ORIGIN OF BRECCIATED INTERVALS AND PETROPHYSICAL ANALYSES; THE THREE FORKS FORMATION, WILLISTON BASIN, NORTH DAKOTA, U.S.A.

by

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A thesis submitted to the Faculty and the Board of Trustees of the Colorado School of Mines in partial fulfillment of the requirements for the degree of Master of Science (Geology and Geological Engineering).

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ABSTRACT

The Three Forks Formation of the Williston Basin in North Dakota is currently of interest to the petroleum industry and can be subdivided into three units: upper, middle, and lower. The Three Forks is Devonian in age and lies stratigraphically below the Bakken Formation. The upper 50ft of the Three Forks is included in the Bakken Petroleum System.

The upper and middle units of the Three Forks are the focus of this study. These units can be subdivided into four lithofacies: (1) a green to gray or red mudstone, (2) a disrupted to mottled, interbedded silty dolostone and mudstone, (3) a silty, tan dolostone, (4) and an interbedded silty dolostone and mudstone. The middle Three Forks consists of a deepening upwards sequence capped by a basin wide mudstone marker. The upper Three Forks represents a shallowing upwards sequence capped by an intertidal lithofacies. The Three Forks contains environments ranging from supratidal to a restricted, basinal mudstone.

The Three Forks, primarily the middle, contains multiple brecciated units that are predominantly the result of reworking of sediments through storm influence. These brecciated units are most commonly found in lithofacies TF2 and TF3, and grade from intraclasts in disrupted dolostone beds to floating clasts in mudstones; however the clasts themselves rarely exhibit any grading. In addition to storm reworking, there are brecciated units in the upper Three Forks that appear to be the result of dissolution collapse.

The Three Forks is a petrophysically complex unit to evaluate, as it contains thin bedded sequences, clays, and conductive minerals that all contribute to inherently low resistivity values. To evaluate water saturation in the Three Forks, all the input variables are analyzed and compared to core data. The density porosity curve demonstrates a favorable comparison to core data when a matrix density of 2.78 g/cm$^3$ is applied. Resistivity is corrected for the presence of pyrite, and other variables are determined using the triple porosity model. All of these inputs lead to the development of a pseudo-Archie equation for evaluation of fluids within
the upper and middle Three Forks that compares favorably to core saturations. In addition to water saturation, a Vsh log is created which demonstrates that the upper Three Forks contains a lower mud content than the middle Three Forks. Data from core indicates that the middle Three Forks has slightly higher porosities and permeabilities, 6.9% and 0.198md, than the upper Three Forks, 6.4% and 0.070md. However, fluid saturations from core and log analyses indicate that the upper Three Forks has a higher hydrocarbon potential.

Regional mapping of the petrophysical attributes and isopachs reveal that the hydrocarbon potential of the Three Forks is stratigraphically constrained. Thickness of the source rock, the Lower Bakken Shale, and stratigraphical vertical distance from the source are the most important factors for hydrocarbon potential within the upper units of the Three Forks. While stratigraphical constraints are the most dominant factor, hydrocarbon potential can be enhanced by structure (i.e. Nesson Anticline and Billings Nose).
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<td>Oil based mud</td>
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<tr>
<td>NDIC</td>
<td>North Dakota Industrial Commission</td>
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<tr>
<td>EIA</td>
<td>Energy Information Administration</td>
</tr>
<tr>
<td>UTF</td>
<td>upper Three Forks</td>
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<td>MTF</td>
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</tr>
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<td>LTF</td>
<td>lower Three Forks</td>
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<tr>
<td>XRD</td>
<td>X-ray diffraction</td>
</tr>
<tr>
<td>XRF</td>
<td>X-ray fluorescence</td>
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<td>Net confining stress</td>
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<td>TCMR</td>
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CHAPTER 1
INTRODUCTION

1.1 Introduction

Recent advancements in drilling procedures, primarily horizontal drilling and hydraulic fracturing, have led to the economic viability of resources that were previously believed to be uneconomic. This revolution of drilling into what is now considered to be unconventional reservoirs has provided a boom for the petroleum industry in the United States. The Bakken Petroleum System of the Williston Basin is at the forefront of this new oil boom and contains mature source rocks (the Bakken Shales) and proven reservoirs (Middle Bakken and Three Forks).

The Three Forks is a heterogeneous reservoir that contains silty dolostones, mudstones, brecciated intervals, and thinly laminated sequences. This heterogeneity leads to complications when evaluating the reservoir by standard petrophysical processes. Recent estimates suggest the Three Forks contains a technically recoverable 3.7 billion barrels of oil; therefore proper petrophysical evaluation of subsurface data is critical. Previous work has highlighted some of the petrophysical problems with evaluating the Three Forks, including inaccurate resistivity and porosity logs leading to an overestimation of water saturations.

This study will evaluate different methods of petrophysical analyses to better quantify this reservoir, as well as reviewing cores to evaluate the existing models of deposition. In addition to petrophysical analysis, extensive mapping of the Three Forks was performed to help better understand the stratigraphical and structural components that influence facies and therefore production.
1.2 Objectives and Purpose

This study focused on three main objectives within the upper and middle Three Forks: (1) to determine the origin and causation of the brecciated intervals of the Three Forks; (2) via petrophysical analysis to delineate the possible extent of the Three Forks as a viable reservoir; (3) to map the Three Forks, including the upper and middle Three Forks and petrophysical characteristics. Identifying the origin of the brecciated intervals will help to increase understanding of the depositional controls and paleoenvironment of the Three Forks. The petrophysical analysis used various methods to attempt to gain a better understanding of ways to identify “sweet spots” within the Three Forks, and then correlate the developed petrophysical models to known production and core data to confirm viability. Extensive mapping will help to define the extent of potential reservoirs.

1.2.1 Brecciated Intervals

- Determine the cyclicity of brecciated intervals.
- Determine if the brecciated zones are predominately clast supported vs. matrix supported.
- Determine if the brecciated intervals are a result of storms, tsunamis, dewatering, dissolution, or other processes.
- Identify depositional environments associated with brecciated intervals and compare to previous interpretations.

1.2.2 Petrophysical Analyses

- Determine which well log(s) best define hydrocarbon potential within the Three Forks.
- Determine which values would be appropriate to define a Vsh (shale volume) cutoff from gamma logs.
• Determine what variables or method(s) are most appropriate to calculate water saturations.
• Determine which density log matrix value correlates well with core derived porosity.
• Determine the suite of logs to identify net pay and/or lithologies.

1.2.3 Regional Mapping

• Determine if structure within the basin correlates with increased hydrocarbon potential.
• Determine if there are any stratigraphical constraints to hydrocarbon potential.
• Determine the lateral extent of the industry benches.
• Determine if the potential of the Three Forks is limited to the areal extents of the Upper/Lower Bakken Shales.
• Map petrophysical attributes to identify potential “sweet spots” within the Three Forks.

1.3 Location of Study Area

The study area (Fig. 1.1) is located in western North Dakota within the eastern half of the Williston Basin. This area was selected as it is receiving increasing petroleum industry focus, and an abundance of public data is available from the North Dakota Industrial Commission. Within this area, the dataset for this study contains 428 wells with digital logs to use for mapping and petrophysical analysis. 5 key wells were also used in the petrophysical analysis, as they contain laboratory derived core data, these wells from north to south, are: Rosenvold 1-30H (30, T160N, R96W), Lokken 2-2H (2, T159N, R95W), Rolf 1-20H (20, T155N, R98W), Charlotte 1-22H (22, T152N, R99W), and Debrecen 1-3H (3, T140N, R99W). Also in Figure 1.1 are the locations of the wells used for detailed core descriptions: Gunnison State 44-36H (36, T161N,
R91W), Rosenvold 1-30H, Uberwachen 22-34 (34, T153N, R95W), Charlotte 1-22H, and Debrecen 1-3H.

Figure 1.1: Structure map of the Williston Basin. The red box indicates the location of the study area within the western portion of North Dakota. Prominent structural features located within the study area include the Nesson Anticline and the Billings Nose. The inset map shows the location of the 428 digital well logs used for subsurface mapping as well as red numbers indicating key wells used for this study: (1) Gunnison State 44-36H (2) Rosenvold 1-30H (3) Lokken 2-2H (4) Rolf 1-20H (5) Uberwachen 22-34 (6) Charlotte 1-22H (7) Debrecen 1-3H (modified from Sonnenberg and Pramudito, 2009).
CHAPTER 2

GEOLOGIC OVERVIEW

The Williston Basin is an intracratonic basin that is elliptical in shape and has an areal extent that includes parts of North Dakota, South Dakota, Montana of the United States; and the Saskatchewan and Manitoba provinces of Canada (Fig. 2.1). The basin was formed in the Late Cambrian and comprises approximately 133,000 mi$^2$ (Gerhard et al., 1990).

The Williston Basin contains approximately 16,000 ft of sediment that spans the Phanerozoic (Gerhard et al., 1990). The Three Forks Formation was deposited during the Late Devonian in what is interpreted to be a shallow, epeiric sea in a depositional setting ranging from open marine to tidal flat-sabkha (Gantyno, 2010). The Three Forks is overlain unconformably by the Bakken Formation of Late Devonian to Early Mississippian time, and is underlain by the Birdbear (Nisku) Formation.

Figure 2.1: Map depicting the areal extent of the Williston Basin. The basin is located in parts of ND, MT, SD, and the Canadian provinces of Saskatchewan and Manitoba. Major basinal structures are also shown, including the Nesson and Billings Anticlines (from NDIC, www.dmr.nd.gov).
2.1 Regional Structure

The Williston Basin is located on the western edge of the North American craton and overlies three Precambrian provinces: (1) Wyoming Craton (2) Trans-Hudson Orogenic Belt (3) and Superior Craton. There are currently two theories for the formation of the Williston Basin; a thermal subsidence model proposed by Fowler and Nisbet (1985), and a Proterozoic left-lateral wrench fault system proposed by Gerhard et al. in 1990. The Williston Basin is bound on nearly all sides by major tectonic features (Fig. 2.2). The southern and southeastern boundaries are defined by the Tertiary Black Hills uplift and the Silurian uplift of the Cedar Creek anticline. The western boundary consists of the Sweetgrass Arch, of Late Devonian age, which separates similar aged sediments of the Alberta Basin to the northwest from the Williston Basin. The Williston Basin is bound to the north by the lower Paleozoic uplift of the Meadow Lake Escarpment. Sediment thinning to the southeast was influenced by the Transcontinental arch, which was first uplifted tin the Silurian (Cobb, 2013; Gerhard et al., 1990).

The wrench faulting proposed by Gerhard et al. (1990) is believed to be responsible for the structural features found within the Williston Basin. A possible early Proterozoic rifting event along the Brockton-Froid fault zone has been associated with the wrench faulting, and could have been responsible for the development of the structural components within the Williston Basin as well as contributing to the subsidence that converted the Williston Basin into a cratonic sag basin (Gerhard et al., 1990). Prominent structural features within the basin (Fig. 2.3) include the Nesson Anticline, where oil was found in 1951 along a trend nearly 75 miles long that has produced oil from at least 11 different lithologic units. The Nesson Anticline has an associated fault system that has been active at different times since the Precambrian (Gerhard et al., 1990). Other important structural features that have associated oil production include the Cedar Creek, Billings, and Little Knife Anticlines (Fig. 2.3). Certain oil producing fields have
also been associated with salt dissolution fold structures (RedBank, Newburg, South Westhope fields) (Gerhard et al., 1990).

Figure 2.2: Map depicting major structures associated with the Williston Basin. These structures influence basin sedimentation and boundaries. The Brockton Froid fault zone is associated with the left-lateral wrench fault system proposed by Gerhard et al. (1990) (from Cobb, 2013; after Gerhard et al., 1990).
Figure 2.3: Prominent structural features found within the Williston Basin. The Brockton-Froid fault zone could have been the originator for the wrench fault system as well as being the original foundation for basement structures. Structures associated with significant oil production include the Nesson, Cedar Creek, and Little Knife Anticlines (from Gerhard et al., 1990).

2.2 Stratigraphy and Lithology

The Bakken Petroleum System is composed of three different formations in ascending order: Three Forks, Bakken, and Lodgepole (Fig 2.4). The Three Forks is Late Devonian in age and corresponds to the Lower Kaskaskia major sequence of sea level rise and sedimentation (Gerhard et al., 1990; Sloss, 1963). During this time, the uplift of the Transcontinental Arch allowed for communication between the Elk Point Basin (Fig 2.5) and the Williston Basin (Gerhard et al., 1990; Cobb, 2013). An unconformity delineates the boundary between the Three Forks and the overlying Bakken, and also corresponds to the beginning of
Figure 2.4: Stratigraphic column of the Williston Basin related to the formation respective Geologic age and major sedimentation sequences (from Cobb 2013; modified from Kowalski, 2010, after Gerhard et al., 1990).
Figure 2.5: Paleographic maps displaying connection of Williston Basin to a marine environment during the Lower and Upper Kaskaskia sequences. During the late Devonian, when the Three Forks was deposited, the Williston Basin was connected to the Elk Point Basin. During the late Devonian and early Mississippian, the Bakken and Lodgepole formations were deposited as part of the Upper Kaskaskia sequence. The Three Forks and Bakken are separated by an unconformity (modified from Gerhard et al., 1990).

the Upper Kaskaskia sequence. During the Kaskaskia sequence, the Williston Basin was connected to the Cordilleran shelf by the Montana trough (Fig 2.5). The Bakken is considered to be Late Devonian to Early Mississippian and the overlying Lodgepole is Mississippian and also falls within the Upper Kaskaskia sequence.

2.2.1 Devonian Duperow and Birdbear/Nisku Formations

The Duperow Formation is composed of limestone, dolomite, anhydrite, siltstone and shale and conformably overlies the Souris River Formation. The Duperow is considered to be both a source rock and reservoir (Fig 2.6), and reaches a maximum thickness of 600 ft in Montana (Cobb, 2013; Sandberg, 1961). The Duperow is conformably overlain by the Birdbear/Nisku Formation which consists of dolomite, limestone, and anhydrite. The contact between the Birdbear/Nisku and the overlying Three Forks is considered to be conformable or
Figure 2.6: Stratigraphic column of the Williston Basin. Formations with importance as a reservoir, source, and known oil/gas production are shown. Of interest to this study are the source rocks of the Bakken formation. Geologic ages as well as known unconformities are also shown (from Bottjer et al., 2011; modified from Peterson, 1996).
sharply planar with only localized erosion evident (Gantyno, 2010). The Birdbear is equivalent to the Nisku, and the two names are used interchangeably in the literature. It has been referenced as the Birdbear by Bottjer et al. (2011), Peterson (1996), and Schietinger (2013). Gantyno (2010) uses the Birdbear and Nisku in conjunction when referencing, and Cobb (2013) uses the term Nisku. This study uses the moniker Birdbear to reference the formation underlying the Three Forks throughout the Williston Basin in North Dakota.

2.2.2 Devonian Three Forks Formation

The Three Forks Formation conformably overlies the Birdbear (Fig 2.6), and is unconformably overlain by the Bakken Formation. The Three Forks is Late Devonian in age and consists of mudstones, silty to sandy dolostones, and anhydrites. The Three Forks has been subdivided into several different naming systems as outlined in Figure 2.7A; to simplify, this study will use the upper (UTF), middle (MTF), and lower (LTF) terminology (Fig. 2.7B). Multiple facies have been identified by Gantyno (2010), Bottjer et al. (2011), and Cobb (2013). Bottjer et al. (2011) and Cobb (2013) only described the facies present in the upper and middle Three Forks, while Gantyno (2010) described the entire Three Forks with facies associations and interpreted depositional environments listed in Figure 2.8.

The Three Forks is considered to be an unconventional reservoir that is charged, at least in part, by the overlying Bakken. However, the underlying Duperow and Birdbear formations are also source rocks, and at least in theory, could also be contributing to the Three Forks (Fig 2.6). The NDIC establishes the Bakken Petroleum System to contain the first 50 feet below the Bakken as part of the system. This would include the upper and parts of the middle Three Forks. The Three Forks has been correlated to the Torquay Formation of the Qu' Appelle Group in Canada and is found throughout the Williston Basin in North Dakota, South Dakota, and Montana. The Three Forks reaches its maximum thickness of 270ft in the basin center and thins to an erosional edge on the basin margins (Bottjer et al., 2011).
Figure 2.7: (A) Naming conventions previously used to subdivide the Three Forks (modified from Bottjer et al., 2011). (B) This study uses the monikers upper, middle, and lower to subdivide the Three Forks, similar to Bottjer et al. (2011) and Dumonceaux (1984), and is outlined using a well log from the Charlotte 1-22H.
Figure 2.8: The 5 facies associations identified by Gantyno (2010) within the Three Forks. These are interpreted to have originated within environments ranging from supratidal to open marine (from Gantyno, 2010).
2.2.3 Late Devonian/Early Mississippian Bakken Formation

The Bakken Formation is late Devonian to early Mississippian in age and unconformably overlies the Three Forks Formation. The Bakken consists of three main members: Lower Bakken Shale, Middle Bakken, and Upper Bakken Shale. The Upper and Lower Bakken shales are proven source rocks with a similar lithology and are composed of an organic-rich, siliceous, pyritic black shale (Cobb, 2013). The Upper Bakken Shale covers a larger areal extent than the lower Bakken Shale within the Williston Basin (Fig 2.9). The Middle Bakken member is a calcareous siltstone and fine-grained sandstone which is a proven reservoir within the Williston Basin (Cobb, 2013). The Bakken Formation has also recently added a fourth member, the Pronghorn which is the most basal unit of the formation. LeFever et al. (2011) proposed the inclusion of the Pronghorn into the Bakken Formation; in the past the Sanish Sand term was used to describe the basal facies found in this unit and had been included in either the top of the Three Forks or the base of the Bakken. The Pronghorn is of varying lithology and has been divided into 4 different lithofacies by Johnson (2013) and primarily consists of very fine-grained sandstones, siltstones, and mudstones. The Bakken Formation reaches a maximum thickness of 145ft east of the Nesson Anticline.

2.2.4 Mississippian Lodgepole Formation

The Mississippian-aged Lodgepole Formation is included in the Madison Group and conformably overlies the Bakken Formation. The lower portions of the Lodgepole, including the “False Bakken” and the Scallion, are considered to be the uppermost units within the Bakken Petroleum System (Bottjer et al., 2011). The Scallion member of the Lodgepole contains the “False Bakken” which is an organic-rich, pyritic shale. The Scallion itself is argillaceous, cherty, and chalky micritic limestone (Cobb, 2013). The Lodgepole is a proven reservoir rock within the Williston Basin and reaches a maximum thickness of 245ft.
Figure 2.9: Areal extents of the Lower, Middle, and Upper Bakken units as well as the Three Forks. The Upper Bakken source rock covers a larger areal extent than the Lower Bakken. Hydrocarbons found within the Upper and Middle Three Forks are most likely sourced from the Bakken and the top 50 feet of the Three Forks is considered to be part of the Bakken Petroleum System (from Sonnenberg et al., 2011).
2.3 Bakken Production and History

Production from the Bakken Petroleum System was first established in 1953 on the Antelope Anticline with the #1 Woodrow Starr drilled by Stanolind Oil and Gas (Nordeng, 2010). Since that time, the Bakken play has evolved with technological advancements leading the way. The first horizontal well within the Bakken, #33-11 MOI-Elkhorn, was drilled in 1987, and the combination of horizontal drilling and hydraulic fracturing has led to successful development of the Bakken Petroleum System.

From the 1970s to the 1980s the Bakken “Fairway” was established as a play within North Dakota. The “Fairway” (Fig. 2.10) is approximately 30 miles wide and 200 miles long and trends from NW to SE on the updip edge of the Bakken (Nordeng, 2010). Here, the Bakken Formation thins over structures, the Lower Bakken Shale pinches out, and production was centered around these structures. Natural fractures were also found to be enhanced by these features, and successful horizontal drilling was realized along the Bakken Fairway until the mid-1990s, when drilling slowed and oil prices collapsed.

The first horizontal well to target the Middle Bakken was drilled in 2000 at Elm Coulee field in Montana (Cobb, 2013; Sonnenberg and Pramudito, 2009). This led to the development of Elm Coulee field, which is a porosity trend controlled stratigraphically by a thick, dolomitized carbonate shoal. A recognition of a similar trend of porosity development led to the discovery of Parshall Field in 2006; and EOG Resources established production on the eastern flank of the Williston Basin in Mountrail County, ND with the Nelson Farms 1-24H (Nordeng, 2010). While the first Three Forks well was drilled in 1953 at Antelope Field, it is only now being truly assessed, as the 2008 USGS assessment did not include the Three Forks. The 2013 USGS assessment of the Three Forks projects that there is a technically recoverable 3.7 BBO in the Three Forks. The EIA has projected Bakken production to exceed 1 million barrels of oil per day in December of 2013 (Fig. 2.11).
Figure 2.10: Location of the Bakken Fairway in western North Dakota. During the late 1970s and early 1980s, production was established on structural features which were found to be in conjunction with a thinning of the Bakken. These features were associated with enhanced natural fractures, with fields clustered on the structures (from Nordeng, 2010).

Figure 2.11: Production from the Bakken from 2007 through 2013. The EIA projects Bakken production to increase to 1 million barrels of oil per day in December 2013 (from www.eia.gov).
CHAPTER 3
PREVIOUS WORK

3.1 Introduction

The Three Forks Formation was first described by Peale in 1893 from outcrops in Gallatin County, Montana where the type section is located. Peale originally described the Three Forks as a shale unit underlying the Jefferson Limestone. Production first occurred in the Three Forks in 1953 at Antelope Field; however it is only recently that the Three Forks has been classified as an unconventional, tight oil play and now is an area of great interest to the petroleum industry.

3.2 Overpressure

Meissner (1978) first demonstrated that the Bakken Petroleum System was overpressured due source rock maturation. This effectively trapped the hydrocarbons within the tight reservoirs of the Bakken and Three Forks, as the inherently low porosities and permeabilities effectively contain the hydrocarbons within the Bakken Petroleum System. This overpressure has been documented in reservoirs at Antelope Field (Murray, 1968; Finch, 1969); this provides strong evidence that hydrocarbon migration has traveled downward from the Bakken Shales into the Three Forks (Bottjer et al., 2011). This overpressuring of the Three Forks, ranging from ~0.55 to 0.80 psi/ft, has also been documented by Theloy and Sonnenberg (2013) and is shown in Figure 3.2. This diagram demonstrates that, in specific areas, the Three Forks is more highly overpressured than the Middle Bakken. Maps of overpressure within the Middle Bakken have been used by the most recent USGS (2013) assessment of the Bakken Petroleum System to identify the “sweet spot” for production within the Middle Bakken (Fig. 3.3). In a USGS report (Gaswirth et al., 2013) the geologic “sweet spot” for the Bakken is where the pressure gradient is above 0.68 psi/ft, identified in the contour map represented by Figure 3.3.
Figure 3.1: Formation fluid pressure profile versus depth within Antelope Field. Sharp spike in gradient is evident at the boundary of the Bakken and Mission Canyon Formations, with a drop in pressure gradient at the Nisku, which underlies the Three Forks. This overpressure has been associated with hydrocarbon generation (from Meissner, 1978).
Figure 3.2: Pressure versus depth within the Bakken Petroleum System. The Three Forks Formation is more highly pressured than the Bakken Formation, with both formations having a higher gradient than normal hydrostatic pressure (0.465 psi/ft) (from Theloy and Sonnenberg, 2013).
Figure 3.3: Pressure gradient map of the Middle Bakken. Highest pressure gradients are measured in northern Dunn and eastern McKenzie counties of North Dakota. This overpressure within the Middle Bakken is correlated to peak hydrocarbon generation and has been used by the USGS to define a geologic “sweet spot” within the Bakken Petroleum System (from Theloy and Sonnenberg, 2013).
3.3 Reservoir and Petrophysical Characteristics

Petrophysical analysis of the Three Forks formations is difficult due to the very heterogeneous nature of the formation and has been documented by multiple authors (Cherian et al. 2013; Bottjer et al., 2011; Ramakrishna et al., 2010). Some of the challenges to formation evaluation include: low porosities and permeabilities, clays, interbedded to laminated sequences, and the presence of conductive minerals (e.g. pyrite). When calculating water saturations from resistivity, Ramakrishna et al. (2010) documented the difficulty of using induction logs, as the thin bedded nature of the Upper Three Forks can affect the log response. It is common for operators to use oil based mud (OBM) when drilling within the Bakken play, which requires an induction resistivity tool. One of the wells within the Ramakrishna et al. (2010) study contained a laterolog resistivity measurement, which was used in a shaly-sand water saturation model to measure fluids within the Three Forks. In addition to a shaly-sand model for water saturation, Ramakrishna et al. (2010) used NMR (nuclear magnetic resonance) logs to evaluate moveable fluids within the Bakken and Three Forks Formation. When compared to core derived oil saturations (Fig. 3.4), it was found that NMR logs tend to underestimate the oil found within the Three Forks. Small amounts of gas were also computed by NMR logs in the areas that showed the highest moveable fluid volume, and gas is produced from this zone within its respective well.

Core analyses examined by Bottjer et al. (2011) demonstrated that the upper Three Forks is an unconventional reservoir, with average porosities of 6.25% and permeabilities of 0.261 md within the clean dolomite lithofacies. This average core porosity increased from 5% in the deep basin to 12% near the Canadian border. The laminated lithofacies showed a higher average porosity, 8.2%, but had a lower permeability, 0.1117 md, than the clean dolomite facies. Natural fractures were also documented within both lithofacies, and are believed to enhance permeability. Using magnetic resonance logs, core fluid data, log calculations, and
ultraviolet light Bottjer et al. (2011) concluded that the clean dolomite facies is not necessarily the best reservoir facies, as the laminated facies had higher porosities and indications of higher concentrations of hydrocarbons than the clean dolomite facies and the Pronghorn.

Bottjer et al. (2011) cautioned that log calculations of pay in the Upper Three Forks were difficult because of the heterogeneous nature of the formation, primarily because of the interlaminated green shales and mudstones. The green shales and mudstones lead to a lower formation resistivity, which in turn lowers hydrocarbon calculated fluids when using Archie’s Equation for water saturations. To offset this, Bottjer et al. (2011) recommended using high resolution resistivity logs, as deep induction logs do not accurately measure the resistivity. For the analysis of existing logs, Bottjer et al. (2011) assumed an aggressive cementation exponent within Archie’s Equation (m = 1.4) to attempt to correct for the induction logs under-calculation of formation resistivity. Bottjer et al. (2011) also used mercury capillary injection data to demonstrate that the pore throat radii within the Upper Three Forks were equal to or superior to the Middle Bakken (Fig. 3.5). Analyses of the green mudstone facies found at the top of the Middle Three Forks indicated that it could act as an impermeable barrier as magnetic resonance logs and dipole sonic logs suggested that it was impermeable.
Figure 3.4: Well log with gamma (red) in track 1, resistivity (green) and core permeabilities in track 3, and oil saturations in track 3. Green line in track 3 represents oil calculated from NMR log, green triangles represent core measured oil saturation, and scale is 0 to 1.0 from right to left. Within the Three Forks (outlined by red box at the bottom of well log), log derived oil saturation is less than oil saturations calculated from cores. Well is unnamed and location is not provided (modified from Ramakrishna et al., 2010).
Figure 3.5: Cross plot of pore throat radius versus mercury saturation as a function of pore space for the Upper Three Forks (pink) and the Middle Bakken (blue). This indicates that the Upper Three Forks is equal to or superior to the Middle Bakken for this measurement of reservoir quality (from Bottjer et al., 2011).
3.4 Depositional Environment

Dumonceaux (1984) divided the Three Forks into five lithofacies within North Dakota and concluded that the Three Forks was deposited in a shallow epeiric sea. The Three Forks was deposited in environments that include: supralittoral, littoral, and sublittoral. Dumonceaux (1984) believed that the Three Forks was deposited in an arid setting in the lowest energy environment of an epeiric sea and that sea level fluctuations and progradations are responsible for the widespread argillaceous material. Gantyno (2010) recognized 11 lithofacies (Fig. 3.6) and 5 facies associations (Fig 2.8) ranging from upper supratidal sabkha to intertidal. Gantyno (2010) identified sequence boundaries within the Three Forks including a transgressive surface in the middle Three Forks and a Type 1 sequence boundary at the top of the Three Forks. Gantyno (2010) also believed the Three Forks has two systems tracts, lowstand and transgressive, and that the Three Forks shows prograding and retrograding patterns in an overall deepening upwards system. Bottjer et al. (2011) provided evidence that the Three Forks represents a shallowing upwards sequence, and is dominated by tidal nearshore facies; however Bottjer (et al., 2011) only examined in detail the upper Three Forks and the upper portion of the middle Three Forks. Berwick (2008) identified 5 different facies (Fig. 3.7) within the upper Three Forks and the Sanish Sand, now the Pronghorn, and placed these facies within a tidal setting.

Egenhoff et al. (2011) identified 6 facies associations within the Three Forks: sabkha, subaerial gravity flow, intertidal, peritidal, and subtidal. It was suggested that these different types of deposits were influenced by both climate and sea-level changes during the Devonian. When the environment was arid, a large sabkha developed (lower Three Forks) with occasional intertidal algal mats (Fig. 3.8) that grade laterally into peritidal then subtidal storm deposits. During a more humid climate (middle and upper Three Forks, and Pronghorn), the subtidal and
peritidal deposits are the dominant facies, with localized paleosols representing areas of non-deposition and abundant debris flows from the craton.

Figure 3.6: 11 lithofacies of the Three Forks as identified by Gantyno (2010). Facies were combined to create 5 facies associations used to interpret environment of deposition (Fig. 2.8). Environments ranged from supratidal to intertidal (from Gantyno, 2010).
| E | Structureless-faintly laminated reddish silty claystone with scattered granule-sized clasts | Claystone, silty, moderate reddish brown (10R 4/6) color and mixed with occasional greenish gray (5G 6/1) mottled colors, firm to hard, non fissile, pyritic, well cemented dolomitic, scattered granule-sized rock fragments/ lithoclasts, mostly structureless with rare inverse grading. | Low energy, possible rare high energy transport or cracking and failure (?), storm influence, possible oxidation, exposure and weathering, stressed condition, possible diagenetic/weathering alteration and dissolution. |
| D | Structureless to faintly laminated silty dolomitic greenish silty claystone with occasional anhydrite beds and nodules | Claystone, silty, greenish gray (5G 6/1) color, structureless, faintly laminated, well cemented, dolomitic, hard, non calcareous, non fissile, occasional anhydrite beds and nodules, and stringers with partly to completely separated by matrix, some distorted anhydrite nodules and beds, not crystal shaped anhydrite; rare granule-sized lithoclasts, compaction and loading features. | Low energy, suspension deposits, evaporation and chemical precipitation, oversaturated fluid/water, relatively high temperature, rare storm influence, stressed condition |
| C | Thinly-bedded reddish-greenish silty claystone and anhydrite beds and nodules | Claystone, silty greenish gray (5G 6/1) and reddish brown (10R 4/6) colors, firm to hard, non calcareous, non fissile, well cemented/lightly packed, rare siltstone stringers, anhydrite beds and nodules, white (N8), hard, sharp planar and irregular contacts, mostly separated by matrix rare dolomitic dikes, occasional desiccation cracks and compaction loading features. | Low energy, suspension deposits, evaporation, oversaturated fluid/water, evaporate deposition, relatively high temperature, possible diagenetic/weathering oxidation-reduction, alteration and desiccation, stressed condition. |
| B | Thinly-bedded reddish silty claystone and anhydrite beds and nodules | Claystone, silty, hard, reddish brown (10R 4/6) color, firm to hard, non calcareous, non fissile, well cemented/lightly packed, pyritic, rare dolomitic siltstone intercalation; anhydrite, white (N8), hard, not crystal shaped, mostly separated by matrix, distorted beds and nodules, sharp planar and irregular contacts, rare granule-sized dolomite clasts. | Low energy, suspension deposits, evaporation, oversaturated fluid/water, evaporate deposition, relatively high temperature, possible diagenetic/weathering oxidation-reduction, alteration and desiccation, stressed condition |
| A | Argillaceous mosaic anhydrite | Anhydrite, hard, white (N8) color, very tight, microcrystalline, rare matrix, not crystal shaped-external form, mosaic structure, not bedded, argillaceous, mix with light greenish gray (5G 6/1) or reddish brown (10R 4/6) claystones, irregular to chaotic, sharp irregular base contact. | Low energy, evaporation and precipitation, oversaturated fluid, relatively high temperature and climate, stressed condition. |

*Crush size is based on Wentworth Grain Size Scale Chart.
Rock color is based on 2009<sup>1</sup>MacGill/Geological Rock Color Chart.
The sedimentary depositional process interpretation using textbook material by Reineck and Singh (1973) and R. N. Ginsburg (1973).
Anhydrite textural and structural classification is based on Makarch et al. (1980).
Figure 3.7: Proposed environment of deposition for the Upper Three Forks and Sanish Sand (now the Pronghorn member of the Bakken Formation) by Berwick (2008). This places the Upper Three Forks in a sequence that is tidal in nature. Facies B is within the Upper Three Forks, and Facies D and C are representative of the Sanish Sand (from Berwick, 2008).
Interbedded organic rich material with millimeter thick irregular dolomitic laminae, identified by Egenhoff et al. (2011) within an interpreted intertidal deposit of the Three Forks, but which is now recognized to be the Pronghorn member of the Bakken Formation (pers comm Sonnenberg). From the Gofor Oil Catherine E. Peck 2 core, represented by the red star on the inset map, in eastern McKenzie County, ND (modified from Egenhoff et al., 2011).

The breccias within the Three Forks have had several theories for their origin: dissolution (Grader and Dehler, 1999); dewatering (LeFever et al., 2013); asteroid impact tsunami (Mescher et al., 2012); and storm deposits (Gantyno, 2010; Berwick, 2008). Evidence provided for the impact tsunami by Mescher et al. (2012) involved high contents of iridium within the Three Forks, crudely fining upwards sequence, and trace amounts of shocked quartz. Storms, dissolution, and dewatering are all inferred from sedimentary characteristics including the size and shape of the clasts; but the origin for the breccia was only examined and described in detail by Gantyno (2010) and Mescher et al. (2012). Bottjer et al. (2011) offered that the mottled breccia in the upper Three Forks was a result of occasional high-energy currents on the distal edge of tidal sand flats, and not a solution collapse breccia. The dolomite clasts exhibited an irregular shape that had rounded and smoothed edges, not the angularity commonly associated with clasts formed due to a solution collapse.
3.5 Petroleum Potential

The Three Forks has been evaluated for its hydrocarbon potential by two recent studies: Department of Mineral Resources (DMR) of North Dakota in 2010 and the USGS in 2013. Nordeng and Helms (2010) of the DMR in North Dakota concluded that the Three Forks contains nearly 20 BBO in place, with the potential to produce 2 BBO. To obtain these numbers, the study first assumed that the Bakken sources the Three Forks, so the Three Forks was not evaluated past the extent of the Bakken shales. Deep induction logs, density porosity logs, and Archie’s equation for water saturation were used to estimate OOIP. Formation porosity was corrected for the higher density of the Three Forks dolomite compared to limestone, and Rw was corrected for depth. To establish pay, incremental thickness, porosity, and water saturations of <50% were used. Gaswirth et al. (2013) of the USGS evaluated the Three Forks, including the Pronghorn which is in communication with the Three Forks, and divided its evaluation into two zones: a conventional AU (assessment unity) that covers the full extent of the Three Forks including the areas not overlain by the Bakken, and a continuous AU that is bound to the areal extent of the upper Bakken Shale member. The continuous AU of the Three Forks is estimated to have technically recoverable resources of 3.7 BBO with the conventional AU having 8 MMBO technically recoverable.
CHAPTER 4
FACIES AND DEPOSITIONAL ENVIRONMENT

4.1 Introduction and Methods

The lithofacies within the Three Forks have been given several different naming systems in recent studies. These include a numbering system (Cobb, 2013), a lettering system (Berwick, 2008; Gantyno, 2010), and a descriptive system (Bottjer et al., 2011). The descriptive system put forth by Bottjer et al. (2011) included a mudstone lithofacies (middle Three Forks); a clean, silty dolostone lithofacies (upper Three Forks); and a laminated lithofacies (Fig. 4.1). The clean, silty dolostone facies contained two separate sub-facies: laminated or mottled. This study will incorporate the stratigraphic framework put forth by Bottjer et al. (2011) and assign a numbering system to lithofacies within the upper and middle Three Forks (UTF and MTF, respectively).

Five cores were described (Fig. 1.1) using HCL and approximation of grain size with hand lens (10x). Silt and mud sized grains were estimated based on previous petrographic work (Bottjer et al., 2011; Gantyno, 2010). From these core descriptions, lithofacies were recognized and the descriptions were digitized within Adobe Illustrator. In addition to the cores described, core photos were also examined via publically available data from the NDIC.

4.2 Lithofacies TF1: Green, Gray, or Reddish Dolomitic Mudstone

TF1 is a green, gray, or reddish dolomitic mudstone (Fig. 4.2) with occasional, subtle internal bedding. TF1 is most prominent as a marker bed between the upper and middle Three Forks. When it occurs at this stratigraphic location, it tends to have a gradational contact above and below. TF1 can contain clasts, both angular and sub-rounded, at the base of the marker bed. The clasts typically consist of a tan, silty dolostone and can exhibit a crude normal grading, but are typically ungraded (Fig. 4.3). In addition to clasts of tan dolostone, clasts of green mudstone have been found within the red mudstone (Fig. 4.4). Aside from the clasts of
different colored mudstones (e.g. green clasts in red mudstone), this lithofacies can also exhibit a mottling texture of green and red without any distinct bed boundaries at the base of the MTF (4.4). While consistently found in the observed cores at the UTF/MTF contact, where it is thickest, this facies can occur multiple times in the MTF while being absent in the UTF.

Figure 4.1: Lithofacies of the Three Forks as identified by Bottjer et al. (2011) within the upper and top of the middle Three Forks. These facies include a green mudstone, a clean silty dolomite facies, and a laminated facies. The clean dolomite facies is further sub-divided into mottled or laminated facies. This study will incorporate these facies within a numbered system, and extend from the Upper Three Forks to the contact with the Lower Three Forks. The far right column with red text demonstrates the terminology for this study within the stratigraphic framework of Bottjer et al. (2011) and will be discussed further in subsequent sections (modified from Bottjer et al., 2011).
Figure 4.2: TF1 is a green, gray, or red dolomitic mudstone most prominent as a marker between the UTF and MTF, and can be found interbedded with other facies. (A) Grayish-green mudstone exhibiting a gradational contact; from Charlotte 1-22H at 11,386ft. (B) Gray mudstone from Gunnison State 44-36H at 8,242ft. (C) Green and red dolomitic mudstone from Debrecen 1-3H at 10,841ft. (D) Grayish dolomitic mudstone from Uberwachen 22-34 at 10,335ft (photos courtesy of NDIC).
Figure 4.3: Clasts of silty dolostone within greenish-gray dolomitic mudstone of facies TF1. (A) Clasts are ungraded and composed of tan sub-rounded to angular clasts within mudstone. From Gunnison State 44-36H at 8,245ft. (B) Angular to sub-rounded tan clasts within greenish-gray mudstone exhibiting a crude upwards grading. From Uberwachen 22-34 at 10,339ft. Both examples are from marker bed in the upper portion of the MTF (photos courtesy of NDIC).
4.3 Lithofacies TF2: Disrupted to Chaotically Bedded Tan, Silty Dolostone and Green Mudstone

This facies (TF2) is a tan, silty dolostone interbedded with a green to gray mudstone. The bedding of TF2 is disrupted and can be wavy and consist of sub-horizontal, horizontal, and sub-vertical tan silty dolostone beds bounded by green to gray or red mudstone (Fig. 4.5). TF2 contains contorted beds, soft sediment deformation, angular to sub-rounded clasts of tan dolostone, and stringers of mudstone (Fig. 4.6). The clasts can be found either within a
mudstone matrix, or as intraclasts within disrupted beds of tan dolostone. For the purpose of this study, intraclasts will be used to refer to clasts that are within a like lithology (e.g. tan silty dolostone clasts in beds of tan silty dolostone), and lithoclasts will refer to clasts in a dissimilar lithology (e.g. tan silty dolostone clasts in a mudstone). TF2 rarely has internal ripple laminations or bedding features within the tan silty dolostone beds. The disrupted bedding occurs in conjunction with green to gray or reddish mudstone and can be either continuous across the core, or truncated by mudstone.

TF2 is can be found at the contacts between the lower/middle and middle/upper Three Forks. When this facies is at the contact with the UTF/MTF it is typically gradational with TF1. This gradational contact is usually represented by an increasing amount of tan, silty dolostone within a green to gray mudstone (Fig. 4.7). TF2 can occur multiple times stratigraphically within the middle Three Forks (Fig. 4.8), but when found in the upper Three Forks it occurs at the base of the UTF and grades upwards into a cleaner tan dolostone and downwards into the marker bed of TF1. When found in the MTF, this facies can have sharp to gradational contacts with other lithofacies.
Figure 4.5: Facies TF2 displaying disrupted bedding of tan silty dolostone. (A) Sub-horizontal to nearly vertical disrupted beds of tan, silty dolostone with greenish gray mudstone. Intraclasts of tan dolostone are included in the beds. Charlotte 1-22H at 11,418ft. (B) Disrupted beds of tan, silty dolostone and grayish mudstone. Rosenvold 1-30H at 9,392ft. (C) Tan, silty dolostone with mudstone stringers throughout exhibiting disrupted bedding. Gunnison State 44-36H at 8,239ft (photos A and C courtesy of NDIC, photo B from Weatherford via NDIC).
Figure 4.6: (A) Mudstone stringers leading to a mottled/chaotic appearance. Charlotte 1-22H at 11,419ft. (B) Disrupted bedding and prolific sub-rounded to angular clasts with gray mudstone interbedded. Uberwachen 22-34 at 10,332ft. (C) Disrupted bedding and sub-rounded to angular intraclasts of tan silty dolostone. Gunnison State 44-36H at 8,262ft.
Figure 4.7: Gradational contact of TF2 when found at the boundary of the UTF/MTF. Increasing occurrence of a chaotically to disrupted beds tan, silty dolostone with the lower green to gray mudstone. (A) is from the Continental Resources Charlotte 1-22H at 10385ft. (B) is from the Continental Resources Rosenvold 1-30H at 9293ft (photo A courtesy of NDIC; photo B courtesy of Weatherford via NDIC).
Figure 4.8: Multiple intervals of TF2 within the middle Three Forks highlighted by the red boxes. Continuous to truncated, horizontal to sub-horizontal, disrupted beds of tan dolostone and grayish mudstone bearing clasts of tan, silty dolostone. Rosenvold 1-30H from 9,423 to 9,441 feet (photo from Weatherford via NDIC).
4.4 Lithofacies TF3: Clean Tan, Silty Dolostone

Lithofacies TF3 is a relatively clean (e.g. low mud content), silty, tan dolostone with occasional very fine-grained sand. TF3 has occasional beds or stringers of green to gray mudstone interspersed throughout, but it is predominantly a silty dolostone. TF3 has parallel ripple laminations, reactivation surfaces, low angle laminae, and soft sediment deformation features (Figs. 4.9 and 4.10). Swaley cross-stratification, bi-directional ripples, and climbing ripples occur in this lithofacies (4.11), but it can also be structureless. Flat-pebble clasts are rare (Fig. 4.12), but can be found where influxes of gray mudstone occur. TF3 is stratigraphically located above TF2 within the UTF, but can occur either below or above TF2 within the MTF. The contact with TF2 is often gradational, with an increasing amount of tan, silty dolostone and a loss of mudstone representing the change.

4.5 Lithofacies TF4: Interbedded Tan Dolostone and Green to Gray Mudstone

Lithofacies TF4 is an interbedded tan dolostone and green to gray mudstone (Fig. 4.13). The predominant grain size is silt, but occasional very-fine sand grains occur. The tan dolostone has bi-directional ripples, climbing ripples, reactivation surfaces, paired laminae, desiccation and syneresis cracks (Fig. 4.14). Possible Skolithos (?) burrowing is also found within this facies. Bedding is typically horizontal to wavy with examples of wavy, lenticular, and flaser bedding common (Fig. 4.14) along with scour surfaces. TF4 has a gradational contact when stratigraphically above TF3, with an increasing amount of interbedding with mudstone representing the transition to TF4. Flat pebble clasts and brittle deformation are found within this facies. Pyrite nodules are typically found at the contacts between tan dolostone and green mudstone, as well as disseminated anhydrite and, rarely, anhydrite nodules. This facies is present in all cores at the contact with the Bakken Formation (Pronghorn member), where an erosional surface is recognized.
Figure 4.9: Facies TF3, a tan silty dolostone, with thin beds of grayish mudstone interbedded. (A) Interbedded gray mudstone and parallel to low-angle laminated silty dolostone. Core photo from Uberwachen 22-34 at 10,326ft. (B) Parallel laminations grading into bi-directional and climbing ripples. Core photo from Charlotte 1-22H at 11,372ft (photos courtesy of NDIC).

Figure 4.10: Loading features representative of soft sediment deformation within TF3. (A) Loading features at contact with thin gray mudstone bed. Core photo from Uberwachen 22-34 at 10,328ft (photo courtesy of NDIC). (B) Flame structure composed of very fine grain sand directed upwards into silty, parallel laminated bedding. Core photo from Charlotte 1-22H at 11,380ft.
Figure 4.11: (A) Swaley cross-stratification from Gunnison State 44-36H at 8,235ft, compare to C. (B) Bi-directional and climbing ripples, from the Charlotte 1-22H at 11,369ft (C) Example of swaley-cross stratification from the Ben Nevis Formation as seen in core (from James and Dalrymple, 2010).
Figure 4.12: Rare flat-pebble clasts within bed of silty dolomite interbedded with a gray mudstone. Red box represents a magnified view of the clasts. Core photo from the Charlotte 1-22H at 11,405ft (photo courtesy of NDIC).

Figure 4.13: Interbedded tan dolostone and green to gray mudstone of TF4. Mud cracks are pervasive throughout this lithofacies. (A) From Debrecen 1-3H at 10,813.5ft. (B) From Charlotte 1-22H at 11,366ft (photos courtesy of NDIC).
4.6 Interpretation of Depositional Environments for Lithofacies

TF1, a mudstone, is interpreted to be the lowest energy facies commonly found within the Three Forks. This is based upon the predominance of mud-sized grains, and the rare bedding features found within this facies. The clasts are believed to be the result of occasional storm reworking of sediments of TF2 and TF3. The coloring, green vs. red, most likely represents a combination of depositional and diagenetic factors. The red mudstone is most common in the LTF, which has been described as a supratidal zone (Dumonceaux, 1984;
Gantyno, 2010), and exhibits bedded anhydrite with red mudstone. The only core where significant amounts of red mudstone occurred in the MTF was in the Debrecen 1-3H, the furthest south and closest to the basin edge. The green mudstone at the contact with the MTF and UTF is likely deeper water based on the absence of anhydrite, which is present in the LTF. However, there is evidence that the color change has a diagenetic component as well. Figure 4.4B shows a mottling of red and green, and Figure 4.4A displays clasts of green mudstone in red mudstone. This diagenetic component could be a reflection of the presence of organic material (e.g. pyrite), or oil saturation, reducing the mudstone and changing the color to green or gray.

TF2, disrupted beds of tan dolostone and mudstone, is interpreted as being a low energy subtidal flat. This is based upon the lack of internal bedding features indicating current flows, but still having a higher ratio of silty dolostone compared to mudstone. These disrupted beds are believed to have either been caused by dewatering or storm influence. The dewatering is best observed in the mottled texture (Fig. 4.6A). The more chaotic beds are more likely to have been the beginning of dolostone beds that were disrupted by storm events, resulting in a failed or distorted bed of dolostone. The presence of intraclasts within the beds (Figs. 4.6B and 4.6C) further suggest that storm derived clasts settled out, and during slack time were included when the system attempted to develop additional dolostone beds. This lithofacies is likely a transitional facies between TF1 and TF3, and its relationship can be likened to representing either a deepening upwards or shallowing upwards sequence.

TF3, a clean tan dolostone, is similar to TF2 lithologically, but does contain less mudstone than is present in TF2. It is interpreted that TF3 is a higher energy end member of the subtidal flat of TF2 based on internal bedding features, i.e. bi-directional and climbing ripples. The swaley bedding is likely caused by storm influence on a shallow marine environment, where aggradation can occur and preserve the features. This bed form is created
under a combination of oscillatory and unidirectional flows above storm base (Dumas and Arnott, 2006). The presence of loading features and climbing ripples within this facies suggests that high sedimentation rates were occurring, which could likely be blamed for the relative absence of burrowing within this zone.

TF4, an interbedded dolostone and mudstone, is interpreted to have been deposited in an intertidal zone. Interbedding of the dolostone and mudstone demonstrate the waxing and waning of tidal currents; silty dolostone deposited during high energy tides and mudstone deposited during slack periods. Flaser, wavy, lenticular bedding, and bi-directional ripples are commonly associated with tidal zones (Reineck and Wunderlich, 1968; Nio and Yang, 1991). The pervasive mud cracks indicate periods of exposure, and flat pebble clasts are also common to this zone. The presence of anhydrite within this facies also suggests a relatively shallow environment over-saturated in salts.

Examination of the overall profile represented by the core descriptions (Fig. 4.15, description legend in Appendix A) and the relationships of the facies, it is believed that there are multiple parasequences consisting of either a shallowing upwards, or a deepening upwards profile. The transition from subtidal to intertidal is common in the MTF and can occur multiple times. The MTF is dominated by TF2 and TF1, and overall has a higher mud content than the UTF. The UTF is more straightforward, as it appears to represent one shallowing upwards sequence. The overall trend in the Three Forks consists of a deepening upwards trend from the supratidal (Gantyno, 2010; Dumonceaux, 1984) upper Birdbear and LTF, recognized by extensive chicken wire anhydrite (Fig. 4.16), to the top of the MTF. This trend then reverses into a shallowing upwards sequence from the top of the MTF to the upper boundary of the UTF. This is then likely followed by another deepening upwards sequence from the Pronghorn into the Lower Bakken Shale (Cobb, 2013; Gantyno, 2010; Johnson, 2013).
Figure 4.15: Core description of the Charlotte 1-22H. The UTF is dominated by TF4 and TF3. The MTF is dominated by TF1 and TF2, which have a higher mud content than the UTF. Overall shallowing upwards trend in the UTF (red triangle) and deepening upwards trend in the MTF (blue triangle). Additional core descriptions and legend located in Appendix A.
Figure 4.15 continued.
Figure 4.16: Chicken wire anhydrite representative of supratidal environments within the LTF (A) and upper Birdbear (B). From the Debrecen 1-3H at 10,977 and 11,002ft, respectively (photos courtesy of NDIC).

4.7 Analog: Shark Bay, Western Australia

A possible analog for the deposition of the Three Forks within the Williston Basin is Shark Bay in Australia. Shark Bay’s geomorphological profile (Fig. 4.17) is similar to the paleogeographic maps of the Williston Basin (Fig. 2.5). Both Shark Bay and the Williston Basin are inland marine depocenters that have been connected to an open marine environment, and in the case of Shark Bay the connection is now restricted due to a sill. It is possible that the connection to the ocean during Devonian time of the Williston Basin was likewise restricted due to the Sweetgrass Arch (Fig. 4.18), which acted as a baffle. The CSPG Atlas demonstrates a transition across Canada from limestones to dolomites and anhydrites at the Sweetgrass Arch during the Devonian (Halbertsma, 1994). Shark Bay presently consists of a shallow (<15m) embayment with two prominent basins, the Hamelin and the Freycinet. They were originally flooded during a Holocene transgression approximately 7000-8000 years B.P., but have more recently undergone a regression that began approximately 5000 years B.P. to present (Hagan and
Figure 4.17: Map of present day Shark Bay in Western Australia. Shark Bay consists of two restricted basins, Hamelin and Freycinet, which have been flooded when transgression of the Indian Ocean occurred approximately 7,000-8,000 years ago. This geomorphological profile is similar to paleogeographic maps of the Williston Basin (Fig. 2.5) when it was connected to an open ocean via the Elk Point Basin (from Hagan and Logan, 1974).
Figure 4.18: Transition of lithofacies across Canada to the U.S. border during the Devonian. A change is observed from limestones to anhydrites and dolomites at the approximate location of the Sweetgrass Arch. This suggests the arch was influencing and restricting sedimentation, likely impacting the Three Forks of North Dakota (from Halbertsma, 1994)
During this recent regression, the basins have experienced thick offlapping sequences, and have entered into metahaline (Freycinet Basin, 40-53% salinity) to hypersaline (Hamelin Basin, 56-70% salinity) conditions. This transition to increased salinity has resulted in a reduction to the observed biodiversity (Hagan and Logan, 1974; Brown and Woods, 1974).

The regional climate of Shark Bay is relatively dry, ~24 cm of precipitation per year, and at most times relatively low energy. The exception to the low energy comes in the form of winter storms, and even more powerful summer cyclones (Brown and Woods, 1974). The cyclones tend to occur on the average of one per 6 years and can generate sustained winds of 70-110 km/hr over 12 hour periods with gusts up to 180 km/hr. These storms generate an intense wave action and move sediments from sublittoral regions onshore, as well as generating a strong longshore drift (Brown and Woods, 1974).

The internal environments of the Freycinet and Hamelin consist of embayment plains, sublittoral (subtidal) platforms, and intertidal to supratidal zones (Fig. 4.19). Tidal currents are greatly reduced in the open embayment plains, but are influential on the sills, and the sublittoral and intertidal platforms (Hagan and Logan, 1974). When observed in cross section, the influence of the sills is recognized as they have the highest vertical relief from the basin floor. The sills can grow aggradationally, and restrict movement into the basins while the sublittoral and intertidal zones prograde into the basin (Fig. 4.20).

Figure 4.20 represents where the lithofacies previously described for the Three Forks would fall into this model. TF1 would be placed in the embayment plain, the lowest energy zone; hence the mudstone of this facies prominent at the MTF/LTF contact. TF2 and TF3 would represent subtidal environments and correspond to the sublittoral sheet. Brown and Woods (1974) documented a mottling texture at the transition zones between facies, as well as a breccia consisting of the underlying substrate (Fig. 4.21), which could be similar to the mottled texture of TF2 representing a transitional phase. Brown and Woods (1974) believe the mottling
texture is the result of new soils filling pre-existing fractures within the substrate, and the breccia a result of reworking. TF4 represents the intertidal zone and corresponds to the like-named area on the cross sections. Within the upper intertidal zone, gypsum develops 10-20cm below the surface in layers, and large crystals grow in the fenestral framework (Brown and Woods,

Figure 4.19: Location of depositional zones within the Hamelin Basin of Shark Bay. The center of the bay (in white) is the embayment plain that does not experience tidal influence. The gray and black zones on the edge of the basin represent sublittoral (subtidal) and intertidal/supratidal. The sills, sublittoral, and intertidal zones all experience varying degrees of tidal influences (from Hagan and Logan, 1974).
Figure 4.20: Cross-section through the Hamelin Basin of Shark Bay. Inset shows where cross section lines occur. A-A’ is through the sill, which can build aggradationally and progradationally. B-B’ and C-C’ show the intertidal and sublittoral sheet prograding into the basin. For the Three Forks, TF2 and TF3 would be the sublittoral sheet, TF4 would be the intertidal veneer, and TF1 would be the basal sheet and possible location is illustrated on the B-B’ section line (modified from Hagan and Logan, 1974).

Figure 4.21: Soil profiles of recent sediments within Hamelin Basin of Shark Bay. (A) Profile of the embayment flat, or plain, which grades from limestone at base, into a mottled zone and breccia of the underlying limestone as intraclasts. (B) Profile of sediments demonstrating mottled zones that grade into the underlying lithofacies (from Brown and Woods, 1974).
Also in this zone, flat pebble breccias are created by the volume change associated with lithification and desiccation. While the majority of rock types identified within Shark Bay are coarser grained (Hagan and Logan, 1974; Brown and Woods, 1974) than what is found in the Three Forks, Hutchison Embayment within the Hamelin Basin is extremely restricted and is dominated by fine-grained sediments instead of skeletal debris (Brown and Woods, 1974), similar to the Three Forks being dominated by fine-grained material.

The supratidal environments (Gantyno, 2010; Dumonceaux, 1984) of the LTF and the upper Birdbear (Fig. 4.15) could have prograded into the Williston Basin during a shallowing sequence. This was then reversed with the upward deepening profile of the MTF, represented by the subtidal lithofacies of TF1 and TF2 retrogradation, culminating in a highstand represented by TF4. Then the shallowing upward succession of the UTF represented by the succession of TF1 to TF2 and culminating in TF3 and TF4 could represent progradation of these facies back into the basin. Applying these successions to the analog would help explain why extensive tidal environments are observed within the Williston Basin. Figure 4.18 could also help to explain the lack of algal evidence in the observed cores in the Three Forks. In Shark Bay, the stromatolites are only located in a few supratidal zones, which would make it unlikely to identify without extensive viewing of all available cores for the Three Forks. With small vertical changes in sea level, the entire Shark Bay embayment can be converted to a laterally extensive tidal flat sequence, similar to what is observed in the Three Forks.
CHAPTER 5
BRECCIATED INTERVALS

5.1 Review of Storm and Impact Tsunami Breccias

The brecciated zones within the Three Forks are most often referred to as possible storm deposits (Gantyno, 2010; Berwick, 2008; Bottjer et al, 2011), however an alternative interpretation involving an impact tsunami exists (Mescher et al., 2012). Research into tsunami deposits is considered to be in its infancy, with 1992 being the first year that more than 10 papers were published on the subject (Bourgeois, 2009). Recently there have been comparisons of modern storm deposits to modern tsunami deposits (Morton et al., 2007), as well as criteria developed by the USGS that has been found to be relatively common to modern tsunami deposits (Peters and Jaffe, 2010). Since the field of research into tsunami deposits is relatively new, little research has been performed on the impacts of tsunamis beyond sub-aerially exposed sediments (Bourgeois, 2009; Morton et al., 2007), with the majority of research restricted to onshore and nearshore environments. Another caveat to using the recent criteria is that recent studies are dominated by earthquake induced tsunamis, as recent and verifiable examples of impact generated tsunamis are unavailable. Impact tsunami studies in the literature are dominated by the Chicxulub impact, which occurred at the Cretaceous-Tertiary (K-T) boundary and is the result of an asteroid impact (Bourgeois, 2009; Kring, 2007).

The Chicxulub impact is approximately 180km in diameter (Kring, 2007) and is located on the Yucatan Peninsula in Mexico (Fig. 5.1). Cores close to the site (Kring, 2007), and outcrops in the U.S. have been studied (Keller, 2008) to describe the lithology and nature of the deposit caused by the impact. The breccia consists primarily of clasts of underlying limestones, dolomites, and anhydrites (Keller et al., 2004), but igneous and volcanic clasts can be common.
Figure 5.1: Location of the Chicxulub impact crater and documented sites in North America that contain ejecta spherules. The Chicxulub impact is the most common analog in the literature with respect to impact tsunamis (from Keller, 2008).

(Keller, 2008). Common to the ejecta deposit associated with the impact are glass spherules and shocked quartz (Kring, 2007), with the glass spherules being documented as far away as Missouri (Keller, 2008). The breccia associated with the deposit is approximately 100m thick 60km southwest of the impact in Mexico, and approximately 10-30m thick in Cuba (Keller, 2008; Keller et al., 2004). The breccias exhibit an erosional base and an upward fining trend with clasts from 2 cm up to 10 m (Keller, 2008). Another likely impact tsunami breccia, the Alamo Breccia, has been documented in Nevada and occurred during the Late Devonian. This deposit is characterized by megabreccia (e.g. ~5.0-10.0m) close to the impact zone; as well as shocked quartz and glass spherules which occur in turbidites in the upper portions of the breccia sequence (Warme and Kuehner, 1998; Warme and Sandberg, 1996). Similar to the Chicxulub impact, the clasts within the Alamo Breccia grade upwards and the unit has an erosional base (Warme and Kuehner, 1998; Warme and Sandberg, 1996).
Defining characteristics associated with the Chicxulub and Nevada impacts include the glass spherules, shocked quartz, and the elevated presence of Iridium (Keller, 2008; Kring, 2007; Morrow et al., 2005; Warme and Kuehner, 1998). Iridium (Ir) is depleted within the earth’s crust, and when Ir is found to be present above background levels it is commonly believed to have been sourced from asteroids or from volcanism (Kring, 2007; Keller, 2008). The presence of Ir at the K-T boundary was first recognized by Alvarez et al. (1980) in Italy, who proposed that an asteroid impacted and ejected the Ir as a dust into the atmosphere which then settled. Ir has since been documented at many sites, and Keller (2008) identified spikes in Ir as high as 4.0ppb with elevated levels considered to be 0.3 to 2.0ppb (Fig. 5.2).

In addition to the K-T boundary, the presence of elevated levels of Ir has been documented worldwide in the Late Devonian (Warme and Kuehner, 1998; Wang et al., 1993; Playford et al., 1984). Warme and Kuehner (1998) associate the spikes in Ir with the Alamo Breccia impact in Nevada. Wang et al. (1993) documented that Ir spikes have been found in areas that do not contain evidence of impacts (e.g. shocked quartz, glass spherules), but are associated with redox boundaries at the base or uppermost portions of black shales (Fig. 5.3). Playford et al. (1984) suggested that the filaments of stromatolites attracted Ir found within seawater, leading to a preferential concentration of Ir in the corresponding stratigraphic layer, which would preclude the need for an extraterrestrial source. Mescher et al. (2012) used XRD (X-ray diffraction) to identify Iridium Oxide concentrations within the interpreted tsunami layer of the Three Forks, and documented levels as high as 0.9% by weight (~8000ppm) in Williams County, ND and 0.39% by weight in Ward County, ND (Fig. 5.4).
Figure 5.2: Lithological description and Ir profile associated with the Chicxulub impact at the K-T boundary. Elevated levels of Ir are considered to be above 0.3ppb (ng/g). Profile of Ir shows spike at K-T boundary above the brecciated layer (from Keller, 2008).

Figure 5.3: Ir levels in pg/g from different locations worldwide during the Late Devonian. Block pattern represents limestones, dotted pattern represents black shales. Spikes in Ir occur at the bases or uppermost portions of the black shales. Ir concentrations are associated with redox boundaries (from Wang et al., 1993).
Figure 5.4: XRD analyses of samples from the Three Forks interpreted tsunami layers. Levels as high as 3515ppm were documented within an upward fining sequence of breccia in the Three Forks. Elevated levels of Ir are commonly believed to have originated from either a cosmic source (asteroids) or volcanism, as Ir is depleted within the Earth’s crust (from Mescher et al., 2012)

Storm deposits are difficult to differentiate from tsunami deposits, as they can have similar sedimentological characteristics (Peters and Jaffe, 2010; Shanmugam, 2009; Morton et al., 2007). Table 5.1 describes characteristics common to recent storm and tsunami deposits; and what is particularly notable are the sedimentary features that can be found in both types of deposits. Storm and tsunami deposits could both exhibit normal grading, inland fining, and abrupt or erosional bases. Rip-up clasts were one feature that were common to modern tsunami deposits, but were rare within storm deposits. Storm deposits were also typically
Table 5.1: Characteristics of two recent storm and two tsunami deposits. Rip-up clasts are common to tsunamis, but not storm deposits. Storm deposits are typically thicker than tsunami deposits. Both types can have sharp or erosional bases (from Morton et al., 2007).

<table>
<thead>
<tr>
<th>Deposit Characteristic</th>
<th>Tsunami</th>
<th>Coastal Storm</th>
<th>Both</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Trench scale (meters)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Maximum clast size</td>
<td>boulders</td>
<td>cobbles and sand</td>
<td>source dependent, both capable of moving large clasts</td>
</tr>
<tr>
<td>Internal mud layers</td>
<td>may be present</td>
<td>not reported</td>
<td></td>
</tr>
<tr>
<td>Vertical grading of entire deposit</td>
<td>normal or no grading, rare inverse grading</td>
<td>normal or inverse grading</td>
<td></td>
</tr>
<tr>
<td>Lateral grading</td>
<td>inland fining</td>
<td>no trend or inland fining</td>
<td></td>
</tr>
<tr>
<td>Sorting</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Average deposit thickness</td>
<td>usually &lt; 25 cm</td>
<td>commonly &gt; 30 cm</td>
<td>depends on cross-shore position and topography</td>
</tr>
<tr>
<td>Sedimentary structures</td>
<td>none or rare laminae</td>
<td>planar laminae, some foresets</td>
<td>can be homogeneous</td>
</tr>
<tr>
<td>Number of layers/laminasets</td>
<td>few</td>
<td>many</td>
<td></td>
</tr>
<tr>
<td>Rip-up clasts</td>
<td>common</td>
<td>rarely present</td>
<td>possible with underlying cohesive layer</td>
</tr>
<tr>
<td>Basal contact</td>
<td>not likely</td>
<td>common</td>
<td>source dependent</td>
</tr>
<tr>
<td>Shell lamina</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Heavy mineral lamina</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Possible associated features</td>
<td>potential earthquake features (buried soils, liquefication structures)</td>
<td>potential slope wash, debris flows, colan deposits</td>
<td></td>
</tr>
<tr>
<td><strong>Transsect scale (10s m)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cross-shore geometry</td>
<td>commonly broad thin drapes, tabular or landward thinning</td>
<td>commonly narrow thick deposits, abrupt landward thinning</td>
<td></td>
</tr>
<tr>
<td>Landscape conformity</td>
<td>mimics landscape</td>
<td>fills lows and levels landscape</td>
<td>affected by antecedent topography</td>
</tr>
<tr>
<td>Extent of subaerial erosion or bypass zone</td>
<td>typical 75 m, maximum 125 m</td>
<td>typically absent, maximum 100s m</td>
<td></td>
</tr>
<tr>
<td>Inundation distance</td>
<td>commonly 400 m, maximum open coast 1000 m, maximum river or estuary 5 km</td>
<td>commonly 200 to 400 m, maximum 1600 m</td>
<td>depends on coastal plain slope</td>
</tr>
<tr>
<td>Landward limit of deposit</td>
<td>10s of meters</td>
<td>100s to 1000s of meters</td>
<td></td>
</tr>
<tr>
<td>Deposit elevation</td>
<td>commonly &gt; 5 m</td>
<td>commonly &lt; 4 m</td>
<td></td>
</tr>
<tr>
<td><strong>Sub-regional scale (10s km)</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Longshore extent</td>
<td>typically 50 km, rare 1000s km</td>
<td>typically 200 km, rare 1000s km</td>
<td>depends on event size and location</td>
</tr>
<tr>
<td>Lateral continuity</td>
<td>patchy to extensive</td>
<td>extensive to patchy</td>
<td>highly variable</td>
</tr>
</tbody>
</table>

thicker (>30cm) than tsunami deposits (<25cm). Peters and Jaffe (2010) from the USGS recently compiled a database of 51 publications covering 15 recent tsunamis to establish a general set of criteria to use to help determine if a deposit is a result of a paleo-tsunami. Characteristics of particular importance include: (1) Sharp or erosional basal contact (2) 1-4 depositional layers that are typically normally graded (3) Thin mud cap over deposit, if an
available source is present (4) Rip-up clasts (5) Sedimentary structures were not common, and ones observed were not unique to tsunamis.

While sedimentary features to storms and tsunamis can be similar, their hydrodynamic forces and duration do differ substantially. Tsunamis in the Indian Ocean, the most tectonically active location today, tend to occur on the order of one per decade, while storms are much more frequent. Tsunamis are typically of short duration, and consist of a wave train of <10 waves that can last for minutes up to hours. Storms can have over 1,000 waves and a duration of hours to days (Morton et al., 2007). Sediment transport associated with tsunamis is dominated by suspension, while bed load traction is the dominant mechanism in storm deposits (Table 5.2). Tsunami flow is typically characterized by a shoreward directed flow that can cause erosion within the vicinity of the shoreface, followed by a return flow, and it is the waning of these velocities that results in the grading and suspension settling of the deposits (Peters and Jaffe, 2010; Morton et al., 2007; Bourgeois, 2009). Whereas the bed load typical to storm deposits can result in sedimentary features including ripples, dunes, hummocky beds, and cross-stratification (Bourgeois, 2009; Seguret et al., 2001; Dumas and Arnott, 2006; Duke, 1990). The creation of the hummocky and swaley cross-stratification has been documented by Dumas and Arnott (2006), and consists of bedforms created by the combination of oscillatory and unidirectional flows generated by storms. Storm hydrodynamics are propelled by wind driven surface waves which then generate an offshore bottom current (Fig. 5.5). This bottom current can increase the shear stress on the substrate (Duke et al., 1991; Duke, 1990), resulting in an increase in pore pressure which can result in a liquefaction of the seabed in pelagic environments (Seguret et al., 2001; Bouchette et al., 2001). This liquefaction has been inferred to be the cause of in situ brecciation of underlying deposits in offshore areas. The resultant bed then consists of clasts floating within a mudstone (Seguret et al., 2001; Bouchette et al., 2001).
Table 5.2: Flow characteristics of tsunamis and coastal storms. Tsunami sediment transport is dominated by suspension, whereas storms are dominated by traction. Storms have significantly longer durations when compared to tsunamis (from Morton et al., 2007)

<table>
<thead>
<tr>
<th>Flow Characteristic</th>
<th>Tsunami</th>
<th>Coastal Storm</th>
<th>Both</th>
</tr>
</thead>
<tbody>
<tr>
<td>Length of coast impacted</td>
<td>10-10000 km</td>
<td>100-600 km</td>
<td>local tsunamis and storms can effect similar lengths of coastline</td>
</tr>
<tr>
<td>Deepwater wave height</td>
<td>&lt; 0.5 m</td>
<td>&gt; 5 m</td>
<td></td>
</tr>
<tr>
<td>Nearshore wave height and period</td>
<td>10-20 m, 100-2000 s</td>
<td>&lt; 10 m, 10-25 s</td>
<td></td>
</tr>
<tr>
<td>Potential wave-runup heights</td>
<td>most are 10s of meters, can be a few hundred meters</td>
<td>a few meters</td>
<td>tsunamiis and storms that are only moderately intense can have similar runup elevations</td>
</tr>
<tr>
<td>Number of overland waves</td>
<td>normally &lt; 10</td>
<td>normally &gt; 1000</td>
<td></td>
</tr>
<tr>
<td>Inundation depth</td>
<td>0-20 m</td>
<td>&lt; 5 m</td>
<td></td>
</tr>
<tr>
<td>Active flow duration</td>
<td>minutes to hours</td>
<td>hours to days</td>
<td>Some tsunamis and storms may have similar flood durations</td>
</tr>
<tr>
<td>Overland floodwater velocity</td>
<td>&lt; 20 m/s</td>
<td>&lt; 5 m/s</td>
<td></td>
</tr>
<tr>
<td>Flow directions</td>
<td></td>
<td></td>
<td>mostly shore normal, can be locally variable</td>
</tr>
<tr>
<td>Flow-direction change</td>
<td>alternating runup and return flow during event</td>
<td>return flow only at end of the event</td>
<td></td>
</tr>
<tr>
<td>Boundary-layer structure</td>
<td>entire water column</td>
<td>current boundary layer</td>
<td></td>
</tr>
<tr>
<td>Influence of wind stress</td>
<td>not a factor</td>
<td>increases water velocities and surge heights</td>
<td></td>
</tr>
<tr>
<td>Sediment transport mechanism</td>
<td>mostly suspension, some traction</td>
<td>mostly traction, some suspension</td>
<td></td>
</tr>
<tr>
<td>Phases of flooding</td>
<td>repeated rapid rise and fall</td>
<td>gradual initial rise, rapid intermediate rise, gradual fall</td>
<td></td>
</tr>
<tr>
<td>Event frequency</td>
<td>moderately frequent locally and globally</td>
<td>frequent locally and globally</td>
<td></td>
</tr>
</tbody>
</table>
Figure 5.5: Storms generate a combined flow consisting of oscillatory and unidirectional flows. Wind driven waves are propelled shoreward generating a current and pressure differences, which then generates a normal to shore bottom flow that increases shear stress on the seafloor. (A) Cross section of current and wave profile generated by a storm (B) Plan view demonstrating normal bottom flow near perpendicular to shore (from Duke, 1990).

5.2 Location and Cyclicity

Brecciated intervals occur throughout the Three Forks; however there are different styles and cyclicity observed in the cores used in this study. Breccias are less common in the upper Three Forks when compared to the middle Three Forks (Fig. 5.6). Within the MTF, it is common to have multiple zones with either lithoclasts in a mud matrix, or intraclasts within beds of dolostone. These brecciated intervals usually occur within the disrupted beds of TF2, or the dolomitic mudstones of TF1. The UTF can have clasts within the intertidal lithofacies, TF4, and the clean subtidal facies, TF3 (Fig. 4.10), but does not typically contain beds of breccia as seen in the MTF.
Figure 5.6: Cyclicity of brecciated intervals through the Three Forks. From the Rosenvold 1-30H at depths of 9,359ft at top left to 9,423ft at bottom right. (A) Contact of UTF and the Bakken system (B) Contact of UTF and MTF; UTF consists primarily of TF4, TF3, and TF2 without any true brecciated zones. C, D, E, and F represent multiple brecciated zones. All show gradational contacts with increasing mud content upwards and matrix supported clasts, while the bases are clast supported (photos from Weatherford via NDIC).
Figure 5.6: cont.
5.3 Brecciated Intervals

Within the UTF of the Charlotte 1-22H core, there was an observed brecciated zone at ~11,356ft (Fig. 5.7). This occurs within the laminated intertidal lithofacies, TF4. There is an approximately 8 inch interval that contains angular clasts of silty dolostone up to 1 inch in size. A v-shaped, downward directed structure filled with mudstone and clasts is capped by anhydrite nodules approximately ½ inch in size. The individual beds of dolostone dip downwards into this structure and contain angular intraclasts. This style of brecciation was only observed within the UTF of the Charlotte 1-22H core.

Within the disrupted bedded lithofacies, TF2, there are zones that have been referred to as having a mottled texture (Bottjer et al., 2011), which are proportionately richer in tan dolostone when compared to mudstone. This mottled texture contains upwards directed gray to green mudstone stringers within a silty, tan dolostone. There are occasional intraclasts within the beds that are sub-rounded to angular and can be elongate (Fig. 5.8). The clasts do not make up a significant enough proportion to be considered a breccia or conglomerate, and are typically found included in disrupted beds of tan dolostone.

The MTF, and rarely the UTF, contain multiple beds that could be referred to as possibly a conglomerate or breccia. These intervals are typically found in beds that grade from intraclasts in the disrupted bedded facies, TF2, into matrix-supported clasts in the dolomitic mudstones of TF4 (Fig. 5.9). The most prevalent occurrence of this type is found at the marker bed at the top of the MTF. The contacts, basal and upper, of the brecciated intervals are predominantly gradational, but can be sharp (Fig. 5.9). The clast size can exhibit a crude normal grading (Fig. 4.14B), but they are predominantly ungraded (Fig. 4.14A, Fig. 5.10). The clasts range in size from <0.10 in to >2.0 in, and can be anywhere within the entire spectrum of angular to rounded (Fig. 5.11). In the Gunnison State 44-36H, clasts >0.10in were counted within a gradational unit of TF2 to TF1. These clasts were then classified as either angular/sub-
angular or rounded/sub-rounded. Over an approximately 5ft interval (8,241 to 8,246ft), 178 clasts were observed, with 99 clasts being sub-rounded to rounded and 79 clasts being angular to sub-angular.

Figure 5.7: Brecciated interval within the UTF of the Charlotte 1-22H at approximately 11,356ft. Two anhydrite nodules are present at the top left of the core image. Bottom of core photo exhibits a downward directed v-shaped filled with angular clasts and mudstone. Beds of grayish-tan dolostone show brittle deformation and dip down into the filled cavity (photo courtesy of NDIC).
Figure 5.8: Mottled texture featuring upwards directed stringers of clay. Elongate intraclasts (inset of B) can be found in this interval, but it is predominantly deformed beds likely caused by dewatering. (A) Rosenvold 1-30H from 9,423-9,424ft (B) Gunnison State from 8,239-8,240ft (Photos courtesy of NDIC)
Figure 5.9: (A) Mudstone, TF1, at base grading into disrupted bedding of TF2. Clasts are mud supported at base transitioning into intraclasts within the TF2 lithofacies at top. From Charlotte 1-22H at 11,415 to 11,416ft. (B) Grading from intraclasts at base into floating clasts at top. From Gunnison State 44-36H at ~8,246ft. (C) Sharp contact at base with TF2 and TF1. Gray mudstone exhibits floating clasts transitioning into disrupted bedding with intraclasts, then a return to a relatively clast free mudstone of TF4. From Rosenvold 1-30H at 9,420 to 9,422ft (photos A and B courtesy of NDIC).
Figure 5.10: Angular to rounded ungraded clasts, with respect to clast size. Clasts are predominantly tan, silty dolostone supported by a mud matrix in TF4; however a few clasts are a green mudstone. (A) From the Debrecen 1-3H at 10,863 to 10,864ft (B) From the Rosenvold 1-30H at 9,404 to 9405ft (photos courtesy of NDIC).
Figure 5.11: Angular, sub-angular, sub-rounded, and rounded clasts of tan dolostone within a mudstone matrix. Inset also demonstrates the typical ungraded nature with regards to clast size typical within the brecciated intervals. 178 clasts from this interval were used to classify on the basis of rounding; 55% were sub-rounded/rounded and 45% were angular/sub-angular. From the Gunnison State 44-36H at 8, 245ft (photo courtesy of NDIC).

5.4 Iridium

Iridium data for the MHA 2-05-04H-148-91 (5, T148N, R91W) was graciously made available for this study. A handheld XRF (X-Ray Fluorescence) analysis was performed at 6 in intervals from the Three Forks through the base of the Lodgepole. The sample times were 75 seconds, and the results are reported in ppm. Figure 5.12 displays the values of Ir on a ppm basis versus depth (see figure caption for color codes by formation). Figure 5.13 illustrates the same interval with respect to aluminum instead of Ir. The comparison between the two demonstrates that the blank areas on the Ir plot were assessed, but below the level of detection.
The vast majority of values through the Bakken and Three Forks are between 20 and 30ppm, with some spikes above 40ppm in the Lower Bakken and from 40 to 50ppm in the lower portion of the Three Forks. The increased values evident in the Three Forks occur below the brecciated intervals in the MTF (Fig. 5.14), within the interpreted supratidal zones of the LTF (Gantyno, 2010; Dumonceaux, 1984).

Figure 5.12: Ir versus depth plot from the MHA 2-05-04H-148-91 QEP Resources core. Spikes above 40ppm occur in the Lower Bakken and the lower portion of the Three Forks. XRF analysis was performed using a hand held device with a run time of 75 seconds and sampled every 6 in (courtesy of QEP Resources).
Figure 5.13: Al versus depth plot from the MHA 2-05-04H-148-91 QEP Resources core. See Fig. 5.11 for color coded legend. Compare to Fig. 5.11, the missing data points for the Ir plot are the result of levels below the detection level of the device. Data are from a handheld XRF machine with a run time of 75 seconds (courtesy of QEP Resources).
Figure 5.14: Core photos of approximate interval of highest measured values of Ir (Fig. 5.11). From upper left at 10,133 to 10,140ft at lower right. Core is from the MHA 2-05-04H-148-91. The highest levels occur in the mosaic to nodular bedded supratidal lithofacies of the lower Three Forks. The middle Three Forks begins at approximately 10,071ft in this core. The highest Ir values in the Three Forks occur below the brecciated units of interest to this study (photos courtesy of NDIC).

5.5 Interpretation

Within the UTF, a possible dissolution collapse breccia (4.21) was identified within TF4, the interbedded tidal facies. This dissolution collapse was only identified within 1 core, the Charlotte 1-22H, but it is possible this type of breccia is more widespread throughout this lithofacies. Anhydrite nodules were observed above the collapsed zone, and within the zone of brecciation angular clasts and downward dipping beds of dolostone are present. The V-shaped nature of the collapse and sharp contact with lower beds are further indicators of dissolution
collapse (Eliassen and Talbot, 2005). The collapse occurs over an interval of approximately 10 inches, and consists of the brittle distortion of multiple beds of dolostone. The presence of the collapse breccia within this facies, along with evaporites, further confirm the interpretation of TF4 being within an intertidal zone. Intertidal zones in arid, restricted environments are conducive to the precipitation of evaporites, which can then be easily removed through dissolution causing a collapse breccia (Lucia, 1972). The presence of evaporites in the intertidal zone was also documented in the analog of Shark Bay (Brown and Woods, 1974).

The mottled texture best represented by Figure 5.8 is believed to have been created by dewatering. The elongate and sub-rounded to angular nature of the clasts suggest that significant movement of the clasts did not occur, and were instead created in-situ. The intraclasts give the appearance that if the mud was removed, the bed could be ‘squeezed’ back together. The dewatering was likely caused by compaction in zones with high sedimentation rates, as this texture is typically stratigraphically below TF3. TF3 contained loading features implying that it was deposited under high sedimentation rates.

The transitional beds characterized by intraclasts at the base (Fig. 5.9, 5.10, 5.11), or top, that grade into floating lithoclasts within the mudstone facies is believed to have been caused by storm influence. As storm energy is directed offshore, the bottom current exerts shear stress on the seafloor creating an increase in pore pressure (Duke, 1990; Duke et al., 1991). This pore-pressure increase then disrupts beds of dolostone, creating in-situ clasts. The close proximity of angular and rounded clasts is then more likely the result of the lithification stage of the beds. The more angular the clast, the more lithified the original sediment source; and the more rounded or elongate the clast is translates into a semi-lithified source. As the relative water depth increases (e.g. more mudstone to dolostone) the types of clasts created by storm influence change. Floating clasts of dolostone are found within the mudstone and are most likely the result of increased pore-pressure inducing liquefaction (Seguret et al., 2001;
Bouchette et al., 2001), which then leads to clasts being created from the underlying dolostone during the storm event. These clasts can then “float” upwards during the event, freezing en masse after the event passes, leaving floating clasts. As the basin deepens, the loss of clasts in the mudstone reflects the limits of the storm induced alteration. In Figure 5.6 the lower left panel illustrates an example of this between the B and C markers. The base of this unit (C) is disrupted bedding, grading into mudstone with floating clasts in the middle, and the top is mudstone absent floating clasts until the boundary reflected by (B) is reached. This demonstrates that as relative water level deepens upward, the effect of storms dissipated and results in a clast free deposition of mudstone. There are also no clear and definite boundaries within this sequence, and are instead gradational, indicating that this happened over a significant period of time and is not simply one event. It is also likely that these clasts are not created by one single storm event creating storm beds, but more the result of multiple storms reworking the sediment over time. Further evidence for storm influence includes the swaley cross-stratification documented in TF3; this is likely the traction influence of storms represented in the shallower subtidal zone.

The stratigraphic location of the disrupted (e.g. mottled) bedding lithofacies is similar to the locations described by Brown and Woods (1972), where it is at the transition zone between deeper and shallower lithofacies. This facies occurs in contact with a deeper facies (TF1) or shallower facies (TF3), and depending on the nature of the sequence (e.g. shallowing or deepening) it reflects the most likely cause for its deformation and clast formation. When bounded at the top by TF3, it is likely that dewatering caused by compaction due to high sedimentation rates is responsible. When TF1 is the top contact, it is likely that storm influence causes the deformation and clast generation. Both of these events create pore-pressure increases (Duke, 1990; Duke et al., 1991; Yu, 2009), with dewatering being an escape
mechanism releasing the increase in pore pressure; and storm influence increasing pore
pressure for a short period of time.

While an impact tsunami cannot be completely eliminated as a possible cause, multiple
factors make it unlikely. The preponderance of gradational contacts compared to sharp bases,
and the ungraded nature with regards to clast size, are both features common to the Three
Forks and not to tsunami deposits. A petrographical analysis was not performed in this study,
but the lack of shocked quartz and glass spherules identified by other studies that did
incorporate thin sections (Mescher et al., 2012; Gantyno, 2010; Bottjer et al., 2011) also
provides further evidence that it is unlikely to have been the result of an impact-tsunami. The
presence of elevated levels of Ir is believed to be in-conclusive. While elevated levels have
been documented within the Three Forks, they are orders of magnitude higher than levels
documented from other locations (ppm in Williston Basin vs. ppb or ppt). The spikes that were
identified by Figure 5.12 are in close proximity to possible redox boundaries (e.g. Lower Bakken
and lower Three Forks), similar to the documentation of elevated levels of Ir found worldwide in
the Devonian by Wang et al. (1993).
CHAPTER 6
RESERVOIR CHARACTERISTICS AND PETROPHYSICS

6.1 Introduction and Dataset

Core data publically available from the NDIC was used in this study for reservoir characteristics and calibration of petrophysical models. All the testing was performed by Weatherford and the cores were provided by Continental Resources. The data includes core porosities, permeabilities, fluid saturations, etc. Data points were taken at approximately 2ft intervals through the Bakken and into the Three Forks. The highest net confining stress data points were used for this study (4,000psi). Figure 3.2 demonstrates a pressure profile for the Three Forks and Bakken which indicates the Three Forks is overpressured, hence the high NCS used in this study. Locations of the wells used for calibration of the petrophysical model are listed in Figure 1.1, and from north to south are: Rosenvold 1-30H, Lokken 2-2H, Rolf 1-20H, Charlotte 1-22H, and Debrecen 1-3H. All petrophysical analyses on logs were performed in IHS Petra; graphs and charts were created in Microsoft Excel and Tibco Spotfire.

6.2 Core Data Characteristics

The upper Three Forks has an average porosity of 6.4% and a permeability of 0.070md. Porosity and permeability exhibit a general correlation, as porosity increases so does permeability (Fig. 6.1). Oil saturations, measured from core and plotted for all 5 wells, have a maximum of 54.07% with an average of 25.45% in the UTF (Fig. 6.1). Figure 6.1 has the data points color-coded on a gradient scale of 0 to 54.07% for oil saturations, with the darkest green indicating the highest oil saturation. A distinct cluster of higher oil content is evident in the 3-6% porosity range.

The middle Three Forks has a slightly higher average porosity, 6.9%, and higher permeability, 0.198md, than the upper Three Forks (Fig. 6.2). The middle Three Forks also
demonstrates a correlation of higher porosities equating to higher permeabilities. However, the oil saturations are lower within the MTF. Average oil saturation is 10.15% with a maximum measured value of 31.60%.

Figure 6.1: Porosity on X-axis, measured in %, and permeability on Y-axis, measured in millidarcy (md) of 5 cores used in this study for the UTF. A general correlation exists between increasing porosity and increasing permeability. Average porosity is 6.4% and average permeability is 0.07md. Blocks are color-coded for core measured oil saturations on a gradient scale with the mid-point being the average value of oil saturations for all 5 cores used in this study. The UTF has a max oil saturation of 54.07% and an average of 25.45%. A cluster of high oil saturations occurs in the 3-6% porosity range.
Figure 6.2: Porosity on X-axis, measured in %, and permeability on Y-axis, measured in millidarcy (md) of 5 cores used in this study for the MTF. A general correlation exists between increasing porosity and increasing permeability. Average porosity is 6.9% and average permeability of 0.198md. Blocks are color-coded for core measured oil saturations on a gradient scale with the mid-point being the average value of oil saturations for all 5 cores used in this study. The MTF has a max oil saturation of 31.60%, and an average value of 10.15%.

Oil saturations on a core by core basis show that the UTF consistently demonstrates higher oil saturations, with a marked drop off occurring at the MTF (Figs. 6.3 to 6.7). The Rolf has the highest oil saturations in both the UTF and the MTF, 33.6% and 15.9% respectively. The lowest oil saturations are in the Debrecen 1-3H, 7.9% and 4.1%. The Debrecen 1-3H is also the furthest south well in this study, while the Rolf is close to the basin center. The UTF consistently demonstrates a lower total fluid saturation (oil + water) than the MTF and LTF (Figs. 6.3 to 6.7), possibly indicating the presence of gas present in-situ that dissipated, and therefore was unmeasurable in laboratory analysis. Figures 6.3 – 6.7 are in order from north to south.
The fluid saturation profile from the core data in Figures 6.3 – 6.7 suggests evidence for the forces of expulsion. The forces of expulsion are the result of a mature source rock (Lower Bakken Shale) generating hydrocarbons, which results in an overpressured compartment (Fig 3.2). This then expels water from the system, and forces hydrocarbons into tight pore spaces (pers. comm., Dr. Larry Meckel). The fluid profiles exhibit higher oil saturations close to the source in the UTF, which then diminishes as stratigraphic distance from the source increases, and is evident as the increased water saturation in the MTF and LTF.

![Fluid saturations (oil + water) from core analysis for the Rosenvold 1-30H. X-axis is depth in ft and colored bar represents units of the Three Forks. Green line is oil saturation, blue line is water saturation, and brown bar represents total fluid saturations. A sharp drop in oil saturation occurs at the UTF/MTF boundary. The UTF has lower total fluids than the MTF and LTF, possibly representing a loss of in-situ gas before analysis. Average oil saturation for UTF is 28.1% and MTF is 5.0%.

Figure 6.3: Fluid saturations (oil + water) from core analysis for the Rosenvold 1-30H. X-axis is depth in ft and colored bar represents units of the Three Forks. Green line is oil saturation, blue line is water saturation, and brown bar represents total fluid saturations. A sharp drop in oil saturation occurs at the UTF/MTF boundary. The UTF has lower total fluids than the MTF and LTF, possibly representing a loss of in-situ gas before analysis. Average oil saturation for UTF is 28.1% and MTF is 5.0%.
Figure 6.4: Total fluids from the Lokken 2-2H. Average oil saturation for the UTF is 27.2% and MTF is 10.5%. See Fig. 6.3 for legend.

Figure 6.5: Total fluids from the Rolf 1-20H. Average oil saturation for the UTF is 33.6% and the MTF is 15.9%. See Fig. 6.3 for legend.
Figure 6.6: Total fluids for the Charlotte 1-22H. Average oil saturation for the UTF is 31.5% and the MTF is 13.6%. See Fig. 6.3 for legend.

Figure 6.7: Total fluids for the Debrecen 1-3H. Average oil saturation for the UTF is 7.9% and the MTF is 4.1%. See Fig. 6.3 for legend.
6.3 Porosity

Core derived porosities were used to calibrate log porosity within IHS Petra. Density porosity (DPHI) was calculated (Appendix B) throughout the UTF and MTF using the average grain densities from core, and compared to the standard limestone density (2.71 g/cm³) porosity (Fig. 6.8). The UTF had an average density of 2.7847 g/cm³ and the MTF had an average of 2.7804 g/cm³. A matrix density value of 2.78 g/cm³ was used to calculate porosity, as this value is more representative of the UTF and MTF (Fig. 6.9). Comparing the two methods, it can be seen that a density of 2.71 g/cm³ underestimates porosity within the UTF and the MTF, and a density of 2.78 g/cm³ is more appropriate for evaluation of the Three Forks.

Figure 6.8: Core porosity versus density porosity from logs based on a limestone matrix, 2.71, presented graphically and in well log. A limestone matrix calculation would result in under calculation of porosity, when compared to core derived porosity. For the log, white shading at top for Middle Bakken, gray for Lower Bakken, blue for UTF, and red for MTF. Gamma ray is in the track 1, deep induction resistivity in track 2, and porosity in the track3. Porosity is measured on a right to left scale of -0.10 to 0.30 with core data represented by black x and log values by the maroon line.
Figure 6.9: Core porosity versus density porosity calculated with a density matrix of 2.78 for the Three Forks presented graphically and in well log. When compared to Fig. 6.8, a closer correlation with core data is evident when a matrix density of 2.78 is used.

Nuclear magnetic resonance (NMR) porosity was also compared to core porosity, as it was available in the log suite. NMR logging tools generate a magnetic current, which polarizes the hydrogen nuclei and then measures the relaxation times (Allen et al., 1997). An advantage to these tools is that they can be lithologically independent, and have the potential to be appropriate to all intervals. Figure 6.10 is the TCMR porosity, or total combinable magnetic resonance, a Schlumberger tool for measuring NMR. A close approximation is evident with core data, and it has the advantage of tracking core porosity very well throughout the entire interval. DPHI based on a limestone matrix tracks well, compared to core porosity, in the Middle Bakken (Fig. 6.8), but not in the Three Forks or Lower Bakken. Likewise, a DPHI based on a 2.78 g/cm$^3$ matrix tracks well in the UTF and MTF, but not in the Lower or Middle Bakken.
Figure 6.10: TCMR porosity versus core porosity for presented graphically and in well log. A very close approximation to core porosity is evident in the log, track 3, from the Middle Bakken through the Three Forks. Where available, this log would be useful for evaluation of the Bakken and Three Forks, as it appears to be lithologically independent.

Whereas Figure 6.10 reflects a close approximation to core porosity throughout the entire interval, so where available, it would be an excellent porosity tool for the entire Bakken Petroleum System. However, in the dataset used in this study only 7 wells had TCMR porosity.

A useful tool to qualitatively identify potential gas in the reservoir is the crossover effect of neutron porosity and density porosity. However, the neutron porosity can be artificially high due to the large thermal absorption of shaly intervals (Allen et al., 1997). When NMR logs, or in this case TCMR, are available the crossover effect can be identified with DPHI and TCMR. When DPHI is greater than TCMR, it can indicate the presence of gas (Allen et al., 1997). This is illustrated in Figure 6.11, and provides further evidence that the lower total fluids (Figs. 6.3-6.7) in the UTF is due to the presence of gas.
Figure 6.11: In track 3 DPHI (light blue), NPOR (black), and TCMR (pink) porosities are plotted. NPHI is consistently greater than DPHI throughout the UTF (blue shading) and MTF (pink shading), and does not display any crossover. A crossover effect (blue shading between curves) is displayed in the UTF and MTF when using DPHI and TCMR in 3 of the 4 wells, suggesting that gas is present in the reservoir. The Debrecen 1-3H does not display any crossover, and it is the well with the lowest oil saturation (Fig. 6.7). Track 4 shows core fluid saturations, total fluids (black) and water (blue) connected by a discrete line. Where crossover occurs, water saturation decreases and total fluids decrease in the UTF.
6.4 Vsh (volume of shale)

The volume of shale can be a useful indicator of lithology, and to an extent the lithofacies described in this study. The standard equation within IHS Petra was used to calculate Vsh:

\[ Vsh = \frac{(Gr - Gr_{cin})}{(Gr_{sh} - Gr_{cin})} \]

The value selected for clean gamma ray was 60 API and for a shaly interval was 115 API (Fig. 6.12). Based on this a 0 to 1.0 scale was created with a three color shading system: green for a high mud content zone, blue for a clean dolostone zone, and gray for a mixed dolostone mudstone zone. This helps to separate lithofacies, as TF1 would be green and TF3 would be blue. However, it is difficult to distinguish TF2 and TF4, as both are a mix of mudstone and dolostone and bedding style is the differentiator between the two lithofacies (Fig. 6.13). This method is valuable in locating the carbonate rich intervals of interest to the industry.

![Cross plot of gamma ray and density porosity. API values of 60 and 115 were selected to represent a clean dolostone and a mudstone, respectively.](image)

Figure 6.12: Cross plot of gamma ray and density porosity. API values of 60 and 115 were selected to represent a clean dolostone and a mudstone, respectively.
Figure 6.13: Vsh in track 3 on a 0 to 1.0 scale. Vsh is a good lithology indicator with green representing a mudstone (TF1), blue for dolostone (TF3), and gray for a mixed lithology of mudstone and dolostone. However, this does not distinguish between lithofacies TF2 and TF4, which are both comprised of a mix of dolostone and mudstone. This can be used to identify the intervals richest in dolostone, but not for extensive mapping of lithofacies. Well log and photos are from the Rosenvold 1-30H (core photos courtesy of NDIC).

6.5 Water Saturation

The petrophysical evaluation of water saturation is most commonly performed through Archie’s equation (Nordeng and Helms, 2010; Asquith and Krygowski, 2004):

$$Sw = \left[\frac{Rw}{(Rt \cdot \phi^m)}\right]^{1/n}$$

Where:

Sw – Fraction of pore space occupied by water

Rw – Resistivity of the formation water (ohm*m)

Rt – Resistivity of the formation (ohm*m)
\[ \Phi \] – Porosity, fraction of the total rock volume that is pore space

Within this equation, Archie (1942) designated \( m=n=2 \) for an ideal clastic reservoir. Subsequent work has identified the ideal characteristics of an Archie reservoir, where the standard equation should be sufficient and is outlined in Table 6.1 (Worthington, 2011).

Table 6.1: Criteria established to define when the standard equation for Archie’s water saturation would be appropriate. The Three Forks contains multiple non-Archie conditions, and should therefore be evaluated through other means (from Worthington, 2011).

<table>
<thead>
<tr>
<th>No.</th>
<th>Archie Criteria</th>
<th>Non-Archie Conditions</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Single rock type</td>
<td>Multiple electrofacies or petrofacies: thin beds</td>
</tr>
<tr>
<td>2</td>
<td>Homogeneous</td>
<td>Heterogeneous (e.g., variable mineralogy/texture)</td>
</tr>
<tr>
<td>3</td>
<td>Isotropic at micro- and mesoscales</td>
<td>Anisotropic (e.g., ellipsoidal grain shape, laminations)</td>
</tr>
<tr>
<td>4</td>
<td>Compositionally clean</td>
<td>Clay minerals</td>
</tr>
<tr>
<td>5</td>
<td>Clay free</td>
<td>Argillaceous</td>
</tr>
<tr>
<td>6</td>
<td>Silt free</td>
<td>Silty</td>
</tr>
<tr>
<td>7</td>
<td>No metallic minerals</td>
<td>Pyrite and other minerals</td>
</tr>
<tr>
<td>8</td>
<td>Unimodal pore-size distribution</td>
<td>Multimodal pore-size distribution including microporosity</td>
</tr>
<tr>
<td>9</td>
<td>Intergranular porosity</td>
<td>(Micro)fractures/fissures/vugs</td>
</tr>
<tr>
<td>10</td>
<td>High-salinity brine</td>
<td>Fresh water</td>
</tr>
<tr>
<td>11</td>
<td>Water-wet</td>
<td>Mixed wettability</td>
</tr>
<tr>
<td>12</td>
<td>( I_r ) is independent of ( R_w )</td>
<td>( I_r ) varies with ( R_w )</td>
</tr>
</tbody>
</table>

The Three Forks meets several of the non-Archie conditions as outlined in Table 6.1, including clays and conductive minerals (pyrite). Previous XRD work has identified that the Three Forks contains \(~2.0\%\) pyrite on average, with \(10.0\%\) clay in the UTF and as high as \(30.0\%\) clay in the mudstone marker of the MTF (Bottjer et al., 2011). Other XRD work by Sonnenberg et al. (2011) has also identified the significant presence of clays and pyrite within the upper Three Forks (Fig. 6.14).
Figure 6.14: XRD analyses for intervals within the UTF. (A) XRD analysis of the Jorgenson 1-15H (15, T148N, R96W) demonstrating that the Three Forks is predominantly dolomite, but does have significant amounts of quartz, pyrite, and clays (from Sonnenberg, et al. 2011). (B) Average XRD values from the Bakken Petroleum System, significant amounts of clay and pyrite in a system dominated by dolomite and silicates in the UTF and MTF (from Bottjer et al., 2011).
To better evaluate water saturations in reservoirs that do not match ideal conditions, there are multiple methods that have worked worldwide. Some of these include a pseudo-Archie method, which varies m (cementation exponent) and n (saturation exponent) values away from the standard 2. The variation of these can be identified by core testing (electrical properties analyses), or through various estimation methods (Worthington, 2011). Other methods for Sw evaluation include variations that incorporate the Vsh term for shaly sand intervals (Worthington, 2011; Worthington, 2000). However, it is recommended that petrophysical analyses should be calibrated against laboratory performed core analyses to verify validity (Worthington, 2011).

For the purpose of this study, the Rw value identified by Nordeng and Helms (2010) of 0.04 ohm*m was used and corrected for depth using Arp’s equation (Nordeng and Helms, 2010). Within the 5 wells of this study, the value ranged from 0.013 to 0.015 ohm*m, and an average of 0.014 ohm*m was used as a standard value. The DPHI based on a 2.78 matrix density was used for the porosity (φ) term. Other values used will be discussed in more detail in the subsequent sections.

6.5.1 Resistivity

Resistivity can be affected by conductive minerals (e.g. pyrite and glauconite), which in effect lower the true resistivity values (Worthington, 2011; Worthington, 2000). Resistivity can also be affected by the log used for measurement. Induction logs have problems averaging the true resistivity when thin bedded sequences are present (e.g. TF4), while laterologs perform better in these sequences (Ramakrishna et al., 2010). The 5 wells used for calibration all had induction logs used for the measurement of resistivity, as they were all drilled with an OBM (oil based mud) which requires the use of an induction log.

To address one of the issues with resistivity measurements, this study incorporated an adjustment factor for pyrite. Based on the XRD work by other studies (Bottjer et al., 2011;
Sonnenberg et al., 2011) a constant of 2.0% pyrite was assumed throughout the Three Forks. Previous studies have measured the resistivity of pyrite in oil producing formations in Alaska and have found that it ranged from 0.03 to 0.8 ohm*m (Clavier et al., 1976). For the purpose of this study, a resistivity factor of 0.5 ohm*m was assumed; and calculations within IHS Petra were performed to account for the presence of pyrite according to equations located within Crain’s Petrophysical Handbook (Appendix B, www.spec2000.net). Introducing the correction for pyrite, a slight increase in resistivity is observed (Fig. 6.15).

Figure 6.15: Comparison of deep resistivity as logged (brown) and adjusted for 2.0% vol pyrite at 0.5 ohm*m (green) in track 2. A slight increase is observed when corrected for the presence of pyrite.
6.5.2 Triple Poroisty Model

As the Three Forks does not fit ideal conditions to be considered an Archie reservoir, core analyses should be used to determine the m and n variables for saturation calculations. This study did not have access to core values for electrical properties, and in lieu of this a model put forth by Al-Ghamdi et al. (2012) was used to estimate these values. Al-Ghamdi et al. (2012) recommended the triple porosity model for use in estimating electrical properties when core data is not available, and showed a close approximation of these derived values within a Middle East carbonate reservoir.

Triple Porosity Equation: \[ m = -\log(\varphi_{nc} + (\frac{1-\varphi_{nc}}{\varphi_2})^2 + \frac{1-\varphi_2-\varphi_{nc}}{\varphi_{b_{mb}}})/\log(\varphi) \]

To use this model, several different types of porosity have to be present in the formation of interest. Interparticle porosity (Fig. 6.16A) is represented by the term \( \varphi_b \) and is derived from the sonic log. Fracture porosity (Fig. 6.16B) is assumed to be the difference between core porosity and sonic porosity (\( \varphi_2 \)). Non-connected porosity (Fig. 6.16C) can be anything from vuggy porosity to fenestral porosity, as long as it’s isolated, and is assumed to be a log derived porosity (DPHI, PHIA, NMR, etc.) minus effective (core) porosity (Al-Ghamdi et al., 2012).

Where log and core data were available, an m value was calculated and plotted versus gamma ray for the Three Forks (Fig. 6.17). As identified by Boyd et al. (1995), the presences of clays are one of the greatest inhibitors to accurate evaluation in low resistivity zones. Based on this, the cluster of data points reflecting high gamma values, inferred to be high clay zones, were averaged and a value of 1.54 was selected for the m variable. For the purpose of this study, n was assumed to equal m, and a value of 1.54 was also used.
Figure 6.16: The triple porosity model for estimation of electrical properties requires the presence of three different types: (A) Interparticle porosity, scale bar 0.1mm (from Bottjer et al., 2011) (B) Fracture porosity and Interparticle porosity; scale bar 0.1mm (from Bottjer et al., 2011) (C) Red arrow denotes vuggy porosity from the Rolf 1-20H at 11,188.10ft; scale bar 0.4mm (photo courtesy of Weatherford via NDIC).
Figure 6.17: M values calculated from the triple porosity method plotted against gamma. A negative correlation is exhibited; a decrease in m corresponds to an increase in gamma. The red circle encapsulates the values averaged for determination of m; inferring a high gamma corresponds to higher clay content.

6.5.3 Comparison of Sw Methods

As mentioned in previous sections, Archie’s Sw method is most likely not the appropriate method for calculations pertaining to the Three Forks. Figure 6.18 exhibits this in both graphical and log representations. Archie’s method grossly over calculates the amount of water present in the Three Forks. Using m=n =1.54 from the triple porosity model, a pseudo-Archie equation is shown in Figure 6.19. This method shows a much closer approximation throughout the Three Forks when comparing core and log derived water saturations.
In addition to the pseudo-Archie and standard Archie methods, two other Sw calculation methods were reviewed. The Simandoux (1963) method incorporates a Vsh term to help account for the presence of clays (Fig. 6.20). Another method used (Fig. 6.21) is referred to as the Shell method and was developed by Shell for use in carbonates (Azar et al., 2007). In this method, the m value is a function of porosity. While both the Shell and Simandoux methods generate better results than the standard Archie method, the Simandoux method does underestimate Sw. The pseudo-Archie method has the closest to a 1:1 linear relationship and, the Shell method has the tightest correlation of data points when represented in graphical form (Fig. 6.22).
Figure 6.19: In track 3 the blue curve is Sw from standard Archie \((m=n=2)\) and purple curve is from pseudo-Archie \((m=n=1.54)\) plotted with core Sw (black dots). The pseudo-Archie method tracks core saturations better through the UTF and MTF. Formation names are labeled in the far right depth track.
Simandoux (1963):

\[
\frac{1}{R_t} = \frac{S^2}{F \cdot R_c} + \frac{\varepsilon V_{th}}{R_{th}}
\]

Figure 6.20: The Simandoux (1963) method for Sw incorporates a Vsh term for shaly sand intervals. This is plotted in track 3 (green) with core Sw (black dots). This method consistently underestimates Sw in the Three Forks, but does appear to be better in the UTF than the MTF. See Fig. 6.19 for formation colors.
Figure 6.21: Shell method for determining Sw where m is a function of porosity; and is represented by the brown curve in track 3 and the black dots represent core Sw. The Shell method performs fairly well in the UTF, but consistently underestimates Sw in the MTF.

\[ M = 1.87 + 1.9 \times PHie \]
Figure 6.22: Graphical representations of the 4 methods for Sw calculation performed in this study, y-axis is log derived and x-axis is core derived with both scales 0 to 100% Sw. The standard Archie eqn. consistently overestimates Sw. The pseudo-Archie method exhibits the best 1:1 relationship. The Simandoux method underestimates Sw. The Shell method underestimates Sw, but does display the tightest correlation of data points.
CHAPTER 7

SUBSURFACE MAPPING

7.1 Structure and Isopachs

All maps were created in IHS Petra using formation tops and petrophysical attributes based on a minimum curvature gridding technique. Figure 7.1 is a structure map based on the top of the Lower Bakken Shale and includes prominent anticlines in western North Dakota. Figure 7.2 is an isopach of the entire Three Forks from the top of the Birdbear to the base of the Pronghorn or Lower Bakken Shale where the Pronghorn is absent. The Three Forks reaches a maximum thickness of 238ft in the center, and thins to 109ft to the west in Montana.

The lower Three Forks (Fig. 7.3A) is the thickest of the three intervals (LTF, MTF, and UTF) with a max of 166ft and a thin of 46ft. The middle Three Forks (Fig. 7.3B) reaches a maximum thickness of 69ft and a thin of 28ft. The upper Three Forks (7.3C) is the thinnest of the three intervals, with a max of 45ft and thinning to 1.0ft to the west. Figure 7.3 displays all three units and a total isopach of the Three Forks. Thins of the LTF correspond to thicks in the MTF, indicating reciprocal sedimentation. While not as clear in the MTF to UTF transition, the overall isopach of the Three Forks closely matches the isopach of the LTF. This suggests that reciprocal sedimentation occurred in the subsequent deposition of the MTF and UTF of the Three Forks. The UTF displays a sharp thinning to the west, while the MTF thins more pronouncedly to the south.

7.2 Petrophysical Characteristics

In addition to structure and isopach maps, shale volume (Vsh) and water saturations (Sw) were mapped. The water saturation method mapped is based on the pseudo-Archie equation with m=n=1.54, as this provided the closest 1:1 approximation with core data (Ch. 6).
Water saturation maps for the MTF and UTF (Figs. 7.4 & 7.5) are based on 0 to 1.0 scale, with blues representing higher water saturations, and greens suggesting higher oil content.

Figure 7.1: Structure map based on the top of the Lower Bakken Shale. Prominent anticlines include: (A) Nesson (B) Antelope (C) Little Knife (D) Billings. Depths are subsea with blues corresponding to lows and reds to highs.
Figure 7.2: Isopach of the total Three Forks, from the contact with the lower Birdbear to the upper Pronghorn or Lower Bakken Shale. The Three Forks reaches a maximum thickness of 238ft in the center, and thins to the west in Montana to 109ft.
Figure 7.3: Reds correspond to thicks and thins are blue. (A) LTF reaches a maximum of 166ft and a minimum of 46ft, C.I. 10ft. (B) MTF reaches a maximum of 69ft and a minimum of 28ft, C.I. 5ft. (C) UTF reaches a maximum of 45ft and a minimum of 1.0ft, C.I. 5ft. (D) Total Three Forks reaches a maximum of 238ft and a minimum of 109ft, C.I. 10ft. The LTF closely resembles the isopach of the entire Three Forks, suggesting reciprocal sedimentation of the MTF and UTF. The UTF has a pronounced thinning to the west, and the MTF thins to the south. The LTF thins to the west, and has a prominent thin in the center.
Figure 7.4: Water saturation map from pseudo-Archie equation (m=n=2) for the MTF on 0 to 1.0 scale with a C.I. of 0.10. Blue represents higher water content and green suggests higher oil content. Overlaid on the Sw map are black contours representing the structure of the overlying Lower Bakken Shale. Highest oil content correlates fairly well to structure, with the darkest green areas on the edge of the Nesson and Antelope structures.
Figure 7.5: Sw of the UTF on a 0 to 1.0 scale with C.I. of 0.10. Greens correlate to higher oil content and blues to higher water content. High oil concentrations can be associated with structures (i.e. Nesson, Antelope, and Billings), but high concentrations can also be found away from structure. The UTF is more oil saturated compared to the MTF (Fig. 7.4).
When comparing the two Sw maps (Figs. 7.4 & 7.5), it is evident that the UTF is more oil saturated than the MTF. The MTF tends to show the highest potential concentrations of hydrocarbons on structures, which holds true to an extent for the UTF. However, the UTF oil saturations tend to be more pervasive throughout the study area, and do not appear to be as structure dependent. The lower concentrations of hydrocarbons in the MTF suggest a stratigraphic component is influential, as reservoir characteristics from core (e.g. porosity and permeability) were slightly better in the MTF than the UTF (Figs. 6.1 & 6.2).

The stratigraphic components most likely contributing to the presence, or absence, of oil within the Three Forks are the Lower Bakken Shale and the Pronghorn. Aside from structure accumulations, the high oil saturations in the center-north of the UTF correspond to thicks in the Lower Bakken Shale (Fig. 7.6). However, oil saturations are also high to the west where the Lower Bakken thins out. This does correspond to a thinning of the Pronghorn (Fig. 7.6), suggesting that the Upper Bakken Shale is contributing where the Lower Bakken Shale and Pronghorn are absent. The high oil saturations in the MTF can also be seen to occur where the Lower Bakken is thickest, and the Pronghorn is thinnest. It is unlikely that freshwater recharge is the reason for the higher water saturations in the center-west of the UTF and MTF. Nordeng and Helms (2010) documented high salinities in this approximate area of North Dakota, hence the low Rw values, which suggests that fresh waters are not being introduced into the system. It is most likely that oil saturations are a function of both structure and vertical stratigraphic thickness away from the source (Bakken Shales).

Vsh is a metric for distinguishing the silty dolostone lithofacies from the mudstone-rich intervals (Fig. 6.13), and can be used to identify the carbonate benches of interest to the petroleum industry. Figure 7.7 is of Vsh on a 0 to 1.0 scale for the MTF with blues representing cleaner, dolostone intervals and grays representing more clay-rich zones. Figure 7.8 displays Vsh for the UTF, on the same scale as Fig. 7.7, and demonstrates that the UTF is richer in
Figure 7.6: Comparison of water saturations with isopachs of the Lower Bakken Shale (A) and the Pronghorn (B). C.I. for the Lower Bakken Shale and Pronghorn is 5ft. High oil saturations in the center of the UTF (C) and MTF (D) correspond to thicks in the Lower Bakken and thins in the Pronghorn. To the west, the high oil saturations in the UTF and MTF are most likely the result of charging by the Upper Bakken, as both the Pronghorn and Lower Bakken thin significantly to the west.
Figure 7.7: Vsh of the MTF on a 0 to 1.0 scale, C.I. is 0.10. Blues represent silty dolostone intervals and grays for more clay-rich intervals. A much higher clay content is evident in the center, and higher dolostone content on the edges, particularly to the east.
Figure 7.8: Vsh of the UTF on a 0 to 1.0 scale; C.I. 0.10. Blues represent higher dolostone content, and grays represent clay-rich intervals. Compare to Fig. 7.7; the UTF has more pervasive dolostone content than the MTF, with clay-rich zones in the center.
in silty dolostone than the MTF. Both display concentrations of mudstone in the center of the map, with higher contents of dolostone evident to the northeast and southwest.

The Vsh of the MTF is influenced by the presence of the marker bed found at the top, TF1. A base for the mud-marker was selected, and then the MTF was mapped as two separate Vsh units: (1) mudstone marker bed (2) base of mudstone to top of LTF (Fig. 7.9). This comparison shows that the marker mudstone, TF1, covers the entire study area likely providing further evidence that it was deposited during the highest sea level occurrence of the Three Forks. The bench representing the MTF, minus the mudstone, then shows it is rich in dolostone across the center of the study area. However, this increase in dolostone content does not correlate with increased amounts of potential hydrocarbons (Fig. 7.9F). The areas with the most potential for hydrocarbons include the center of the study area in close proximity to the Nesson Anticline, and to the west where the UTF (Fig. 7.3C) and Pronghorn (Fig. 7.6B) decrease in thickness. This provides further evidence that the stratigraphic vertical distance from the source, and structural components, are the factors influencing hydrocarbon potential within the Three Forks.

Induction and laterologs do pose a challenge when mapping Sw, as referenced in Chapter 6. Figure 7.10 displays a cross section through an area to the west in Montana. A high Sw zone in the UTF is observed, with the highest values being recorded in wells measured with induction logs. In contrast, the lowest Sw is evident in the laterologs. However, there is still a trend from high to low Sw observed across this zone, regardless of the log used. While the absolute value appears to reflect a log bias, there is still an observable transition of Sw in the UTF. It should also be noted that the wells in Figure 7.10 were all drilled in the 1970s and 1980s. Figure 7.11 illustrates another cross section through low Sw areas of the UTF. These wells all contain induction logs, but were spudded in 2011. This could indicate that a better resolution is found in modern logs, and caution should be exercised in using older wells.
Figure 7.9: Comparison of Vsh and Sw for the MTF (A, D), mud marker of the MTF (B, E), and MTF minus the mud marker (C, F). When the mudstone of TF4 is removed from the MTF (C), an increase in dolostone is evident. However, this increase in dolostone content does not translate to an increase in potential hydrocarbons (F).
Figure 7.10: Inset map shows area of high Sw in Montana for the UTF. The two wells with the red star measured resistivity with induction logs, and the other 3 were measured by laterologs. The absolute value reflects higher Sw in the induction wells than the laterolog wells. However, there is still an identifiable trend observed through this zone. These wells were drilled in the 1970s and 1980s. To better reflect the Sw map, the Sw curve in track 3 is shaded in red for values below 0.50. Brown dashed line reflects the base of the mud marker.
Figure 7.11: Cross section from low Sw to high Sw in the UTF. All wells were measured by induction logs and spudded in 2011. Low Sw is observed in the Rosenvold, Lokken, and Rolf wells in the UTF. While induction logs could observe lower resistivities than laterologs; at least in the case of more modern wells, the values should be appropriate for identifying potential hydrocarbon bearing zones. However, caution should be used in older wells. To better reflect the Sw map, Sw in track 3 is shaded in red for values below 0.50. The brown dashed line reflects the base of the mud marker.
7.3 Comparison to Production

In addition to core saturation data, the calculated Sw values were also compared to production. From the IHS database, wells within the study area that reported production within the Three Forks was incorporated into a bubble map (Fig. 7.12). The production data was filtered to 6 month cumulative oil production and separated into 5 categories, color coded, and sized to reflect the greatest production. The attributes are overlaid onto a Sw map of the UTF, and correspond fairly well with potential hydrocarbon bearing zones. Nearly all of the highest producing wells, represented by orange and green bubbles, fall within areas of <50% water saturation. In addition to the bubble map, the Rosenvold 1-30H tested a zone from the Lower Bakken Shale into the top of the middle Three Forks and reported an IP of 492 bbls of oil, 516 mcf, and 520 bbls of water.

7.4 Cross Sections

Stratigraphic cross sections are used to illustrate the thickness of the units, UTF and MTF, across structure. Structure cross sections are not viable, as the relief is too high and the units too thin to portray in detail. Water saturations are shaded in red when below 50%, to better highlight potential hydrocarbon bearing zones. Locations of the three cross sections are located in Figure 7.13. Figure 7.14 is a cross section from west to east across the Nesson Anticline. It demonstrates a thinning of the UTF at the Larsen 1-16H, which is on the peak of the Nesson. The UTF is thickest on both flanks of the Nesson, and thins to the east and west. The MTF is thinnest west of the Nesson, and is thickest to the east. The thinning suggests the Nesson influenced deposition. An increase in Sw is evident to the west in both the UTF and MTF, with a decrease in Sw first occurring in the UTF as the Nesson is approached. Immediately on the Nesson, and to the east, an increase in hydrocarbon potential is observed in both the UTF and MTF. The UTF remains a high hydrocarbon potential zone farther to the east.
Figure 7.12: Bubble map of first 6 month cumulative oil production overlain with Sw map of the UTF. Size and color reflect the amount of production, with green bubbles representing the highest 6 month cumulative production. Highest producing wells match, reasonably well, with the low Sw fairway from north to south.
Figure 7.13: Locations of three cross sections in the subsequent figures. Cross section lines are in blue, and red dots represent well locations. Cross sections are overlain on Sw for the UTF in color contours, and black contours represent structure for the top of the Lower Bakken Shale. A to A’ is west to east across the Nesson Anticline. B to B’ is north to south through the study area. C to C’ is west to east across the study area.
Figure 7.14: Cross section from west to east across the Nesson. Cross section is flattened on the top of the UTF (blue). Track 3 is Sw, shaded red for values under 50%. The UTF demonstrates a thinning on the Nesson at the Larsen 1-16H, and thickens on each flank before thinning on the margins. The MTF is thickest to the east, and demonstrates a subtle thinning to the west of the Nesson. Sw increases approaching the Nesson for the UTF and MTF. Hydrocarbon potential for the UTF extends further from the Nesson than for the MTF. Well locations can be seen in Figure 7.13.
than the MTF. The MTF potential appears to be confined to proximity to the Nesson in this section.

From north to south in Figure 7.15 the UTF thins as it approaches the Nesson, then thickens south of the Nesson, reaching its thickest point near the basin center in the Erickson 11-1H. The MTF nearly mirrors this trend, but shows a stronger proclivity to thickening in the basin center. Sw is lowest in the north, at the Rosenvold 1-30H, and on the Nesson in the Olson 9-11H. The basin center and south have the lowest potential hydrocarbon bearing zones, as seen in the Erickson 11-1H and the Debrecen 1-3H.

West to east across the study area is illustrated in the cross section of Figure 7.16, and crosses south of the Nesson. This profile demonstrates the abrupt thinning to the west of the UTF, while the MTF stays fairly constant in thickness to the west. The MTF is thinnest in the basin center, seen in the Charlotte 1-22H, and thickest to the east in the Linseth 4-8H and Sun Marathon Shobe 1. The UTF and the MTF both show higher hydrocarbon potential on the eastern edge, compared to basin center and to the west. The UTF demonstrates a higher potential for hydrocarbons compared to the MTF in this cross section, as well as in all previous maps and cross sections.
Figure 7.15: North to south cross section across the study area. The UTF (blue) and MTF (pink) are thickest in the basin center, with the MTF showing a very pronounced increase in thickness. They both thin as the Nesson is approached (JV-P Nelson) and thicken south of it (Olson). For the MTF and UTF, Sw decreases immediately north and south of the Nesson, and increases towards the basin center (Erickson) and south (Debrecen).
Figure 7.16: West to east cross section from Montana into North Dakota. Abrupt thinning in the west is evident in the UTF, while the MTF is more consistent in thickness. The MTF is thinnest in the basin center (Charlotte) and thickest on the eastern flank (Linseth and Sun Marathon). The MTF shows higher hydrocarbon potential in the east, rather than the west. The UTF mirrors this trend, but is more consistently saturated with hydrocarbons than the MTF.
CHAPTER 8
CONCLUSIONS AND RECOMMENDATIONS

8.1 Conclusions

The main objectives of this study were threefold, and included: (1) the origin and cyclicity of the brecciated intervals within the upper and middle Three Forks, (2) identify petrophysically the suite(s) of logs that can best define hydrocarbon potential, (3) and to then map the petrophysical attributes to identify the areas and factors that contribute to an increase in hydrocarbon potential.

The conclusions from this study are as follows:

- The upper and middle Three Forks can be divided into 4 lithofacies: (1) TF1, a green to gray or red mudstone, (2) TF2, a mottled to chaotically interbedded silty dolostone and mudstone (3) TF3, a low mud content (clean) silty dolostone (4) TF4, an interbedded tan, silty dolostone and green to gray mudstone
- The Three Forks was deposited in a tidally dominated, storm influenced, relatively low energy environment. The Three Forks was likely a relatively shallow basin, restricted from an open marine environment by the Sweetgrass Arch.
- The MTF represents an overall deepening upwards sequence, with parasequences that can reflect short transitions to shallowing upwards sequences.
- The UTF represents a shallowing upwards sequence, from the mudstone of TF1 at the contact of the MTF/UTF to a decidedly intertidal sequence represented by a capping of lithofacies TF4.
- Brecciated intervals are most common in the MTF, and are likely the result of storm influence. Bottom flows generated by storms likely caused an increase in pore pressure, leading to an in situ brecciation of previously deposited sediments. This resulted in
gradational units of intraclasts within disrupted silty dolostone beds, and floating clasts in mudstones. In addition to storm influence, minor occurrences of dissolution collapse breccia and dewatering deformation did occur; a careful examination of bounding lithofacies can determine the origin of the brecciated unit in question.

- TCMR porosity provides the best correlation to core porosity, and where available can be used throughout the Bakken Petroleum System. Where TCMR porosity is not available, DPHI with appropriate matrix density for the UTF and MTF can give a close approximation to core porosities, and be used for evaluation purposes.

- Vsh can differentiate between lithofacies TF1 and TF3; however TF2 and TF4 give similar log readings. Mapping of Vsh can identify areas with a high concentration of silty dolostone (i.e. industry benches), and identifies that the UTF has a lower content of mud than the MTF.

- A pseudo-Archie equation for water saturation provides a good approximation to core water saturation values. Inputs for the equation include resistivity corrected for pyrite, DPHI, and m=n=1.54 from the triple porosity model.

- Slightly better core characteristics, 6.9% porosity and 0.198md permeability, were observed in the MTF than the UTF, 6.4% and 0.070md respectively. However, fluid saturations from core and logs indicate that the UTF has a higher concentration of hydrocarbons.

- Mapping revealed that hydrocarbon concentrations of the Three Forks is influenced by stratigraphy, and enhanced by structure. A thick Lower Bakken Shale, and thin Pronghorn, represents areas where hydrocarbon potential for the UTF is greatest. If combined with structure (i.e. Nesson Anticline), the hydrocarbon potential increases even more. Where the Lower Bakken Shale and Pronghorn are thinnest, which also coincides with a thinning of the UTF, there is evidence that the Upper Bakken Shale is
possibly sourcing the UTF and MTF. Hydrocarbon potential within the MTF is less than that of the UTF, but there are areas where structure and stratigraphy lead to increased hydrocarbon potential within the MTF.

8.2 Recommendations

The recommendations for future work include:

- Petrographic analysis to determine the provenance for the predominantly silt to mud sized grains within the Three Forks.
- Further analyses of the upper Three Forks to explain how an intertidal zone can encompass an extensive area of the basin.
- Extensive pressure mapping of the Three Forks to determine if pressure trends can be identified with respect to stratigraphic distance from the source (i.e. Lower/Upper Bakken Shales); and if pressure trends correlate to Sw trends and further confirm the forces of expulsion.
- Determine why iridium levels are orders of magnitude higher in the Bakken system than values documented in other intervals, such as other Devonian black shales and the K-T boundary.
- Lithofacies and petrophysical analyses of the lower Three Forks to determine its viability as a possible petroleum reservoir.
- Expand the study area west into Montana to determine the relationship of lithofacies, and extents of the UTF and MTF.
REFERENCES


Simandoux, P., 1963, Dielectric measurements of porous media: Application to measurement fo water saturations-study of the behavior of argillaceous formation, Rev. de l’institut Francais du Petrole, supplementary issue.


APPENDIX A

CORE DESCRIPTIONS

Provided below are two additional core descriptions of the Rosenvold 1-30H and the Debrecen 1-3H. The Rosenvold 1-30H is in the north of the study area and the Debrecen 1-3H is in the south of the study area. The Charlotte 1-22H (Fig. 4.15) is approximately in the basin center. These three wells provide a north to south transect through the study area. The legend for the following core descriptions is provided in the Figure A.1. Locations of the cores is provided in the header, as well as in Chapter 1 (Fig. 1.1)
**CORE DESCRIPTION LEGEND**

**Lithology**

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**Sedimentary Structures**

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*Figure A.1: Core description legend (modified from Cobb, 2013).*
Figure A.2: Core description of the Rosenvold 1-30H. Multiple sequences of deepening upwards are observable in the MTF, with an overall deepening upwards trend. The UTF is a shallowing upwards sequence. The MTF is dominated by TF2, while the UTF is dominated by TF4.
Figure A.3: Core description of the Debrecen 1-3H. The MTF is dominated by a deepening upwards trend, and the UTF is shallowing upwards. The MTF is dominated by a reddish mudstone that contains both clasts of green mudstone and a mottled green and red mudstone.
APPENDIX B
PYRITE AND DPHI

To correct for the presence of pyrite, the methodology as outlined by Crain’s Petrophysical Handbook was used (www.spec2000.net). The first step is to identify the conductivity of pyrite:

\[ C_{pyr} = \left( \frac{1000}{R_{pyr}} \right) \times V_{pyr} \]

Where: 
- \( C_{pyr} \) is the conductivity of pyrite
- \( R_{pyr} \) is the resistivity of pyrite (assumed to be 0.5 ohm\( \cdot \)m)
- \( V_{pyr} \) is the volume of pyrite, assumed to be 2.0% from XRD (Fig. 6.14)

The resistivity log is actually measured in conductivity, which is simply the reciprocal and for purpose of conversion factors it divided by 1000. To correct for the conductivity, convert the deep resistivity log to conductivity:

\[ C_{log} = \left( \frac{1000}{RESD} \right) - C_{pyr} \]

Where: 
- \( RESD \) is the deep resistivity log
- \( C_{pyr} \) is the conductivity of the assumed volume and resistivity of pyrite

The last step is to then convert the created conductivity log back to a resistivity log, which is now adjusted for the assumed amount of pyrite in the interval.

\[ RESD_{pyr} = \frac{1000}{C_{log}} \]
DPHI was calculated using the standard equation within IHS Petra:

\[ DPHI = \frac{RHOMA - RHOB}{RHOMA - RHOF} \]

Where:

- RHOMA is the average density of the matrix, taken from core for this study.
- RHOB is the bulk density log.
- RHOF is the assumed density of the fluid, 1.0 in this case.