Geologic Considerations for Enhanced Oil Recovery in Elm Coulee Field, Richland County, Montana, Williston Basin

by

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ABSTRACT

The Elm Coulee field in Richland County, Montana, was discovered in 2000 and historically is the largest field producing from the Devonian – Mississippian Bakken Formation in the Williston Basin. The 530 square mile field has an estimated ultimate recovery of 300 million barrels or more of oil. Significant reserves are still present in the reservoir, making the Bakken Formation in the Elm Coulee Field an attractive target for enhanced oil recovery (EOR).

The Middle Bakken Member (MBM) is the most significant reservoir of the Bakken Petroleum System in the Elm Coulee Field and will be the focus of this study. The MBM was most likely deposited in a shallow to distal shelf environment and then dolomitized according to the seepage-reflux model. There is a NW – SE trending MBM thick in the Elm Coulee Field, which was most likely formed as a result of the multistage Prairie Formation evaporite dissolution. Hydrocarbon production from the Elm Coulee Field also has a NW – SE trend but does not directly correlate with the MBM thick. Preferential dolomitization of the MBM is the driving force for reservoir quality, and is the likely cause for the discrepancy between these two NW – SE trends.

Hydrocarbon production in the Elm Coulee Field is characterized by liquids-rich wells that produce comparatively very little water. The average estimated ultimate recovery (EUR) of a well in the field is 269,000 bbl of oil. The original oil in place (OOIP) of the MBM reservoir is calculated to be 2.02 Bbbl. The recovery for the field factor was calculated to be 13%. Water saturation in the pay interval is extremely low, however there is a sharp contact in the reservoir between pay, and decidedly much more water saturated non-reservoir rock. Fluid saturation in the MBM is a function of pore throat size distribution; intervals with larger pore throats are more
likely to be oil saturated and intervals with smaller pore throats are more likely to be water saturated. Pore throat size distribution appears to be related to mineralogy, specifically dolomite.

The pay interval in the MBM reservoir in the Elm Coulee Field appears to be preferentially oil – wet. This is supported by high oil saturations in the pay, preferential adsorption of organic material onto dolomite crystals and pore lining clays, and experimental core tests. The wettability of the MBM reservoir has direct consequences on historic production, as well as current and future EOR attempts. Most importantly, an oil – wet reservoir will have more oil adsorbed onto matrix rock, and as a result, will have lower recovery factors compared to an equivalent preferentially water – wet reservoir.

This study examines the three most viable EOR methods for an unconventional: solvent flooding (miscible CO₂ and hydrocarbon gas), surfactant flooding, and fresh water flooding (also known as low – sal). Experimental and pilot well studies were reviewed to evaluate potential methods for EOR in the MBM. Surfactant solutions lowered the interfacial tension (IFT) between the Bakken crude and water. These solutions also successfully recovered significant amounts of oil from cores saturated in oil. Surfactants dissolved in fresh water were much more effective than those dissolved in produced water. Additionally, fresh water successfully recovered amounts similar amounts of oil, compared to surfactants dissolved in fresh water, from an oil saturated core. Three mechanisms describing hydrocarbon recovery from fresh water injection are proposed. Two of these methods also provide an explanation for the preferential adsorption of organic material onto pore lining clays.

The Burning Tree 36-2H well was a CO₂ “huff and puff” pilot test in the MBM reservoir in the Elm Coulee Field. The CO₂ injection from this well could be responsible for an additional production of 8,596 bbl of oil with a carbon utilization ratio of 5.23 mcf/bbl. Water breakthrough
was reported in the Staci 1-11H following water injection in the adjacent 3-11H well. This breakthrough could have been due to extensive hydraulic fracturing, however it is more likely due to a pre-existing preferential flow path related to regional structure and fracture trends.

The results of this study argue that the MBM reservoir in the Elm Coulee Field is a viable target for EOR. The large amounts of residual oil present in the MBM reservoir can be mobilized through chemical, solvent, or low salinity water injections. However, more characterization is necessary prior to any large-scale economic endeavor. The nature of the fracture network must be better understood in order to completely optimize any future injections. Pending further characterization, and under the right economic conditions, the Elm Coulee Field could serve as a good example of EOR in an unconventional reservoir.
## CONTENTS

Abstract ........................................................................................................................................ iii

Contents .......................................................................................................................................... vi

List of Figures ................................................................................................................................ xii

List of Tables .................................................................................................................................. xxiii

Acknowledgements ..................................................................................................................... xxv

Chapter 1. Introduction ................................................................................................................... 1

1.1 Objectives and Purpose ........................................................................................................ 2

1.2 Study Area ............................................................................................................................. 4

1.3 Data Used ................................................................................................................................ 4

1.4 Previous Work and Research .............................................................................................. 6

1.4.1 Sonnenberg and Pramudito, 2009 .................................................................................. 6

1.4.2 Shoaib and Hoffman, 2009 ............................................................................................ 7

1.4.3 Adrian Almanza, 2011 ..................................................................................................... 7

1.4.4 Chloe Alexandre, 2011 .................................................................................................... 8

1.4.5 Sonnenberg, LeFever, and Hill, 2011 .............................................................................. 8

1.4.6 B. Todd Hoffman, 2012 .................................................................................................... 9

1.4.7 Henriette Eidsnes, 2013 .................................................................................................. 9

1.4.8 Wanli Pu, 2013 ................................................................................................................. 10

1.4.9 Fakcharoenphol et al., 2013 ......................................................................................... 10
<table>
<thead>
<tr>
<th>Section</th>
<th>Title</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.4.10</td>
<td>Basak Kurtoglu, 2013</td>
<td>11</td>
</tr>
<tr>
<td>1.4.11</td>
<td>Cosima Theloy, 2014</td>
<td>11</td>
</tr>
<tr>
<td>1.4.12</td>
<td>Ling et al., 2014</td>
<td>12</td>
</tr>
<tr>
<td>1.4.13</td>
<td>Hoffman et al., 2014</td>
<td>13</td>
</tr>
<tr>
<td>2.1</td>
<td>Williston Basin Structural Geology</td>
<td>18</td>
</tr>
<tr>
<td>2.2</td>
<td>Williston Basin Stratigraphy</td>
<td>20</td>
</tr>
<tr>
<td>2.2.1</td>
<td>Bakken Formation Sediment Source</td>
<td>22</td>
</tr>
<tr>
<td>2.3</td>
<td>The Bakken Petroleum System</td>
<td>22</td>
</tr>
<tr>
<td>2.3.1</td>
<td>Bakken Source Rocks</td>
<td>23</td>
</tr>
<tr>
<td>2.3.2</td>
<td>Bakken Reservoir Rocks</td>
<td>23</td>
</tr>
<tr>
<td>2.3.2.1</td>
<td>Reservoir Wettability</td>
<td>24</td>
</tr>
<tr>
<td>2.3.2.2</td>
<td>Diagenesis in the Middle Bakken Member</td>
<td>25</td>
</tr>
<tr>
<td>2.3.3</td>
<td>Bakken Formation Well Log Characteristics</td>
<td>26</td>
</tr>
<tr>
<td>2.4</td>
<td>The Elm Coulee Field</td>
<td>26</td>
</tr>
<tr>
<td>2.5</td>
<td>Discussion</td>
<td>27</td>
</tr>
<tr>
<td>3.1</td>
<td>The Upper Three Forks Formation</td>
<td>40</td>
</tr>
<tr>
<td>3.1.1</td>
<td>Facies 1 (TF1)</td>
<td>41</td>
</tr>
<tr>
<td>3.1.2</td>
<td>Facies 2 (TF2)</td>
<td>41</td>
</tr>
</tbody>
</table>
3.1.3 Facies 3 (TF3) ........................................................................................... 41
3.1.4 Facies 4 (TF4) ........................................................................................... 41
3.1.5 Depositional Environment (TRFK) .......................................................... 42
3.2 The Bakken Formation ............................................................................. 42
   3.2.1 Pronghorn (PRHN) Facies ........................................................................ 43
   3.2.2 Bakken Lag (LAG) Facies ........................................................................ 43
   3.2.3 Lower Bakken Member (LBM) Facies ..................................................... 43
   3.2.4 Middle Bakken Member A Facies (MBM A) ........................................... 44
   3.2.5 Middle Bakken Member B Facies (MBM B) ........................................... 44
   3.2.6 Middle Bakken Member C/E Facies (MBM C/E) .................................... 45
   3.2.7 Middle Bakken Member D Facies (MBM D) ........................................... 46
   3.2.8 Middle Bakken Member F Facies (MBM F) ............................................ 46
   3.2.9 Upper Bakken Member (UBM) ............................................................... 46
   3.2.10 Depositional Environment (PRHN, LAG, LBM) ..................................... 47
   3.2.11 Depositional Environment (MBM) .......................................................... 47
   3.2.12 Depositional Environment (UBM) .......................................................... 48
3.3 The Lower Lodgepole Formation ............................................................. 48
   3.3.1 Scallion Facies (SCAL) ............................................................................ 49
   3.3.2 False Bakken Facies (FBKN) ................................................................... 49
   3.3.3 Depositional Environment (SCAL and FBKN) ........................................ 50
Chapter 6. Pore Characterization ........................................................................................................ 107

6.1 Qualitative Observations .............................................................................................................. 107

6.1.1 The Pay Interval ....................................................................................................................... 109

6.1.2 The Marginal Reservoir Interval ............................................................................................. 110

6.1.3 The Non-Reservoir Interval ................................................................................................... 110

6.1.4 The Role of Clay and Wettability in the MBM ......................................................................... 111

6.2 Quantitative Observations ........................................................................................................... 111

6.3 Discussion .................................................................................................................................... 113

Chapter 7. Reservoir Fluids and Wettability ..................................................................................... 135

7.1 MBM Reservoir Fluid Properties in the Elm Coulee Field ....................................................... 135

7.2 Oil Drop Core Tests ..................................................................................................................... 137

7.3 Injected Fluid Properties .............................................................................................................. 138

7.3.1 CO₂ ....................................................................................................................................... 138

7.3.2 Hydrocarbon Gas ................................................................................................................... 139

7.4 Surfactant and Bakken Crude Experiments .............................................................................. 140

7.5 Core Plug Imbibition Tests ......................................................................................................... 141

7.6 Fresh Water Flooding .................................................................................................................. 141

7.6.1 “Ion Bridge Removal” Resulting in Wettability Alteration................................................. 143

7.6.2 pH Increases Near Clay Surfaces ........................................................................................ 144

7.6.3 Recovery through Osmosis .................................................................................................. 145

x
LIST OF FIGURES

Figure 1.1: Structure map of the base of lower Mississippian strata, showing the limits of the Williston Basin (green line) and the Bakken Formation (dashed orange line). The red shaded polygon marks the extent of the continuous oil accumulation in the Bakken Formation. Major producing fields are shown in green filled polygons. Note the position of the Elm Coulee Field and its proximity to the limit of the Bakken Formation. Major structural features are also shown, including the Cedar Creek Anticline, the Billings Nose, and the Nesson Anticline (Theloy, 2014 modified from Sonnenberg and Pramudito, 2009) .................................................................................... 14

Figure 1.2: Map showing the location of the Elm Coulee Field relative to the state of Montana. The limits of Richland County are shown in red. The black line outlines Elm Coulee Field. Blue dots indicate cores described for this study, and except for Lucille 2-27, all of them have thin sections. Red dots indicate cores that weren’t described for this study but have available routine core analysis data. Green dots show the location of the two pilot injection wells, which are discussed in Chapter 8. Well labels are abbreviated accordingly: BT = Burning Tree 36-2; CP = Coyote Putnam; LU = Lucille 2-27H; PJ = Peanut Jimmy; PM = Peabody Minifie; SJ = Stockade Jayla; ST = Staci 3-11H. ................................................................................... 15

Figure 2.1: North American paleogeography and black shale deposits of the Late Devonian (360 Ma). Structural geologic features include: CS = Canadian Shield; AOB = Antler orogenic belt; AH = Acadian Highlands; TA = Transcontinental Arch. Black shale deposits include: B = Bakken; E = Exshaw; S = Sappington; CC = Cottonwood Canyon; L = Leatham; P = Pilot; PR = Percha; W = Woodford; C = Chattanooga; NA = New Albany; A = Antrim. The position of the paleo-equator (EQ) is marked by a dashed line. The transition from shallow to deeper waters is marked with a dotted line. Note the connection between the Elk Point and Williston Basin, as well as the Williston Basin’s proximity to the paleo-equator (Sonnenberg and Pramudito, 2009; modified from Blakey, 2005) .................................................................................. 28

Figure 2.2: Underlying Precambrian basement provinces the Williston Basin. The north – south trending Trans-Hudson orogenic belt appears to control the orientation of the north – south and northwest – southeast trending structures. Note the location of the Poplar Anticline and the Brockton Froid Fault Zone, as both are structural features that have influenced the Elm Coulee Field (Sonnenberg et al., 2011). ................................................. 29

Figure 2.3: Petal and open fracture directions observed in oriented Bakken cores, oriented Mission Canyon cores at Little Knife, and regional maximum horizontal stress directions (Sonnenberg et al., 2011). ................................................................. 30
Figure 2.4: Generalized stratigraphic column of the Williston Basin, showing major sequences as well as stratigraphic units that produce oil and gas (Gerhard et al., 1990). .......................................................... 31

Figure 2.5: Schematic diagram illustrating the four main stages involved in the salt dissolution and multistage salt collapse structures. Note how the syndepositional dissolution of the Prairie Formation Salt resulted in creation of anomalously thick sections in the Bakken Formation (Rolfs, 2015; modified from Oglesby, 1988). .......... 32

Figure 2.6: Model illustrating the Prairie Formation Salt dissolution and the resultant thick Bakken Formation in the Elm Coulee Field. A) Following Three Forks Formation deposition, meteoric recharge initiates the dissolution of the Devonian Prairie Salts. B) An accommodation space is created as a result of dissolution, allowing for the formation of a Bakken Formation thick. Further meteoric input lead to dolomitization in accordance with the seepage-reflux model (Sonnenberg and Pramudito, 2009)............................................................................................................... 33

Figure 2.7: Generalized stratigraphic column of the Bakken Petroleum System not specific to the Elm Coulee Field. Note that the Pronghorn is labeled as its historic name, the Sanish (modified from Sonnenberg et al., 2011). ............................................................. 34

Figure 2.8: Modified Van Krevelen diagram for the Bakken Formation shales. The majority of samples indicated a type I and II oil-prone kerogen. HI = Hydrogen Index; OI = Oxygen Index (Sonnenberg, 2011). .................................................................................. 35

Figure 2.9: The different play subdivisions within the Bakken unconventional play. Note that each field or area has its own different set of conditions that have contributed to its production success (Theloy, 2014). ............................................................. 36

Figure 2.10: Series of diagenetic events that occurred in the Middle Bakken Member in North Dakota (Pitman, et al., 2001). .................................................................................................. 37

Figure 2.11: Series of diagenetic events that occurred in the Middle Bakken Member in the Elm Coulee Field specifically (Alexandre, 2011). ............................................................. 38

Figure 2.12: Well log from the Franz well (UWI: 25083216430000) that shows the entire Bakken Petroleum System in the Elm Coulee Field. Lithology from the upper Three Forks, Bakken, and lower Lodgepole Formations are displayed. TRFK = Three Forks; LBM = Lower Bakken Member; MBM = Middle Bakken Member; UBM = Upper Bakken Member; SCAL = Scallion; FBKN = False Bakken. Note the high gamma ray response in the Upper Bakken Shale, over 200 API, as well as the high resistivity response, over 2000 ohm.m. Also observe the low porosity in the Middle Bakken Member, which is below 10%. ............................................................. 39
Figure 3.1: A) Core photograph of Three Forks Facies 2 (TF2) taken from the Peanut Jimmy core at 10486’. B) Core photograph of Three Forks Facies 3 (TF3) taken from the Coyote Putnam core at 10393’. Pencils for scale. ................................................................. 53

Figure 3.2: A) Core photograph of Three Forks Facies 4 (TF4) taken from the Peabody Minifie core at 10445.1’. Note the ripple lamination and alternating coarse/fine intervals. B) Core photograph of Pronghorn facies (PRHN) taken from the Stockade Jayla core at 9755.5’. Note the light grey banding. Pencils for scale. .............................. 54

Figure 3.3: Six photomicrographs illustrating the facies of the Middle Bakken Member in Elm Coulee. Each photograph was taken in plane polarized light (PPL) and features a 1 mm long scale bar. A) Photograph of the MBM A with brachiopod fragments. Taken from Peanut Jimmy core at 10466.65’. B) Photograph of the MBM B (non-reservoir rock) with Helminthopsis. Taken from Peanut Jimmy core at 10447.5’. B2) Photograph of the MBM B (reservoir rock) featuring blue epoxy that fills porosity. Taken from the Peanut Jimmy core at 10439.25’. C/E) Photograph of the MBM C/E with lamination. Taken from Peabody Minifie core at 10413’. D) Photograph of the MBM D with coarser grains and some porosity indicated by blue epoxy. Taken from the Stockade Jayla core at 9721.8’. F) Photograph of the MBM F with an altered bioclasts and pink epoxy indicating porosity. Taken from the Peanut Jimmy core at 10432.55’. .......................................................................................................................... 55

Figure 3.4: A) Core photograph of the Bakken lag (LAG) taken from the Lucille 2-27H core at 10109.25’ with pencil for scale. Note the dark black organic rich rip-up clasts present in the lag interval. B) Core photograph of the Lower Bakken Member (LBM) taken from the Peabody Minifie core at 10437.5’ with pencil for scale. Note the coarser and siltier nature of the LBM. ............................................................................................................. 56

Figure 3.5: A) Core photograph of the Middle Bakken Member A facies (MBM A) taken from the Peabody Minifie core at 10435.4’. Arrow marks the brachiopod fossil fragments. B) Core photograph of the Middle Bakken Member B facies (MBM B) taken from the Peabody Minifie core at 10428.5’. Arrow marks the abundant Helminthopsis bioturbation. Pencils for scale. ................................................................. 57

Figure 3.6: A) Core photograph of the Middle Bakken Member C/E facies taken from the Peabody Minifie core at 10413’. Note the wavy clay - rich laminations. B) Core photograph of the Middle Bakken Member D facies taken from the Stockade Jayla core at 9719’. Note the subtle wavy cross laminations. Pencils for scale. ............................................. 58

Figure 3.7: A) Core photograph of the Middle Bakken Member F facies (MBM F) taken from the Coyote Putnam core at 10348’. Arrows mark the bioclasts (pink arrow) and sharp contact with the UBM (yellow arrow). B) Core photograph of the Upper Bakken Member facies (UBM) taken from the Peabody Minifie core at 10407.5’. Note the subtle laminations. Arrow marks pyrite blebs around the calcite cemented oblong feature. Pencils for scale. ......................................................... 59
Figure 3.8: A) Core photograph of the Scallion facies (SCAL) taken from the Peabody Minifie core at 10400’. Note the mottled texture and arrow marks crinoids present. B) Core photograph of the False Bakken (FBKN) facies taken from the Peabody Minifie core at 10391’. Note the rare crinoids (marked with arrow). Pencils for scale. .. 60

Figure 4.1: Key for the lithologic symbols and patterns used in the core description columns in Figures 4.2 – 4.6. ........................................................................................................... 71

Figure 4.2: Digitized core description of the Stockade Jayla well. MR = marginal reservoir; PAY = pay; NR = non – reservoir. ........................................................................................................... 72

Figure 4.3: Digitized core description of the Lucille 2-227H well. No other data was made available. ........................................................................................................................... 73

Figure 4.4: Digitized core description of the Peabody Minifie well. Note that while the density porosity log was not calibrated properly, it exhibits the same UBM trend present in other parts of the field. MR = marginal reservoir; PAY = pay; NR = non – reservoir. ........................................................................................................................... 74

Figure 4.5: Digitized core description of the Coyote Putnam well. MR = marginal reservoir; PAY = pay; NR = non – reservoir. ................................................................................... 75

Figure 4.6: Digitized core description of the Peanut Jimmy well. MR = marginal reservoir; PAY = pay; NR = non – reservoir. ................................................................................... 76

Figure 4.7: Location map for the cross section of the five cores described in this study. Black polygon indicates limits of Elm Coulee Field. Faint grey line indicates the mapped limit (from well logs) of the MBM. .................................................................... 77

Figure 4.8: Cross section of the five cores described for this study. The cross section runs from west to east. The datum is the base of the UBM. ..................................................... 78

Figure 4.9: Graph of XRD data from the Stockade Jayla well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus. ........................................................................ 79

Figure 4.10: Graph of the fluid saturation data from the Stockade Jayla well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus. ........................................................................ 80

Figure 4.11: Graph of XRD data from the Coyote Putnam well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus. ........................................................................ 81
Figure 4.12: Graph of the fluid saturation data from the Coyote Putnam well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus................................. 82

Figure 4.13: Graph of XRD data from the Peabody Minifie well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus ........................................ 83

Figure 4.14: Graph of the fluid saturation data from the Peabody Minifie well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus ........................................ 84

Figure 4.15: Graph of XRD data from the Peanut Jimmy well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus........................................... 85

Figure 4.16: Graph of the fluid saturation data from the Peanut Jimmy well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus........................................... 86

Figure 5.1: Structure map of the top of the Three Forks Formation. Richland County, MT, is outlined in red and the Elm Coulee Field polygon is outlined with the thick black line. Depth values are ft in Sub-Sea True Vertical Depth (SS TVD). ......................... 93

Figure 5.2: Structure map of the top of the Bakken Formation. Richland County, MT, is outlined in red and the Elm Coulee Field polygon is outlined with the thick black line. Depth values are ft in Sub-Sea True Vertical Depth (SS TVD). ......................... 94

Figure 5.3: Isopach map of the entire Bakken Formation. Thickness is in ft. The formation pinch-out is marked in the south to southwest with a black/orange contour line. ............ 95

Figure 5.4: Isopach map of the Middle Bakken Member. Thickness is in ft. The formation pinch-out is marked in the south to southwest with the “0” contour line. ..................... 96

Figure 5.5: Oil production from the MBM reservoir in the Elm Coulee Field and surrounding area. Bubble size is based on EUR value, which was calculated using the effective exponential Arp’s equation.................................................................. 97

Figure 5.6: Probability distribution of EUR by well in the Elm Coulee Field. The blue line is comprised of individual points from roughly 600 EUR values calculated from wells in only the Elm Coulee Field. The Swanson’s mean value for EUR in the field is 269,175 bbl. The arithmetic mean value for EUR in the field is 266,969 bbl. Both of
these mean values are higher than the P50 value calculated for EUR in the field, 221,528 bbl. .......................................................................................................................... 98

Figure 5.7: A decline curve for a well with below average EUR. The calculated EUR is 58,707 bbl. The well is Boulder Stone 26-16H (UWI: 25083220560000). ...................... 99

Figure 5.8: A decline curve for a well with a roughly average EUR. The calculated EUR is 259,210 bbl. The well is Antone-Dombrowski 17-4-H ............................................ 100

Figure 5.9: A decline curve for a well with an above average EUR. The calculated EUR is 751,972 bbl. The well is Frasca 24X-14 (UWI: 25083220810100). .............................. 101

Figure 5.10: The EUR bubble map placed on top of the MBM Isopach. The production trend also runs NW – SE but does not directly correlate with the thickness trend. This is likely due to lateral changes in lithology/mineralogy in the area, which then subsequently affects pore geometry and fluid saturations. ............................................. 102

Figure 5.11: Attribute map displaying major E&P operators working the Elm Coulee Field. Lyco and Enerplus are assigned one color and considered one company, given that Enerplus bought Lyco. ............................................................................................................. 103

Figure 5.12: Contour map of the average water saturation for the entire MBM interval. Contours are based on decimal values, and every 0.2 is bolded. ................................. 104

Figure 5.13: Bubble map displaying the cumulative oil/ oil + water production. Hotter colors represent wells that almost exclusively produced oil and colder colors represent wells that produced comparatively more water. All wells displayed are horizontal wells drilled after 2000 with the MBM as a lateral target. ............................................................... 105

Figure 5.14: Hydrocarbon pore volume map, also known as SoPhiH map. Contours represent 0.1 hydrocarbon pore-ft. ................................................................................. 106

Figure 6.1: A) Example of lithology in the pay interval. Taken from MBM B in the Peanut Jimmy well (MD: 104224.3’). Epifluorescent light used to highlight porosity. B) Example of lithology in the non-reservoir interval. Taken from MBM B in the Peanut Jimmy well (MD: 10457.6’). Epifluorescent light used to emphasize lack of porosity. ................................................................................................................................. 115

Figure 6.2: Example of the lithology in the pay interval. Taken from MBM C in the Stockade Jayla well (MD: 9721.8’). A) Taken with epifluorescent light to emphasize porosity. Pink arrow marks intercrystalline “slot pore. Green arrow marks secondary dissolution pore. Blue circle marks microporosity. B) Taken with cross-polarized
light to emphasize mineral content. Red arrow marks dolomite rhomb. Green arrow marks oil staining ................................................................. 116

Figure 6.3: Figure 6.2 under less magnification, in order to emphasize the extensive pore network and the various pore types present in the pay interval. Blue circle marks microporosity. Pink marks intergranular porosity. Green arrow marks intergranular “slot porosity”. Blue Arrow marks intercrystalline porosity ................................................................. 117

Figure 6.4: Example of the lithology in the pay interval. Taken from the MBM B in the Coyote Putnam well (MD: 10358’). A) Taken with epifluorescent light to emphasize porosity and microfractures present. Blue circle marks mircoporosity. Blue arrow marks microfracture. Green arrow marks secondary dissolution porosity. B) Taken with plane-polarized light to emphasize mineral content (note the dolomite rhombs) and porosity (shown in pink dye). Green arrow marks dolomite rhomb .............................................. 118

Figure 6.5: Example of lithology in the calcite and clay rich marginal reservoir interval. Taken from MBM C in the Coyote Putnam well (MD: 10348.49’). A) Taken with epifluorescent light to emphasize lack of porosity. B) Taken with cross-polarized light to emphasize the higher clay and calcite content. Blue circle marks detrital clay. Green arrow marks calcite. Pink arrow marks a dolomite rhomb ...................................................... 119

Figure 6.6: Example of the lithology in the pervasive dolomite marginal reservoir interval. Taken from the MBM D in the Stockade Jayla well (MD: 9719.7’). A) Taken with epifluorescent light to emphasize relative lack of porosity. Green arrow marks microfracture. Pink arrow marks microporosity. Orange arrow marks “slot porosity”. B) Taken with cross-polarized light to emphasize mineral content. Note the anhydrite cement. White circle marks anhydrite. Pink arrow marks dolomite ...................................................... 120

Figure 6.7: Example of the lithology in the non-reservoir interval. Taken from the MBM B in the Peanut Jimmy well (MD: 10457.6’). A) Taken with epifluorescent light to emphasize relative lack of porosity. B) Taken with cross-polarized light to emphasize mineral content (features calcite and higher clay content). Pink arrow marks calcite. Red arrow marks clay ............................................................................. 121

Figure 6.8: Argon ion milled FE-SEM image taken with a backscatter electron beam. Taken from the Coyote Putnam well (MD: 10,350.3’) Q = quartz; D = dolomite ; ill = illite. Note how the majority of pore volumes are filled primarily with illites ................................................................. 122

Figure 6.9: Argon ion milled FE-SEM image taken with a backscatter electron beam. Taken from the Stockade Jayla well (MD: 9727.6’) Qtz = quartz; Dolo = dolomite; ill = illite; Nsp = Sodium feldspar; Ksp = potassium feldspar. Note how illite lines and bridges each pore present. Additionally, illite fills or lines each path for pores to communicate with each other ................................................................. 123
Figure 6.10: Energy-dispersive X-ray spectroscopy (EDAX) “map” taken from the Coyote Putnam well (MD: 10350.3’). Aluminum is used as a proxy for the presence of clays, and is shown in orange. This map illustrates the relative abundance of clays, especially in between crystals and grains, presumably filling pores. ................................. 124

Figure 6.11: Broken sample FE-SEM image taken with a secondary electron beam. Sample taken from the Coyote Putnam well (MD: 10353.25’). D = dolomite; Ksp = Potassium feldspar; ill = illite. Illites bridge and fill intercrystalline pore space. ............. 125

Figure 6.12: Argon ion milled FE-SEM image taken with a backscatter electron beam. Taken from the Stockade Jayla well (MD: 9721.8’). D = dolomite; Q = quartz; ill = illite; ogm = organic matter. Illite lines the large pore in the center, and appears to preferentially adsorb the organic material. Additionally, dolomite appears to adsorb organic material as well. ................................................................................................. 126

Figure 6.13: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,350.3’). Taken from the MBM C. RCA and XRD show that porosity = 5.9%; So = 40%; Sw = 11.8%; dolomite wt% = 47.6%; calcite wt% = 0%. Data courtesy of Enerplus. ...................................................................................................... 127

Figure 6.14: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,353.3’). Taken from the MBM B. RCA and XRD show that porosity = 7.8%; So = 49.6%; Sw = 1%; dolomite wt% = 55%; calcite wt% = 0%. Data courtesy of Enerplus. ...................................................................................................... 128

Figure 6.15: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,356.4’). Taken from the MBM B. RCA and XRD show that porosity = 5.9% ; So = 40%; Sw = 11.8% ; dolomite wt% = 47.6%; calcite wt% = 0%. Data courtesy of Enerplus. ...................................................................................................... 129

Figure 6.16: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,364.4’). Taken from the MBM B. RCA and XRD show that porosity = 4.2%; So = 0%; Sw = 67.4%; dolomite wt% = 37.5%; calcite wt% = 6.7%. Data courtesy of Enerplus. ...................................................................................................... 130

Figure 6.17: Pore throat size and distribution of a sample from the Bullwinkle Yahoo well (MD: 10,462.3’). Taken from the MBM C. RCA and XRD show that porosity = 10.6%; So = 40%; Sw = 7.7%; dolomite wt% = N/A%; calcite wt% = N/A%. Facies taken from Eidsnes (2013). Data courtesy of Enerplus. ......................................................... 131

Figure 6.18: Pore throat size and distribution of a sample from the Bullwinkle Yahoo well (MD: 10,467.45’). Taken from the MBM B. RCA and XRD show that porosity = 9.3%; So = 38%; Sw = 10%; dolomite wt% = 44%; calcite wt% = 0%. Facies taken from Eidsnes (2013). Data courtesy of Enerplus. ......................................................... 132
Figure 6.19: Pore throat size and distribution of a sample from the Bullwinkle Yahoo well (MD: 10,472.25'). Taken from the MBM B. RCA and XRD show that porosity = 6%; So = 30%; Sw = 27%; dolomite wt% = 42.8%; calcite wt% = 0%. Facies taken from Eidsnes (2013). Data courtesy of Enerplus. ........................................................... 133

Figure 6.20: Pore throat size and distribution of a sample from the Peabody Minifie well (MD: 10,425'). Taken from the MBM B. RCA and XRD show that porosity = 7.2%; So = 39%; Sw = 12%; dolomite wt% = N/A%; calcite wt% = N/A%. Data courtesy of Enerplus. ..................................................................................................................... 134

Figure 7.1: A) Comparison of oil drop and produced water drop imbibing into a cleaned core over time. B) Oil drop imbibing into a core treated with produced water over time. All core samples taken from the Peabody Minifie 26 – 14 well. Data courtesy of Enerplus via Surtek. ............................................................................................................. 150

Figure 7.2: A) Comparison of oil drop and fresh water drop imbibing into a cleaned core over time. B) Oil drop imbibing into a core treated with fresh water over time. All core samples taken from the Peabody Minifie 26 - 14 well. Data courtesy of Enerplus via Surtek. ....................................................................................................................... 151

Figure 7.3: Summary of interfacial tension (IFT) between Bakken crude oil and surfactants dissolved in produced water at 180°F. Only Zonyl FSO showed considerable changes in IFT with increased concentration. Data courtesy of Enerplus via Surtek.….. 154

Figure 7.4: Summary of interfacial tension (IFT) between Bakken crude oil and surfactants dissolved in fresh water at 180°F. Only Petrostep A6 showed considerable changes in IFT with increased concentration, however, it also formed an emulsion with the Bakken crude oil. Data courtesy of Enerplus via Surtek. ............................................... 156

Figure 7.5: Summary of interfacial tension (IFT) between Bakken crude oil and surfactants dissolved in fresh water at 180°F. Data courtesy of Enerplus via Surtek. ...................... 157

Figure 7.6: Schematic drawing of the core plug imbibition test apparatus. ............................... 159

Figure 7.7: Percentage of oil recovered from Peabody Minifie cores versus time. Both surfactants dissolved in fresh water and fresh water itself outperformed surfactants dissolved in produced water and produced water as imbibition fluids. Data courtesy of Enerplus via Surtek. ............................................................................................................. 162

Figure 7.8: Percentage of oil recovered versus time. Taken from core plug 3 using fresh water following produced water injection. Data courtesy of Enerplus via Surtek. ....... 163

Figure 7.9: Ion bridge mechanism proposed by Ligthlellem et al. (2009). ................................. 164
Figure 7.10: Cartoons illustrating the bonding between the clay surface and oil in a highly saline compared to a low saline environment. The Ca$^{2+}$ ion represents multivalent cations that act as an “ion bridge” Ligthelem et al. (2009).......................... 164

Figure 7.11: Proposed mechanism for low salinity EOR effects. Upper three panels demonstrate the desorption of basic material. The lower three panels demonstrate the desorption of acidic material. Initial pH conditions for this reaction are roughly 5 (Austad et al., 2010)........................................................................................................ 165

Figure 7.12: Schematic showing oil-water flow in shale and the effect of osmosis: (a) pore space at initial conditions where oil is essentially the only moveable fluid and high-salinity brine is bound to clay sheets. (b) clay in comes in contact with fresh water, which then pushes oil out of meso-pores (Fakcharoenphol et al., 2014)................. 165

Figure 8.1: Close up location map of the Burning Tree 36-2H well. The well has a shorter than average lateral length for the Elm Coulee Field. Note the lateral orientation as well; it appears to be nearly perpendicular to the maximum horizontal stress in the Bakken Formation of the Williston Basin. ................................................................. 174

Figure 8.2: Oil production in the Burning Tree 36-2H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate period of the CO2 injection is marked on the curve as well................................................................. 175

Figure 8.3: Oil production in the Burning Tree State 36-2H well. Monthly production rate vs cumulative oil produced is plotted on a linear plot. The approximate period of the CO2 injection is marked on the curve as well. ................................................................. 176

Figure 8.4: Oil production in the Burning Tree 36-2H well. Monthly production rate vs year is plotted on a semi-log plot. A decline curve was fitted on the pre-injection production trend using Arp’s effective exponential equation to determine EUR........... 177

Figure 8.5: Oil production in the Burning Tree 36-2H well. Monthly production rate vs year is plotted on a semi-log plot. A decline curve was fitted on the post-injection production trend using Arp’s effective exponential equation to determine EUR........... 178

Figure 8.6: Close up location map of the Staci wells (1-11H, 2-11H, and 3-11H). Each well is respectively labeled by its surface location. Bottomholes are indicating by filled in green dots. Both the producing wells (1-11H and 2-11H) feature two separate laterals going north and south respectively. The Staci 3-11H well, a production well converted to an injector, only has one lateral, running north to south. Note the proximity of the 3-11H well to the 1-11H well, the producer that was possibly affected by the 3-11H injection....................................................... 179
Figure 8.7: Production (oil, gas, and water) plot of the Staci 3-11H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate injection time of the injection period is marked. Plot modified from the Montana Board of Oil and Gas Online Data. ................................................................. 180

Figure 8.8: Production (oil, gas, and water) plot of the Staci 1-11H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate injection time of the injection period is marked. Plot modified from the Montana Board of Oil and Gas Online Data. ................................................................. 181

Figure 8.9: Production (oil, gas, and water) plot of the Staci 2-11H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate injection time of the injection period is marked. Also note the “frac hit” marked prior to the Staci 3-11h injection. Plot modified from the Montana Board of Oil and Gas Online Data. 182

Figure 8.10: Aerial photo of several Enerplus owned wells in a 1X2 mile area in the Elm Coulee Field. Colored dots indicate microseismic responses from hydraulically induced fractures. Known faults are mapped with red dashed lines. Note how the faults, the induced fractures, and the surficial stream features have a consistent NE – SW orientation. Another important detail is that often surficial streams are expressions of subsurface features such as faults (O’Brien et al., 2011). ....................... 183

Figure 8.11: Aerial map of the Staci wells (1-11H, 2-11H, and 3-11H). Green triangles represent surface locations of each well and green circles represent well bottomholes. Approximate well paths are marked with green lines. Relevant townships are marked with red squares and numbered respectively. There are three main NE – SW trending surficial drainage features, which could reflect controlling subsurface features. Photo modified from Google Earth. ................................................................. 184

Figure 8.12: Topographic map featuring the Staci wells (1-11H, 2-11H, and 3-11H). Green triangles represent surface locations of each well and green circles represent well bottomholes. Approximate well paths are marked with green lines. Relevant townships are marked with black squares and numbered respectively. The main NE – SW trending surficial drainage features, which could reflect controlling subsurface features are marked with dashed red lines. Topographic map was made from merging the following USGS 1:24,000 quadrangles in Richland County: Lambert, Fox Lake, Three Buttes Creek West, and Three Buttes Creek East (modified from USGS Historical Topographic Maps). ................................................................. 185
LIST OF TABLES

Table 1.1: Summary of available Elm Coulee core data for this study. It should be noted that only the four cores with thin sections and Lucille 2-27 were studied for this project. All other cores were used to corroborate field-wide trends. “Desc.” indicates the core was described; “T.S.” indicates the core had thin sections available for this study; “RCA” indicates that routine core analysis was performed and the data is available; “SEM” indicates that scanning electron microscope samples were prepared from the core for this study; “MICP” indicates that mercury injection capillary pressure data was made available; “Other” indicates that wettability and imbibition experiments were performed on the core. No core data was available for the Staci 3-11H injection well...................................................... 16

Table 1.2: Screening criteria for EOR methods and average Bakken Formation properties, modified from Ling et al. (2014). Each column describes ideal reservoir conditions for each EOR method. The rightmost column describes average Bakken Formation properties throughout the entire basin for the unconventional Bakken play, along with recommendations for future EOR................................................................. 17

Table 3.1: Summary of facies present in Bakken Petroleum System in the Elm Coulee Field. These facies are modified from the Colorado School of Mines Bakken Consortium facies (Sonnenberg, 2010). .................................................................................................................................. 52

Table 7.1: Analysis of produced water from the Peabody Minifie 26 - 14 well in the Elm Coulee Field as well as a fresh water sample for comparison. Data courtesy of Enerplus via Surtek................................................................. 147

Table 7.2: Summary of water analyses taken from three separate fields producing from the Bakken Formation in North Dakota (Kurtoglu, 2013).................................................. 148

Table 7.3: Summary of crude oil analysis taken from the Peabody Minifie well in the Elm Coulee Field. Data courtesy of Enerplus via Surtek................................................................. 148

Table 7.4: Summarization of crude oil analyses taken from three separate fields producing from the Bakken Formation in North Dakota (Kurtoglu, 2013).................................................. 149

Table 7.5: Summarization of conventional saturates, aromatics, resins, and asphaltenes (SARA) analysis and medium-pressure liquid chromatography (MPLC) analysis. Note the concentration of resins, asphaltenes, and aromatics (Kurtoglu, 2013).............. 149

Table 7.6: Summarization of total acid number (TAN) and total base number (TBN) of Bakken crude oil from two fields in North Dakota (Kurtoglu, 2013) ......................... 149
Table 7.7: Summary of minimum miscibility pressures found through experimental means (RBA) and popular models. The oil used was a recombined Bakken crude sample from a North Dakota field. CO₂ has the lowest MMP of all injected fluids (Adekunle, 2014). .............................................................................................................................. 152

Table 7.8: Summary of Bakken crude oil swelling and viscosity reduction tests. Performed at 237° F with CO₂ as the solvent. ........................................................................................................................................ 152

Table 7.9: Summary of the surfactants dissolved in produced water. Table includes structure, solution activity, and supplier. Data courtesy of Enerplus via Surtek. ............... 153

Table 7.10: Summary of the surfactants dissolved in fresh water. Table includes structure, solution activity, and supplier. Data courtesy of Enerplus via Surtek. ............... 155

Table 7.11: Summary of each core plug used for the imbibition study. Includes core dimensions, density, weight, estimated porosity, and estimated oil saturation following Bakken crude oil imbibition. Data courtesy of Enerplus via Surtek. ............. 158

Table 7.12: Summary of cores and respective imbibition fluid used. Displays volume oil displaced over time from Peabody Minifie core plugs. Data courtesy of Enerplus via Surtek. ............................................................................................................................. 160

Table 7.13: Summary of cores and respective imbibition fluid used. Displays volume oil displaced over time from Peabody Minifie core plugs. Data courtesy of Enerplus via Surtek. ............................................................................................................................. 161

Table 8.1: CO₂ utilization ratios by development phase for various petroleum producing regions throughout the United States (Wallace and Kuuskraa, 2014)................................. 179
Figuratively, scientific progress is not made in a vacuum by a single individual. It is the culmination of previous work and collaborative thinking. So while this study may only have one author, it is the product of many hearts and minds. First and foremost, I would like to thank my advisor, Dr. Stephen Sonnenberg, for supporting and guiding me through the difficult process of graduate school. I would also like to thank my committee members, Dr. Hossein Kazemi, for teaching a geologist engineering concepts, and Dr. Mary Carr, for asking the necessary tough questions. In addition, I would like to thank my peers from the Bakken Research Consortium, for their willingness to discuss problems and play devil’s advocate when need be. In particular, I would like to thank James Friedrich, Thomas Lockwood, Amanda Wescott, and Matthew Bauer.

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CHAPTER 1. INTRODUCTION

The Upper Devonian-Lower Mississippian Bakken Formation is a highly economic play within the Williston Basin (North Dakota and Montana, US). The Elm Coulee Field, located in Richland County, Montana, was discovered in 2000 by Lyco Energy (now Enerplus), and has historically been the largest field in the unconventional Bakken play. The field is projected to have an estimated ultimate recovery of potentially over 300 million barrels of oil (Theloy, 2014). As of 2013, the Elm Coulee Field has cumulatively produced 137 MMBO (Department of Natural Resources and Conservation of the State of Montana, 2013).

The Bakken Formation consists of three members in Elm Coulee Field: an upper shale member, a middle silty dolostone member (known as the Middle Bakken Member, or, MBM), and a locally present lower silty/shale member. The MBM is the main reservoir of the field however, it is characterized by low porosity and permeability throughout the field. Due to its poor reservoir quality, production from the MBM in Elm Coulee would not be possible without recent advances in technology, most notably horizontal drilling combined with multi-stage hydraulic fracturing. In order to continue improving production, further unconventional technologic advances and considerations must be made. In spite of these unconventional approaches to development, the primary recovery factor of the field remains low, ranging from 5 to 10% of OOIP. Significant oil reserves are available for secondary and tertiary production, but any attempts at enhanced oil recovery (EOR) must be deliberately approached given the challenging nature of the reservoir.

This study synthesizes field- to nano-scale geologic data in order to better understand the MBM at Elm Coulee, so that EOR attempts can be optimized. Popular EOR methods, such as solvent flooding (CO₂ and hydrocarbon gas injection), chemical injection (surfactants), and fresh
water flooding (also known as low–salinity flooding) will be examined with respect to the reservoir characterization performed.

1.1 Objectives and Purpose

Although the Bakken Formation has been thoroughly studied throughout the Williston Basin, including Elm Coulee, there have been no in depth reservoir characterization studies published with respect to EOR in the Elm Coulee Field specifically. Recently, several simulated academic production models have been made (Shoaib and Hoffman, 2009; Pu, 2013), as well as discussions of constraints related to engineering aspects of EOR (Kurtoglu, 2013). The reservoir characterization performed by Kurtoglu (2013) made some geologic observations, but none specific to the Elm Coulee Field. Previous work discussing the Elm Coulee Field has focused on initial reservoir characterization, fracture characterization, and the role of diagenesis on reservoir quality. However, these analyses do not contain modern production data. Additionally, these studies have not included mercury injection capillary pressure, field emission scanning electron microscopy, or experimental wettability data, which will give greater insight into reservoir conditions that could directly affect EOR methods. This project provides an updated reservoir characterization of the MBM in Elm Coulee, which can be compared to updated estimated ultimate recovery (EUR) trends throughout the field.

The general objectives of this study are:

- Identify and describe facies present in the Bakken Petroleum System in Elm Coulee.

- Determine target intervals and reservoir quality in the MBM using routine core plug analysis data.
• Map geologic and production trends on a field scale, and integrate any observations made with core data.

• Characterize the pore system using both qualitative and quantitative methods. This characterization will be performed considering both historical primary production and future tertiary production.

• Describe the fluid properties in the MBM reservoir, as well as the fluid-rock interactions that occur. Also, describe how these fluid-rock interactions can be changed.

• Examine case study data from two pilot well injections in the Elm Coulee Field: the Burning Tree 36-2 well, drilled by Lyco/Enerplus (UWI: 25083218810000), a CO₂ “huff and puff” injection; the Staci 3-11H well, drilled by Continental Resources (UWI: 25083227480100), a water injection well.

Ling et al. (2014) argues that there are twelve relevant geologic and fluid features of a field that must be taken into account for EOR reservoir characterization: oil gravity, oil viscosity, reservoir depth, reservoir temperature, reservoir thickness, oil saturation, reservoir pressure, gas cap, and reservoir heterogeneity, porosity, permeability, and lithology. In addition to these twelve factors, reservoir fracture density and geometry must also be taken into account. These listed factors, once described adequately, can be used to assess not only what EOR method should be used but how the specific method should be implemented. This study will address oil gravity and viscosity as well as reservoir depth, thickness, oil saturation, heterogeneity, porosity, permeability, and lithology.
1.2 Study Area

The Elm Coulee Field is an approximately 530 square mile oblong producing area located near the southwest margin of the Williston Basin in Richland County, Montana (Figure 1.1). The primary study area consists of this entire field, which consists of about 30 townships (Figure 1.2). The well-log suite provided through the Bakken Research Consortium at Colorado School of Mines was used to constrain the boundaries of the field. Production in the Elm Coulee is from a silty-dolostone in the Middle Bakken Member (MBM) of the Bakken Formation and as of 2013 137 MMBO has been produced (Montana Oil and Gas Commission, 2013).

1.3 Data Used

As this thesis project focuses on reservoir characterization of a mature field, a wide array of data was available for analysis. Much of this data was acquired from cores present in the field (Figure 1.2), all of which are summarized in (Table 1.1). All cores used for this study are supplied courtesy of Enerplus, excluding the Lucille 2-27H core, which was taken by Continental Resources and is available at the USGS CRC. Given the scope of this project, an emphasis was placed on using data from the four Enerplus cores with available petrographic thin sections. The Lucille 2-27H core was also described, despite its relative lack of other associated data, because a description of the core has not yet been published. Core description from this study focused on picking facies boundaries, determining lithologies, and describing relevant sedimentary structures or bioturbation that are present. Available cores that were not described or discussed in this study were used to corroborate trends seen in the described cores throughout the field.
Mercury injection capillary pressure (MICP) tests were performed on rock samples from the Coyote Putnam, Peabody Minifie, and Bullwinkle Yahoo cores to better understand pore throat geometries. A field emission scanning electron microscope (FE-SEM) was used to image both broken and argon ion milled samples taken from the Stockade Jayla and Coyote Putnam cores. In addition to secondary and backscatter imaging, the FE-SEM was used for Energy-dispersive X-ray spectroscopy (EDX) in order to create “mineral-maps” of the prepared FE-SEM samples. Core imbibition and wettability experiments were also performed on samples from the Peabody Minifie core by Surtek Inc., located in Golden, Colorado.

Geologic and production mapping was performed using IHS Petra. In total, 477 digital well logs from both North Dakota and Montana were used to map geologic features and regional trends in Elm Coulee. Monthly production data was obtained from the IHS Enerdeq database in late 2015 to map production trends and determine EUR values of wells throughout the field. Also, 692 wells were used for production analysis. Criteria for these necessitate that they are horizontal wells drilled after 2001, with the Bakken (the MBM specifically) as a target formation. These criteria ensure consistency of play type and data throughout the process.

Monthly production data from IHS Enerdeq was used in the presentation of the Burning Tree 36-2 well mini-injection case study. In addition to this production data, details discussing the injection scheme and initial reservoir conditions were provided courtesy of Enerplus. Monthly production data was also taken from the Montana Board of Oil and Gas website in order to discuss the Staci 3-11H pilot water injection well.
1.4 Previous Work and Research

There has been extensive research conducted on the Bakken and Three Forks formations in the Williston Basin, with material published on the subject dating back to the 1940s. Robinson, LeFever, and Gaswirth (2011) published and compiled an extensive list of roughly 200 references that focused on the Bakken and Three Forks formations in the Williston Basin. This list covers topics including: sequence stratigraphy, depositional environments, paleoenvironmental settings, mineralogy, structural lineament mapping, reservoir characterization, specific field studies, horizontal drilling and well studies, and other relevant subjects. With respect to EOR, Ling et al. (2014) published a review of EOR methods historically applied throughout conventional plays in the Williston Basin, beginning with water injection in 1958 and followed by other methods in the mid 1980s.

The Bakken Research Consortium at the Colorado School Mines began publishing material specifically on Elm Coulee in 2008 and has continued up to the present, including this study. Previous work relevant to this study conducted by the Bakken Research Consortium and other authors are summarized below.

1.4.1 Sonnenberg and Pramudito, 2009


This paper serves as an excellent introduction to the Bakken Petroleum System and is quite comprehensive of the fundamental portions of the system. This paper covers the paleogeographic and paleoenvironmental conditions during Bakken Formation deposition, and includes a possible depositional model. The paper also covers the structural geology of the Bakken Formation in Elm Coulee, the stratigraphic trap in the south and west portions of the
field, and the NW – SE thickness trend in the Middle Bakken in the field. This thickness trend is related to accommodation space created by the two stage-dissolution of the underlying evaporite deposits in the Devonian Prairie Formation. Other topics covered include: source rock characteristics, well log characteristics of the Bakken Formation in Elm Coulee, porosity/permeability characteristics of the Bakken Formation, bottom hole temperatures, and crude oil properties.

1.4.2 Shoaib and Hoffman, 2009

Paper title: “CO₂ Flooding the Elm Coulee Field”.

This paper is based on the results of various Bakken Formation simulations performed in order to compare CO₂ injection strategies in Elm Coulee. The first comparison the paper presents is a black oil model, which represents the reservoir on a primary recovery mechanism. This is compared to a solvent model, which represents the reservoir after CO₂ injection and the resulting effect on recovery factor. Methods of CO₂ injection are then compared including: horizontal versus vertical injectors; cyclic versus continuous injection.

1.4.3 Adrian Almanza, 2011


This paper features a three-dimensional geologic model of the Bakken Formation in Elm Coulee that displays facies and their reservoir properties. Alamanza (2011) also presents a reservoir fracture model that incorporates a matrix porosity model. This model features an idealized description of the three components of the fracture system which involves: regional fracture fabrics oriented NE-SW (maximum principal stress) that are spaced ~1,250 ft apart;
fractures orthogonal to the maximum principal stress that are spaced ~2,500 ft apart; and NE-SW fracture swarms that are spaced ~25,000 ft apart. Alamanza (2011) concludes that “The regional fracture fabrics … are interpreted as having an influence on artificially induced fractures, but are not interpreted as major contributors to sweet spot production… The fracture swarms are interpreted to have the greatest influence on fracture fabric and contribution to production”.

1.4.4 Chloe Alexandre, 2011

“Reservoir Characterization and Petrology of the Bakken Formation, Elm Coulee Field, Richland County, MT”

This paper primarily focuses on petrographic analysis of thin sections, through standard methods as well as cathodoluminescent and epifluorescent methods. Combined with core description, Alexandre (2011) identified six shallow marine facies (A through F) in the Middle Bakken Member. The paper also features a diagenetic history of the MBM: first processes include mechanical compaction, early dolomitization in a seepage-reflux setting, and pyrite formation; following this, de-dolomitization occurs, then deeper burial-related dolomitization, and formation of secondary mineral cements. Alexandre (2011) concludes that Elm Coulee would not have produced significant volumes of petroleum if not for these diagenetic factors that resulted in a dolomite-rich reservoir.

1.4.5 Sonnenberg, LeFever, and Hill, 2011


This paper discusses the natural fracture system found in the Bakken Petroleum System. It concludes that there are three dominant origins for the fractures present: regional stress related, tectonic, and pore pressure related fractures. These three fracture types play a role in production,
however it is concluded that the systematic regional northeast – trending fractures are the most important with respect to production. The northeast direction of the maximum horizontal stress appears to control both natural and hydraulically-induced fracture orientation.

1.4.6 B. Todd Hoffman, 2012

Paper title: “Comparison of Various Gases for Enhanced Recovery from Shale Oil Reservoirs”.

Hoffman (2012) compares three separate injection case scenarios derived from simulations: immiscible hydrocarbon, miscible hydrocarbon, and miscible CO₂ injection. Simulation results showed that the miscible and CO₂ injection recovery factors were similar compared to the immiscible injection, considering that in the immiscible scenario an oil bank is not formed and residual saturations are not reduced. For the two miscible scenarios, the hydrocarbon injection was more efficient: it produced about the same amount of oil (CO₂ injection produced 0.3% more) while injecting 10% less solvent.

1.4.7 Henriette Eidsnes, 2013


This paper integrates data from subsurface cores, well logs, and three overlapping 3-D seismic surveys. The primary interpretation tool used was the Petrel module Ant Tracking. This module was used to automatically extract faults from a pre-processed seismic volume, which resulted in an attribute volume that displays fault zones in detail. This processing displayed NW – SE trending fracture swarms that agree with previous literature. When compared with previously made EUR maps of Elm Coulee, Eidsnes (2013) could not determine a conclusive
relationship between the fracture swarms and a higher hydrocarbon accumulation network potential.

1.4.8 Wanli Pu, 2013

Paper title: “EOS Modeling and Reservoir Simulation Study of Bakken Gas Injection Improved Oil Recovery in the Elm Coulee Field, Montana”.

This paper discusses static reservoir and fluid property models that were separately built. Additionally, Pu (2013) compares a compositional model simulation to a Todd-Longstaff solvent model simulation to describe a theoretical miscible gas injection. Compositional simulations yielded lower oil recovery compared to the solvent model simulations. Another comparison made was between the efficiency of water-alternating-gas (WAG) injection and continuous gas injection; WAG is simulated to have comparatively lower recovery factors. However WAG also involves comparatively lower injected and produced solvent volumes.

1.4.9 Fakcharoenphol et al., 2013

Paper Title: “The Effect of Water-Induced Stress to Enhance Hydrocarbon Recovery in Shale Reservoirs”.

This paper presents a practical numerical model that can be used to study the effect of pore-pressure change and temperature change during water injection on stress redistribution in the reservoir and surrounding rock. Conventional waterflooding can result in reservoir cooling and increases in pore-pressure, which can potentially reactivate or create macro- and micro-fractures. According to the authors of the paper “In shale reservoirs… stress changes during water injection can improve oil recovery by opening some of the old macro-fractures and creating new micro-fractures perpendicular to the surface of the matrix block”. These micro-
fractures affect oil production in several ways. Initially, micro-fractures promote shallow water invasion into the rock matrix which causes oil to move into the fractures through counter-current flow and then is displaced by water towards the production wells; these micro-fractures also provide additional interface area between macro-fractures and matrix to improve drainage.

1.4.10 Basak Kurtoglu, 2013


Kurtoglu (2013) provides detailed coverage of factors that must be considered for EOR methods in the Bakken Formation MBM. The paper covers: petrophysical properties, petrofacies, reservoir fluid properties (in several fields not including Elm Coulee), static core characterization, dynamic flow measurements, pressure transient test applications, rate transient analysis, and a workflow to integrate geologic descriptions into a multi-layer compositional dual-porosity simulation model. Key conclusions include: dual porosity modeling is recommended due to flow hierarchy (oil flows from matrix, to micro- and macro-fracture network, to hydraulic fractures, to horizontal well bore); laboratory tests revealed that injectants recover oil from the matrix by counter – current flow; and that oil production through CO₂ injection is higher than waterflooding. However, field pilot tests must be implemented before any major projects are pursued.

1.4.11 Cosima Theloy, 2014

Theloy (2014) is possibly the most comprehensive source mentioned in this section. This paper characterizes six major play types in the Bakken Petroleum System: Rough Rider, Elm Coulee, Upper Bakken, Bear Den, Sanish-Parshall, and North Nesson. Theloy (2014) describes many relevant characteristics including: play specific lithofacies, reservoir pressure, fracture density, fracture orientation, trap type, fluid production ratios, and much more. In addition to describing geologic factors that affect production, Theloy (2014) also describes several technological factors: differences in operators, number of hydraulic fracturing stages, and the effect of proppant choice.

1.4.12 Ling et al., 2014


Ling et al. (2014) provide an introductory review of all EOR projects in the Williston Basin that have published data. An important point demonstrated by the paper is its emphasis that there are no available reports on successful EOR attempts of the deep, light oil in the Bakken Formation (the portion of the reservoir relevant to this study). The paper does, however, cover water flooding, high pressure air injection (HPAI), CO\(_2\) injection, hydrocarbon gas injection (HC), and thermal methods (steam injection) that have been applied for historic EOR attempts in the shallower Bakken Formation in the Saskatchewan or other formations in the Williston Basin. Several fields that are discussed have similar reservoir properties and can be used as reasonable analogues, failing other availability: Cedar Hills Field, ND (HPAI); Little Knife Field, ND (CO\(_2\) injection mini-test); and Dolphin Field, ND (HC injection). Ultimately, Ling et al. (2014) summarized limiting conditions for each EOR method and recommend a Water-Alternating-Gas (WAG) injection combined with fracturing for the MBM (Table 1.2).
1.4.13 Hoffman et al., 2014

Paper title: “The Benefits of Reinjecting Instead of Flaring Produced Gas in Unconventional Oil Reservoirs”.

Hoffman et al. (2014) address the intrinsic waste associated with flaring, and emphasize the economic and public relations benefits possible from reinjecting produced gas back into an unconventional reservoir. Flaring is a multidisciplinary issue and reinjecting produced gases can provide possible solutions to this multifaceted issue.
Figure 1.1: Structure map of the base of lower Mississippian strata, showing the limits of the Williston Basin (green line) and the Bakken Formation (dashed orange line). The red shaded polygon marks the extent of the continuous oil accumulation in the Bakken Formation. Major producing fields are shown in green filled polygons. Note the position of the Elm Coulee Field and its proximity to the limit of the Bakken Formation. Major structural features are also shown, including the Cedar Creek Anticline, the Billings Nose, and the Nesson Anticline (Theloy, 2014 modified from Sonnenberg and Pramudito, 2009)
Figure 1.2: Map showing the location of the Elm Coulee Field relative to the state of Montana. The limits of Richland County are shown in red. The black line outlines Elm Coulee Field. Blue dots indicate cores described for this study, and except for Lucille 2-27, all of them have thin sections. Red dots indicate cores that weren’t described for this study but have available routine core analysis data. Green dots show the location of the two pilot injection wells, which are discussed in Chapter 8. Well labels are abbreviated accordingly: BT = Burning Tree 36-2; CP = Coyote Putnam; LU = Lucille 2-27H; PJ = Peanut Jimmy; PM = Peabody Minifie; SJ = Stockade Jayla; ST = Staci 3-11H.
Table 1.1: Summary of available Elm Coulee core data for this study. It should be noted that only the four cores with thin sections and Lucille 2-27 were studied for this project. All other cores were used to corroborate field-wide trends. “Desc.” indicates the core was described; “T.S.” indicates the core had thin sections available for this study; “RCA” indicates that routine core analysis was performed and the data is available; “SEM” indicates that scanning electron microscope samples were prepared from the core for this study; “MICP” indicates that mercury injection capillary pressure data was made available; “Other” indicates that wettability and imbibition experiments were performed on the core. No core data was available for the Staci 3-11H injection well.

<table>
<thead>
<tr>
<th>Core Name</th>
<th>UWI</th>
<th>Interval (MD)</th>
<th>Desc.</th>
<th>T.S.</th>
<th>RCA</th>
<th>SEM</th>
<th>MICP</th>
<th>Other</th>
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<tr>
<td>Burning Tree State 36 – 2</td>
<td>25083218810000</td>
<td>9742’ – 9776’</td>
<td></td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Boulder Stone 26-16H</td>
<td>25083220560000</td>
<td>8334’ – 8358’</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Peabody Minifie</td>
<td>25083224320000</td>
<td>10388’ – 10448’</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Brutus East Lewis</td>
<td>25083225070000</td>
<td>10372’ – 10430’</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>RR Lonetree Edna</td>
<td>25083226950000</td>
<td>10368’ – 10428’</td>
<td></td>
<td>X</td>
<td></td>
<td></td>
<td>X</td>
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<tr>
<td>Jackson Rowdy</td>
<td>25083227930000</td>
<td>7627’ – 7658’</td>
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<td>X</td>
<td></td>
<td></td>
<td>X</td>
<td></td>
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<tr>
<td>Coyote Putnam</td>
<td>25083227350000</td>
<td>10336’ – 10373’</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Peanut Jimmy</td>
<td>25083227360000</td>
<td>10429’ – 10488’</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Stockade Jayla</td>
<td>25083227370000</td>
<td>9707’ – 9766’</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Foghorn Ervin</td>
<td>25083227390000</td>
<td>10487’ – 10547’</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Bullwinkle Yahoo</td>
<td>25083228370000</td>
<td>10430’ – 10520’</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>Lucille 2-27H</td>
<td>25083229257000</td>
<td>10050’ – 10327’</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
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</tbody>
</table>
Table 1.2: Screening criteria for EOR methods and average Bakken Formation properties, modified from Ling et al. (2014). Each column describes ideal reservoir conditions for each EOR method. The rightmost column describes average Bakken Formation properties throughout the entire basin for the unconventional Bakken play, along with recommendations for future EOR.

<table>
<thead>
<tr>
<th>EOR method</th>
<th>Air Injection</th>
<th>CO₂ Injection</th>
<th>HC gas injection</th>
<th>Chemical injection</th>
<th>Thermal method (Steam injection)</th>
<th>Bakken reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lithology</td>
<td>Sandstone</td>
<td>Sandstone Carbonate</td>
<td>Sandstone Carbonate</td>
<td>Sandstone Carbonate</td>
<td>Sandstone</td>
<td>Carbonate and shale</td>
</tr>
<tr>
<td>Fracture</td>
<td>No fracture</td>
<td>No fracture</td>
<td>No fracture</td>
<td>No fracture</td>
<td>No fracture</td>
<td>Natural fracture</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>&gt;2000</td>
<td>&gt;2500</td>
<td>&gt;5000</td>
<td>&lt;10000</td>
<td>&lt;4000</td>
<td>6000-11000</td>
</tr>
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<td>Porosity</td>
<td>Not critical</td>
<td>Not critical</td>
<td>Not critical</td>
<td>&gt;0.1</td>
<td>&gt;0.15</td>
<td>0.02-0.1</td>
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<td>Permeability (md)</td>
<td>&gt;1</td>
<td>&gt;1</td>
<td>&gt;1</td>
<td>&gt;10</td>
<td>&gt;50</td>
<td>0.0001-0.19</td>
</tr>
<tr>
<td>Reservoir thickness (ft)</td>
<td>&gt;10</td>
<td>&gt;10</td>
<td>&gt;10</td>
<td>Not critical</td>
<td>&gt;10</td>
<td>10-40</td>
</tr>
<tr>
<td>Oil API gravity</td>
<td>&gt;20</td>
<td>&gt;20</td>
<td>&gt;25</td>
<td>15-40</td>
<td>&gt;10</td>
<td>&gt;40</td>
</tr>
<tr>
<td>Oil viscosity (cp)</td>
<td>&lt;100</td>
<td>&lt;10</td>
<td>&lt;5</td>
<td>&lt;400</td>
<td>&lt;200000</td>
<td>0.2-0.4</td>
</tr>
<tr>
<td>Oil saturation</td>
<td>&gt;0.25</td>
<td>&gt;0.2</td>
<td>&gt;0.2</td>
<td>&gt;0.3</td>
<td>&gt;0.4</td>
<td>0.75-0.9</td>
</tr>
<tr>
<td>Reservoir pressure (psia)</td>
<td>No critical</td>
<td>&gt;MMP</td>
<td>&gt;MMP</td>
<td>Not critical</td>
<td>low</td>
<td>6000-8000</td>
</tr>
<tr>
<td>Gas cap</td>
<td>No gas cap</td>
<td>No gas cap</td>
<td>No gas cap</td>
<td>No gas cap</td>
<td>Not critical</td>
<td>No gas cap</td>
</tr>
<tr>
<td>Reservoir temperature (°F)</td>
<td>&gt;spontaneous ignition temperature</td>
<td>&lt;190</td>
<td>&lt;190</td>
<td>&lt;205</td>
<td>Not critical</td>
<td>190-220</td>
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<tr>
<td>Recommendation</td>
<td>WAG with fracturing</td>
<td></td>
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</tbody>
</table>
CHAPTER 2. GEOLOGIC BACKGROUND

The Elm Coulee Field is located on the western side of the Williston Basin and is close to the southwestern extent of the Bakken Formation (Figure 1.1). In order to fully understand and appreciate factors affecting reservoir quality on a field scale, one must understand the large-scale geologic context that controlled deposition before, during, and after the deposition of the Bakken Formation throughout the basin. This chapter discusses structural features in the Williston Basin, the stratigraphy of the basin, as well as the Bakken Petroleum System as a whole. A general overview of these subjects not only provides context for the reader, but also helps explain seemingly anomalous features present in Elm Coulee and elsewhere in the Bakken Formation.

2.1 Williston Basin Structural Geology

The Williston Basin is a large, semicircular intracratonic basin located on the western edge of the North American craton. Bounded by slight structural highs, this structurally depressed basin spans approximately 133,000 square miles and has approximately 16,000 cubic ft of sedimentary fill (Gerhard et al., 1990). The basin is present in northwest South Dakota, central and western North Dakota, northeastern Montana, southern Saskatchewan, and southwest Manitoba (Figure 2.1). Sediment within the Williston Basin unconformably lies on fault-bounded Precambrian rock, which is comprised of three provinces: the Wyoming craton, the Trans-Hudson orogenic belt, and the Archean Superior craton (Pitman et al., 2001) (Figure 2.2). These underlying rock provinces have played influential roles in the depositional environment,
sedimentation, structural features, and hydrocarbon potential of strata during Williston Basin evolution (Gerhard et al., 1990).

Much of the structural architecture of the Williston Basin is not only related to Precambrian structural deformation and basement rooted faulting, but also deformation related to the Trans-Hudson Orogenic belt (Gerhard et al., 1990). The Trans-Hudson orogeny involved the following northeast-trending fault and lineament zones: the Transcontinental Arch, Brockton-Froid Fault Zone, Great Falls Tectonic Zone, and Hindsdale fault (Gerhard et al., 1987; LeFever, 1992). The Brockton-Froid Fault Zone and the Transcontinental Arch are left-lateral fault zones that had significant influence in controlling the orientation of other structural features found in the Williston Basin (Gerhard et al., 1990).

Prominent geologic structures related to the Brockton-Froid Fault Zone (BFFZ) in the Williston Basin are primarily north-south or northwest–southeast trending, such as the Nesson Anticline (North Dakota) and the Cedar Creek Anticline (South Dakota) (Figure 2.2). Both of these features are fault bounded anticlines. In particular, the Nesson Anticline in has a major fault system along its western side that has been active since the Precambrian (Gerhard et al., 1990). The Nesson Fault System, in addition to a fault zone between the Superior Craton and the Trans-Hudson orogenic belt, is postulated to have served as a medium for fluid flow that assisted with the dissolution of the Devonian Prairie Formation salts (LeFever et al., 1991).

While the BFFZ does not directly run through the Elm Coulee Field area, there are smaller NE–SW trending lineaments that do. Eidsnes (2013) argues that these lineaments could be related to the BFFZ. O’Brien et al. (2011) argues that these subsurface features can influence surficial topography, and correspond to drainage features such as streams. Regional fractures in the Williston Basin also have a NE–SW trend. These fractures are an expression of the direction
of maximum stress throughout the basin, and Sonnenberg et al. (2011) argues that these fractures are not influenced by local structural features (Figure 2.3).

During the time of Bakken Formation deposition, the proto-Williston Basin was an extension of the Devonian Elk Point Basin of Canada. During the Devonian/Mississippian boundary, the basin was located in a tropical region near the equator (Figure 2.1) (Sonnenberg and Pramudito, 2009).

2.2 Williston Basin Stratigraphy

Approximately 16,000 cubic ft of deposited sediment have been preserved in the Williston Basin (Figure 2.4). This infill is composed of cyclic deposition of clastic and carbonate sediment during the Phanerozoic. Carbonate sediment dominated Paleozoic deposition (primarily Cambrian to middle Mississippian) and clastic sediment dominated Mesozoic and Cenozoic deposition (Pitman et al., 2001; Sonnenberg and Pramudito, 2009). Additionally, a major unconformity separates Paleozoic from Mesozoic strata (LeFever et al., 1992). The basin depocenter is located east of the Nesson Anticline and east of the present-day deepest part of the Williston Basin (Carlisle et al., 1992) (Figure 2.2).

Sloss (1963) and Gerhard et al. (1990) describe four unconformity-bound stratigraphic sequences that contain petroleum systems in the Williston Basin: the Sauk, Tippecanoe, Kaskaskia, and Absaroka sequences (Figure 2.4). The Zuni and Tejas sequences described by Sloss (1963) and Gerhard et al. (1990) (Jurassic to contemporary age) will not be addressed as they lack petroleum systems in the Williston Basin.

The Sauk Sequence consists of the Cambro-Ordovician Deadwood Formation, which was deposited unconformably on the Precambrian basement as a result of a transgression of the Sauk Sea. The Tippecanoe Sequence unconformably overlies the Sauk Sequence and contains
Ordovician and Silurian age sediments. The Winnipeg Group at the base of the Tippecanoe contains a basal transgressive sand, which is then overlain by carbonate sediments of the Red River Formation. Tippecanoe Sequence sedimentation ends due to a regression at the end of the Silurian, resulting in erosion of underlying sediment (Gerhard et al., 1990).

The Kaskaskia Sequence unconformably overlies the Tippecanoe Sequence and was deposited following the uplift of the Transcontinental Arch. This uplift caused the marine connection of the proto-Williston Basin with the Elk Point Basin in Canada. The Kaskaskia Sequence is divided in two by the Acadian unconformity. This is located between the Three Forks and the Bakken formations, which are located in the upper and lower Kaskaskia subsequences. Respectively, these two sub-sequences represent two regional sea level transgressions (Gerhard et al., 1990).

The Kaskaskia Sequence contains the entire Bakken Petroleum System, as well as underlying sediments that have directly affected the Bakken Petroleum System, so it deserves particular attention. The most significant underlying sediment to the development of the Bakken Petroleum System is the Devonian Prairie Formation. The Prairie Formation stratigraphically underlies the Bakken Petroleum System by about 800 to 1100 ft. (Sonnenberg and Pramudito, 2009). The Prairie Formation can be subdivided into four halite members, each separated by potash beds: the Ratner, Esterhazy, Belle Plaine, and Mountrail. These four halite members are then capped by a “Second Red Bed” consisting of non-fossiliferous, red to green dolomites and calcareous shales. These salts range from several to 600 ft (Oglesby, 1998; LeFever and LeFever, 2005). Dissolution of the Prairie Formation Salt has occurred multiple times, including during Bakken Deposition. This multistage dissolution caused overlying strata to collapse and the syndepositional dissolution of the Prairie Formation Salts created thickness anomalies within
the Bakken Formation (Figures 2.5 and 2.6) (LeFever and Le Fever, 2005; Sonnenberg and Pramudito, 2009).

The Absaroka sequence unconformably overlies the Kaskaskia Sequence, and began deposition in the Early Pennsylvanian when North American tectonism was widespread – causing uplift and erosion that lead to deposition of Pennsylvanian to Triassic age strata (Gerhard et al., 1990).

2.2.1 Bakken Formation Sediment Source

While this topic could constitute an entire study by itself (and has), a general understanding of possible sediment sources is necessary in order to completely comprehend the Bakken Formation. The percentage of siliciclastic material in the Bakken Formation increases to the northeast, making the Precambrian Canadian shield a possible sediment source (Nordquist, 1953; Webster, 1984; Carlisle et al., 1991). However, Pramudito (2008) argues that another sediment input is from the south and southwest, which makes the Transcontinental Arch another possible provenance. The carbonate material found in the Bakken Formation most likely had two sources: some was formed in situ and some was derived from uplift and erosion of the underlying Three Forks Formation in adjacent areas (Sonnenberg and Pramudito, 2009).

2.3 The Bakken Petroleum System

The Bakken Petroleum System consists of the upper 50 - 100 ft. of the Devonian Three Forks Formation, all three members of the Devonian- Mississippian Bakken Formation (an average of 140 ft thick in the center of the Williston Basin), and the lowermost 50 ft. of the Mississippian Lodgepole Formation (Figure 2.7) (Nordeng, 2009). It is classified as a continuous tight-oil unconventional accumulation, with hydrocarbon saturations over a large areal extent.
(Figure 1.1). The system is over-pressured throughout a large area in the basin, has low porosity and permeability values, and may contain dense areas of stress-induced fractures (Sonnenberg and Pramudito, 2009).

2.3.1 Bakken Source Rocks

The Bakken Petroleum System is primarily sourced by the organic-rich source beds of the Upper and Lower Bakken members. The Upper Bakken shale generally ranges from 10 – 16 weight percent total organic content (TOC), while the more organic-rich lower Bakken shale ranges from 10 – 22 weight percent TOC (Sonnenberg, 2011). The breadth of these ranges is in part due to their geographic location in the basin; TOC laterally changes over small distances from as little as 1% weight at shallower basin margins to up to 20% weight in deeper parts of the basin (Jin and Sonnenberg, 2013). The False Bakken of the lower Lodgepole Formation also functions as a source rock, but has comparatively less TOC (2 – 8 weight %) when compared to the Bakken members. Kerogen in the Bakken Formation shales is mostly types I and II based on the hydrogen and oxygen index, but type III kerogen is also present on the east flank of the basin (Figure 2.8) (Sonnenberg, 2011).

2.3.2 Bakken Reservoir Rocks

There are several potential reservoirs in the Bakken Petroleum System. These include the upper Three Forks Formation, the Pronghorn (historically known as the Sanish), the Middle Bakken Member, and the Lower Lodgepole Formation. However, since this study focuses on the Elm Coulee Field, the Middle Bakken Member is the only relevant reservoir. The Middle Bakken Member exhibits a high degree of heterogeneity across the basin, but it can generically be described as a light to dark grey interbedded calcareous siltstone of siliciclastic dolostone with
varying (both vertically and horizontally) amounts of shale, silt, sand, ooids, and bioclasts (LeFever et al., 1991; Pitman et al., 2001). Porosity values range from about 3% to 9% and the average permeability is approximately 0.04 md (Sonnenberg and Pramudito 2009). This lower quality reservoir is enhanced by microfracture permeability brought on by catagenesis, as well as other fracture sources (Sonnenberg et al., 2011).

This study focuses on the parts of the Bakken Formation that are considered a continuous, unconventional style play. Meaning, the unconventional play has poorly defined boundaries and oil is contained by smaller pore throats and comparatively higher capillary forces rather than conventional stratigraphic or structural traps (Nordeng, 2009). Theloy (2014) identifies several different subdivisions of play type in the Bakken Formation, some of which incorporate conventional style play elements but are still definitely unconventional style plays (Figure 2.9). The Elm Coulee Field, for example, features a stratigraphic pinch-out that functions as a trap in addition to unconventional play conditions.

2.3.2.1 Reservoir Wettability

Wettability can be defined as the preference of a solid to be in contact with one particular fluid rather than any other. In the case of an oil reservoir, the reservoir is described as oil – wet, water – wet, or intermediate wet. When a surface of a solid is oil – wet, the solid preferentially adsorbs oil, which then has a contact angle close to 180°. Comparatively, when a nonwetting phase (in the case of an oil – wet reservoir, water) is dropped onto a surface with a wetting phase already adsorbed, the nonwetting phase will bead up with minimal contact (with a contact angle approaching 0°) on the solid. An intermediate-wet reservoir refers to a lack of preference for adsorbing either water or oil, and liquid phases have a contact angle between 0° and 180° (Abdallah et al., 2007).
Reservoir pore space of the Middle Bakken Member are preferentially oil-wet to intermediate-wet, depending on location and depth within the Williston Basin (Wang et al., 2012). In addition to recent experimental data, there are several pieces of historical evidence to support this claim as well. No formation fluid was recorded during drill-stem tests or initial well completions, indicating that the relative permeability of formation fluid is very low, and that hydrocarbons comprise the vast majority of moveable fluids in the reservoir (Meissner, 1978). Additionally, high initial reservoir pressure suggest that the Middle Bakken Member is especially oil saturated (Murray, 1968).

2.3.2.2 Diagenesis in the Middle Bakken Member

While fractures do play a significant role in Middle Bakken Member reservoir quality, (especially permeability) matrix porosity and permeability created through diagenetic processes arguably are even more crucial. However, given the heterogeneous nature of the Middle Bakken Member, there are evidently several different diagenetic events recorded in the Bakken Formation. Last and Edwards (1991) have identified five key diagenetic stages in the Middle Bakken Member in Manitoba:

1. Dolomite and pyrite formation
2. Dolomite and feldspar dissolution, and formation of illite rims
3. Quartz overgrowths
4. Neoformed K-feldspar precipitation
5. Anhydrite cement

Pitman et al. (2001) have described ten key Middle Bakken Member diagenetic events that occurred in North Dakota, and Alexandre (2011) has described thirteen Middle Bakken Member diagenetic events that occurred in the Elm Coulee Field specifically (Figures 2.10 and
2.11). Alexandre (2011) places special emphasis on how dolomitization, as a result of seepage reflux, is responsible for reservoir quality in the Elm Coulee Field. It should be noted that each of these diagenetic sequences involves some form of matrix grain dissolution or dolomite formation, which created the crucial secondary matrix porosity observed throughout the Middle Bakken Member.

### 2.3.3 Bakken Formation Well Log Characteristics

The Bakken Formation exhibits unique well log characteristics that allow it to be distinguished from adjacent strata. The Bakken Formation shales are characterized by: high resistivities due to nonconductive hydrocarbon saturation; high gamma ray response due to uranium sequestration within the shale matrix; and high density porosity log readings due to the relatively lower density of organic material appearing on the logs as pore space (Meissner, 1978; Schmoker and Hester, 1983). Middle Bakken Member well log responses exhibit typical log responses for fine-grained clastic and carbonate cemented rocks (Pitman et al., 2001). However, it can be difficult to distinguish the Middle Bakken Member from the upper Three Forks Formation, where the Lower Bakken Member is not present, given the similarities in log signatures (Figure 2.12). This is the case in the Elm Coulee Field.

### 2.4 The Elm Coulee Field

Several significant differences exist between the Bakken Formation in the Elm Coulee Field from the Bakken Formation in other portions of the Williston Basin. Most notably, the entire Bakken Formation is approximately 50 ft at its thickest in the Elm Coulee Field, which is comparatively thinner than the average for the rest of the basin. The Lower Bakken Member is only locally present, and pinches out at the south and southwest portions of the field. Where the
Lower Bakken Member is present, it occurs as a siltier time equivalent variant instead of the
typical black shale found in more basinward areas of the Bakken Formation. Finally, the Middle
Bakken Member is decidedly more dolomitized in the Elm Coulee Field than other areas in the
basin. At the Elm Coulee Field, production relies heavily on matrix and secondary porosity, or in
a more general sense, the depositional and diagenetic history of the reservoir rock (Sonnenberg
and Pramudito, 2009).

2.5 Discussion

This chapter presented the geologic background that will give context to observations
made later in this study. The regional and local trends discussed have a significant effect on
reservoir quality. Several points from this chapter must be emphasized:

- Major structural trends, most notably the BFFZ, as well as regional fractures trend
  NE – SW.
- The Bakken Formation is the result of a transgression, followed by a regression,
  and another transgression.
- Thickness anomalies are present in the Bakken Formation due to Prairie
  Formation salt dissolution
- There are several subdivisions of play-type in the Bakken Formation throughout
  the Williston Basin. The Elm Coulee Field is successful due to a combination of
diagenetic and stratigraphic traps.
- Dolomitization is a driving force for reservoir quality in the Elm Coulee Field.
  Dolomite was most likely created from seepage reflux (Alexandre, 2011).
Figure 2.1: North American paleogeography and black shale deposits of the Late Devonian (360 Ma). Structural geologic features include: CS = Canadian Shield; AOB = Antler orogenic belt; AH = Acadian Highlands; TA = Transcontinental Arch. Black shale deposits include: B = Bakken; E = Exshaw; S = Sappington; CC = Cottonwood Canyon; L = Leatham; P = Pilot; PR = Percha; W = Woodford; C = Chattanooga; NA = New Albany; A = Antrim. The position of the paleo-equator (EQ) is marked by a dashed line. The transition from shallow to deeper waters is marked with a dotted line. Note the connection between the Elk Point and Williston Basin, as well as the Williston Basin’s proximity to the paleo-equator (Sonnenberg and Pramudito, 2009; modified from Blakey, 2005).
Figure 2.2: Underlying Precambrian basement provinces the Williston Basin. The north–south trending Trans-Hudson orogenic belt appears to control the orientation of the north–south and northwest–southeast trending structures. Note the location of the Poplar Anticline and the Brockton Froid Fault Zone, as both are structural features that have influenced the Elm Coulee Field (Sonnenberg et al., 2011).
Figure 2.3: Petal and open fracture directions observed in oriented Bakken cores, oriented Mission Canyon cores at Little Knife, and regional maximum horizontal stress directions (Sonnenberg et al., 2011).
Figure 2.4: Generalized stratigraphic column of the Williston Basin, showing major sequences as well as stratigraphic units that produce oil and gas (Gerhard et al., 1990).
Figure 2.5: Schematic diagram illustrating the four main stages involved in the salt dissolution and multistage salt collapse structures. Note how the syndepositional dissolution of the Prairie Formation Salt resulted in creation of anomalously thick sections in the Bakken Formation (Rolfs, 2015; modified from Oglesby, 1988).
Figure 2.6: Model illustrating the Prairie Formation Salt dissolution and the resultant thick Bakken Formation in the Elm Coulee Field. A) Following Three Forks Formation deposition, meteoric recharge initiates the dissolution of the Devonian Prairie Salts. B) An accommodation space is created as a result of dissolution, allowing for the formation of a Bakken Formation thick. Further meteoric input lead to dolomitization in accordance with the seepage-reflux model (Sonnenberg and Pramudito, 2009).
Figure 2.7: Generalized stratigraphic column of the Bakken Petroleum System not specific to the Elm Coulee Field. Note that the Pronghorn is labeled as its historic name, the Sanish (modified from Sonnenberg et al., 2011).
Figure 2.8: Modified Van Krevelen diagram for the Bakken Formation shales. The majority of samples indicated a type I and II oil-prone kerogen. HI = Hydrogen Index; OI = Oxygen Index (Sonnenberg, 2011).
Figure 2.9: The different play subdivisions within the Bakken unconventional play. Note that each field or area has its own different set of conditions that have contributed to its production success (Theloy, 2014).
Figure 2.10: Series of diagenetic events that occurred in the Middle Bakken Member in North Dakota (Pitman, et al., 2001).
Figure 2.11: Series of diagenetic events that occurred in the Middle Bakken Member in the Elm Coulee Field specifically (Alexandre, 2011).
Figure 2.12: Well log from the Franz well (UWI: 25083216430000) that shows the entire Bakken Petroleum System in the Elm Coulee Field. Lithology from the upper Three Forks, Bakken, and lower Lodgepole Formations are displayed. TRFK = Three Forks; LBM = Lower Bakken Member; MBM = Middle Bakken Member; UBM = Upper Bakken Member; SCAL = Scallion; FBKN = False Bakken. Note the high gamma ray response in the Upper Bakken Shale, over 200 API, as well as the high resistivity response, over 2000 ohm.m. Also observe the low porosity in the Middle Bakken Member, which is below 10%.
CHAPTER 3. FACIES DESCRIPTIONS AND DEPOSITIONAL ENVIRONMENTS

This study has identified 14 facies in the Bakken Petroleum System which are present in five described cores. These facies include the Upper and Lower Bakken Member facies, the six Middle Bakken Member facies, a Bakken Lag facies, the Pronghorn Member facies, three Three Forks Formation facies, and two lower Lodgepole facies. These proposed facies are variants of the Colorado School of Mines Bakken Consortium facies scheme, and are the product of thin section and core descriptions (Sonnenberg et al., 2011). Fourteen facies and their key identifying features can be observed in core are summarized in Table 3.1

3.1 The Upper Three Forks Formation

The Three Forks Formation averages 150 ft in thickness throughout the Williston Basin, and is comprised of green, grey, pink, brownish - red, and yellowish dolomitic siltstones and shales (Meissner, 1978). The Three Forks Formation overlies the Birdbear Formation and it unconformably underlies the Bakken Formation along the margins of the Williston Basin (Webster, 1984; Nordeng, 2009). This unconformity can be observed in core as a one to several inch thick lag between the top of the Three Forks Formation and the bottom of the Bakken Formation. The Three Forks contained a regionally present, quartz – rich upper sandstone interval, historically called “Sanish Sand”. However, this interval has been renamed as the Pronghorn Member and has been reclassified as the basal member of the Bakken Formation (Kume, 1963; Webster, 1984; LeFever et al. 2011).
3.1.1 Facies 1 (TF1)

The Three Forks Facies 1 (TF1) was not observed in any of the discussed cores. It has been previously described by another member of the CSM Bakken Consortium in Eidsnes (2013). The TF1 was observed in the Bullwinkle Yahoo well.

3.1.2 Facies 2 (TF2)

The Three Forks Facies 2 (TF2) is a reddish-brown, massive silty dolostone with darker laminations. There are also intermittent irregular grey/green colorations present (Figure 3.1). Three Forks Facies 2 has a gradational contact with the overlying Three Forks Facies 3.

3.1.3 Facies 3 (TF3)

The Three Forks Facies 3 (TF3) is reddish-brown to green, massive to mottled silty dolostone (Figure 3.1). Typically this facies is thin, generally only several inches thick, and is considered as a transitional facies from TF2 to TF4. Three Forks Facies 3 has a gradational contact with the overlying Three Forks Facies 4.

3.1.4 Facies 4 (TF4)

The Three Forks Facies 4 (TF4) consists of two different irregularly alternating finer and coarser layers. The green/grey layers consist of dolomitic mud, and the pink/tan layers are a silty dolostone. These layers vary in thickness, from less than an inch to a maximum of 3 inches thick. Pyrite is common throughout this interval, and occurs as discontinuous lenses that are 0.25 inches thick or thinner. There are many sedimentary structures present in this facies, including: one to several inch tall fluid escape structures, loading structures, wavy to ripple lamination,
syneresis cracks, and brecciated layers up to 1.5 ft thick with clasts ranging in size from 0.05 to 0.25 inches (Figure 3.2). The Three Forks Facies 4 has a sharp erosive contact with the overlying Bakken Formation.

### 3.1.5 Depositional Environment (TRFK)

Newnam (2015) argues that the Three Forks was deposited in a mixture of shallow shelf marine, intertidal, supratidal, and storm dominated mixed flats. The abundant sedimentary structures present in the Three Forks reflect an “intimate relationship” between depositional processes of storms and tides. Given the presence of these structures, combined with the abundance of dolomite and anhydrite, it is likely that the Three Forks was deposited in a peritidal to sabkha environment (Newnam, 2015).

### 3.2 The Bakken Formation

The Bakken Formation ranges in thickness from 0 to over 140 ft at its thickest, in near the center of the basin in North Dakota. In the Elm Coulee Field the Bakken Formation ranges in thickness from 10 to 60 ft, and pinches out to the south and west outside of the field (defining the field margins) (Sonnenberg and Pramudito 2009). The Bakken Formation unconformably overlies the Three Forks Formation in the Elm Coulee Field, and stratigraphically consists of the silty locally present Pronghorn Member, the silty/shaly Lower Bakken Member (where present), the Bakken Lag, the silty dolostone Middle Bakken Member, and the shaly Upper Bakken Member. The Middle Bakken Member is the target reservoir in the Elm Coulee Field, as well as the focus of this study.

According to the Bakken Consortium facies scheme, there are six facies present in the middle Bakken Member (MBM A – F) (Sonnenberg, 2010) (Table 3.1, Figure 3.3). However, as
Middle Bakken Member D facies is only locally present (it was observed in only one core used for this study), and the lithologic similarity between the Middle Bakken Member C facies (MBM C) and E facies (MBM E), MBM C and E have been combined into one facies (MBM C/E) for use in this study.

### 3.2.1 Pronghorn (PRHN) Facies

Where present, the Pronghorn facies unconformably overlies the Three Forks Formation. This contact is observed as a sharp erosive contact. The Pronghorn facies is a light to dark grey, silty bioturbated dolostone that alternates irregularly between light grey layers (commonly no thicker than two inches) that contain dark grey rip-up clasts (less than 0.25 inches in diameter) and dark grey mottled to massive layers. Rare planar laminations are present as well as blebs (mm to cm diameter wide) of pyrite (Figure 3.2).

### 3.2.2 Bakken Lag (LAG) Facies

A lag facies is present between the top of the Three Forks Formation and base of the Bakken Formation (not including the Pronghorn facies). Since these lags are present in every described core and exhibits sufficient differing characteristics from the surrounding rock, they are described as a separate facies. Each lag has different features, however there are several consistent features: each lag is 0.1 to 2 inches thick, has a black/green mudstone matrix, and contains broken bioclasts, rip – up clasts (that are occasionally organic rich), pyrite, and pyritized bioclasts (Figure 3.4).

### 3.2.3 Lower Bakken Member (LBM) Facies

The Lower Bakken Member in Elm Coulee Field contains several differences from the shales found in other portions of the basin. Most notably, the LBM reaches its depositional limit
south of the Elm Coulee Field. Another important difference is that the LBM in Elm Coulee is a siltier, time-equivalent to the black shale facies in the remainder of the basin (Sonnenberg and Pramudito, 2009). The Lower Bakken Member is a dark grey, bioturbated clay-rich dolomitic siltstone. Horizontal fractures are present in the Lower Bakken Member and each fracture appeared to be unmineralized (Figure 3.4). Observed fossils types include conodonts and phosphatic fish fragments. Source rock analysis performed on four LBM facies samples from Elm Coulee Field cores has an average TOC of 11.45% (Alexandre, 2011). There is a sharp contact between the Lower Bakken Member and the MBM A facies.

### 3.2.4 Middle Bakken Member A Facies (MBM A)

The Middle Bakken Member A facies (MBM A) is a dark to medium grey, fossiliferous and bioturbated silty dolo- to limestone. Compared to other facies present in the Middle Bakken Member, the MBM A facies has the highest clay content. Common fossils within the A facies include brachiopod and crinoid fragments. Bioturbation in the A facies includes mud-rich *Helminthopsis* and *Scalarituba* burrows (Figures 3.3 and 3.5). Some sub-horizontal fractures are present, commonly where the coarser detrital matrix interfaces with mud-rich bioturbation. Occasional pyrite blebs are also present. The MBM A facies has a gradational contact with the overlying MBM B facies. This gradational contact is defined by an evident decrease in fossil fragment content, as well as a significant increase in bioturbation, especially *Helminthopsis*.

### 3.2.5 Middle Bakken Member B Facies (MBM B)

The Middle Bakken Member B facies (MBM B) is a medium brownish/grey, bioturbated silty dolostone. It is the thickest facies present in the Elm Coulee Field, and also contains the majority of the reservoir rock in the Elm Coulee Field. Bioturbation of this facies ranges from 5
– 60%, and appears to increase in concentration upsection. The most common forms of bioturbation are *Helminthopsis* and *Scalarituba*, however there are also rare examples of *Teichichnus* (Figure 3.3 and 3.5). Similar to the MBM A facies, sub-horizontal fractures are preferentially located on bioturbation/matrix interfaces. Uncommon pyrite blebs are also present. Fossils are rare, but where present, include brachiopod and crinoid fragments that are typically found near the gradational lower contact. The MBM B facies has a gradational upper contact with the overlying MBM C facies. This contact is defined by a noticeable decrease in bioturbation, as well as an increase in planar/sub-planar features and laminations.

3.2.6 Middle Bakken Member C/E Facies (MBM C/E)

Due to the similarities of the MBM C and E facies, as well as the rare presence of the MBM D facies in the Elm Coulee Field, the MBM C and E facies have been interpreted as one facies for the purpose of this study. The Middle Bakken Member C/E facies (MBM C/E) is a brownish/grey irregularly laminated silty dolostone. Occasionally, this facies contains quality reservoir rock, but is not as thick as the MBM B facies. The MBM C/E facies contains several types of laminations including planar/sub-planar, wavy, and cross lamination. These laminae are darker than the surrounding matrix, due to a higher concentration of organic matter and clay (Figures 3.3 and 3.6). Compared to the MBM B facies, MBM C/E has noticeably less bioturbation, which is typically *Planolites*, and rare occurrences of *Helminthopsis*. No fossils were observed in core or thin section. The MBM C/E facies has a sharp upper contact with the overlying MBM D facies where present.
3.2.7 Middle Bakken Member D Facies (MBM D)

The Middle Bakken Member D facies (MBM D) is a medium to light grey, cross laminated sandy dolostone. Containing very fine sand sized siliciclastic components, it is the coarsest grained facies in the Middle Bakken Member. It is only locally present throughout the field. The MBM D facies does not contain noticeable bioturbation or fossil content, and has very little clay (Figure 3.3, Figure 3.6). In other areas of the Williston Basin, the MBM D facies is a coarse grained sandstone that contains ooids and occasionally quality reservoir rock (Alexandre, 2011).

3.2.8 Middle Bakken Member F Facies (MBM F)

The Middle Bakken Member F facies (MBM F) is a dark grey, mud-rich, silty massive to mottled dolostone. The MBM F facies appears to be similar to the MBM A facies, in that it contains brachiopod and crinoid fossil fragments, and the uncommon *Helminthopsis* and *Scalarituba* burrows. Occasional planar to wavy laminations are present, as well as occasional pyrite blebs (Figures 3.3 and 3.7). The MBM F facies has a sharp upper erosional contact with the overlying Upper Bakken Member.

3.2.9 Upper Bakken Member (UBM)

The Upper Bakken Member is a dark black organic - rich shale with irregular silty laminations. These laminations are typically less than an inch thick, and often contain pyrite and fossil fragments. Common fossils include brachiopods and conodonts. Pyrite blebs are also present throughout the shale and are randomly dispersed. Horizontal fractures are common, and are both unmineralized and mineralized with calcite or pyrite (Figure 3.7). Source rock analysis performed on 29 samples from Elm Coulee Field cores shows that the average TOC is 12.35%,
which is higher than the Lower Bakken Member TOC (Alexandre, 2011). There is a sharp upper contact between the Upper Bakken Member and the Scallion Member of the lower Lodgepole Formation.

3.2.10 Depositional Environment (PRHN, LAG, LBM)

There is an evident change in depositional environment between the Three Forks Formation to the Bakken Formation, which include a period of erosion and/or nondeposition. This period is expressed as the unconformity observed between the two formations in core from the Elm Coulee Field. As it is only locally present, contains observed bioturbation and limited fossil content, the Pronghorn facies is likely an erosional remnant of an offshore to distal marine environment. The Bakken Lag is interpreted to be a transgressive marine deposit in a restricted environment, considering that each example of the facies observed is present either prior to or during a deep water marine shale deposition. The Lower Bakken Member is interpreted to have been deposited under anoxic conditions in an offshore deep water - below wave base at the least - environment with a stratified water column. The LBM in the Elm Coulee Field is siltier than the remainder of the time equivalent strata in the Williston Basin, which suggests that it may have been deposited in a relatively shallower water environment.

3.2.11 Depositional Environment (MBM)

The Middle Bakken Member is a regressive deposit that shallows then deepens between the two separate transgressive depositions of the LBM and UBM. The shoaling trend begins with the MBM A facies, which is interpreted to be an offshore marine to distal shelf environment below wave base. The abundant *Helminthopsis* and *Scalarituba* burrows, as well as the rare presence of *Teichichnus*, not only define the MBM B facies but also provide an interpretation for
a depositional environment. All three of these bioturbation types belong to the *Cruziana* ichnofacies, which suggests that the MBM B facies was deposited in a mid to distal shelf environment (Benton and Harper, 1997; Pemberton, 1999; Vickery, 2010; Alexandre 2011). As the MBM B transitions into the MBM C/E facies, the observed sedimentary structures and ichnofossils suggest further facies shallowing. The *Planolites* ichnogenus also belongs to the *Cruziana* ichnofacies, but laminations are much more prevalent in the MBM C/E facies. This suggests that the MBM C/E facies deposited in a shallower paleoenvironment than the MBM B facies, most likely on the mid – basinal shelf. The MBM D facies represents the shallowest point of deposition for the Middle Bakken Member. The coarse grain size and lack of bioturbation and fossil content suggests a higher energy setting, such as bar or a shallow water shelf environment. The MBM F facies was likely deposited in an environment similar to the MBM A: an offshore marine to distal shelf environment, below wave base.

### 3.2.12 Depositional Environment (UBM)

In terms of depositional environment, the Upper Bakken Member is somewhat similar to the Lower Bakken Member. However, given the above average silt content of the LBM facies in the Elm Coulee Field, the UBM facies was more likely deposited in a relatively deeper or more restricted environment. This facies was likely deposited in a stratified water column in an offshore marine environment that was subjected to restricted and anoxic conditions. This is evident in the abundance of preserved organic matter and pyrite throughout the interval.

### 3.3 The Lower Lodgepole Formation

The Lodgepole Formation is the oldest unit in the Mississippian Madison Group. The Lodgepole Formation has a maximum thickness of 900 feet, which is located in eastern
McKenzie County, North Dakota. The lower Lodgepole Formation conformably overlies the Bakken Formation, and consists of dark grey to brownish grey limestone and dark grey calcareous shale. The Scallion Member, a medium grey limestone, and the False Bakken Member, a thin black silty shale or are present in the center of the Williston Basin (Webster, 1984; Stroud, 2010). The Scallion and False Bakken members are the only components of the Lodgepole Formation that are included in the Bakken Petroleum System (Sonnenberg and Pramudito, 2009).

### 3.3.1 Scallion Facies (SCAL)

The Lower Lodgepole Formation Scallion facies is a medium to light brownish/grey, bioclastic mottled wackestone. The most common fossils observed are crinoid fragments, which typically are less than 0.25 inches wide in diameter. The facies is moderately bioturbated to mottled throughout the observed interval. Stylolites are common (Figure 3.8). The facies has a gradational upper contact with the overlying False Bakken, which is marked by a decrease in bioclastic content and an increase in clay content.

### 3.3.2 False Bakken Facies (FBKN)

The “False Bakken” is an informal term used to describe the radioactive clay-rich limestone that overlies the Scallion member and has a similar electric well log signature as the Upper Bakken Shale (LeFever, 1991). The False Bakken facies is a dark to medium brownish/grey, silty to shaly mudstone. Some bioclasts are present, however there are considerably less observed in the Scallion facies. Bioclasts mostly consist of brachiopod and crinoid fragments. There are abundant horizontal fractures, which are both unmineralized and mineralized with calcite or pyrite. Some blebs of pyrite are present (Figure 3.8).
3.3.3 Depositional Environment (SCAL and FBKN)

The Scallion member consists of sediments deposited at the deepest part of a carbonate ramp, likely due to turbidity currents (Grover, 1996; Stroud, 2010). The depositional environment is interpreted as deep-water marine setting that existed in aerobic to dysaerobic conditions. Compared with the restricted, anaerobic Upper Bakken Member facies, there is a noticeable difference in environment, which is observed in core as a sharp stylolitized boundary between the Bakken and lower Lodgepole Formations (Stroud, 2010).

The False Bakken facies contain a relative increase of terrigenous silts and clay, which suggests deposition in a stratified water column or a restricted, dysoxic environment. The terrigenous material is most likely a result fluvial input, which likely reduced the rate of carbonate production (Grover, 1996; Stroud, 2010). Abundant organic matter is preserved in this interval (Peters and Cassa, 1994).

3.4 Discussion

This chapter described the facies present in the Bakken Petroleum System and the environments in which they were deposited. These data are essential in any geologic study, as they provide context for any subsequent sedimentological observations. Several points from this chapter must be emphasized:

- Fifteen facies were observed in the Bakken Petroleum System. Two of those facies from the MBM were combined for the sake of simplicity.

- The Three Forks Formation is a mixed clastic carbonate system that was likely deposited in a sabkha and peritidal environment.
• The MBM is a mixed clastic carbonate system that was likely deposited on a shallow to distal shelf position.

• The UBM and LBM in the Elm Coulee Field both have relatively high TOC contents. Both were likely deposited in a deep water environment with a stratified water column under anoxic conditions.
Table 3.1: Summary of facies present in Bakken Petroleum System in the Elm Coulee Field. These facies are modified from the Colorado School of Mines Bakken Consortium facies

<table>
<thead>
<tr>
<th>Formation</th>
<th>Facies</th>
<th>Photo</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lodgepole</td>
<td>False Bakken (FBKN)</td>
<td></td>
<td>Brownish-dark grey siltstone/mudstone with horizontal fractures and some brachiopods.</td>
</tr>
<tr>
<td></td>
<td>Scallion (SCAL)</td>
<td></td>
<td>Grey limestone (mud/wackestone) with crinoids and stylolites.</td>
</tr>
<tr>
<td>Bakken</td>
<td>Upper Bakken Member (UBM)</td>
<td></td>
<td>Dark grey to black organic-rich shale with silty laminations, fractures, and pyrite framboilds.</td>
</tr>
<tr>
<td></td>
<td>Middle Bakken Member: F (MBM F)</td>
<td></td>
<td>Dark grey silty dolostone with mottled or massive texture. Brachiopod fragments present and occasional laminations.</td>
</tr>
<tr>
<td></td>
<td>Middle Bakken Member: D (MBM D)</td>
<td></td>
<td>Brown – grey very fine sandy dolostone with cross lamination.</td>
</tr>
<tr>
<td></td>
<td>Middle Bakken Member: C/E (MBM C/E)</td>
<td></td>
<td>Brown - grey silty/v.f. sandy dolostone with wavy and planar laminations. Occasional bioturbation.</td>
</tr>
<tr>
<td></td>
<td>Middle Bakken Member: B (MBM B)</td>
<td></td>
<td>Brown – grey silty dolostone with abundant clay-rich bioturbation (Helminthopsis and Scalarituba burrows).</td>
</tr>
<tr>
<td></td>
<td>Middle Bakken Member: A (MBM A)</td>
<td></td>
<td>Brown – grey silty dolostone (or limestone) with brachiopod and crinoid fragments. Clay rich with occasional bioturbation</td>
</tr>
<tr>
<td></td>
<td>Lower Bakken Member (LBM)</td>
<td></td>
<td>Dark brown to black clay – rich siltstone with occasional bioturbation</td>
</tr>
<tr>
<td>Bakken Lag (LAG)</td>
<td></td>
<td></td>
<td>Lag deposit one to several inches thick. Contains pyrite, fossil fragments (some pyritized), and organic rich rip-ups</td>
</tr>
<tr>
<td>Pronghorn (PRHN)</td>
<td></td>
<td></td>
<td>Dark grey silty mottled dolostone with some bioturbation and lighter colored 1” thick intervals</td>
</tr>
<tr>
<td></td>
<td>Three Forks 3 (TF3)</td>
<td></td>
<td>Green and reddish – brown mottled or massive silty dolostone</td>
</tr>
<tr>
<td></td>
<td>Three Forks 2 (TF2)</td>
<td></td>
<td>Green and reddish – brown silty dolostone with occasional irregular laminations</td>
</tr>
</tbody>
</table>
Figure 3.1: A) Core photograph of Three Forks Facies 2 (TF2) taken from the Peanut Jimmy core at 10486’. B) Core photograph of Three Forks Facies 3 (TF3) taken from the Coyote Putnam core at 10393’. Pencils for scale.
Figure 3.2: A) Core photograph of Three Forks Facies 4 (TF4) taken from the Peabody Minifie core at 10445.1’. Note the ripple lamination and alternating coarse/fine intervals. B) Core photograph of Pronghorn facies (PRHN) taken from the Stockade Jayla core at 9755.5’. Note the light grey banding. Pencils for scale.
Figure 3.3: Six photomicrographs illustrating the facies of the Middle Bakken Member in Elm Coulee. Each photograph was taken in plane polarized light (PPL) and features a 1 mm long scale bar. A) Photograph of the MBM A with brachiopod fragments. Taken from Peanut Jimmy core at 10466.65’. B) Photograph of the MBM B (non-reservoir rock) with Helminthopsis. Taken from Peanut Jimmy core at 10447.5’. B2) Photograph of the MBM B (reservoir rock) featuring blue epoxy that fills porosity. Taken from the Peanut Jimmy core at 10439.25’. C/E) Photograph of the MBM C/E with lamination. Taken from Peabody Minifie core at 10413’. D) Photograph of the MBM D with coarser grains and some porosity indicated by blue epoxy. Taken from the Stockade Jayla core at 9721.8’. F) Photograph of the MBM F with an altered bioclasts and pink epoxy indicating porosity. Taken from the Peanut Jimmy core at 10432.55’.
Figure 3.4: A) Core photograph of the Bakken lag (LAG) taken from the Lucille 2-27H core at 10109.25’ with pencil for scale. Note the dark black organic rich rip-up clasts present in the lag interval. B) Core photograph of the Lower Bakken Member (LBM) taken from the Peabody Minifie core at 10437.5’ with pencil for scale. Note the coarser and siltier nature of the LBM.
Figure 3.5: A) Core photograph of the Middle Bakken Member A facies (MBM A) taken from the Peabody Minifie core at 10435.4’. Arrow marks the brachiopod fossil fragments. B) Core photograph of the Middle Bakken Member B facies (MBM B) taken from the Peabody Minifie core at 10428.5’. Arrow marks the abundant Helminthopsis bioturbation. Pencils for scale.
Figure 3.6: A) Core photograph of the Middle Bakken Member C/E facies taken from the Peabody Minifie core at 10413’. Note the wavy clay - rich laminations. B) Core photograph of the Middle Bakken Member D facies taken from the Stockade Jayla core at 9719’. Note the subtle wavy cross laminations. Pencils for scale.
Figure 3.7: A) Core photograph of the Middle Bakken Member F facies (MBM F) taken from the Coyote Putnam core at 10348’. Arrows mark the bioclasts (pink arrow) and sharp contact with the UBM (yellow arrow). B) Core photograph of the Upper Bakken Member facies (UBM) taken from the Peabody Minifie core at 10407.5’. Note the subtle laminations. Arrow marks pyrite blebs around the calcite cemented oblong feature. Pencils for scale.
Figure 3.8: A) Core photograph of the Scallion facies (SCAL) taken from the Peabody Minifie core at 10400’. Note the mottled texture and arrow marks crinoids present. B) Core photograph of the False Bakken (FBKN) facies taken from the Peabody Minifie core at 10391’. Note the rare crinoids (marked with arrow). Pencils for scale.
CHAPTER 4. CORE DESCRIPTION AND ANALYSIS

Core description is an invaluable practice in any subsurface study for a variety of reasons. First and foremost, describing a core provides geological context for any and well log data that is used. The importance of actually looking at the rock cannot be emphasized enough. Additionally, describing the lithology of cores ensures job security for any geologist. Describing core in order to understand lithology is the foundation of reservoir characterization.

Routine core analysis (RCA) supplements qualitative lithologic observations with quantitative measurements of porosity, permeability, fluid saturation, and density (bulk and grain). Often but not always, X-ray Diffraction (XRD) is performed in addition to RCA in order to determine a relative sense of the rock’s mineralogical content.

This chapter first presents lithologic descriptions of this study’s five cores alongside well log data, RCA, and XRD (when available). Then the XRD and fluid saturation portions of the RCA are revisited in order to emphasize crucial trends that will be discussed for the remainder of this study. Figure 4.1 provides a key for the symbols used in the lithologic descriptions.

4.1 Lithologic Descriptions and Trends

This section features five core lithologic descriptions, four of which are compared to available well log, XRD, and RCA data. Lucille 2-27H did not have any additional data available, but was included in this study considering no published descriptions of it could be found and because it is more southerly than any other cores discussed in this study (Figure 1.2). Each description features (provided data is available) from left to right:

- a corrected measured depth column
- a column assigning the facies described in the previous chapter
• a column illustrating grain size and key lithologic features (with colors to help separate each lithofacies)
• a gamma ray log (to qualitatively assess shale and organic content)
• RCA porosity and permeability data (data courtesy of Enerplus)
• XRD data (weight percent normalized to 100) (data courtesy of Enerplus)
• RCA fluid saturation (data courtesy of Enerplus)
• a resistivity log (to determine in situ fluid saturation)
• a density porosity log (using a 2.71 g/cm³ limestone matrix)

The XRD data column is color coded according to general mineral content: yellow represents siliciclastic minerals (quartz, orthoclase, and plagioclase); pink represents dolomite (including ferroan dolomite); blue represents calcite; black represents pyrite; grey represents clays (chlorite and illite primarily); and green represents unknown mineral content (a common artifact of collecting the data). The RCA fluid saturation column is not normalized and is color coded according fluid: blue represents water; green represents oil; and white (or lack of color) presumably represents hydrocarbon gas and other volatile components. Core descriptions in this section are presented from west to east for the sake of simplicity. Many of the Enerplus provided cores (and their corresponding wells) are named after popular classic cartoon characters created by American animators Chuck Jones or Jay Ward.
4.1.1 **Stockade Jayla (NW NE NW 32 25N 54E)** (Figure 4.2)

Stockade Jayla is a fitting starting point because not only is it the west-most core described in this study, but it is the only described core featuring every MBM facies. Drilling began on November 24th, 2008, and the well was completed on January 11th, 2009. Initial production was 57 BPD oil.

The 61 foot cored interval features the upper Three Forks, the Pronghorn, the Middle Bakken Member, the Upper Bakken Member, and the Scallion. Starting at the bottom, there are six feet of TF4. The TF4 interval then has a sharp contact with the overlying Pronghorn. This Pronghorn interval is 8 feet thick and then has a sharp contact into the Bakken Lag. In this core the Bakken Lag is a 2 inch black and dark-green mudstone with pyrite blebs and pyritized bioclasts. The LBM is not present at Stockade Jayla, and the well is close to the western extent of the LBM for the field and the Williston Basin. Instead, approximately 5.5 feet of the MBM A directly overlies the Bakken Lag. The MBM A then gradually turns into the MBM B as fossil content reduces and bioturbation increases. The MBM B is the volumetric bulk of the core, the entire interval is 22.5 feet thick, which then gradationally transitions into the MBM C/E as prevalence of horizontal features and laminations increases and bioturbation decreases. MBM C/E is three feet thick and then transitions into a 3.5 foot thick MBM D interval. Stockade Jayla was the only core described for this study that features the MBM D facies. There is a sharp contact featuring pyrite blebs between MBM D and the two foot thick MBM F interval. The MBM F interval then has a sharp contact with the overlying six feet UBM facies. The top of the core features four feet of the SCAL that overlies a sharp contact with the UBM.
4.1.2  Lucille 2-27H (SW SE 27 23N 55E) (Figure 4.3)

The Lucille 2-27H well is the most southern well described in this study and it is either on or past the southern extent of the LBM in the field and the Williston Basin in Montana. Another detail to note is the promising IP despite the relative lack of thickness of the MBM and reservoir rock. Drilling for the pilot well that this core was taken from started in January 28th, 2012, and was finished on February 22nd. Two horizontal laterals were then drilled starting March 6th, 2012, and subsequently completed on April 19th, 2012. The combined IP for these two laterals was 643 BPD.

The entire core consists of 30 nine foot boxes, however only the first nine boxes contain the Bakken Petroleum System. The 80 foot cored interval features the upper Three Forks, the Middle Bakken Member, the Upper Bakken Member, the Scallion, and the False Bakken. The described portion of the core begins with 10.8 feet of TF2 that gradually transitions into a foot of TF3 as the rock texture becomes more massive. The TF3 then has a sharp contact with the overlying TF4, which can be seen as planar and ripple laminations. The TF4 interval is 9.75 feet thick and is overlain by the Bakken Lag. In the Lucille core, the Bakken Lag is two inches thick and features bioclasts and abundant organic rich rip-up clasts (.1 to .25 inches in diameter). Neither the LBM nor the MBM A are present, so 4.85 feet of MBM B directly overlay the Bakken Lag. As bioturbation decreases, the MBM B grades into the MBM C/E, a 2.15 foot thick interval. Both the MBM B and C/E intervals are dark brown and extensively oil stained in this core. The MBM C/E has a sharp contact, expressed as a half inch pyrite rich lag, with the overlying UBM. The UBM is 5.75 feet thick and has a sharp contact with the overlying 10 foot thick SCAL. The SCAL appears to have a gradational contact into the five feet of overlying
FBKN. The remainder of the core features part of the lower Lodgepole that is not described as part of the Bakken Petroleum System.

4.1.3 Peabody Minifie (SE SE SW 26 24N 56E) (Figure 4.4)

Drilling for the Peabody Minifie well began on March 17th, 2006, and the well was completed on May 6th, 2006. The 60 foot core was taken from driller’s depths of 10,388 to 10,448, which required a six foot correction to match up with the collected logs, which is reflected in the core description. Initial production was 22 BPD.

The base of the core begins 10.2 feet of TF4 which then has a sharp contact with the overlying Bakken Lag. In the Peabody Minifie core, the Bakken Lag is a 2 inch grey/green lag that features broken bioclasts (mostly brachiopods), pyrite blebs, and organic rich rip-up clasts. The Bakken Lag has a sharp contact with 1.7 feet of the overlying LBM. The MBM A facies is present in this core, and is 3.55 feet thick. The MBM A has a gradual contact with the MBM B, which is 18.5 feet thick and makes up the majority of the MBM in this core. The MBM B then has a gradual contact with the 4.5 foot MBM C/E. The MBM C/E has a sharp contact with overlying 0.5 foot thick MBM F. The MBM F in this core is particularly interesting, considering the sharp contact with MBM F and UBM can be seen in core as a 1 to 2 inch lag deposit. This lag deposit contains bioclasts and pyrite. The UBM in this core is 5.5 feet thick and has a sharp contact with the overlying SCAL. The SCAL is 11.25 feet thick and then has a sharp contact with the 4.25 thick interval of the FBKN which marks the end of the cored interval.
4.1.4 **Coyote Putnam (SW SW SE 9 23N 57E) (Figure 4.5)**

Drilling for the Coyote Putnam well began on January 28\textsuperscript{th}, 2012, and the well was completed on February 22\textsuperscript{nd}, 2012. An initial production value was not posted in the provided scout ticket.

The base of the 60 foot core begins with two feet of TF2 which then gradually transitions into one foot of TF3. A 15 foot TF4 interval then overlies the TF3, following a gradational contact. The TF4 has a sharp contact with the 1 to 3 inch thick Bakken Lag. In this core, the Bakken lag features broken bioclasts (primarily brachiopods) and abundant pyrite blebs. The LBM is present in this core, and is 1.3 feet thick. The LBM has a gradational contact into the MBM A, which is 4 feet thick. The MBM A then has a gradational contact with the 18.5 foot thick MBM B interval. The MBM B has a gradational contact with the overlying 5 foot thick MBM C/E interval. The MBM C/E has a sharp contact with the 2.5 foot thick MBM F interval. The MBM F has a sharp contact with the overlying UBM, however, unlike Peabody Minifie, no lag was observed at this contact. The UBM interval is 4 feet thick and has an obvious sharp contact with the overlying SCAL. The remainder of the cored interval is 6.5 feet of the SCAL.

4.1.5 **Peanut Jimmy (NW NE NW 22 24N 57E) (Figure 4.6)**

The Peanut Jimmy core is the east-most core described for this study. Drilling for the well began on September 9\textsuperscript{th}, 2008, and the well was completed on October 22\textsuperscript{nd}, 2008. Initial production for the well was 3 BPD.

The 60 foot cored interval begins 3.5 feet of TF2 which then gradually transitions into 0.75 feet of TF3. An 11.25 foot TF4 interval then overlies the TF3, following a gradational contact. The TF4 has a sharp contact with the overlying PRHN, which is 2.7 feet thick in this
core. The Bakken Lag is comparatively large in this core, reaching a thickness of up to 3 inches. In this core, the grey/green Bakken Lag features broken bioclasts and abundant pyrite blebs. The LBM is present in this core, and is 2 feet thick. The LBM has a gradational contact into the MBM A, which is 5 feet thick. The MBM A then gradationally transitions into the MBM B, which is 25 feet thick in this core. The MBM B has a gradational contact with the overlying 4 foot thick MBM C/E interval. The MBM C/E has a sharp contact with the overlying MBM F. The MBM F is 2.5 feet thick and has a sharp contact with the UBM, but a lag was not observed between the two. The remainder of the cored interval is 3.5 feet of the UBM.

4.2 Cross Section

Figure 4.7 illustrates the spatial distribution of the lithofacies described in core. Well logs are not especially good indicators of facies transitions within the MBM, so a cross section using core data is best to observe facies trends throughout the field. Several key trends can be observed in the MBM. Only the MBM B and MBM C appear to be consistent throughout the Elm Coulee Field. The MBM B comprises the bulk of the MBM. The MBM A, the MBM, D, and the MBM F all appear to be only locally present throughout the Elm Coulee Field. The cross section datum is hung on the bottom of the UBM in order to emphasize MBM stratigraphy and a possible paleohigh and/or shoreline.

4.3 Lithologic, XRD, and RCA Trends

Figures 4.2 through 4.6 display lithofacies and their relation to mineralogy, porosity, permeability, and fluid saturations. Figures 4.9 through 4.16 emphasize the mineralogical and fluid saturation trends, to better visualize the conditions that contribute to reservoir quality and wettability. In Figures 4.2 through 4.6, the MBM is subdivided into three separate categories.
based on reservoir quality: the marginal reservoir interval (labeled with a MR); the pay interval (labeled with PAY); and the non–reservoir interval (labeled with NR). Each of these intervals can be distinguished based on XRD, RCA, fluid saturation, well log trends, and core porosity in particular.

4.3.1 The Pay Interval

This interval can be identified in digital well logs by a relative increase in resistivity and density porosity following (from a driller’s perspective) the marginal reservoir interval. The pay interval has the highest porosity values for the entire MBM, and core porosities typically range from 7 to 10%. Though, the porosity cutoff defining this interval is between 4 and 5% (depending on the oil/water saturation ratio). The relative increase in resistivity seen in well log data can also be correlated to the substantial increase in oil saturation. The low water saturation and high oil saturation in the pay interval also suggests that the reservoir is oil wet. The most obvious mineralogical trend present in the XRD data is the relative abundance of dolomite compared to low calcite and clay components. The bulk of this interval is in the upper portion of the MBM B, though can be present in lower portions of the MBM C/E as well. Petrographic descriptions of this interval are presented in Chapter 6.

4.3.2 The Marginal Reservoir Interval

This interval can be identified in digital well logs by a relative decrease in resistivity and density porosity between the higher values associated with the UBM and the pay interval. The density porosity spike in the UBM is much more pronounced due to the effect of organic materials on density logs. This relative decrease in porosity, compared to the pay interval, can
also be seen in the porosity and permeability data. The relative decrease in resistivity seen in well log data can also be correlated to the relative decrease in oil saturation combined with the relative increase in water saturation seen in core fluid saturation data. There are two separate mineralogical trends present in the XRD data that are likely explanations for the marginal reservoir quality: an increase in calcite, clay, and pyrite (Figure 4.4), or an increase in dolomite relative to the pay interval (Figure 4.2). Typically this interval is in the MBM C/E, D, and, occasionally, F facies. This interval is still considered possible reservoir rock, given that there is still significant oil saturation compared to the water saturation. Fluid saturation is the most important cutoff for this portion of the MBM. Petrographic descriptions of this interval are presented in Chapter 6.

4.3.3 The Non–Reservoir Interval

This interval can be identified in digital well logs by the continuous decrease of resistivity and porosity seen in the pay interval. Unfortunately, a cutoff cannot be made based on digital well logs, due to differences in data quality. However, these changes in well log data can also be seen core porosity and fluid saturation, so the interval can still be defined provided core data is present. Core porosity in this interval is typically below 5%. This interval has the highest water saturation in the entire MBM, and little to no oil saturation. Changes in fluid saturation and core porosity can be related to mineralogical trends present in XRD data. As water saturation increases, so does calcite, clay, and pyrite content. The increase of clay and calcite also result in the relative decrease in dolomite content. This interval is present in the MBM A as well as lower portions of the MBM B. Petrographic descriptions of this interval are presented in Chapter 6.
4.4 Discussion

This chapter presented available core data with a particular emphasis on facies abundance and controls on reservoir quality. There are likely mineralogic controls on reservoir quality, which affect porosity and fluid saturations. As a general trend, the “right” amount of dolomite content combined with low clay and calcite content result in the best reservoir conditions. Several key points from this chapter must be emphasized:

- The MBM B is the largest facies in the MBM throughout the field.
- Only the MBM B and the MBM C/E are continuous throughout the field, all other MBM facies appear to be discontinuous.
- There are three intervals within the MBM that relate to reservoir quality: the marginal reservoir, the pay interval, and the non–reservoir.
- The pay interval is defined by porosity ranging from 7 – 10%, relatively high dolomite content, and high oil saturation.
- The high oil saturation and low water saturation in the pay interval provide evidence to suggest that the pay interval in the Elm Coulee Field is preferentially oil–wet.
Figure 4.1: Key for the lithologic symbols and patterns used in the core description columns in Figures 4.2 – 4.6.
Figure 4.2: Digitized core description of the Stockade Jayla well. MR = marginal reservoir; PAY = pay; NR = non-reservoir.
Figure 4.3: Digitized core description of the Lucille 2-227H well. No other data was made available.
Figure 4.4: Digitized core description of the Peabody Minifie well. Note that while the density porosity log was not calibrated properly, it exhibits the same UBM trend present in other parts of the field. MR = marginal reservoir; PAY = pay; NR = non – reservoir.
Figure 4.5: Digitized core description of the Coyote Putnam well. MR = marginal reservoir; PAY = pay; NR = non–reservoir.
Figure 4.6: Digitized core description of the Peanut Jimmy well. MR = marginal reservoir; PAY = pay; NR = non–reservoir.
Figure 4.7: Location map for the cross section of the five cores described in this study. Black polygon indicates limits of Elm Coulee Field. Faint grey line indicates the mapped limit (from well logs) of the MBM.
Figure 4.8: Cross section of the five cores described for this study. The cross section runs from west to east. The datum is the base of the UBM.
Figure 4.9: Graph of XRD data from the Stockade Jayla well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.10: Graph of the fluid saturation data from the Stockade Jayla well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.11: Graph of XRD data from the Coyote Putnam well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.12: Graph of the fluid saturation data from the Coyote Putnam well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.13: Graph of XRD data from the Peabody Minifie well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.14: Graph of the fluid saturation data from the Peabody Minifie well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.15: Graph of XRD data from the Peanut Jimmy well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
Figure 4.16: Graph of the fluid saturation data from the Peanut Jimmy well. Facies boundaries for available data are marked in black. Not all facies in the Bakken Petroleum System were sampled. Data courtesy of Enerplus.
CHAPTER 5. GEOLOGIC AND PRODUCTION SUBSURFACE MAPPING

This chapter presents a series of maps that illustrate the changes in subsurface lithology (structural and isopach maps), historic production (EUR, O/O+W, operator attribute maps), and fluid saturation (water saturation and hydrocarbon pore ft, or SoPhiH, maps). The entire Bakken Petroleum System was mapped for this study, however, the bulk of the maps presented will feature the MBM in some form. Fortunately, the Elm Coulee Field is mature when compared to the remainder of the Bakken, and there is a comparatively greater amount of well control. Every aspect of mapping was performed using IHS Petra and a digital log suite made available through the Colorado School of Mines Bakken Consortium. Correlations of member surfaces were performed using roughly 700 digital well logs from wells in both North Dakota and Montana. Estimate ultimate recovery calculations used for production mapping were performed using the IHS Petra monthly production module. Decline curves were fitted to determine EUR in this module using an effective exponential Arp’s equation. Roughly 700 (separate) wells were used for EUR calculations and were chosen based on the following criteria: the MBM was posted as a target, the well was drilled after 2000, and the well was horizontally drilled.

5.1 Structure Maps

Subsea (SS TVD) structure maps were created for the top of the Three Forks Formation (Figure 5.1) and the top of the Bakken Formation (Figure 5.2). Both of these maps show the same general southeast dipping trend. No significant structural features are present, however some more subtle folds are present, which could suggest some tectonic influence. Sonnenberg and Pramudito (2009) argue that these subtle structural features may be associated with denser fracture networks than the rest of the Elm Coulee Field.
5.2 Isopach Maps

Isopach maps were created for the entire Bakken Formation (Figure 5.3) and the Middle Bakken Member (Figure 5.4). Both maps feature 5 ft contours, so that any changes in thickness between the two maps can be compared. The similarity in thickness trends between the two maps suggests that the MBM is the main controlling factor for Bakken Formation thickness trends in the Elm Coulee Field. As an extension of that logic, the MBM B is likely to be the most prevalent facies throughout the field, as shown in Chapter 4.

These Isopach maps both emphasize the stratigraphic trap that is present in the Elm Coulee Field. The MBM pinches out just miles to the southwest of the field’s extent and the entire Bakken Formation pinches out further to the south and southwest of the field’s extent. There is one prominent thickness trending with a NW – SE orientation going through Elm Coulee Field. This trend was most likely created by the two–stage evaporite dissolution of the Prairie Formation discussed in Chapter 2.

5.3 Production Maps

Roughly 700 wells and their respective production histories were evaluated in order to determine production trends in the Elm Coulee Field. Only horizontal wells drilled in 2000 or later with the MBM as a target were selected for EUR calculations. Estimated ultimate recovery calculations were performed using the IHS Petra monthly production module using the effective exponential Arp’s equation. Figure 5.5 plots EUR calculations throughout the field and outside the field for comparison. Figure 5.6 delineates the Elm Coulee Field EUR values on a probability distribution chart. The chart displays that the P10 value is 97,249 bbl, the P50 value is 221,528 bbl, and the P90 value is 504,630 bbl. The arithmetic mean value for EUR is 269,175 bbl and the
Swanson’s mean value is 269,175 bbl. Figures 5.7, 5.8, and 5.9 illustrate below mean, roughly mean, and above mean EUR value decline curves for wells in the Elm Coulee Field.

Figure 5.10 plots EUR calculations on top of a MBM isopach. The main production trend does not directly correspond with the thickness trend present in the MBM, though both do have a NW – SE trend. Instead, the production trend is likely due to differences in both engineering (from operator to operator) and lateral changes in lithology/mineralogy throughout the Elm Coulee Field and the surrounding area. Figure 5.11 plots major E&P operators present in the Elm Coulee Field. Naturally, completion designs varied from operator to operator and are responsible for some of the differences present in EUR, however six of the seven operators (Lyco Energy Corp was purchased by Enerplus Resources, and the two are respectively considered one company) have acreage in the NW part of the field and production values are comparable among all operators. Different engineering methods arguably do not overshadow geologic controls on reservoir quality. Changes in fluid saturation throughout the field and the surrounding are also likely due to lateral changes in preferential dolomitization, similar to the vertical changes seen in Chapter 4. Heterogeneity in mineralogy and as a result, pore geometry and fluid saturation will be discussed in greater detail in Chapter 6.

5.4 Fluid Saturation Maps

Water saturation for the Elm Coulee Field and the surrounding area was calculated using Archie’s equation with the following parameters: $a = 1; m = 1.4; n = 1.74; r_w = 0.02$.

Additionally, the density porosity well log used was cut off at 1% porosity, because Archie’s equation “breaks” at low porosities and reports impossible water saturations greater than 100%.

Figure 5.12 plots the average water saturation value for the entire MBM present in the Elm Coulee Field and the surrounding area.
The majority of the area in the Elm Coulee Field has a comparatively much lower water saturation than the surrounding area. The field is bounded to the NW and NE by areas of comparatively higher water saturation. An anomalous low is present in the NE corner of Richland County, however this is an artifact of data availability rather than actual reservoir conditions. Conventional vertical wells were drilled in the Red River and Mission Canyon Formations on structural highs in the 1970’s and 1980’s and a majority of the well logs exist only as raster files. In addition to data availability, the structural highs present in the Red River Formation affected the overlying Bakken Formation, by causing relative structural highs and subsequently affecting local fluid saturation. However, these skewed water saturations are not present in the Bakken Formation throughout this NE corner in Richland County. Figure 5.13 best illustrates this discrepancy. Figure 5.13 plots bubbles with colors based on the ratio of cumulative oil to the sum of cumulative oil and water produced (cooler colors are more water produced and hotter colors are more oil produced) Wells used in this map are the same as those used to map production and EUR values. Horizontal wells that landed in the Bakken Formation outside of the Elm Coulee Field produced substantially higher amounts of water, suggesting that the water saturations are much higher. This map further demonstrates the field’s bounds as the O/O+W ratio quickly changes at field boundaries. Both Figures 5.12 and 5.13 suggest that the Elm Coulee Field is preferentially oil – wet, considering the MBM (B, C/E, D, and facies) has such a low average water saturation and produces much more liquid hydrocarbons compared to water.

Figure 5.14 is a hydrocarbon pore-ft map (or SoPhiH) that was made using the water saturation curves from Figure 5.12. As a result, Figure 5.14 displays similar trends to Figure 5.12. Contours were clipped by the Elm Coulee Field polygon in order to determine original oil
in place. Volumetrics were calculated in IHS Petra and OOIP was determined to be 2.02 Bbbl. A rough calculation of recovery factor for this field is 13%. This calculation is based on the assumption that each of the 1259 horizontal wells in the Elm Coulee Field will produce the P50 EUR value.

5.5 Discussion

This chapter primarily presented how the thickness and lithology/mineralogy of the Bakken Formation, especially the MBM, changed throughout the Elm Coulee Field and its surrounding area. These changes affect fluid saturation, and consequently, historic and future hydrocarbon production. Several key points from this chapter must be emphasized:

- There is a NW – SE trending thick in the MBM, which was most likely caused by Prairie Salt dissolution.
- The MBM thickness controls the overall thickness of the Bakken Formation in the Elm Coulee Field.
- The MBM pinches out to the south and southwest of the field, creating a stratigraphic trap in addition to the continuous accumulation.
- The hydrocarbon production trend also has a NW – SE orientation, but it does not directly relate to the MBM thick.
- The average EUR of a well in the Elm Coulee Field is 269,000 bbl.
- Production declines quickly in the first two to three years and then gradually declines for the remainder of the well’s life.
- There are differences in EUR due to differing completion strategies from operator to operator, however, lateral changes in lithology/mineralogy likely play a larger role. Especially considering lithology/mineralogy controls fluid saturation to some degree.
- The MBM in the Elm Coulee Field has a low average water saturation and produces relatively high amounts of liquid hydrocarbons compared to water. These observations provide further evidence suggesting that the MBM reservoir in the Elm Coulee Field is preferentially oil wet.
- The OOIP of the Elm Coulee Field is 2.02 billion barrels of oil.
- A rough recovery factor for the field (without EOR methods) is 13%.
Figure 5.1: Structure map of the top of the Three Forks Formation. Richland County, MT, is outlined in red and the Elm Coulee Field polygon is outlined with the thick black line. Depth values are ft in Sub-Sea True Vertical Depth (SS TVD).
Figure 5.2: Structure map of the top of the Bakken Formation. Richland County, MT, is outlined in red and the Elm Coulee Field polygon is outlined with the thick black line. Depth values are ft in Sub-Sea True Vertical Depth (SS TVD).
Figure 5.3: Isopach map of the entire Bakken Formation. Thickness is in ft. The formation pinch-out is marked in the south to southwest with a black/orange contour line.
Figure 5.4: Isopach map of the Middle Bakken Member. Thickness is in ft. The formation pinch-out is marked in the south to southwest with the “0” contour line.
Figure 5.5: Oil production from the MBM reservoir in the Elm Coulee Field and surrounding area. Bubble size is based on EUR value, which was calculated using the effective exponential Arp’s equation.
Figure 5.6: Probability distribution of EUR by well in the Elm Coulee Field. The blue line is comprised of individual points from roughly 600 EUR values calculated from wells in only the Elm Coulee Field. The Swanson’s mean value for EUR in the field is 269,175 bbl. The arithmetic mean value for EUR in the field is 266,969 bbl. Both of these mean values are higher than the P50 value calculated for EUR in the field, 221,528 bbl.
Figure 5.7: A decline curve for a well with below average EUR. The calculated EUR is 58,707 bbl. The well is Boulder Stone 26-16H (UWI: 25083220560000).
Figure 5.8: A decline curve for a well with a roughly average EUR. The calculated EUR is 259,210 bbl. The well is Antone-Dombrowski 17-4-H (UWI: 25083219170000).
Figure 5.9: A decline curve for a well with an above average EUR. The calculated EUR is 751,972 bbl. The well is Frasca 24X-14 (UWI: 25083220810100).
Figure 5.10: The EUR bubble map placed on top of the MBM Isopach. The production trend also runs NW – SE but does not directly correlate with the thickness trend. This is likely due to lateral changes in lithology/mineralogy in the area, which then subsequently affects pore geometry and fluid saturations.
Figure 5.11: Attribute map displaying major E&P operators working the Elm Coulee Field. Lyco and Enerplus are assigned one color and considered one company, given that Enerplus bought Lyco.
Figure 5.12: Contour map of the average water saturation for the entire MBM interval. Contours are based on decimal values, and every 0.2 is bolded.
Figure 5.13: Bubble map displaying the cumulative oil/oil + water production. Hotter colors represent wells that almost exclusively produced oil and colder colors represent wells that produced comparatively more water. All wells displayed are horizontal wells drilled after 2000 with the MBM as a lateral target.
Figure 5.14: Hydrocarbon pore volume map, also known as SoPhiH map. Contours represent 0.1 hydrocarbon pore-ft.
CHAPTER 6. PORE CHARACTERIZATION

Technologic advances, most notably horizontal drilling combined with multistage fracturing, are responsible for the production success of the Elm Coulee Field as well as many other unconventional plays. However, hydraulic fractures only create enhanced permeability to help recover hydrocarbon fluids from existing pores. This chapter characterizes the pores in reservoir and non-reservoir rock in order to determine the role matrix porosity plays in flow units, fluid saturation, and reservoir wettability. Qualitative data from petrographic thin sections and field emission scanning electron microscope (FE-SEM) imaging, as well as quantitative data from mercury injection capillary pressure (MICP) data, will be presented in order to show trends that significantly affect reservoir quality. The pore systems discussed in this chapter will appear to not accommodate Darcy style flow, and that is an important distinction to make from conventional reservoirs. In low porosity, low permeability, tight reservoirs such as the tight MBM, fluid flow can be described with a combination of advective and diffusive flow; advective flow occurs in mesopore or larger networks and fractures while diffusive flow occurs in micropore or smaller networks (Hawthorne et al., 2013; Wan and Sheng, 2015; Alharthy et al., 2015; Jin et al., 2016). This is the case in both primary recovery with hydraulic fracturing and tertiary recovery using a form of solvent flood.

6.1 Qualitative Observations

Chapter 4 discussed core-scale trends in differentiating pay, primarily by showing that intervals with comparatively higher dolomite and lower clay content were more likely to have higher porosity values and oil saturations. Chapter 5 argued that the main production trend in the Elm Coulee Field is present because of preferential dolomitization on a field scale. This
section and the following will discuss mineralogic controls on reservoir quality, with an emphasis on dolomite and clay minerals, specifically illite.

A majority of the photomicrographs presented were taken under epifluorescent light, which makes pore spaces fluoresce orange to red, allowing for the clear distinction between the pay interval and non-reservoir rock (Figure 6.1). Alexandre (2011) states that there are six main pore types present in the Elm Coulee Field: microporosity, fractures, intercrystalline, intergranular, secondary (dissolution), and “slot” pores. While not an accepted technical term, a “slot” pore is defined by O’Brien et al. (2011) as a “three dimensional pore system consisting of intercrystalline pores, generally oriented parallel to the grain and crystal surfaces that are often enhanced by secondary porosity development.” This study confirms the presence of all six pore types, but will differ from Alexandre (2011) in evaluating the importance of these separate pore types; Alexandre (2011) argued that microporosity does not significantly contribute to reservoir quality. Instead, the reservoir is primarily controlled by intercrystalline, intergranular, secondary, and “slot” pores. While these four pore types do play a major role in the reservoir, the figures presented in this section and the next will argue that microporosity is significant factor as well. Fracture porosity does contribute as well, but is simply not as abundant as the other five porosity types.

Chapter 4 divided the MBM into three general reservoir intervals: marginal reservoir, which occurs above the pay interval and can be oil saturated despite lower porosity values; the pay interval, which has the highest porosity and oil saturation values; and non-reservoir, which is below the pay interval, has the least amount of visible porosity, the highest water saturation, and typically no oil saturation.
6.1.1 The Pay Interval

The pay interval is defined by high porosity, high oil saturation, higher dolomite content, lower clay content, lower calcite content, and low water saturations. This interval features intercrystalline, intergranular, dissolution, fracture, micro-, and “slot” porosity. In epifluorescent light, many of these pores appear to be connected, though these connections appear to be quite small (1 micron or less). There are comparatively more intercrystalline, intergranular, dissolution and “slot” pores in the pay interval than the other two. Additionally, pores in the pay interval are generally larger as well (Figures 6.1 – 6.4). The presence of dolomite plays a large role in the reservoir quality of this interval: many intercrystalline and “slot” pores are related to dolomite crystals in the matrix. The importance of these slot pores must be emphasized, considering they provide a means for communication between pores in an already tight, low permeability reservoir (Alexandre, 2011).

While the presence of an ideal amount of dolomite is an indicator of a good quality reservoir, the dolomitization process arguably plays a more complex role. Lucia (2004) argues that the origin of porosity in a dolomitized reservoir is more complex than ion rich fluid flow that then enhances porosity. Lucia (2004) argues that the porosity present in a dolostone is inherited from the precursor limestone present. While Paleozoic dolostones typically have more porosity than associated limestones, Lucia (2007) argues that this is a reflection of differential compaction rather than dolomitization enhancing porosity. This differential compaction between limestones and dolostones has been recorded in both South Florida and the Ghawar field in Saudi Arabia (Schmoker and Halley, 1982; Powers, 1962; Lucia, et al., 2001).
6.1.2 The Marginal Reservoir Interval

Chapter 4 discussed the two trends responsible for the change from pay interval to marginal reservoir: an increase in clay and calcite content (Figure 6.5), or pervasive dolomitization (Figure 6.6). These two trends that define the marginal reservoir interval can both be explained by preferential dolomitization, or lack thereof. In the case for marginal intervals that follow the calcite and clay rich trend, less initial porosity was present for ion rich fluids to pass through pore spaces and subsequently create dolomite (as described by the seepage-reflux dolomitization model). This interval features intercrystalline, intergranular, and microporosity, albeit in small amounts (Figure 6.5) In the case for marginal intervals that follow the pervasive dolomitization (or overdolomitized) trend, dolomite rhombs grew too large and cements filled in pore spaces that otherwise would have made an ideal reservoir. This interval features intercrystalline, intergranular, micro- , fracture, and “slot” porosity. Comparatively, the overdolomitized interval appears to have more visible porosity than the other type of marginal reservoir (the calcite and clay rich interval).

6.1.3 The Non-Reservoir Interval

The non-reservoir interval is characterized by high calcite content, high clay content, higher pyrite content, low dolomite content, high water saturation, and the lowest oil saturation in the MBM. Once again, the reservoir quality, or lack thereof, of this interval is primarily due to preferential dolomitization. Less initial porosity was present for ion rich fluids to pass through pore spaces and subsequently create dolomite. No porosity was inherited by the dolomitization process, because no porosity was initially present. Alternatively, what porosity that was present was then subsequently lost to compaction. This interval generally has the lowest amount of
visible porosity in thin section and features intercrystalline, intergranular, and microporosity (Figure 6.7). Microporosity is the most commonly observed porosity.

6.1.4 The Role of Clay and Wettability in the MBM

As previously emphasized, the presence of clay in the reservoir is generally seen as detrimental, however the role of clay is inevitably more complex. This complexity can be best seen in FE-SEM imaging rather than standard petrographic microscopy. When abundant enough, clay minerals can almost completely occlude pore spaces (Figure 6.8). However, high resolution imaging reveals that essentially every pore in the MBM, even those in the pay intervals, contains pore bridging and/or lining clays (Figure 6.9). Clays are even present in “slot” pores and other means by which pores communicate (Figures 6.10 and 6.11). Given their structure and placement in the pore space, these clays appear to be authigenic and formed following dolomitization in the reservoir.

Pore lining clays also appear to preferentially adsorb organic materials, which given the presence of clays in the pay interval, suggests that it is oil–wet (Figure 6.12). This preferential adsorption of organic material onto illite can be seen in other parts of the MBM reservoir in North Dakota (Li et al., 2015). In addition to clay, dolomite appears to preferentially adsorb organic material (Figure 6.12). This observation is consistent with historic approaches to carbonate reservoirs throughout the US, and the world (Manrique et al., 2006). It appears that both minerals contribute to the oil–wet condition of the reservoir.

6.2 Quantitative Observations

This section will focus on mercury injection capillary pressure (MICP) data taken from the Coyote Putnam well. MICP analysis was also performed on samples from the Bullwinkle
Yahoo and Peabody Minifie wells, however due to inconsistencies in XRD data sampling, they will not be discussed in depth. The purpose of MICP analysis is to measure the size and distribution of pore throats. This measurement gives insight into the capillary forces present in the reservoir, and how they may affect fluid saturations.

Figures 6.13 – 6.20 illustrate the pore throat distributions of the rock, derived from the mercury saturation and pressure. A common trend present in all 8 samples is that the majority of pore throat radii present are in the micro range. This confirms the qualitative observations made in the previous section. Figures 6.15 and 6.17 are partial exceptions to this trend, however, they both still contain micro sized pore throats in addition to meso sized pore throats. Another trend present in the Coyote Putnam and Bullwinkle Yahoo samples is the relationship between pore – throat size and the fluid saturation of the sample. The samples with larger pore throats had higher oil saturations and lower water saturations than samples with smaller pore throat sizes. This trend is especially apparent in the four Coyote Putnam samples. The sample with the lowest pore throat size distribution is the only sample analyzed with no oil saturation whatsoever (Figure 6.16).

Every sample displays a unimodal pore throat size (radius) distribution, except for figure 6.14, which appears to have a bimodal pore throat size distribution. Incidentally, this sample is pervasively dolomitized, to the point where porosity is negatively affected, as discussed in the previous section (Figure 6.6). This sample can serve as an endmember for discussing dolomite as a mineralogical control over pore throat size distribution, and subsequently fluid saturation. The sample taken from figure 6.14 Figure 6.16 serves as an endmember on the other side of the spectrum, illustrating that below a certain dolomite content, pore throat size distribution is negatively affected, leading to high water saturations. The other MICP samples present appear to
fall into the “goldilocks zone” of dolomite content, roughly between 40 and 60% weight percent. This apparent relationship supplements the observations made in the previous section, as well as those made by Alexandre (2011), that the presence of dolomite is related to reservoir quality in the Elm Coulee Field.

6.3 Discussion

This chapter presented qualitative and quantitative data that illustrated additional differences between the pay interval and other intervals present in the Elm Coulee Field. Special attention was placed the role of preferential dolomitization in creation of the reservoir. Several key points from this chapter must be emphasized:

- The pay interval in the Elm Coulee Field is defined by a higher porosity, high dolomite content, high oil saturation, low clay and low calcite content interval.
- This pay interval has six types of porosity: intercrystalline, intergranular, fracture, secondary, dissolution, and “slot”. “Slot” pores contribute to pore communication.
- Clays, most commonly illite, line and bridge pores throughout the entire MBM interval, including the pay interval.
- These clays, illite in particular, appear to preferentially adsorb organic material. This provides further evidence that the pay interval in the Elm Coulee Field is preferentially oil – wet.
- In addition to clay, dolomite appeared to preferentially adsorb organic material. This provides further evidence that the pay interval in the Elm Coulee Field is preferentially oil – wet.
• Fluid saturation is related to pore throat size: intervals with larger pore throats are more oil saturated, and intervals with smaller pore throats are more water saturated.

• Pore throat size is related to dolomite content.

• Preferential dolomitization, or lack thereof, is the driving factor in reservoir quality in the Elm Coulee Field. Dolomite content reflects inherited porosity present from the precursor limestone.

• Authigenic clay that formed after dolomite occludes pores and pore throats.
Figure 6.1: A) Example of lithology in the pay interval. Taken from MBM B in the Peanut Jimmy well (MD: 104224.3’). Epifluorescent light used to highlight porosity. B) Example of lithology in the non-reservoir interval. Taken from MBM B in the Peanut Jimmy well (MD: 10457.6’). Epifluorescent light used to emphasize lack of porosity.
Figure 6.2: Example of the lithology in the pay interval. Taken from MBM C in the Stockade Jayla well (MD: 9721.8’). A) Taken with epifluorescent light to emphasize porosity. Pink arrow marks intercrystalline “slot pore. Green arrow marks secondary dissolution pore. Blue circle marks microporosity. B) Taken with cross-polarized light to emphasize mineral content. Red arrow marks dolomite rhomb. Green arrow marks oil staining.
Figure 6.3: Figure 6.2 under less magnification, in order to emphasize the extensive pore network and the various pore types present in the pay interval. Blue circle marks microporosity. Pink marks intergranular porosity. Green arrow marks intergranular “slot porosity”. Blue Arrow marks intercrystalline porosity.
Figure 6.4: Example of the lithology in the pay interval. Taken from the MBM B in the Coyote Putnam well (MD: 10358’). A) Taken with epifluorescent light to emphasize porosity and microfractures present. Blue circle marks microporosity. Blue arrow marks microfracture. Green arrow marks secondary dissolution porosity. B) Taken with plane-polarized light to emphasize mineral content (note the dolomite rhombs) and porosity (shown in pink dye). Green arrow marks dolomite rhomb.
Figure 6.5: Example of lithology in the calcite and clay rich marginal reservoir interval. Taken from MBM C in the Coyote Putnam well (MD: 10348.49'). A) Taken with epifluorescent light to emphasize lack of porosity. B) Taken with cross-polarized light to emphasize the higher clay and calcite content. Blue circle marks detrital clay. Green arrow marks calcite. Pink arrow marks a dolomite rhomb.
Figure 6.6: Example of the lithology in the pervasive dolomite marginal reservoir interval. Taken from the MBM D in the Stockade Jayla well (MD: 9719.7’). A) Taken with epifluorescent light to emphasize relative lack of porosity. Green arrow marks microfracture. Pink arrow marks microporosity. Orange arrow marks “slot porosity”. B) Taken with cross-polarized light to emphasize mineral content. Note the anhydrite cement. White circle marks anhydrite. Pink arrow marks dolomite.
Figure 6.7: Example of the lithology in the non-reservoir interval. Taken from the MBM B in the Peanut Jimmy well (MD: 10457.6’). A) Taken with epifluorescent light to emphasize relative lack of porosity. B) Taken with cross-polarized light to emphasize mineral content (features calcite and higher clay content). Pink arrow marks calcite. Red arrow marks clay.
Figure 6.8: Argon ion milled FE-SEM image taken with a backscatter electron beam. Taken from the Coyote Putnam well (MD: 10,350.3’) Q = quartz; D = dolomite; ill = illite. Note how the majority of pore volumes are filled primarily with illites.
Figure 6.9: Argon ion milled FE-SEM image taken with a backscatter electron beam. Taken from the Stockade Jayla well (MD: 9727.6’) Qtz = quartz; Dolo = dolomite; ill = illite; Nsp = Sodium feldspar; Ksp = potassium feldspar. Note how illite lines and bridges each pore present. Additionally, illite fills or lines each path for pores to communicate with each other.
Figure 6.10: Energy-dispersive X-ray spectroscopy (EDAX) “map” taken from the Coyote Putnam well (MD: 10350.3’). Aluminum is used as a proxy for the presence of clays, and is shown in orange. This maps illustrates the relative abundance of clays, especially in between crystals and grains, presumably filling pores.
Figure 6.11: Broken sample FE-SEM image taken with a secondary electron beam. Sample taken from the Coyote Putnam well (MD: 10353.25'). D = dolomite; Ksp = Potassium feldspar; ill = illite. Illites bridge and fill intercrystalline pore space.
Figure 6.12: Argon ion milled FE-SEM image taken with a backscatter electron beam. Taken from the Stockade Jayla well (MD: 9721.8’). D = dolomite; Q = quartz; ill = illite; ogm = organic matter. Illite lines the large pore in the center, and appears to preferentially adsorb the organic material. Additionally, dolomite appears to adsorb organic material as well.
Figure 6.13: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,350.3’). Taken from the MBM C. RCA and XRD show that porosity = 5.9%; So = 40%; Sw = 11.8%; dolomite wt% = 47.6%; calcite wt% = 0%. Data courtesy of Enerplus.
Figure 6.14: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,353.3'). Taken from the MBM B. RCA and XRD show that porosity = 7.8%; So = 49.6%; Sw = 1%; dolomite wt% = 55%; calcite wt% = 0%. Data courtesy of
Figure 6.15: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,356.4'). Taken from the MBM B. RCA and XRD show that porosity = 5.9%; So = 40%; Sw = 11.8%; dolomite wt% = 47.6%; calcite wt% = 0%. Data courtesy of Enerplus.
Figure 6.16: Pore throat size and distribution of a sample from the Coyote Putnam well (MD: 10,364.4’). Taken from the MBM B. RCA and XRD show that porosity = 4.2%; So = 0%; Sw = 67.4%; dolomite wt% = 37.5%; calcite wt% = 6.7%. Data courtesy of Enerplus.
Figure 6.17: Pore throat size and distribution of a sample from the Bullwinkle Yahoo well (MD: 10,462.3’). Taken from the MBM C. RCA and XRD show that porosity = 10.6%; So = 40%; Sw = 7.7%; dolomite wt% = N/A%; calcite wt% = N/A%. Facies taken from Eidsnes (2013). Data courtesy of Enerplus.
Figure 6.18: Pore throat size and distribution of a sample from the Bullwinkle Yahoo well (MD: 10,467.45’). Taken from the MBM B. RCA and XRD show that porosity = 9.3%; So = 38%; Sw = 10%; dolomite wt% = 44%; calcite wt% = 0%. Facies taken from Eidsnes (2013). Data courtesy of Enerplus.
Figure 6.19: Pore throat size and distribution of a sample from the Bullwinkle Yahoo well (MD: 10,472.25’). Taken from the MBM B. RCA and XRD show that porosity = 6%; So = 30%; Sw = 27%; dolomite wt% = 42.8%; calcite wt% = 0%. Facies taken from Eidsnes (2013). Data courtesy of Enerplus.
Figure 6.20: Pore throat size and distribution of a sample from the Peabody Minifie well (MD: 10,425’). Taken from the MBM B. RCA and XRD show that porosity = 7.2%; So = 39%; Sw = 12%; dolomite wt% = N/A%; calcite wt% = N/A%. Data courtesy of Enerplus.
CHAPTER 7. RESERVOIR FLUIDS AND WETTABILITY

This chapter discusses the fluid properties of the Middle Bakken Member (MBM) reservoir in the Elm Coulee Field, how these fluids interact with the reservoir rock, how the reservoir fluids interact with various injected fluids, and how injected fluids alter the interaction between reservoir fluids and rock. The majority of the data discussed in this chapter is from a Surtek Inc report commissioned by Enerplus Corporation and experimental work performed by petroleum engineering students at Colorado School of Mines.

This chapter will also provide further evidence that the pay interval in the MBM reservoir is oil-wet. Special emphasis has been placed on the reservoir “wetness” in this study due to the consequences of reservoir “wetness” on EOR. The most important consequence is that there is a significant amount of residual oil left adsorbed to the reservoir rock in-situ. Because of this, the Elm Coulee Field is both an attractive and potentially challenging candidate for EOR. This chapter presents various experimental methods that show how the oil – wet nature of the reservoir can be exploited or altered so that additional oil can be recovered.

7.1 MBM Reservoir Fluid Properties in the Elm Coulee Field

Bakken crude oil and produced water samples were taken from the Peabody Minifie 26 - 14 well to be analyzed. The produced water was 0.45 micron filtered and analyzed for total dissolved solids (TDS), pH, resistivity, density, and the following ions: calcium, magnesium, barium, strontium, iron, sodium, potassium, chloride, sulfate, carbonate, and bicarbonate. The crude oil sample was characterized by measuring the API gravity and Brookfield viscosity.

Table 7.1 summarizes the analyses performed on the produced water compared with an analyzed fresh water sample. The TDS in the produced water are several orders of magnitude
greater than the fresh water (258,900 mg/L v 1,242 mg/L respectively). The salinity of the Bakken produced water cannot be emphasized enough, especially since it is an order of magnitude greater than the average seawater salinity (~35,000 mg/L TDS). Special attention should be paid to the concentration of magnesium, calcium, and sodium. The concentration of these divalent and monovalent cations potentially have effects on the reservoir and flooding mechanisms which will be discussed later in the chapter. On a similar note, the pH difference between the produced water and the fresh water is substantial (4.37 v 8.1 respectively). These produced water trends are not unique to the Elm Coulee Field, as shown in Table 7.2.

Table 7.3 summarizes analyses of Bakken crude oil taken from the Peabody Minifie well. The Bakken crude is a relatively low viscosity, light oil. Unsurprisingly, the interfacial tension between the oil and produced or fresh water is relatively high. Kurtoglu (2013) performs even more in-depth analyses of Bakken crude from three fields in North Dakota, which can be reasonably used as a proxy for the Bakken crude in the Elm Coulee Field. Comparing the values of Table 7.3 and 7.4, the API gravity of the oil samples are similar; however the viscosities are an order of magnitude different. This is due to different measuring environments: the Elm Coulee viscosity values on Table 7.3 crude were measured at ambient pressure and 180° F, whereas the North Dakota values on Table 7.4 were determined at bubble point pressure and reservoir temperature.

In addition to single-stage flash tests, Kurtoglu (2013) also measured the saturates, aromatics, resins, and asphaltenes (SARA) present in the Bakken crude Table 7.5. This measurement was made in order to identify Bakken crude oil components according to their polarity and polarizability. Resins and asphaltenes have polar substituents, and aromatics are slightly more polarizable. Saturates consist of nonpolar material. The presence of polar
components in the Bakken crude can affect reservoir properties, specifically fluid adsorption onto clays, and will be discussed later in this chapter. Kurtoglu (2013), also measured the total acid number (TAN), the total base number (TBN), and the water content of the Bakken crude Table 7.6. These measurements were performed in order to determine the potential for possible operational issues (corrosion, etc.) as well as the potential for acidic and/or basic components from the Bakken crude to adsorb onto clays present in the reservoir.

### 7.2 Oil Drop Core Tests

The wettability of the reservoir rock will invariably affect primary, secondary, and tertiary production. Arguably, the wettability of the reservoir will affect tertiary production the most, considering that not only the relative permeabilities of in situ reservoir fluids are affected but also the relative permeabilities of any injected fluids. In the case of an oil-wet reservoir with high irreducible oil saturations, the relative permeability of water can be quite low. Kurtoglu (2013) measured the relative permeabilities of oil and water at irreducible water saturation and irreducible oil saturation respectively in the North Dakota MBM. The relative permeability of oil at irreducible water saturation was found to be 0.103 md, comparatively higher to the relative permeability of water at irreducible oil saturation, which was 0.0241 md.

A recurring and important argument of this study is that the pay interval in the MBM is preferentially oil wet and that this reservoir wetness will affect all future EOR attempts. Chapter 2, discussed historic arguments in favor of preferential oil wetness, Chapter 4 illustrated the high oil saturations present in the high porosity zones, Chapter 5 showed the low water saturations present in the reservoir production fairway, and Chapter 6 featured FE-SEM images where organic materials preferentially adsorbed onto pore lining clay minerals. Figures 7.1 and 7.2 provide further qualitative evidence that the reservoir rock in the Elm Coulee Field is
preferentially oil wet. Core samples were dried and cleaned prior to fluid droplet emplacement, or were then dried, cleaned, and treated with water (either produced or fresh respectively). Figure 7.1 demonstrates oil imbibition into both a clean core as well as a core treated with produced water. Figure 7.2 demonstrates oil imbibition into both a clean core as well as a core treated with fresh water. In both cases, the produced and fresh water did not imbibe to a significant degree.

7.3 **Injected Fluid Properties**

This section discusses the properties of common EOR fluids that were not used in any experiments for this study. More specifically, this section addresses the effects of CO₂ and hydrocarbon gas when injected into crude oil. Injections using CO₂ and hydrocarbon gas (or any phase miscible with liquid or gaseous hydrocarbons) are referred to as solvent injections. The main recovery mechanism of this injection type is mass transfer through partial or complete miscibility. Other common injected fluids, such as surfactants (used for a surfactant flood) and fresh water (also known as a low – sal flood), are respectively addressed in other sections of this chapter along with relevant experimental data.

7.3.1 **CO₂**

Carbon dioxide injection is an attractive method for its technical advantages in addition to providing the possibility for of carbon sequestration. Compared to other miscible injections into crude oil, a miscible CO₂ injection has several advantages: CO₂ has a comparatively lower minimum miscibility pressure (MMP), it reduces oil viscosity, and it causes oil to swell. Table 7.7 summarizes the MMPs for several prospective injection fluids in the Bakken found through both experimental rising bubble apparatus (RBA) experiments as well as through modeling. Of the five gases Adekunle (2014) studied, CO₂ had the lowest MMP by at least ~700 psia.
Carbon dioxide is capable of swelling oil up to 1.5 times its original volume, which promotes sweeps across a reservoir, promoting further recovery. This swelling process is a function of pressure, temperature, and relative volume of the oil (Adekunle, 2014). Kurtoglu (2013) conducted experiments to demonstrate and quantify both CO\(_2\) causing oil to swell as well as its capacity to reduce an oil’s viscosity. The results of these experiments are summarized in Table 7.8, which quantify the swelling and viscosity capacity of a North Dakota Bakken crude oil sample.

### 7.3.2 Hydrocarbon Gas

Injecting hydrocarbon gas does not provide some of the unique advantages of CO\(_2\) injection, however, it still becomes readily miscible (though at higher pressures) and reinjecting produced gas provides an alternative to flaring. Reinjecting gas that could have been flared has advantages in many different capacities, many of which are not relevant to the topic at hand, but are discussed in Hoffman et al. (2014). The remainder of this section discusses the benefits of a miscible injection using a hydrocarbon gas.

When two fluids are miscible, the interfacial tension (IFT) between the phases is 0, meaning there is no interface between the two fluids. While miscibility is not essential for a solvent method EOR, it is the ideal case. This is because a completely miscible injection will have a larger displacement efficiency, because there are no residual phases. Complete miscibility is rarely practical or possible, which is why the term solvent flooding is generally used to describe this particular method. The main recovery method of crude oil in a solvent injection is mass transfer. Miscibility itself is achieved through mass transfer of intermediate hydrocarbon components, whether through vaporizing gas drive (intermediate components in the crude are
vaporized in the solvent) or condensing gas drive (intermediate components in the solvent are condensed into the crude) (Lake et al., 2014).

### 7.4 Surfactant and Bakken Crude Experiments

The word surfactant is a contraction of the phrase “surface active agent”, which gives insight into their primary purpose: this group of chemicals concentrate at the surface (or interface) between immiscible fluids, in this case oil and water. Surfactants reduce the interfacial tension (IFT) at the interface of these two substances. Lowering the IFT between oil and water (either produced or fresh) decreases the wetting forces present in the reservoir, which then mobilizes more hydrocarbons.

A series of surfactants were dissolved in both produced water and fresh water then combined with Bakken crude. This was done to determine the comparative change in IFT between the water/crude oil and the surfactant solution/crude oil systems. Table 7.9 summarizes the 13 surfactants dissolved in produced water discussed in this study. Figure 7.3 displays the effect of each surfactant on the IFT between the surfactant/crude oil systems. Eleven of the thirteen surfactants dissolved in the produced water reduced the IFT. Zonyl FSO was the only surfactant dissolved in produced water that noticeably reduced the IFT as its concentration increased.

Table 7.10 summarizes the 20 surfactants dissolved in fresh water discussed in this study. Figures 7.4 and 7.5 display the effect of each surfactant on the IFT between the surfactant/crude oil systems. All twenty surfactants dissolved in the fresh water reduced the IFT. Petrostep A6 reduced the IFT the most of all the surfactants used, however it did form an emulsion with the Bakken crude, which could pose a problem in any attempted future injections. Overall, the surfactants dissolved in fresh water outperformed the surfactants dissolved in produced water.
This discrepancy is to be expected. An easy way to visualize this discrepancy is by trying to use soap in hard water. Dissolving surfactants into fresh water may not be a viable injection option though, given the high salt concentration in the Bakken Formation brine.

### 7.5 Core Plug Imbibition Tests

Core plug imbibition tests were performed in order to better quantify the potential of different chemical solutions to recover oil. Seven core plugs were cleaned, then placed in Bakken crude for three weeks at 75°F. Temperature was then increased to 175°F and the cores continued to saturate for another seven weeks. Table 7.11 summarizes each core plug’s dimensions, sample depth, and oil saturation following the ten week saturation period. Saturated plugs were placed into the imbibition test apparatus (Figure 7.6), which was then filled with chemical solution and incubated at 180°F. Each test was terminated once oil recovery was asymptotic. Produced water, fresh water, and several surfactants were selected as the chemical solution based on previous IFT measurements. Tables 7.12 and 7.13 and Figures 7.7 and 7.8 summarize the fluid properties used in the imbibition tests as well as the recovery factor for each respective OOIP. Similar to the crude IFT tests, the surfactants dissolved in fresh water outperformed those dissolved in produced water. Fresh water also outperformed surfactants dissolved in produced water, which deserves further discussion due to potential consequences related to reservoir wettability in the Bakken Formation.

### 7.6 Fresh Water Flooding

Fresh water flooding, also known as low – salinity flooding, is a relatively new idea in the field of petroleum geology and engineering. As shown in Figure 7.8, fresh water seems to overcome antagonistic capillary forces and produce substantial amounts of OOIP. This
phenomenon is not unique to the Bakken Formation reservoir in the Elm Coulee Field either. Kurtoglu 2013 demonstrated a similar property in North Dakota Bakken Formation reservoir rock as well. Moreover, this phenomenon is not unique to the Bakken Formation as a whole: several core low – salinity core floods performed on rock from basins throughout the world have been documented in literature (Tang and Morrow, 1999; Alotaibi et al., 2010; Romanuka et al., 2012).

Kurtoglu (2013) argues that there are several necessary conditions in order for low – salinity flooding to be effective:

- The formation must contain a typical non – swelling clay type with a high cation exchange coefficient (CEC) in sufficient quantities.
- The crude oil must contain polar components.
- Formation brine must contain divalent cations.

Each of these conditions are present in the MBM reservoir in the Elm Coulee Field: the dominant clay type in the reservoir is illite, which does not swell significantly and has a relatively higher CEC; the crude oil contains polar components (most notably aromatic components) as well as polar acidic and basic components; the formation brine contains abundant Mg$^{2+}$ and Ca$^{2+}$, both divalent cations. The mechanism behind low – salinity water flooding is still controversial, but the three most popular theoretical mechanisms each involve these described conditions.

The three most popular mechanisms for oil recovery via low – salinity flooding are:

- Wettability alteration through removal of the “ion bridge”, also known as the ionic double layer effect (Lager et al. 2007; Ligthelem et al., 2009).
- pH changes close to pore – lining clay surfaces (Austad et al., 2010).
- Recovery through osmosis (Fakcharoenphol et al., 2013)
The remainder of this section will describe these three proposed mechanisms.

7.6.1 “Ion Bridge Removal” Resulting in Wettability Alteration

This mechanism seems to best explain the preferential adsorption of organic material on clay lining pores shown in Chapter 6. Positively charged multivalent cations, such as Ca$^{2+}$ and Mg$^{2+}$, in the formation brine act like bridges between the negatively charged oil and clay minerals (Lager et al., 2007; Ligthelem et al., 2009). In the presence of a high salinity environment, such as the MBM, sufficient amounts of positively charged divalent cations would be able to effectively suppress electrostatic repulsive forces from the negatively charged oil and clay surface (Figure 7.9). In this environment, oil has the potential to react with clay particles to form organometallic complexes, like those seen in Chapter 6 (Rueslatten et al., 1994). The formation of these complexes makes the pores lined with clays preferentially oil – wet (Clementz, 1982).

The efficacy of fresh water flooding (Figure 7.8), then, is the result of the inverse of this binding mechanism. When brine salinity or composition changes, the surface energy of the mineral – fluid interface will change. A salinity gradient is created following fresh water imbibition, this gradient results in the reduction in the ionic content in the brine, and consequently the elimination of these “ion bridges”. Without sufficient divalent cations present to mitigate the effects of electrostatic repulsion, oil particles have the potential to desorb from clay surfaces, eventually resulting in a more preferentially water-wet pore space (Figure 7.10).

This “ion bridge” is only a specific example of describing the mechanism of how mineral surfaces preferentially adsorb oil and subsequently how this property is exploited for EOR. Additionally, the “ion bridge” model cannot necessarily explain the mechanism by which carbonates preferentially adsorb organic material either. A more general theory that can be
combined with the “ion bridge” theory (in principle) is that wettability is based on an
electrochemical – potential gradient rather than just a concentration gradient alone. Mahani et al.,
2015a & b argues that DLVO theory can adequately explain why both carbonates and clays are
preferentially oil – wet in high salinity environments, and why this can be exploited for EOR.
DVLO theory sums the effects of van der Waals attraction and the electrostatic repulsion due to
the electrical double layer. Depending on the relationship between the zeta potential of the two
substances, in this case oil and mineral, they either attract or repel. Mahani et al., 2015b
demonstrated that in high salinity conditions, carbonates and crude oil have zeta potentials with
different signs, meaning that they will attract. In lower salinity conditions, the two substances
will have the same sign zeta potential and will repel. In addition to concentration gradients,
electrochemical – potential gradients play a role in wettability.

7.6.2 pH Increases Near Clay Surfaces

Austad et al. (2010) argues that the changes in the ionic layer close to the clay surface
(described above) are only a secondary mechanism. Rather, the driving force behind low –
salinity waterflooding is an acid – base reaction that desorbs oil from a clay’s surface as a result
of a local increase in pH. Instead of the desorption of Ca$^{2+}$ or Mg$^{2+}$ from the clay surface being
the main reason for oil desorption, it is the first step in a series of reactions.

Prior to fresh water injection, the system is presumably in equilibrium with basic and
acidic organic materials, as well as inorganic cations, adsorbed on the clay surface. Initial pH of
this system is roughly 5 or lower at reservoir temperatures and pressures. Once the low salinity
water is injected, cations are desorbed from the clay surface. Following this desorption, protons
(H$^+$) adsorb onto the clay surface in a form of compensation, which in turn creates a local
increase in pH close to the clay surface. Figure 7.11 illustrates the proposed mechanism
occurring on the clay surface. Additionally, the adsorption and desorption of basic and acidic materials onto clay materials is dependent on changes in pH. A low pH environment (roughly ranging from 5 to 4) is favorable for organic material to adsorb onto clay minerals, so, increasing the pH assists in further desorption.

7.6.3 Recovery through Osmosis

Fakcharoenphol et al. (2014) demonstrates that osmotic pressure created from a low – salinity flood promotes water-oil counter-current flow and as a result, oil production. The low – salinity flood creates a salinity gradient and the salty brine moves accordingly. At this point, oil mobilization is a matter of mass transfer. High salinity brine flows from within inter- and intra-clay porosity, fractures, and other pore types, towards the point of injection. The injected low salinity fluids then enter inter- and intra-clay pore spaces and any adsorbed oils are expelled in a counter-current flow due to an increase pressure (Figure 7.12). Additionally, Fakcharoenphol et al. (2014) suggests that the removal of the “ion bridge” (discussed above), and the subsequent change in wettability, can work concurrently with osmotic forces. This concurrent process could possibly explain the imbibition of fresh water occurring so readily in figure (fresh imbibition), and overcoming antagonistic capillary forces.

7.7 Discussion

This chapter presented experimental data that demonstrated the laboratory efficacy of several possible EOR injection schemes in the MBM of the Bakken Formation. In a general sense, three separate types of injections were discussed: solvent (CO₂ and hydrocarbon gas), chemical (surfactants), and low – salinity flood (fresh water). The data presented from these
injections show that the oil–wet nature of the reservoir in the Elm Coulee Field can be exploited or changed for future EOR attempts. Several key points from this chapter must be emphasized:

- Bakken crude is a light oil with relatively low viscosity
- Formation water in the MBM is extremely salty, containing over 250,000 mg/L TDS
- “Oil drop” core tests demonstrated that crude oil preferentially imbibed into treated cores, compared to water which did not. This provides evidence that suggests the reservoir is oil–wet.
- Surfactants dissolved in fresh water and produced water were able to lower the IFT between Bakken crude and plain fresh water.
- Surfactants dissolved in fresh water and fresh water itself recovered a significant amount of oil from a saturated core. Surfactants dissolved in produced water did not perform as well comparably.
- The efficacy of fresh water flooding can also give insight into the initial wetting mechanism in the reservoir. The “ion bridge” provides a specific example for why organic matter could preferentially adsorb onto clays. A more general explanation relies on DLVO theory and the manipulation of electrochemical – potential gradients.
- Osmotic forces due to differences in salinity could also provide a physical explanation for the efficacy of fresh water injection. This does not however, provide insight into the wetting mechanism in the reservoir.
Table 7.1: Analysis of produced water from the Peabody Minifie 26-14 well in the Elm Coulee Field as well as a fresh water sample for comparison. Data courtesy of Enerplus via Surtek.
Table 7.2: Summary of water analyses taken from three separate fields producing from the Bakken Formation in North Dakota (Kurtoglu, 2013).

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Sample #</th>
<th>Chloride (mg/L)</th>
<th>Sulfate (mg/L)</th>
<th>Bicarbonate (mg/L)</th>
<th>Sodium (mg/L)</th>
<th>Calcium (mg/L)</th>
<th>Magnesium (mg/L)</th>
<th>Iron (mg/L)</th>
<th>Barium (mg/L)</th>
<th>Strontium (mg/L)</th>
<th>TDS (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reunion Bay</td>
<td>1</td>
<td>172500</td>
<td>223</td>
<td>122</td>
<td>85730</td>
<td>19790</td>
<td>1253</td>
<td>333</td>
<td>23</td>
<td>1458</td>
<td>281,448</td>
</tr>
<tr>
<td>Murphy Creek</td>
<td>2</td>
<td>169500</td>
<td>291</td>
<td>37</td>
<td>87277</td>
<td>16750</td>
<td>1488</td>
<td>30</td>
<td>10</td>
<td>1200</td>
<td>276,569</td>
</tr>
<tr>
<td>Bailey</td>
<td>3</td>
<td>182200</td>
<td>270</td>
<td>110</td>
<td>84966</td>
<td>24980</td>
<td>1753</td>
<td>241</td>
<td>16</td>
<td>1921</td>
<td>296,463</td>
</tr>
<tr>
<td>Bailey</td>
<td>4</td>
<td>183400</td>
<td>260</td>
<td>122</td>
<td>95138</td>
<td>17870</td>
<td>1268</td>
<td>210</td>
<td>18</td>
<td>1377</td>
<td>299,677</td>
</tr>
</tbody>
</table>

Table 7.3: Summary of crude oil analysis taken from the Peabody Minifie well in the Elm Coulee Field. Data courtesy of Enerplus via Surtek.

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude Oil Well</td>
<td>Peabody-Minifie 26-14</td>
</tr>
<tr>
<td>Log #</td>
<td>231-07</td>
</tr>
<tr>
<td>API Gravity</td>
<td>40.6</td>
</tr>
<tr>
<td>Density at 180°F</td>
<td>0.7770</td>
</tr>
<tr>
<td>Density at 75°F</td>
<td>0.8195</td>
</tr>
<tr>
<td>Density at 59°F</td>
<td>0.8256</td>
</tr>
<tr>
<td>Water Content**</td>
<td>&lt; 0.02</td>
</tr>
<tr>
<td>Water Content**(used in evaluation)**</td>
<td>&lt; 0.02</td>
</tr>
<tr>
<td>Viscosity+ at 180°F</td>
<td>1.3</td>
</tr>
<tr>
<td>Interfacial Tension*** between oil and produced water</td>
<td>11.96</td>
</tr>
<tr>
<td>Interfacial Tension*** between oil and fresh water</td>
<td>14.26</td>
</tr>
</tbody>
</table>

+ - Viscosity is a Brookfield viscosity, UL adaptor at 6 rpm
* - API gravity is by ASTM C287
** - Water content is by Karl Fisher ASTM E-203
*** - Interfacial Tension is by Dunowo Ring
Table 7.4: Summarization of crude oil analyses taken from three separate fields producing from the Bakken Formation in North Dakota (Kurtoglu, 2013).

<table>
<thead>
<tr>
<th>Field Name</th>
<th>Well #</th>
<th>Sample Formation</th>
<th>Properties at Bubble Point Pressure ($P_b$)</th>
<th>Single Stage Flash (Standard Condition)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>$T_R$</td>
<td>$P_b$</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>psia</td>
<td>psia</td>
</tr>
<tr>
<td>Reunion Bay</td>
<td>1</td>
<td>Middle Bakken</td>
<td>212</td>
<td>2304</td>
</tr>
<tr>
<td></td>
<td>2</td>
<td>Middle Bakken</td>
<td>237</td>
<td>2530</td>
</tr>
<tr>
<td></td>
<td>3</td>
<td>Three Forks</td>
<td>239</td>
<td>1753</td>
</tr>
<tr>
<td>Bailey</td>
<td>4</td>
<td>Middle Bakken</td>
<td>245</td>
<td>2674</td>
</tr>
<tr>
<td></td>
<td>5</td>
<td>Middle Bakken</td>
<td>240</td>
<td>1778</td>
</tr>
<tr>
<td></td>
<td>6</td>
<td>Middle Bakken</td>
<td>240</td>
<td>2057</td>
</tr>
<tr>
<td>Murphy Creek</td>
<td>7</td>
<td>Middle Bakken</td>
<td>240</td>
<td>1657</td>
</tr>
<tr>
<td></td>
<td>8</td>
<td>Middle Bakken</td>
<td>240</td>
<td>1389</td>
</tr>
</tbody>
</table>

Table 7.5: Summarization of conventional saturates, aromatics, resins, and asphaltenes (SARA) analysis and medium-pressure liquid chromatography (MPLC) analysis. Note the concentration of resins, asphaltenes, and aromatics (Kurtoglu, 2013).

<table>
<thead>
<tr>
<th>Method</th>
<th>Field</th>
<th>Sample #</th>
<th>Saturates</th>
<th>Aromatics</th>
<th>Resins</th>
<th>Asphaltene</th>
<th>Saturates/Aromatic</th>
<th>Asphaltene/Resin</th>
</tr>
</thead>
<tbody>
<tr>
<td>SARA</td>
<td>Bailey</td>
<td>1</td>
<td>51.69</td>
<td>40.90</td>
<td>7.35</td>
<td>0.06</td>
<td>1.3</td>
<td>0.01</td>
</tr>
<tr>
<td>SARA</td>
<td>Reunion</td>
<td>2</td>
<td>46.55</td>
<td>46.55</td>
<td>6.55</td>
<td>0.35</td>
<td>1.0</td>
<td>0.05</td>
</tr>
<tr>
<td>MPLC</td>
<td>Reunion</td>
<td>3</td>
<td>49.83</td>
<td>28.09</td>
<td>8.03</td>
<td>0.33</td>
<td>1.8</td>
<td>0.04</td>
</tr>
<tr>
<td>MPLC</td>
<td>Reunion</td>
<td>4</td>
<td>41.76</td>
<td>27.24</td>
<td>8.24</td>
<td>6.09</td>
<td>1.5</td>
<td>0.74</td>
</tr>
</tbody>
</table>

Table 7.6: Summarization of total acid number (TAN) and total base number (TBN) of Bakken crude oil from two fields in North Dakota (Kurtoglu, 2013)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Method</th>
<th>Bailey</th>
<th>Reunion Bay</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Acid (mg KOH/g)</td>
<td>ASTM D664</td>
<td>0.09</td>
<td>Not detected</td>
</tr>
<tr>
<td>Total Base (mg KOH/g)</td>
<td>ASTM D2896</td>
<td>Not measured</td>
<td>1.16</td>
</tr>
<tr>
<td>Water Content (wt %)</td>
<td>ASTM D 4377</td>
<td>0.01</td>
<td>0.02</td>
</tr>
</tbody>
</table>
Figure 7.1: A) Comparison of oil drop and produced water drop imbibing into a cleaned core over time. B) Oil drop imbibing into a core treated with produced water over time. All core samples taken from the Peabody Minifie 26 – 14 well. Data courtesy of Enerplus via Surtek.
Figure 7.2: A) Comparison of oil drop and fresh water drop imbibing into a cleaned core over time. B) Oil drop imbibing into a core treated with fresh water over time. All core samples taken from the Peabody Minifie 26 - 14 well. Data courtesy of Enerplus via Surtek.
Table 7.7: Summary of minimum miscibility pressures found through experimental means (RBA) and popular models. The oil used was a recombined Bakken crude sample from a North Dakota field. CO₂ has the lowest MMP of all injected fluids (Adekunle, 2014).

Table 7.8: Summary of Bakken crude oil swelling and viscosity reduction tests. Performed at 237°F with CO₂ as the solvent.
Table 7.9: Summary of the surfactants dissolved in produced water. Table includes structure, solution activity, and supplier. Data courtesy of Enerplus via Surtek.

<table>
<thead>
<tr>
<th>Name of Surfactant</th>
<th>Structure</th>
<th>% Activity As Used in Lab Evaluation</th>
<th>Supplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>Agnique PG 8107U</td>
<td>C8-C10 glycoside</td>
<td>69.9</td>
<td>Cognis</td>
</tr>
<tr>
<td>Agnique PG 8166</td>
<td>C8-C16 glycoside</td>
<td>50</td>
<td>Cognis</td>
</tr>
<tr>
<td>Agnique PG 9116</td>
<td>C9-C11 glycoside</td>
<td>50</td>
<td>Cognis</td>
</tr>
<tr>
<td>Amphosol 810-B</td>
<td>N/A</td>
<td>35.7</td>
<td>Stepan</td>
</tr>
<tr>
<td>Amphosol CG</td>
<td>N/A</td>
<td>30</td>
<td>Stepan</td>
</tr>
<tr>
<td>Amphosol LB</td>
<td>N/A</td>
<td>35</td>
<td>Stepan</td>
</tr>
<tr>
<td>Zonyl FSH</td>
<td>Fluoro-surfactant</td>
<td>50</td>
<td>DuPont</td>
</tr>
<tr>
<td>Zonyl FSO</td>
<td>Fluoro-surfactant</td>
<td>50</td>
<td>DuPont</td>
</tr>
<tr>
<td>SS-C9</td>
<td>cationic surfactant</td>
<td>100</td>
<td>OCT</td>
</tr>
<tr>
<td>SS-C12</td>
<td>cationic surfactant</td>
<td>100</td>
<td>OCT</td>
</tr>
<tr>
<td>Petrostep M4</td>
<td>amphoteric surfactant</td>
<td>28.4</td>
<td>Stepan</td>
</tr>
<tr>
<td>Petrostep M5</td>
<td>amphoteric surfactant</td>
<td>26.9</td>
<td>Stepan</td>
</tr>
<tr>
<td>Petrostep SXS</td>
<td>sodium xylene sulfonate</td>
<td>40.5</td>
<td>Stepan</td>
</tr>
</tbody>
</table>

The thirteen surfactants were dissolved in produced water at 0.1 wt%, 0.3 wt%, and 0.5 wt%. Interfacial tensions were measured between Sleeping Giant crude oil and surfactant solutions at 180°F.
Figure 7.3: Summary of interfacial tension (IFT) between Bakken crude oil and surfactants dissolved in produced water at 180°F. Only Zonyl FSO showed considerable changes in IFT with increased concentration. Data courtesy of Enerplus via Surtek.
Table 7.10: Summary of the surfactants dissolved in fresh water. Table includes structure, solution activity, and supplier. Data courtesy of Enerplus via Surtek.

<table>
<thead>
<tr>
<th>Name of Surfactant</th>
<th>Structure</th>
<th>% Activity As Used in Lab Evaluation</th>
<th>Supplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>SS 880</td>
<td>amphoteric</td>
<td>54</td>
<td>OCT</td>
</tr>
<tr>
<td>Petrostep A1</td>
<td>heavy sulfonate</td>
<td>6.8</td>
<td>Stepan</td>
</tr>
<tr>
<td>Petrostep A6</td>
<td>heavy sulfonate</td>
<td>42</td>
<td>Stepan</td>
</tr>
<tr>
<td>AES 4-22</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 6-130</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 7-58</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 122</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 205</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 403</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 409</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 601</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>AES 1220</td>
<td>alcohol ether sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>ORS-62 HF</td>
<td>alkyl aryl sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>Avanel S 70</td>
<td>ethylene oxide</td>
<td>35</td>
<td>PPG Chemical</td>
</tr>
<tr>
<td>Avanel S 74</td>
<td>ethylene oxide</td>
<td>35</td>
<td>PPG Chemical</td>
</tr>
<tr>
<td>12-58-1</td>
<td>alkyl aryl sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>12-58-2</td>
<td>alkyl aryl sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>12-58-3</td>
<td>alkyl aryl sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>12-58-4</td>
<td>alkyl aryl sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
<tr>
<td>12-58-5</td>
<td>alkyl aryl sulfonate</td>
<td>50</td>
<td>OCT</td>
</tr>
</tbody>
</table>

Interfacial tensions were measured for all the surfactants listed above dissolved fresh water. Most of the surfactants were tested at 0.1 wt%, 0.3 wt%, and 0.5 wt%. The concentration of five surfactants were extended to 0.05 wt% and one to 0.75 wt%. Interfacial tensions were measured at 0.3 wt% concentration only for five 12-58-x series surfactants.
Figure 7.4: Summary of interfacial tension (IFT) between Bakken crude oil and surfactants dissolved in fresh water at 180°F. Only Petrostep A6 showed considerable changes in IFT with increased concentration, however, it also formed an emulsion with the Bakken crude oil. Data courtesy of Enerplus via Surtek.
Figure 7.5: Summary of interfacial tension (IFT) between Bakken crude oil and surfactants dissolved in fresh water at 180°F. Data courtesy of Enerplus via Surtek.
Table 7.11: Summary of each core plug used for the imbibition study. Includes core dimensions, density, weight, estimated porosity, and estimated oil saturation following Bakken crude oil imbibition. Data courtesy of Enerplus via Surtek.

<table>
<thead>
<tr>
<th>Core Information</th>
<th>Core Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth (ft)</td>
<td>10415.00</td>
<td>10417.15</td>
<td>10420.00</td>
<td>10422.15</td>
<td>10422.80</td>
<td>10425.20</td>
<td>10427.00</td>
<td></td>
</tr>
<tr>
<td>Diameter (cm)</td>
<td>2.40</td>
<td>2.39</td>
<td>2.40</td>
<td>2.40</td>
<td>2.40</td>
<td>2.40</td>
<td>2.39</td>
<td></td>
</tr>
<tr>
<td>Length (cm)</td>
<td>8.10</td>
<td>8.17</td>
<td>8.26</td>
<td>7.00</td>
<td>8.69</td>
<td>7.56</td>
<td>8.20</td>
<td></td>
</tr>
<tr>
<td>Bulk Volume (cm³)</td>
<td>38.63</td>
<td>36.75</td>
<td>37.23</td>
<td>35.59</td>
<td>39.16</td>
<td>34.11</td>
<td>36.91</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Crude Oil Information</th>
<th>Core Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Density at 75°F (g/ml)</td>
<td>0.820</td>
<td>0.820</td>
<td>0.820</td>
<td>0.820</td>
<td>0.820</td>
<td>0.820</td>
<td>0.820</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Core Saturation</th>
<th>Core Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core Dry Weight (g)</td>
<td>92.59</td>
<td>93.48</td>
<td>95.62</td>
<td>93.43</td>
<td>100.64</td>
<td>88.43</td>
<td>94.77</td>
<td></td>
</tr>
<tr>
<td>Core Saturated Weight (g)</td>
<td>96.25</td>
<td>96.05</td>
<td>97.86</td>
<td>95.88</td>
<td>103.14</td>
<td>88.53</td>
<td>97.11</td>
<td></td>
</tr>
<tr>
<td>Initial Oil Volume in Core at 75°F (ml)</td>
<td>3.24</td>
<td>3.14</td>
<td>2.77</td>
<td>3.00</td>
<td>3.05</td>
<td>2.57</td>
<td>2.85</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Initial Oil Saturation Based on Estimated Porosity and Sand Grain Density</th>
<th>Core Number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
</tr>
</thead>
<tbody>
<tr>
<td>Estimated Porosity (%)</td>
<td>9.00</td>
<td>8.60</td>
<td>7.50</td>
<td>8.60</td>
<td>7.90</td>
<td>7.90</td>
<td>7.80</td>
<td></td>
</tr>
<tr>
<td>Estimated Pore Volume (ml)</td>
<td>3.30</td>
<td>3.16</td>
<td>2.79</td>
<td>3.03</td>
<td>3.09</td>
<td>2.69</td>
<td>2.88</td>
<td></td>
</tr>
<tr>
<td>Initial Oil Saturation (PV)</td>
<td>0.99</td>
<td>0.99</td>
<td>0.99</td>
<td>0.99</td>
<td>0.99</td>
<td>0.95</td>
<td>0.99</td>
<td></td>
</tr>
<tr>
<td>Estimated Sand Grain Density (g/cm³)</td>
<td>2.78</td>
<td>2.79</td>
<td>2.78</td>
<td>2.87</td>
<td>2.79</td>
<td>2.75</td>
<td>2.79</td>
<td></td>
</tr>
<tr>
<td>Estimated Pore Volume (ml)</td>
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Figure 7.6: Schematic drawing of the core plug imbibition test apparatus.
Table 7.12: Summary of cores and respective imbibition fluid used. Displays volume oil displaced over time from Peabody Minifie core plugs. Results from the fresh water test are emphasized with the red rectangle. Data courtesy of Enerplus via Surtek.

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160
Table 7.13: Summary of cores and respective imbibition fluid used. Displays volume oil displaced over time from Peabody Minifie core plugs. Results from the fresh water test are emphasized with the red rectangle. Data courtesy of Enerplus via Surtek.

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<th>Recovery (%)</th>
<th>Free Oil Displaced (ml)</th>
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Emulsified Oil - End of Test

Free Oil Displaced (ml) | Oil Left in the Core (ml) | Recovery (%)  |
2.00 | 0.50 | 82.5  |

9. Fresh Water

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Figure 7.7: Percentage of oil recovered from Peabody Minifie cores versus time. Both surfactants dissolved in fresh water and fresh water itself outperformed surfactants dissolved in produced water and produced water as imbibition fluids. Data courtesy of Enerplus via Surtek.
Figure 7.8: Percentage of oil recovered versus time. Taken from core plug 3 using fresh water following produced water injection. Data courtesy of Enerplus via Surtek.
Figure 7.9: Ion bridge mechanism proposed by Ligthelem et al. (2009).

Figure 7.10: Cartoons illustrating the bonding between the clay surface and oil in a highly saline compared to a low saline environment. The Ca$^{2+}$ ion represents multivalent cations that act as an “ion bridge” Ligthelem et al. (2009).
Figure 7.11: Proposed mechanism for low salinity EOR effects. Upper three panels demonstrate the desorption of basic material. The lower three panels demonstrate the desorption of acidic material. Initial pH conditions for this reaction are roughly 5 (Austad et al., 2010).

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<th>Initial situation</th>
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<td><img src="image3" alt="Final situation" /></td>
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Figure 7.12: Schematic showing oil-water flow in shale and the effect of osmosis: (a) pore space at initial conditions where oil is essentially the only moveable fluid and high-salinity brine is bound to clay sheets. (b) clay in comes in contact with fresh water, which then pushes oil out of meso-pores (Fakcharoenphol et al., 2014).

![Figure 7.12](image4)
CHAPTER 8. INJECTION WELL CASE STUDIES

This chapter discusses all public and confidential data available regarding two EOR injection wells in the Elm Coulee Field. The first injection discussed is a CO₂ test “huff-and-puff” injection in the Burning Tree State 36-2H well (UWI: 25083218810000) (Location: T25N R54E sec 36). A “huff and puff” scheme refers to a single well CO₂ injection (the “huff”), followed by a temporary well closure (the “soak”). Then, the well is then opened and allowed to produce again (the “puff”).

Available data relevant to the CO₂ injection is limited, however, several key points can be learned. Production trends from before and after the injection are compared to determine the CO₂ utilization ratio. The CO₂ utilization ratio of the pilot injection is then compared to other ongoing CO₂ field injections within the continental United States.

The second injection discussed is a waterflood, implemented by Continental Resources in the Staci 3-11H well (UWI: 25083227480000) (Location: T23N R55E secs 11&14). This injection appears to have affected production in a west offset well, Staci 1-11H (UWI: 25083221530000) (Location: T23N R55E secs 11&14) but not the east offset well, Staci 2-11H (UWI: 25083225700000) (Location: T23N R55E secs 11&14). A more in-depth discussion of this injection can be found in Hoffman and Evans (2016).

More information regarding ongoing and planned pilot to reservoir-scale EOR projects, can be found in the Oil and Gas Journal’s 2014 Worldwide EOR Survey edited by Leena Koottungal. The survey is extensive and pays particular attention to all conventional EOR attempts in the United States, but still covers EOR projects worldwide.

This chapter argues that while it may be difficult to prove the efficacy of these injections, these efforts show promise on the whole. Additionally, these presented injections and any future
injections are subject to geologic factors, which can either help or harm EOR attempts. Any future attempts at unconventional EOR, whether in the Elm Coulee Field or elsewhere, must be a collaborative effort between geoscientists and engineers. Ultimately, the two presented case studies serve as a metaphorical “light at the end of the tunnel”, and should serve as inspirations to continue scientific investigations into EOR in unconventional style plays.

8.1 Burning Tree 36-2H Well (Figure 8.1)

Burning Tree 36-2H is the discovery well for the unconventional Bakken play in the Elm Coulee Field. Drilling began on March 20th, 2000, and the well was completed on September 5th, 2000. Initial production was 196 BPD oil with a gravity of 40.1° API. The well was recompleted in 2002 and put on pump in 2004, resulting in an increase of monthly production rates from 1748 bbl/month to 4090 bbl/month (Figures 8.2 and 8.3). Following a decline in production, Enerplus Resources, XTO Energy, and Continental Resources worked together in 2008 to propose and develop a CO₂ pilot injection.

8.1.1 Injection Scheme and Results

A total of 45,000 mcf (2570 tons) of CO₂ were injected into the Burning Tree well over the course of 45 days from January 16th to February, 28th, 2009. Following this injection period, the well was capped and allowed to “soak” for 64 days from March 1st to May 3rd, 2009. On May 4th, the well was opened and allowed to flow freely. Eight days after the well was brought back on, oil production peaked at approximately 160 bbl/day. Production then settled at an average rate of ~20 bbl/day, which was below pre-injection rates. The well was then put on pump at the end of June 2009. Oil production continued to rise and then returned to pre-injection rates in
December 2009. Post-injection oil production continued to rise and then peaked in March 2010. Oil production eventually fell below pre-injection rates in November 2010 (Figures 8.2 and 8.3).

### 8.1.2 Injection Efficacy

Analysis of the Burning Tree well injection performance must be made within context. Essentially no unconventional pilot CO\(_2\) injection EOR efforts have been publically discussed until recently, so there are few (if any) relevant fair points of comparison. There are, however, sufficient data regarding the efficacy of conventional play EOR attempts, including those specifically in the Williston Basin (Ling et al., 2014). The Burning Tree 36-2H well must be regarded as a scientific test, and should not be evaluated on economic terms. At the very least, the well does prove that CO\(_2\) can successfully be injected into an unconventional reservoir, specifically the Bakken Formation.

Limitations of the available data make it difficult to determine how much the CO\(_2\) injection influenced subsequent oil production. Minimal CO\(_2\) monitoring data ultimately results in subjective and inconclusive analysis of the injection’s efficacy. The only available data is gas analysis that showed approximately 50% of the injected CO\(_2\) volume was recovered from the Burning Tree 36-2H well from May 2009 to August 2009. There is no data available from surrounding offset wells, so CO\(_2\) movement and subsequent oil mobilization within the reservoir could not be determined.

### 8.1.3 Speculative Conclusions

Additional conclusions (besides “proof of concept”) can be drawn assuming the entirety of the production increase is due to the CO\(_2\) injection. When comparing the production trends pre-injection and post-injection, the post-injection decline curve is arguably different, even when
accounting for pressure build-up associated with the shut-in (Figures 8.4 and 8.5). The post-injection trend projection suggests that the well will produce an additional 8,596 bbl oil over the course of its production “life”. While this may not seem like a significant amount, it is a 3.2% percent increase in EUR.

Additionally, the relatively low injection volume that is typical of pilot well tests must be considered. The CO₂ utilization ratio for this injection would be 5.23 mcf/bbl, meaning that one barrel of oil would be produced for every 5.23 mcf injected into the subsurface. To provide context, Wallace and Kuuskraa (2014) discussed the CO₂ utilization ratio of extant and modeled prospective floods in the United States. Wallace and Kuuskraa (2014) state that, on average, initial conventional CO₂ floods in petroleum systems throughout the Rockies would have a CO₂ utilization ratio of 19 mcf/bbl (Table 8.1). This comparison is not entirely useful given the difference between conventional and unconventional systems, in addition to the difference between pilot tests and full field endeavors, but it still provides context for those unfamiliar with CO₂ injection efficacy.

8.2  The Staci Wells (1-11H, 2-11H, and 3-11H) (Figure 8.6)

Drilling for the Staci 3-11H well began on April 30th, 2008, and the well was completed on May 31st, 2008. The Staci 3-11H production well was converted to an injector on January 10th, 2014, and eventually shut in on July 2nd, 2015 (Figure 8.7). Drilling began for the Staci 1-11H well on August 8th, 2004, and was completed on October 9th, 2004. The Staci 1-11H well was recompleted on February 23rd, 2007 (Figure 8.8). Drilling began for the Staci 2-11H well on November 27th, 2006, and was completed on February 21st, 2007 (Figure 8.9).
8.2.1 Injection Scheme and Results

Injection in the Staci 3-11H well began in January at an average rate of 1700 stb/day. Injection continued at this rate for three months and then decreased to 1000 stb/day for five additional months of injection (Figure 8.7). Injection then stopped and the well was shut in less than a year later. Hoffman and Evans (2016) claim water broke through into the Staci 1-11H well (approximately 880 ft away) one week after the injection. Water production increased and reached an all-time high throughout the entire injection period but it is important to note that oil production in the Staci 1-11H did not increase during the Staci 3-11H injection period (Figure 8.8). Water and oil production increased in the Staci 2-11H several months prior to the 3-11H injection but not during the majority of the injection period. It appears that the 2-11H well was not affected by the Staci 3-11H injection (Figure 8.9).

Continental ran an injection profile log in Staci 3-11H during the last month of water injection and determined that approximately half of the fluid volume was flowing into the two hydraulic fracture stages closest to the heel of the well. The remainder appeared to flow into the other nine fracture stages (Hoffman and Evans 2016). The Staci 1-11H well was then shut in for a ~60 day period between January and March, and re-opened for production. Initially production rose and reached a peak rate of 1449 bbl/month in July, 2015, then lowered until reaching a low of 731 bbl/month in December, 2015, and rose to a recent peak of 1660 bbl/month in April, 2016. This increase in production could be the result of the waterflood in 2014, however, more time is needed before any further conclusions can be made.
8.2.2 Injection Efficacy and Data Quality

Both the availability of data and the quality of the data that is available pose a problem for any meaningful analysis. Nearby wells were being hydraulically fractured before and during the Staci 3-11H injection. A “frac-hit” or “well bash” occurs when a well’s hydraulic fracturing affects an adjacent well’s production (Lawal et al., 2013; King, 2014; Kurtoglu and Salman, 2015; Hoffman and Evans, 2016). The effect of a “frac-hit” can best be seen in the water and oil production increases in the Staci 2-11H well just prior to the Staci 3-11H injection (Figure 8.9).

The Staci 1-11H well shut-in further complicates the data set. There was only a water production increase during the Staci 3-11H injection period. Oil production increased following the shut-in; post-injection oil production increase could simply be the result of pressure buildup from the shut in. However, it is likely the result of the water injection. Adjacent wells were fractured before and during the Staci 3-11H injection, not after, so a “frac-hit” is not likely to be responsible for this production increase in Staci 1-11H (Hoffman and Evans, 2016). The increase in water production in Staci 1-11H during the injection period could be due to “well-bashing” in addition to the water breakthrough. Ultimately, there are too many variables in play to truly determine the efficacy of the injection. It may be possible to determine the effect of the injection several years from now, following a stabilization in the production trend.

8.2.3 The Role of Regional Fracture and Fault Trends

Hoffman and Evans (2016) report that during the last month of the Staci 3-11H injection, Continental ran an injection profile log and determined “half of the injection was going in the two [hydraulic fracture] stages closest to the heel of the well while the rest of the water was spread out over the other nine stages”. There are several possible reasons why this may occur:
initial completion design/execution, induced fracture communication, or the injection well intersected with either a natural fracture system or fault. Considering the Staci 3-11H well was completed in 2008, the Staci 1-11H well was completed in 2004, and then the Staci 1-11H well was recompleted in 2007; it is unlikely that many extant induced fractures between the two wells remained propped during the water injection in 2014. Due to data limitations, this study cannot determine if all of the fracture stages in Staci 3-11H were effective or if a preferential fluid pathway was created due to completion execution. It is possible that the Staci 3-11H well intersects a fault or a regional fracture feature.

O’Brien et al. (2011) suggest that faults and regional fracture trends affect surficial features in the Elm Coulee Field, which reflect the basin-wide direction of maximum stress (Figures 8.10 and 2.3). Figure 8.11 displays the Staci wells’ (1-11H, 2-11H, and 3-11H) surface locations, bottomhole locations, and their approximate well path on an aerial photograph (courtesy of Google Earth). Figure 8.12 displays the same features on four merged USGS quadrangle topographic maps to emphasize the NE–SW streams/drainage features present in the map. These regional NE–SW fracture trends and/or faults have the potential to affect fluid flow, and there is the possibility that these regional features played a role in the breakthrough from the Staci 3-11H injection into the Staci 1-11H well.

8.3 Discussion

This chapter presented two separate pilot injection well case studies. While both injections had limited data available, conclusions can still be made regarding both. Several key points must be emphasized.

- Following CO₂ “huff and puff” in the Burning tree 36-2H well, there was an increase in production.
• Assuming that this increase in production was due to the injection. An additional 8,596 bbl are projected to be produced from the well. The injection would have a carbon utilization ratio of 5.23 mcf/bbl.

• Water breakthrough was reported in a well (Staci 1-11H) following water injection in an adjacent well (Staci 3-11H).

• The effect of the Staci 3 – 11H water injection on oil production in the Staci 1-11H well is indeterminate at the moment. It is likely to have increased oil production though.

• However, the breakthrough is evident. The breakthrough could have been caused due to an extensive hydraulically fractured network, however it is more likely due to a pre – existing NE – SW preferential flow related to either regional structure or fracture trends.

• When performing future injections, the NE – SW features must be taken into account, as they could function as “thief zones” and negatively injection efficacy.

• While concrete conclusions cannot be made, both injections show promising results given the scope of each project. These should serve as inspirations for continuing work and pilot injections, not damnations of EOR methods in unconventional plays.
Figure 8.1: Close up location map of the Burning Tree 36-2H well. The well has a shorter than average lateral length for the Elm Coulee Field. Note the lateral orientation as well; it appears to be nearly perpendicular to the maximum horizontal stress in the Bakken Formation of the Williston Basin.
Figure 8.2: Oil production in the Burning Tree 36-2H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate period of the CO2 injection is marked on the curve as well.
Figure 8.3: Oil production in the Burning Tree State 36-2H well. Monthly production rate vs cumulative oil produced is plotted on a linear plot. The approximate period of the CO2 injection is marked on the curve as well.
Figure 8.4: Oil production in the Burning Tree 36-2H well. Monthly production rate vs year is plotted on a semi-log plot. A decline curve was fitted on the pre-injection production trend using Arp’s effective exponential equation to determine EUR.
Figure 8.5: Oil production in the Burning Tree 36-2H well. Monthly production rate vs year is plotted on a semi-log plot. A decline curve was fitted on the post-injection production trend using Arp’s effective exponential equation to determine EUR.
Table 8.1: CO2 utilization ratios by development phase for various petroleum producing regions throughout the United States (Wallace and Kuuskraa, 2014)

<table>
<thead>
<tr>
<th>CO2 Utilization (Mcf/Bbl)</th>
<th>Initial</th>
<th>Developing</th>
<th>Mature</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian Basin</td>
<td>-</td>
<td>12.0</td>
<td>9.1</td>
</tr>
<tr>
<td>Gulf Coast</td>
<td>25.0</td>
<td>20.0</td>
<td>15.0</td>
</tr>
<tr>
<td>Rockies</td>
<td>19.0</td>
<td>9.0</td>
<td>5.0</td>
</tr>
<tr>
<td>Mid-Continent</td>
<td>12.5</td>
<td>7.0</td>
<td>6.0</td>
</tr>
</tbody>
</table>

Figure 8.6: Close up location map of the Staci wells (1-11H, 2-11H, and 3-11H). Each well is respectively labeled by its surface location. Bottomholes are indicating by filled in green dots. Both the producing wells (1-11H and 2-11H) feature two separate laterals going north and south respectively. The Staci 3-11H well, a production well converted to an injector, only has one lateral, running north to south. Note the proximity of the 3-11H well to the 1-11H well, the producer that was possibly affected by the 3-11H injection.
Figure 8.7: Production (oil, gas, and water) plot of the Staci 3-11H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate injection time of the injection period is marked. Plot modified from the Montana Board of Oil and Gas Online Data.
Figure 8.8: Production (oil, gas, and water) plot of the Staci 1-11H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate injection time of the injection period is marked. Plot modified from the Montana Board of Oil and Gas Online Data.
Figure 8.9: Production (oil, gas, and water) plot of the Staci 2-11H well. Monthly production rate vs year is plotted on a semi-log plot. The approximate injection time of the injection period is marked. Also note the “frac hit” marked prior to the Staci 3-11h injection. Plot modified from the Montana Board of Oil and Gas Online Data.
Figure 8.10: Aerial photo of several Enerplus owned wells in a 1X2 mile area in the Elm Coulee Field. Colored dots indicate microseismic responses from hydraulically induced fractures. Known faults are mapped with red dashed lines. Note how the faults, the induced fractures, and the surficial stream features have a consistent NE – SW orientation. Another important detail is that often surficial streams are expressions of subsurface features such as faults (O’Brien et al., 2011).
Figure 8.11: Aerial map of the Staci wells (1-11H, 2-11H, and 3-11H). Green triangles represent surface locations of each well and green circles represent well bottomholes. Approximate well paths are marked with green lines. Relevant townships are marked with red squares and numbered respectively. There are three main NE–SW trending surficial drainage features, which could reflect controlling subsurface features. Photo modified from Google Earth.
Figure 8.12: Topographic map featuring the Staci wells (1-11H, 2-11H, and 3-11H). Green triangles represent surface locations of each well and green circles represent well bottomholes. Approximate well paths are marked with green lines. Relevant townships are marked with black squares and numbered respectively. The main NE–SW trending surficial drainage features, which could reflect controlling subsurface features are marked with dashed red lines. Topographic map was made from merging the following USGS 1:24,000 quadrangles in Richland County: Lambert, Fox Lake, Three Buttes Creek West, and Three Buttes Creek East (modified from USGS Historical Topographic Maps).
CHAPTER 9. DISCUSSION, CONCLUSIONS, AND RECOMMENDATIONS

9.1 Discussion and Conclusions

The main objective of this study was to identify how geologic conditions present in the Elm Coulee Field affected historic production and how geologic conditions will affect any current or future enhanced oil recovery endeavors. This is a general question, and for the sake of this study it was subdivided into several discrete objectives:

- Identify and describe facies present in the Bakken Petroleum System in Elm Coulee.
- Determine target intervals and reservoir quality in the MBM using routine core analysis and x-ray diffraction data. Correlate facies changes, if applicable, to target intervals present in the MBM.
- Map geologic and production trends on a field scale, and correlate trends on the map scale with observations made with core data.
- Characterize the pore system of the pay interval and surrounding rock in the MBM. Compare to field and core trends.
- Describe fluid properties, as well as fluid-rock interactions that occur in the MBM. Then, determine if and how fluid properties as well as fluid-rock interactions can be changed.
- Examine case study data from a CO₂ “huff-and-puff” injection well and a water injection well in the Elm Coulee Field. Then, determine the efficacy of these injections.
In this process of investigating these questions, several key conclusions were made in regards to the Bakken Petroleum System in the Elm Coulee Field, specifically, the MBM reservoir.

- The MBM reservoir was deposited in a shallow to distal shelf environment. The Bakken Formation unconformably overlies the Three Forks Formation which was deposited in a sabkha environment (Chapter 3).

- Preferential dolomitization of the MBM in the Elm Coulee Field is the driving force for reservoir quality. This can be seen in core data (XRD and RCA) as well as thin section petrography. (Chapters 4 and 6)

- There is a NW - SE trending MBM thick in the Elm Coulee Field. It was most likely the result of multistage Prairie Formation evaporite dissolution, as proposed by Sonnenberg and Pramudito (2009). (Chapter 5)

- The production fairway in the Elm Coulee Field also trends NW – SE. However, it does not directly correlate with the MBM thick. This production trend is most likely related to dolomitization rather than isopach thickness. (Chapter 5)

- Estimated ultimate recovery of the average well in the Elm Coulee Field is 266,000 to 269,000 bbl. The original oil in place of the Elm Coulee Field is 2.02 Bbbl. The recovery factor for this field is 13%. (Chapter 5)

- Fluid saturation in the MBM is a function of pore throat size distribution; intervals with larger pore throats are more likely to be oil saturated and intervals with smaller pore throats are more likely to be water saturated. These pore throats appear to be related mineralogy, specifically dolomite. (Chapter 6)
The pay interval in the Elm Coulee Field is preferentially oil – wet. This is supported by high oil saturations in the pay interval, preferential adsorption of organic material on dolomite crystals and pore lining clays, and experimental core tests. (Chapter 4, 5, 6, and 7)

Special emphasis must be placed on the fact that the MBM reservoir is preferentially oil – wet. This has direct consequences on historic production as well as current and future EOR attempts. An oil – wet reservoir will have more oil adsorbed onto matrix rock, and as a result, lower recovery factors compared to an equivalent preferentially water – wet reservoir. Combined with high – oil saturations, an oil – wet reservoir will have low relative permeability to water and other non-miscible injected fluids. However, wettability can be changed, whether through surfactants, or through exploiting the initial wetting mechanism. High amounts of residual oil and the capacity to change wettability make the Elm Coulee Field an attractive target for EOR. Experimental laboratory and pilot well studies were reviewed to evaluate potential methods for EOR in the Elm Coulee Field.

- Surfactants solutions successfully lowered the interfacial tension (IFT) between water and the Bakken crude. Surfactant solutions also successfully recovered oil from cores saturated in oil. Surfactants dissolved in fresh water were much more effective than those dissolved in produced water. (Chapter 7)

- Additionally, fresh water successfully recovered comparable amounts of oil to surfactants dissolved in fresh water. Recovery from fresh water is not unique to the Elm Coulee Field, as it was observed in parts of the North Dakota MBM as well. There are three current proposed mechanisms for why this may be the case. One is
due to physical properties (osmosis) and two are due to chemical processes (“ion bridge” and acid-base reactions). (Chapter 7)

- Both of these chemical mechanisms also provide an explanation for the preferential adsorption of organic materials onto illites. The high ionic concentration of the Bakken formation water is an important factor in both of these mechanisms. Also, while the physical mechanism of osmosis used to describe fresh water recovery does not explain the reservoir’s wettability, it also takes the high salinity of the formation water into account (Chapter 7)

- Following the CO₂ “huff – and – puff” in the Burning Tree 36-2H well, there was an increase in production rate that could potentially be tied to the CO₂ injection. If the injection was responsible for this increase, this injection will be responsible for an additional production of 8596 bbl of oil. Meaning, the injection could potentially have had a carbon utilization ratio of 5.23 mcf/bbl. (Chapter 8)

- Water breakthrough was reported in a well (Staci 1-11H) following water injection in an adjacent well (Staci 3-11H). While it is still not determined whether or not this injection affected production in either wells, the breakthrough seems evident. However, an increase in oil production in the Staci 1-11H well due to the Staci 3-11H injection is likely. (Chapter 8)

- This breakthrough could have been caused due to an extensive hydraulically fractured network, however it is more likely due to a pre-existing NE – SW preferential flow path related to regional structure (either a fault or natural fracture network). (Chapter 8)
9.2 **Recommendations for Future Work**

Since the nature of this study combines both geologic and engineering concepts, recommendations will be made in both fields of work. Despite the fact that this study primarily focused on important geologic factors, the two fields are inextricably tied when discussing EOR, and in a more general sense, any applied petroleum geology project. Recommendations include:

- **Further investigation of the cause of dolomitization in the MBM in the Elm Coulee Field.** This would include stable isotope analysis, and, under ideal circumstances, delineation of a paleoshoreline to help explain the spatial distribution of dolomite.

- **Creation of a multimineral model using digital well logs.** While porosity can be mapped with the assumption that it is primarily associated with dolomite content, it is always fun to be proved wrong. The creation of an effective multimineral map would give insight into the spatial distribution of dolomite in the Elm Coulee Field area. This would contribute to the argument that dolomite is crucial for the MBM reservoir.

- **Thorough analysis of FMI logs throughout the field.** This will help better quantify the role of fractures in the MBM reservoir. Very little quantitative data is available regarding fractures in the Elm Coulee Field.

- **Analysis of NMR logs in addition to more MICP data.** When combined these two forms of data provide insight into pore and pore throat size and distribution. Additionally, once NMR logs are calibrated to MICP data, they can provide insight into pore throat size using well logs.

- **Obtain core data from the area directly northeast of the Elm Coulee Field.** There is a sudden change in fluid saturation to the northeast boundary of the field, and core data
on the other side of this boundary could provide evidence in favor of arguments put forth by this study.

- Obtain additional FE–SEM samples throughout the field in order to confirm observations made.
- Determine an experimental method to give insight into the mechanism responsible for the Elm Coulee Field’s wettability conditions.
- Continue imbibition experiments taken from Elm Coulee Field cores.
- Determine the significance of completion design in the Elm Coulee Field. This would be done by examining completion strategies and their evolutions over time from company to company.
- Investigate pilot well tests performed in the MBM in North Dakota. While the MBM in the Elm Coulee Field may have some unique characteristics, an understanding of how the Bakken Petroleum System as a whole should be approached for EOR is an especially marketable skill.
- Investigate any future pilot wells in the Elm Coulee Field. They are bound to happen.
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