuMap, 2021
Injection Well Radius (m)	0.15	AccuMap, 2021
Model Length (m)	10,000	N/A
Injection Time (yrs.)	20	AccuMap, 2021

Hydraulic conductivity and porosity values for both the sandstones and shales were taken from Freeze and Cherry (1979) due to there being limited data which is mainly related to the shale formations, much of which is likely biased due towards higher values due to the time required to test low permeability materials. When comparing to horizontal core data from AccuMap to literature values the sandstone values were within the same order of magnitude, but the shale values were off by a few orders of magnitude with the core values being higher which shows that those core values would not have been representative of the actual subsurface. When inputting hydraulic conductivity values from the shales the model was not able to stay at a steady state with no injection taking place. This detailed that the core value had a bias towards sandstones and were not representative of the formations they were taken from. For this reason, the core values for shale were not used and for simplicity core values for both sandstones and shales were taken from Freeze and Cherry (1979) which is in line with more data presented in Hendry et.al (2016) and Smith et.al (2016). The hydraulic conductivity values were inputted to create an isotropic condition within the sandstone and shales. This was done to again investigate a worst-case scenario as the vertical hydraulic conductivity would typically be less than the horizontal. The difference would not cause the overall outcome of the simulations to change much. The water injection rate was based off injection rates into the Mannville in Saskatchewan which were taken from IHS AccuMap (2021) and mainly ranged from below 0.001 m^3/s to above 0.1 m^3/s, with a higher value being taken to help simulate a worst case scenario. The placement of the water table was based on the water table being close to the surface in Saskatchewan; i.e., for simplicity it was placed at ground level (elevation of 0 m). This assumes that there are approximately hydrostatic conditions within the Judith/Belly River Formation. The well radius was built to be 0.15m which is a common size for wells (IHS AccuMap, 2021) and the 20-year injection time frame for a well was a common higher end value for an injection timeframe (IHS AccuMap, 2021) in the study area, but this better allows the effects of this long-term injection wells on the natural flow regimes to be detailed. Modflow 6 assumes a constant fluid density within the model however this would cause some differences in the results if the densities were different. In general, Mannville Group fluids or injection fluid densities are greater than Belly/Judith River Formation fluid densities due to their higher TDS values.

The boundary conditions of the model included each aquifer having a fixed head boundary value that were placed along the entire eastern and western sides of the model. The head values that were used for the boundary conditions were based off work from Palombi (2008). The Belly/Judith River Formation had a head value of 580 meters on the east and 590 meters on the west. The Viking Formation had values of 530 meters and 540 meters, and the Mannville Group had head values of 720 meters and 730 meters. These values allow the model to be as close to known conditions with respect to background regional groundwater flow.

The Mannville Group is approximately 60 meters thick across the west central portion of Saskatchewan (Morshedian et.al, 2012) and is mainly consistent through the east central portions losing some thickness as it moves east. The Viking Formation has a thickness ranging from 15 – 35 meters across Saskatchewan with the majority being on the lower end (Walz et.al, 2015). The other formations and groups thickness values in the model are consistent with literature values (Hayes et.al, 1994). The permeability values taken from Freeze and Cherry (1979) were consistent with findings from the analyzed DST for the sandstone members along with core values as well. The shales were somewhat off from the literature compared to the core values but core testing from units that are predominantly shales can be biased towards sandstone layers interbedded into the shales. These factors make this model a fair representation of the study area.

The leaky well was incorporated in the model using the multi well aquifer package in Modflow with well screens in the Belly/Judith River Formation, Viking Formation, and the Mannville Group depending on what is being investigated. The multi well aquifer package allows for a well to be open to multiple units or formations (Langevin et al., 2017), unlike the well package which only allows the well to be open to one unit. The Modflow Zone Budget solution solver package was used to determine the volume of water movement between aquifers. To get this solver to work, three regions were defined in the aquifers so the solver could compute the regional water budgets using the results of the model (Langevin et al., 2017). The package then calculated the volume of water in and out of the defined region and the mechanism that is allowing the water to enter or exit the region.

4.3 The Role of the Horizontal Distance Between Wells

The horizontal distance between the injection well and the leaky well affects the amount of water that can move between aquifers. As the horizontal distance between the injection well and the leaky well increases, less water moves between the aquifers (Table 4-2). As the leaky well is moved further away from the injection well the injected water becomes more dispersed in all directions within the formation instead of directly to the leaky well which causes changes in the formational/group hydraulic head values as difference volumes (Figure 4-2 and Figure 4-3). The further away the leaky well is from the injection well the Mannville Group is more broadly affected by the injected water and the overlying Viking and Belly/Judith River Formations are less affected (Figure 4-4). With more room to dissipate the pressure pulse from injection in the Mannville Group with a larger horizontal distance, this leads to less water migrating through the leaky well which leads to lower fluxes of water into the Viking and Judith/Belly River formations. The Viking Formation is more greatly affected by the inflow of water in a relative sense. However, less water flows into the Viking than the Judith/Belly River Formation because of its thickness. The initial head value in the Viking Formation is lower compared to the Mannville and Belly/Judith River Formation and the model predicts a larger change in the hydraulic head values of the Viking Formation. The Belly/Judith River Formation receives most of the water that is lost from the Mannville Group through the leaky well. Overall, when the leaky well is 100 meters away compared to 800 meters away from the injection well we expect just over 9 million more cubic liters of water that leaves the Mannville Group and into the above aquifers.

Table 4-2: Water Volumes In and Out of Formations/Groups for the different Horizontal Distance between the Injection Well and the Leaky Well.

Horizontal Distance Between Wells = 100m		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	3.44×10^{7}	0.00
Viking	9.73×10^{6}	0.00

Mannville Group	5.05×10^7	4.41×10^7

Horizontal Distance Between Wells = 200m		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	3.31×10^7	0.00
Viking	9.67×10^6	0.00
Mannville Group	5.05×10^7	4.28×10^7

Horizontal Distance Between Wells = 400m		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	2.98×10^7	0.00
Viking	9.03×10^6	0.00
Mannville Group	5.05×10^7	3.88×10^7

Horizontal Distance Between Wells = 800m		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	2.66×10^7	0.00
Viking	8.43×10^6	0.00
Mannville Group	5.05×10^7	3.51×10^7

Difference in Hydraulic Head Maps for Horizontal Distance between Injection Well and Leaky Well

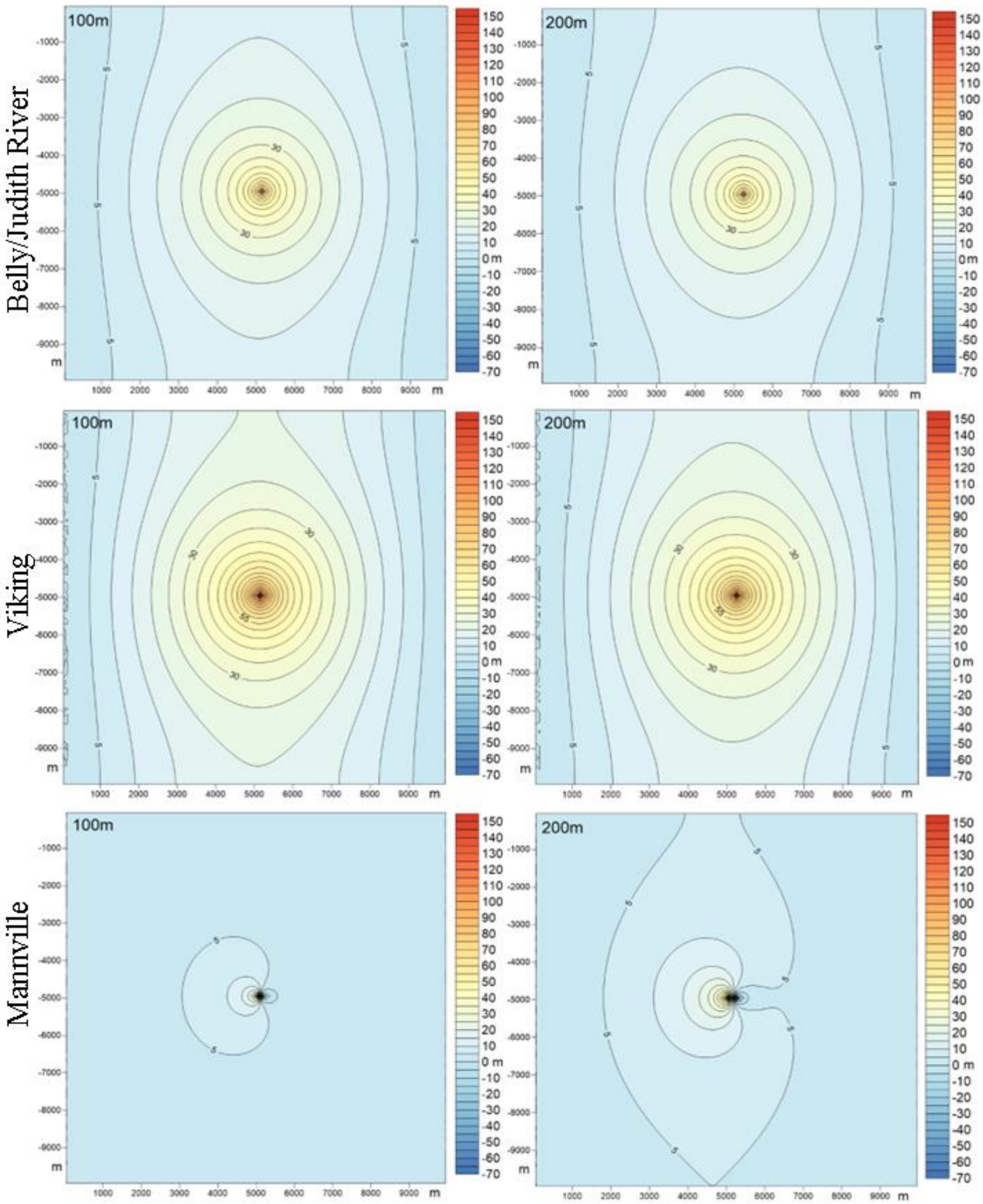

Figure 21-2: Difference between initial hydraulic heads and final head values (in m) after 20 years of injection for 100m & 200m horizontal distance between injection and leaky wells. (These values are the difference between the initial steady state of each formation/group and the formation/group after the injection timeframe has passed)

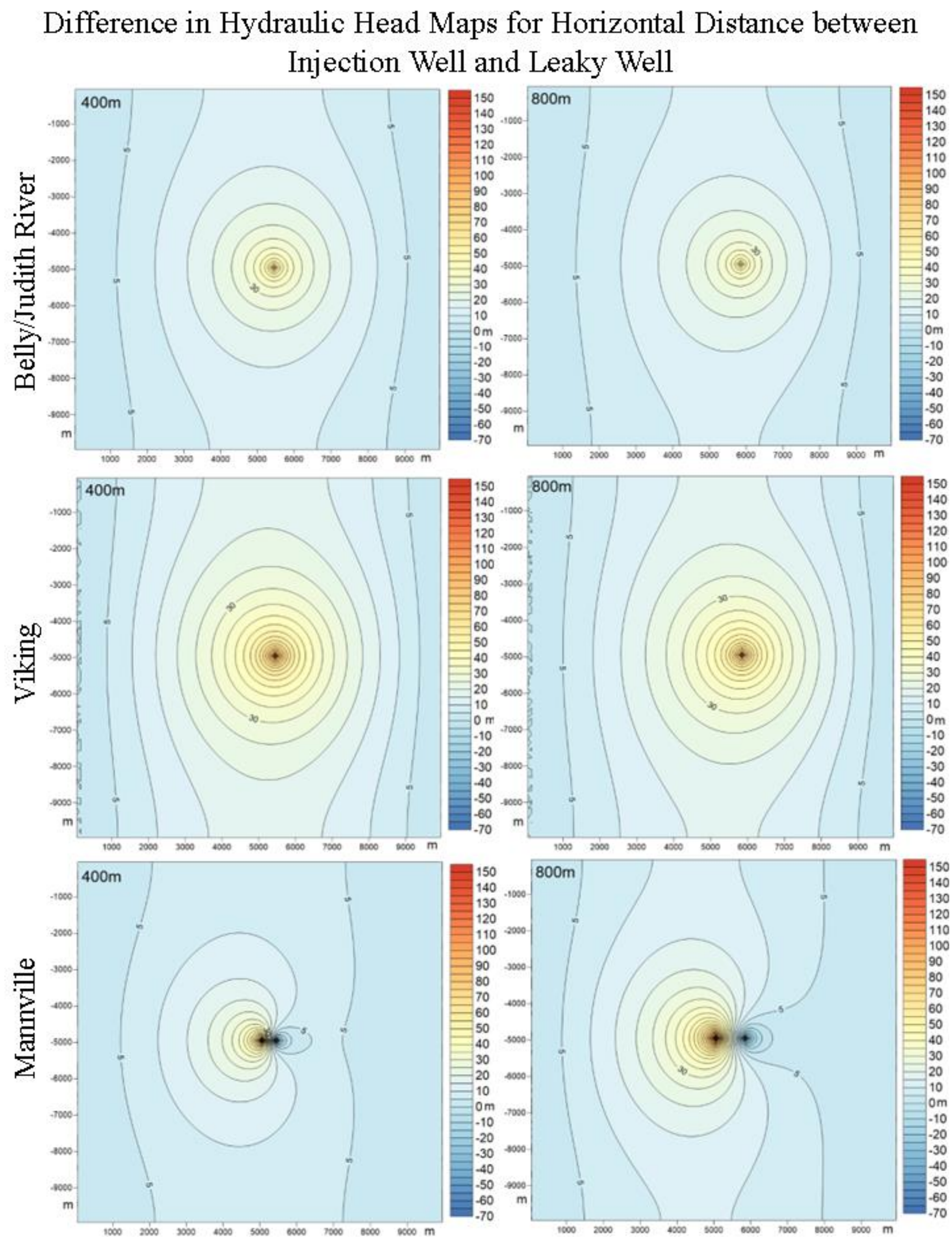

Figure 22-3: Difference in hydraulic head values of initial head values and final head values after 20 years of injection for 400m & 800m horizontal distance between injection and leaky wells (These values are the difference between the initial steady state of each formation/group and the formation/group after the injection and timeframe have passed)

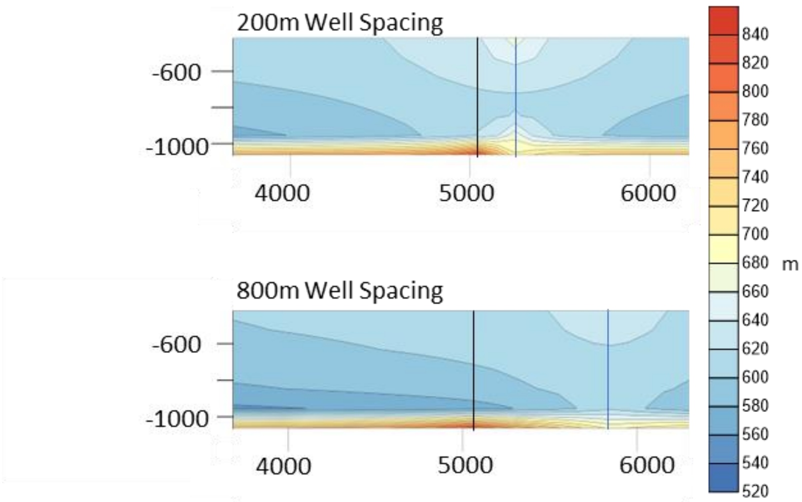

Figure 23-4: Difference in hydraulic head values as the distance between the injection well and the leaky well is changed. The black line represents the injection well and the blue line represents the leaky well.

4.4 The Role of the Hydraulic Conductivity of Viking

The hydraulic conductivity of the Viking Formation affects the volume of water that leaks out of the Mannville Group through the leaky well (Figure 4-5 and Table 4-3). If the hydraulic conductivity of the Viking Formation is an order of magnitude greater than the value extracted from literature (i.e., the base case) and the mean log k value that was obtained from the DST's, then most of the water flows into the Viking Formation instead of the Belly/Judith River Formation. This also results in more water flowing out of the Mannville Group. However, when the hydraulic conductivity is lower than the base case value there is overall less water that leaves the Mannville Group. This results in more water flowing into the Belly/Judith River Formation, which contains the well plug at the top of model. However, flow into the Belly/Judith River is limited by its hydraulic conductivity, which results in more water remaining in the Mannville Group and dissipation of fluid within the Mannville Group itself. If the Viking's hydraulic conductivity is an order of magnitude greater it would be able to provide greater protection for the aquifers above. However, this most likely isn't the case for the Viking Formation because mean hydraulic conductivity is approximately 9 x 10^{-6} -m/s from the DST analyzed. Further hydraulic characterization of the Viking and other intermediate aquifers would allow for an improved assessment of the level of protection these Intermediate Zone aquifers provide to overlying groundwater supplies.

Table 4-3: Water Volumes In and Out of Formations/Groups for Different Viking Formation Hydraulic Conductivity Values.

Viking Hydraulic Conductivity $K = 10^{-5}$		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	7.76×10^{6}	0.00
Viking	5.07×10^{7}	0.00
Mannville Group	5.05×10^{7}	5.85×10^{7}

Viking Hydraulic Conductivity $K = 10^{-6}$		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	3.31×10^{7}	0.00
Viking	9.67×10^{6}	0.00
Mannville Group	5.05×10^{7}	4.28×10^{7}

Viking Hydraulic Conductivity $K = 10^{-7}$		
Formation	Water In (L3)	Water Out (L3)
Belly/Judith River	3.86×10^{7}	0.00
Viking	8.31×10^{5}	0.00
Mannville Group	5.05×10^{7}	3.94×10^{7}

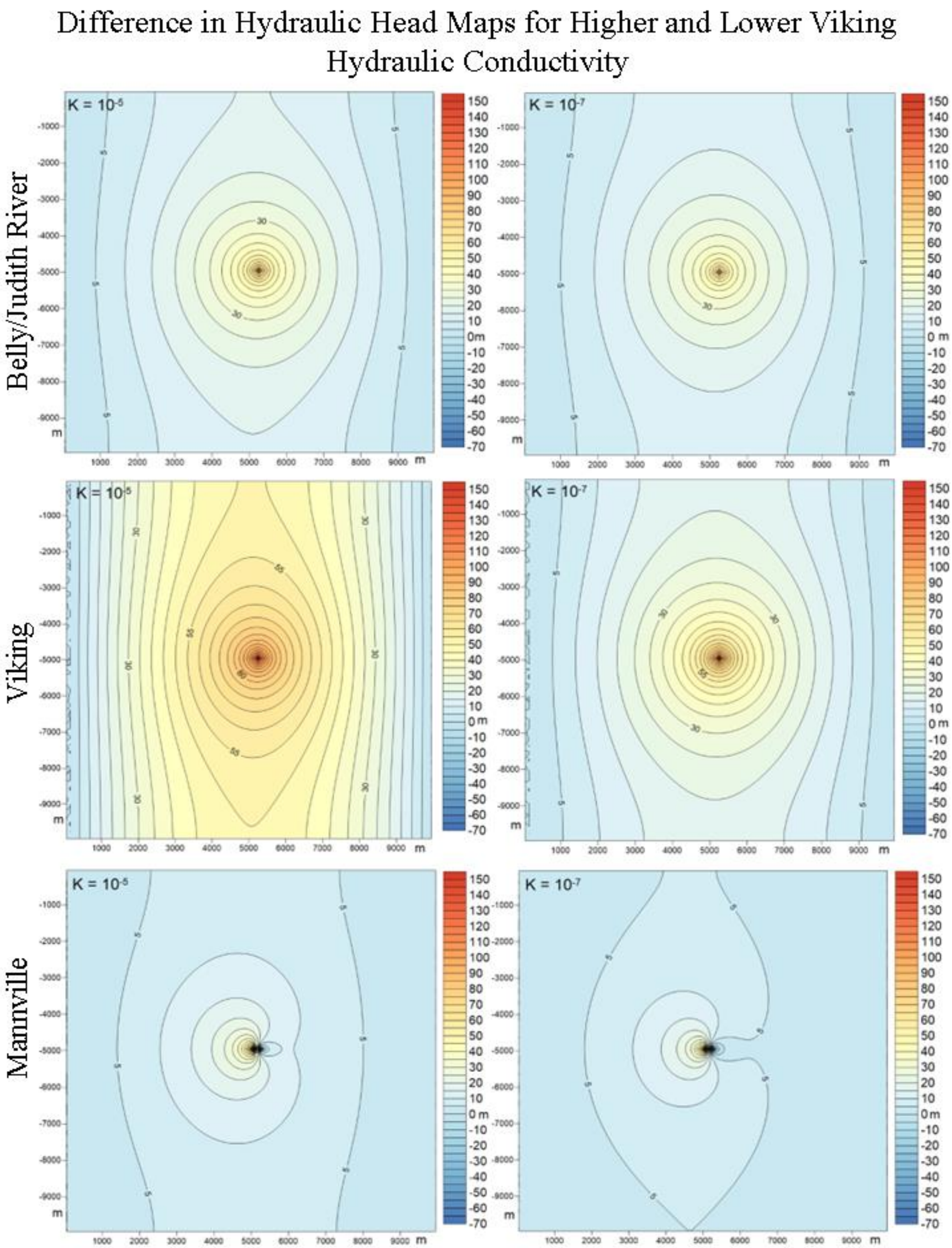

Figure 24-5: Difference in hydraulic heads of initial head values and final head values after 20 years of injection of the three aquifers for when the hydraulic conductivity of the Viking is raised and lowered by an order of magnitude.

4.5 The Role of the Shale Aquitards

Although the shales were not directly investigated through the modeling they were indirectly investigated. This indirect investigation involved the shale hydraulic conductivity that was used in the models to allow the hydraulic heads within the aquifers to remain constant through the same timeframe with no injection. The Viking Formation, as previously noted, has a lower hydraulic head compared to the Belly/Judith River Formation and Mannville Group. This is likely attributable to unloading during erosion during the Neogene period (Corbet and Bethke, 1992), similar to those documented in similar strata in southeastern Alberta (Corbet and Bethke, 1992). Therefore, if the shales did not have the hydraulic conductivity of 10^{-11} m/s that was used in the model and noted in Chapter 4 then this would not be possible. This demonstrates that the permeability is so low that upward transport rates would be insignificant, and the shales would provide protection from large amounts of water leaking into the above formations. If leaky wells were not present the shales would provide enough protection to limit the amount of water that leaks upwards.

5.0 Discussion

5.1 Implications for Saskatchewan and Western Canada

Water has most likely been moved in and out of different key formations or groups through leaky wells for years. These leaky wellbores can significantly affect the flow field in a system with multiple aquifers and aquitards and they can rapidly transmit contaminants through low-permeability strata into otherwise uncontaminated aquifer (Lacombe et al., 1995). However, this study demonstrates that water may not reach shallow groundwater aquifers even though it can migrate from reservoirs hosting injection wells to overlying aquifers if the injection well and a leaky well are within close proximity. It is commonly assumed that most produced water is reinjected into its source formations; however, water can often be produced from one formation and injected into a different reservoir (Jellicoe, 2021). While water is being reinjected into formations the proximity of abandoned wells to those injection wells is important, and the placement of plugs in those abandoned wells is also important (Perra, 2020). Plugs are not placed at every formation and/or group that has perforated, which can facilitate this water movement (Perra, 2020). However, based on the timeframe used in the model these formational water (injected disposal waters and existing formational waters) have been migrating throughout these formations for some time. This migration is continuing today if leaky wells are present. This water that has been injected into the Mannville Group has most likely already migrated through leaky wells and into the Belly/Judith River Formation as it would act as a sink, so the main concern would be to protect the waters in the freshwater aquifers above if there are no plugs in the abandoned wells.

The injection well in the model produced here has no downtime, which is likely to occur in reality to allow for well workovers, lack of water to inject, or numerous other reasons. Other studies such as Liu et al (2020) have looked at the effect cyclic water injection has on formations with respect to oil production. While this is not the scenario as injection of disposal fluids, it has the same basic premise of injecting water into a formation through one well and then fluids flow through a second well. Based on this fact this pressure downtime would not cause notable changes to the results of the simulations. Once injection stops the pressures would eventually go back to close to their original values once the pressures have dissipated outwards, although this could take months to years depending upon how much pressure is built up. The model also operates with a constant fluid density which in not entirely correct, however the fluid densities within the Intermediate Zone would differ for each group/formation. This would lead to upward fluxes being slightly overestimated with the constant density approach.

This model predicted upward fluxes of water injected into the Mannville Group and through a leaky well into the Belly/Judith River above. By looking at geochemistry parameters such as elevated salinity values, higher concentrations of calcium, sodium, magnesium and chloride along with the sodium to chloride ratio and chloride to bromide ratio it can help determine if Mannville Group waters are migrating upwards through a leaky well and into the Belly/Judith River. This parameters can be looked at more closely in current oil and gas areas in the study area to closely monitor fluid migration within the Intermediate Zone to better protect and monitor fresh water aquifers.

The Government of Saskatchewan water flooding incentive program (2019) encourages new wells to be drilled for the purpose of waterflooding or converting older producers to injection wells. This would increase the amount of water that is being injected into formations for oil production and would increase the amount of water produced which would need to be disposed of. The Government of Saskatchewan's Carbon Capture plan (2021) involves the production of more oil and gas, which in turn will involve the production of more water. This additional water will need to be disposed of, with the main method likely being injection into a disposal zone. Within Saskatchewan this produced water would most likely be injected into the Mannville Group or other formations of similar depth. This extra water may cause more over pressuring in the Mannville Group when injected than there already is and with numerous wells in the province that may be leaky this could cause more of an issue than previously noted. This water would lead to more over pressuring in the Mannville Group which leads to having that water migrate up leaky wells and into the Judith/Belly River Formation which eventually could get over pressured itself and that water could possibly migrate upwards even further into the freshwater aquifers above.

5.2 Implications for Intermediate Zones Around the World

This study focused on the WCSB Intermediate Zone in Saskatchewan but there are numerous other Intermediate Zones around the world where these same oil and gas industry practices are in play today and have been for decades (McIntosh and Ferguson, 2019). Many of these areas are water-stressed and are experiencing deeper drilling for freshwater resources (Perrone and

Jasechko, 2019). This is where this model can provide insights into the potential impacts of leaky wells not only in the WCSB but all over the world. Even though the model was built specifically for the study area within Saskatchewan it can be edited and changed to match other areas around the world. The layer thicknesses, depths, hydraulic conductivities, porosities, along with the injection rate, number or wells and the layers that the leaky well leaks into can be changed to fit the specific area making the model versatile. This versatility allows this model to be changed to fit the Intermediate Zone in different parts of the WCSB all the way to different Intermediate Zones and basins from around the world. This could help determine the proximity between injection wells and possibly leaky wells in any region of the world. In the United States it is noted that the transition zone between fresh and brackish water occurs within a few hundred meters of the land surface (Stanton, 2017; Ferguson et al., 2018) which aligns with the Intermediate Zone in the study area. In the Michigan Basin gas wells are installed as shallow as 270 m, in the Wind River Basin hydraulic fracturing occurs at depths as shallow as 372 m and coalbed methane wells in basins that intermingle with freshwaters (Ferguson et al., 2018). This demonstrates that this is a problem that exists in other basins around the world and could affect freshwater supplies there as well. It can also be noted that brines have been injected at depths of less than 100 m in the Illinois Basin and at depths of less than 300 m in Wind River Basin (Ferguson et al., 2018). This shows that these basins have much smaller freshwater zones and the Intermediate Zones within are much more important than previously thought.

This study could help regulators determine a minimum distance between an injection well and a well that has been suspended or abandoned nearby. It can also help jurisdictions around the world with prioritizing funds from suspended/orphaned well decommissioning programs to wells that are nearby injection wells or near future injection wells. This helps as these programs normally do not have sufficient funding to address the full size of the problem (Detrow, 2012). This study also demonstrates that Intermediate Zone aquifers around the world could be more important to the protection of overlying groundwater supplies along with the aquitards, especially in settings where leaky wells exist. This study could help determine the impact of injecting disposal fluids into Intermediate Zones around the world while giving a clearer picture on the potential impacts on freshwater aquifers above those Intermediate Zones.

6.0 Conclusions and Recommendations

6.1 Conclusions

As oil and gas production continues to increase in years to come, increases in the volumes of water associated with production will occur. Produced water is sometimes reinjected into the source formation or used in a different reservoir to produce more oil, but it is more commonly reinjected into different formations which are known as disposal formations. This can cause changes to the normal reservoir pressures which can lead to water migrating upwards through leaky wells and into freshwater aquifers above. This study has shown that disposal fluids injected into the Mannville Group can migrate upwards through leaky wells and into the aquifers above which changes the local hydraulic heads and natural flow patterns within the formations. These changes in local hydraulic heads and flow patterns can lead to contamination of the overlying freshwater aquifers where leaky wells are present.

Several studies have shown that the Mannville Group has had more water injected into it than has been produced out of it along with the other studies that have noted the presence of improperly plugged (abandoned) wells within a 200 m proximity of current disposal wells. By modeling this injection, the Belly/Judith River Formation absorbs most of the water that is injected into the Mannville Group because it travels from high to low hydraulic head through the leaky wellbore. The Belly/Judith River Formation is used as a freshwater source in some areas however, if this leaking contamination were to occur, the Belly/Judith River Formation may not be able to be used as a fresh water source in the future.

6.2 Recommendations

To further improve the understanding of the injection of disposal fluids and their migration through leaky wells to freshwater aquifers at the basin scale, it is recommended that:

- Additional data be collected to supplement and build upon current available data.
- Increasing the number of fluid pressure measurements taken from injection wells.
- Monitoring hydraulic head changes from injection of disposal fluids are recommended.
- Monitor other wells within a 1 km radius of the injection well to better predict pressure and chemistry to determine if solute transport is taking place.
- Perform a more detailed sensitivity analysis with the model in regard to injection rates, injection timeframes and other parameters.

Expanding the number of available hydrogeological measurements (porosity, permeability, etc.) can increase the accuracy of the models to better predict hydraulic head and pressure measurements. Creating models that are regionally specific to better understand each region in the province can help better understand the role injection plays in different areas of the province. Creating models to understand injection rates and put volume limits on injection of a certain period of time could allow for pressures to stabilize within the disposal formation before it makes it to a migration pathway. Implementing a more extensive fluid analysis testing program for injection wells along with wells within a 1 km radius of an injection well to better predict how contaminants travel over time along with looking at multiple aquifers above the disposal zone to see possible contamination through leaky wells. It is recommended that governments look more closely at wells within a 1 km radius of injection wells for proper abandonment through orphan well action plans to better project freshwater aquifers above disposal zones. It is also recommended that a more intensive sensitivity analysis be performed with the model to help better understand the response to injection by looking at different injection rates, different injection timeframes and lengths and possible cyclic injection of disposal waters.

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