January 2016

Reservoir Characterization And Modeling: Winnipegosis Formation, Temple Field, Williston Basin, North Dakota

Benjamin Steven Oster

RESERVOIR CHARACTERIZATION AND MODELING: WINNIPEGOSIS FORMATION, TEMPLE FIELD, WILLISTON BASIN, NORTH DAKOTA

by

Benjamin Steven Oster
Bachelor of Science in Geology, University of North Dakota, 2013

A Thesis

Submitted to the Graduate Faculty

of the

University of North Dakota

In partial fulfillment of the requirements

for the degree of

Master of Science

Grand Forks, North Dakota
May
2016

This thesis, submitted by Benjamin Steven Oster in partial fulfillment of the requirements for the Degree of Master of Science from the University of North Dakota, has been read by the Faculty Advisory Committee under whom the work has been done and is hereby approved.

Mehdi Ostadhassan, Ph.D.,-Chairperson

Richard LeFever, Ph.D.,-Committee Member

Stephan Nordeng, Ph.D.,-Committee Member

This thesis is being submitted by the appointed advisory committee as having met all of the requirements of the School of Graduate Studies at the University of North Dakota and is hereby approved.

Wayne Swisher
Dean of the School of Graduate Studies

Date

PERMISSION

Title	Reservoir Characterization and Modeling: Winnipegosis Formation, Temple Field, Williston Basin, North Dakota
Department	Geology
Degree	Master of Science

In presenting this thesis in partial fulfillment of the requirements for a graduate degree from the University of North Dakota, I agree that the library of this University shall make it freely available for inspection. I further agree that permission for extensive copying for scholarly purposes may be granted by the professor who supervised my thesis work or, in her absence, by the Chairperson of the department or the dean of the School of Graduate Studies. It is understood that any copying or publication or other use of this thesis or part thereof for financial gain shall not be allowed without my written permission. It is also understood that due recognition shall be given to me and to the University of North Dakota in any scholarly use which may be made of any material in my thesis.

Benjamin Steven Oster
May 5, 2016

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

ACKNOWLEDGEMENTS

I would like to thank my committee members Dr. Mehdi Ostadhassan, Dr. Richard D. LeFever, and Dr. Stephan H. Nordeng. I am especially thankful for the patience and motivation provided by my advisor Dr. Mehdi Ostadhassan during this thesis. I would also like to thank all the faculty and staff at the Harold Hamm School of Geology and Geological Engineering for their friendship and support.

I would like to thank the North Dakota Geological Survey for use of their cores with a special thanks to Julie LeFever for her assistance during this study.

I would like to thank the staff at the Energy and Environmental Research Center for the opportunity to grow my scientific knowledge, with a special thanks to Mr. Nick Bosshart, Mr. Wes Peck, and Mr. Charlie Gorecki.

I would like to thank all of my friends and family for their continual love and support.

ABSTRACT

The Winnipegosis Formation of Temple Field represents the most prolific production from the formation in North Dakota in a platform margin environment.

Temple Field production is from a combination of structural and stratigraphic traps on a small anticlinal structure with an up-dip porosity pinchout, along the larger Nesson Anticline. In this study a geocellular model was constructed of the field for increased understanding of the facies and petrophysical property distributions within the field. Facies interpretations from cores were tied to well log signatures and then used to create a facies model. The facies model was then used to constrain the petrophysical property distributions. Petrophysical properties including porosity, permeability, and water saturation were then predicted within the model through geostatistical analysis. An original oil in place of 21.7 to 24.1 million barrels, was estimated from the model. This made the current recovery from the field 27-30 percent.

CHAPTER I

INTRODUCTION

The Winnipegosis Formation is a Middle Devonian carbonate formation in the Elk Point Group (Figure 1) in the Williston Basin. The formation represents a platform and basin complex in the Williston Basin and greater Elk Point Basin. It is a hydrocarbon producing formation in North Dakota and Temple Field represents the most prolific oil production from the formation in the state.

Regional Geologic Setting

The Elk Point Basin (Figure 2) is the large intracratonic platform and basin complex of the north-central United States and west-central Canada that was formed during the Devonian Period, with the southern portion known as the Williston Basin. The Williston Basin is a roughly circular intracratonic basin covering approximately 150,000 square miles of eastern Montana, western North Dakota, northwestern South Dakota, and southern Saskatchewan and Manitoba and contains approximately 16,000 feet of sediments. Sediments ranging in age from Cambrian to Holocene were deposited on top of the Precambrian unconformity located near the basin center in McKenzie County, North Dakota.

During the Devonian, the Transcontinental Arch was responsible for the connection of the Williston Basin to the Elk Point Basin on the north. This movement was controlled by tectonic stresses of the Acadian and Antler orogenies from movement of the Colorado-Wyoming shear zone (Gerhard et al., 1982).

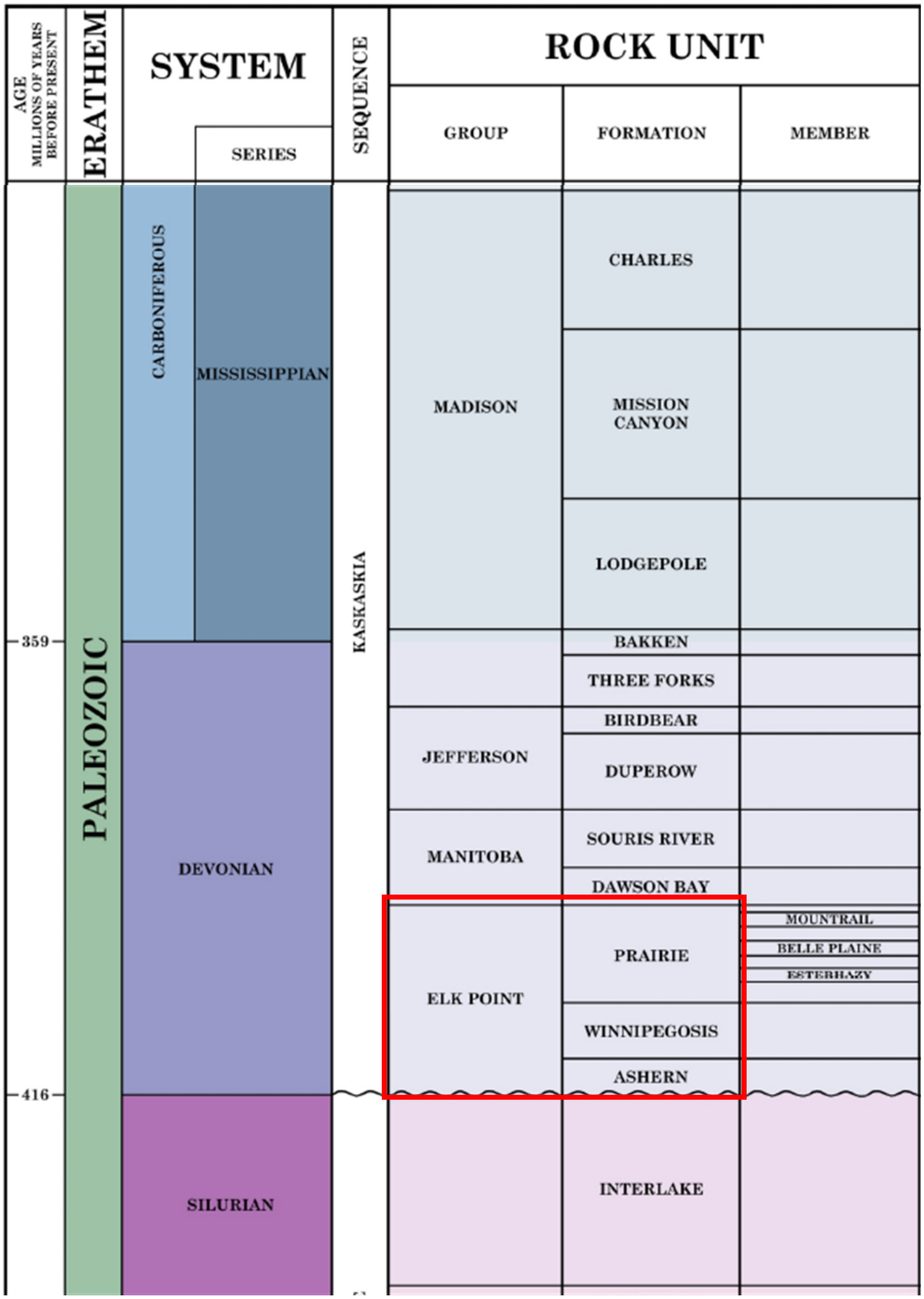

Figure 1. Stratigraphic column of the Kaskaskia Sequence in North Dakota. (modified from Murphy et al., 2009)

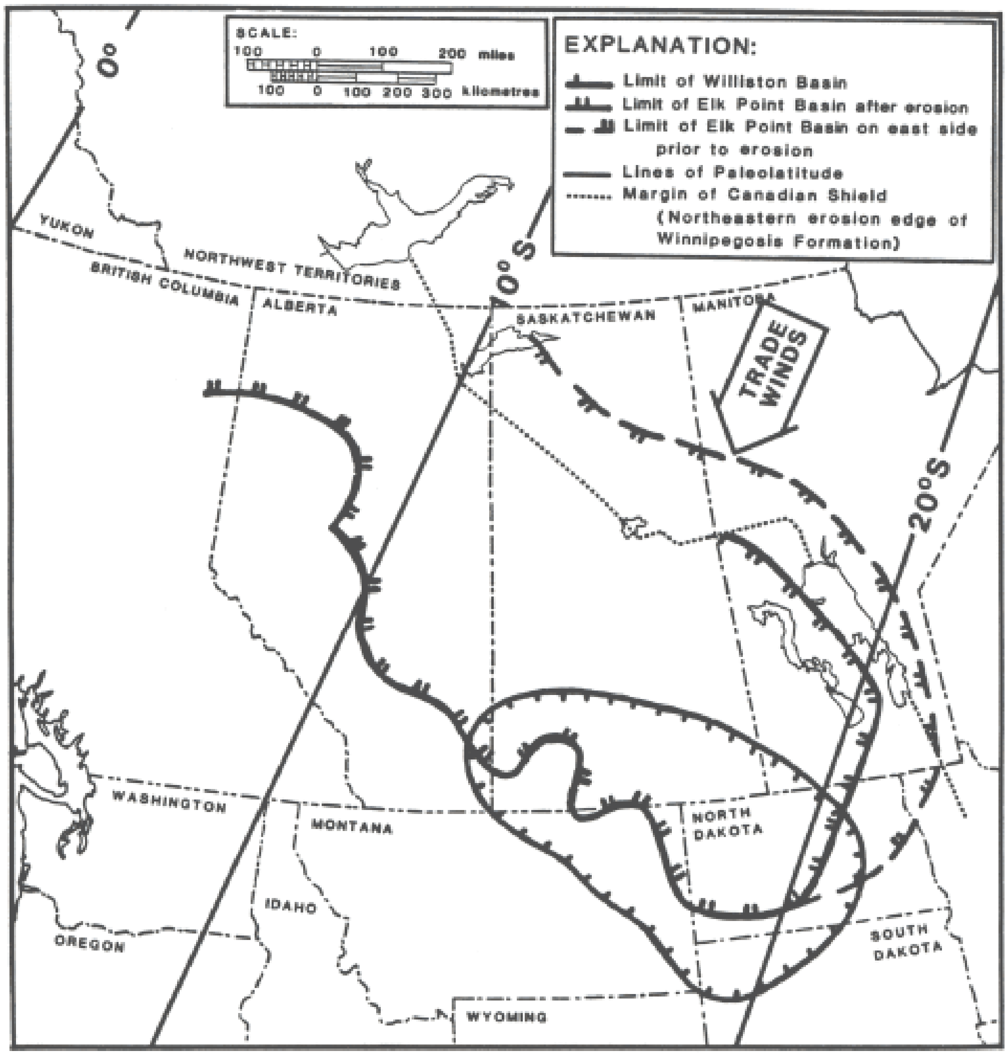

Figure 2. Limit of the Elk Point Basin and Williston Basin. (Perrin, 1987)

Structural features within the Williston Basin (Figure 3) show a north- and northwest trend similar to the Rocky Mountain province. These structures include the Cedar Creek and Antelope Anticlines, trending to the northwest. The north-trending structures include the Nesson, Billings, and Little Knife Anticlines. The Nesson Anticline is one of the main structures within the Williston Basin and a major fault system on the west side of the anticline has been active since Precambrian time. (Gerhard, 1987).

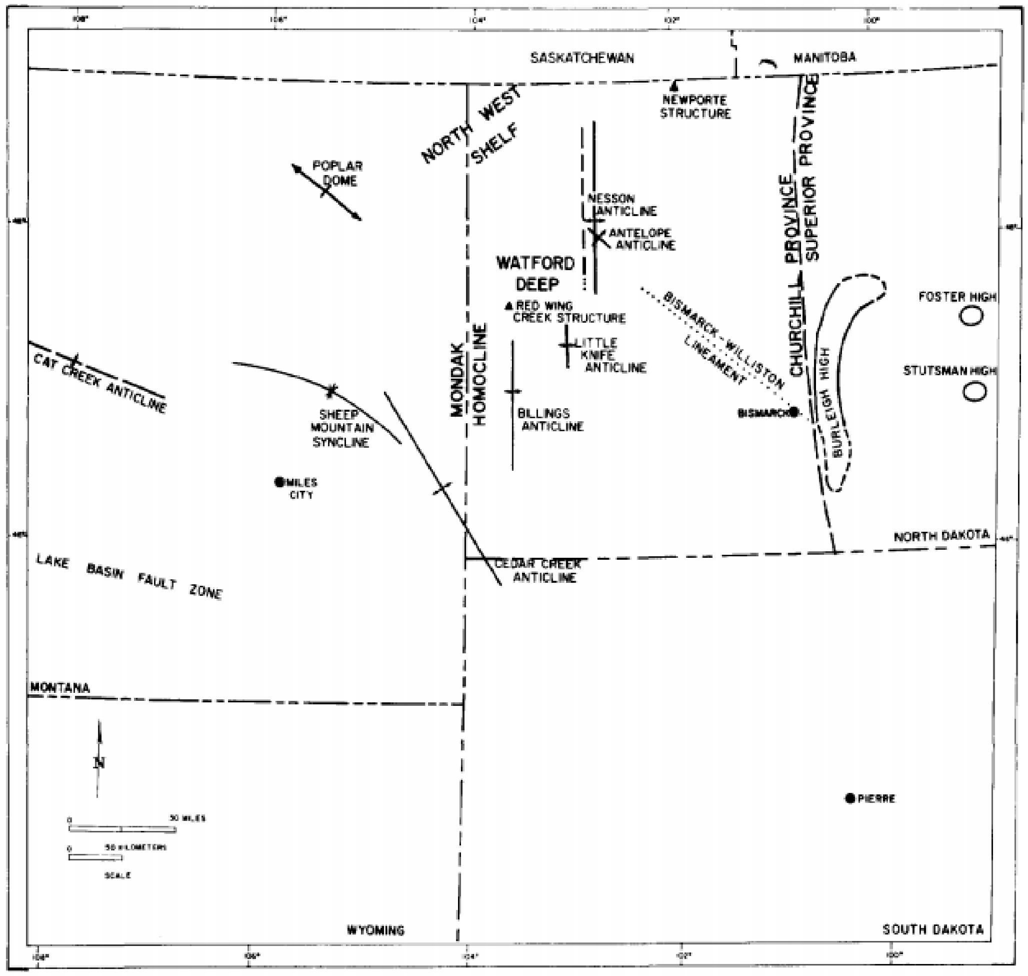

Figure 3. Williston Basin major structural features map. (Gerhard et al., 1982)

Area of Study

The study area (Figure 4) for this thesis is Temple Field. The field is located in northeastern Williams County in the northwestern portion of the Williston Basin of North Dakota. The field covers an area of approximately 34 square miles and is located on the western side of the Nesson Anticline. Within Temple Field, 40 wells were studied for this research to develop a geocellular model of the field. In total, 782 wells in northwestern

North Dakota were used to generate structure and isopach maps of the formations within the Elk Point Group over northwestern North Dakota.

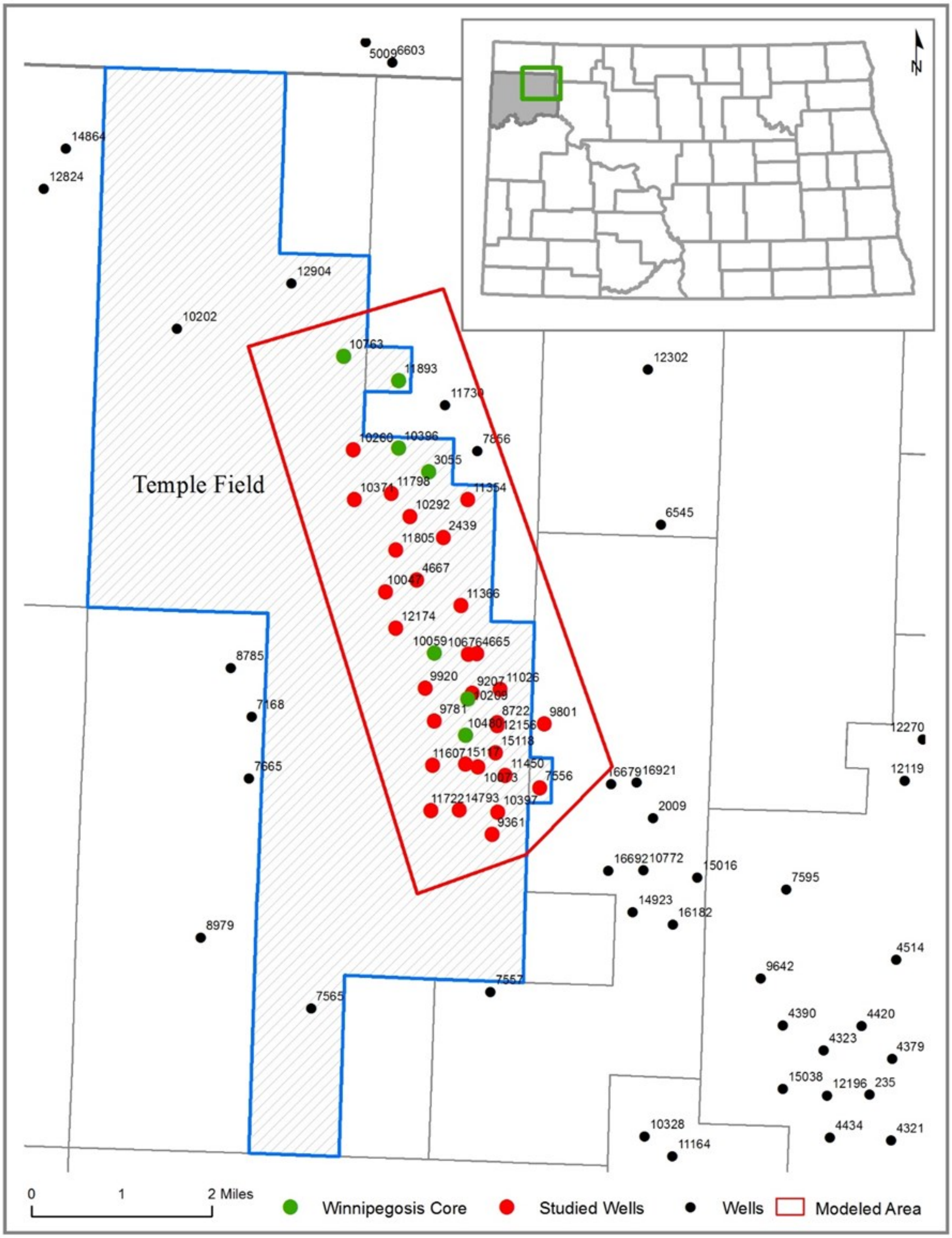

Figure 4. Map of the wells in the study area.

Purpose and Objectives

The purpose of this study is to: (1) complete an examination of the reservoir properties of the Winnipegosis petroleum system in Temple Field, (2) construct a three dimensional geologic model to show the distribution of the different facies within the Winnipegosis Formation and their associated reservoir properties, and (3) estimate original oil in place (OOIP) and potential reserves in the field.

Temple Field is an older field with most of the drilling and production beginning in the mid-1980s. Modeling of the field will facilitate better understanding of the reservoir facies and the associated porosity and permeability within each facies. Estimates of OOIP will help to determine the remaining reserves within the field and better reveal further operations of the field to maximize the remaining potential.

The objectives of the study are to: (1) understand the lateral and vertical facies relationships within the Winnipegosis Formation of Temple Field, (2) correlate core data to allow for better delineation of the facies and petrophysical properties within the field, and (3) develop a reservoir model for volumetric calculation of remaining hydrocarbon reserves of the field.

Methods

An investigation of core data, well log data, drill stem tests, and production data from the field was performed for this study. All information for the research was collected from the North Dakota Industrial Commission (NDIC) website. The available well logs within the Temple Field study area and surrounding area, were transformed from images into digital files using the digitizing software Neuralog (2010). Structural well tops of the Prairie, Winnipegosis, and Ashern Formations were used to construct structural contour and isopach maps of the formation in Temple Field and the northwestern portion of North Dakota.

Seven Winnipegosis geologic cores were available within the area of interest, which were used to assess lateral and vertical facies associations. The core information and petrophysical properties were depth matched with the logs and shifted where necessary. Facies and member tops were determined based on core descriptions and well logs signatures and used to create structural surfaces.

All data were then used to create a facies model and multiple property models using Schlumberger's commercial software Petrel. Figure 4 shows the boundary of the final grid used in modeling and calculations. The model was clipped to this boundary since it represents the producing area from the Winnipegosis Formation within Temple Field. The boundaries for this model were developed based on a porosity pinchout of the reservoir facies to the east, limited production from the formation to the north, the end of the anticlinal structure to the south, and the end of the producing wells to the west.

Previous Work

Jones (1965) was the first to divide the Winnipegosis into Lower and Upper Members based on subsurface work in Saskatchewan. He interpreted the Lower Member was deposited in a broad epicontinental, relatively shallow, open marine sea. Jones recognized the Upper Member of the formation was separated into basin and shelf environments.

The first major Winnipegosis Formation depositional environment work was done by Kinard and Cronoble (1969) shortly after hydrocarbon production started from the formation in North Dakota. Their work focused on the formation in eastern Montana, in which they defined six Winnipegosis facies: restricted lagoonal, shallow shoal, interbioherm, bioherm, deep shoal, and restricted shallow water.

The most extensive research on the Winnipegosis Formation of North Dakota was completed by Perrin (1982, 1987) in which she determined and explained depositional environments and diagenesis of the formation. Perrin divided the formation into three episodes, represented by 22 lithofacies in seven depositional environments, which occurred during the first transgressive-regressive pulse of the Kaskaskia sequence (Figure 5).

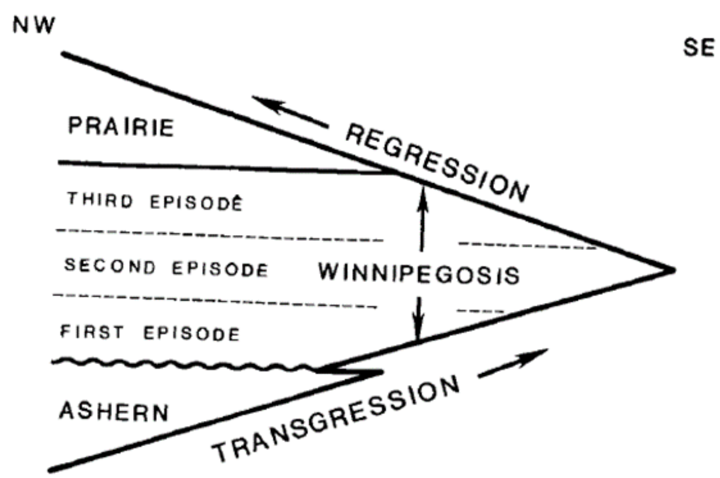

Figure 5. Diagram of Winnipegosis episodes of deposition. (Perrin, 1982)

Perrin's first episode of deposition represents a transgression, following deposition of the Ashern Formation, in a shallow marine environment. The second episode established the differentiation between the shelf and deep basin of the formation. Thick carbonates were deposited on the shelf and within the deeper basin as pinnacle reefs. Four different environments represent the platform: shallow marine, patch reef, lagoon, and tidal flat. Two environments represent the basin: pinnacle reefs and a deep marine basin environment with limited deposition. The third episode represents the overall regression of the sea. The evaporites of the Prairie Formation were then deposited over the Winnipegosis Formation in the Elk Point Basin.

Perrin and Precht (1985) examined reef cores and studied reef lithologies, biofacies, and diagenesis of the pinnacle and patch reefs of North Dakota. Patch reefs in their study were located within the eastern platform margin and are composed of stromatoporoid, tabulate coral boundstone lithofacies. They explained that the dimensions of the patch reefs could be determined by their thickness. Patch reefs on the eastern province were estimated to be 55 feet thick, 275 feet wide, and 2,750 feet long.

Ehrets and Kissling (1987) studied the reservoir aspects of Temple Field in North Dakota. They determined Temple Field is located in the platform margin environment and is characterized by basin slope, platform reef, and peritidal facies. Other characteristic facies within the field included the argillaceous Alpha and Beta Marker facies, which are known to operators as the "Winnipegosis shales."

This led Ehrets and Kissling to develop an idealized depositional model of the platform margin environment of Temple Field (Figure 6). Their research determined the reservoir within Temple Field was in the basin slope dolomudstone facies, which was developed between relatively impermeable strata overlying and underlying the facies. A mixing zone was created by downward and seaward movement of meteoric water into connate waters along the margin, creating the reservoir facies. In their study, only 18 percent of all slope facies porosity and permeability analyses were of reservoir quality (at least 8% porosity and 3 mD permeability).

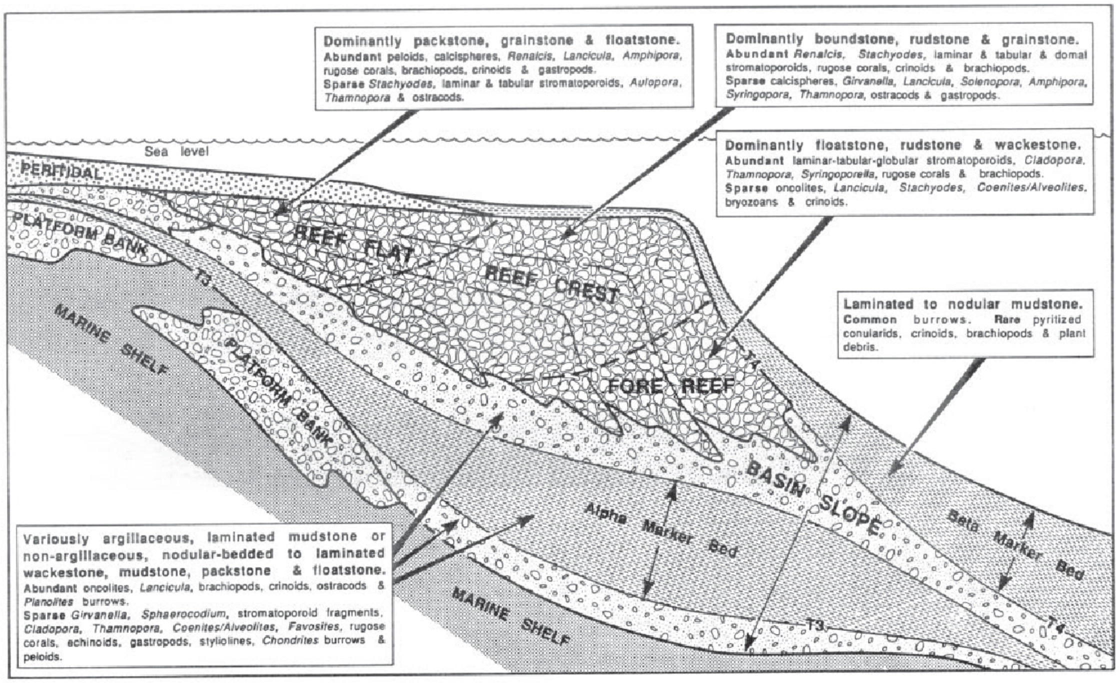

Figure 6. Field model illustration of Temple Field. (modified from Ehrets and Kissling, 1987)

Kostelnyk (1998) evaluated the dolomitization process of the Winnipegosis Formation in North Dakota and was able to identify three temporal stages of dolomitization: synsedimentary, early diagenetic, and late diagenetic.

Bosshart (2014) studied the potential for CO_2 enhanced oil recovery (EOR) and storage in the pinnacle reef environments of the formation through geocellular modeling with dynamic reservoir simulation. His study determined the potential of various size pinnacle reefs to store at least one million tons of CO_2.

Extensive research has been conducted on the Winnipegosis Formation in Canada. Rosenthal (1988) studied outcrops and cores of carbonate buildups of the formation in Central Manitoba. Jin and Bergman (1999 and 2001) developed new nomenclature for the Saskatchewan portion of the Winnipegosis by assigning the Ratner

Laminate as a separate "transitional formation" between the Winnipegosis and Prairie Formations. Fu and others (2006) focused on paleokarst features on Winnipegosis mud mounds in south-central Saskatchewan based on core and thin section examination. Zhang and others (2004) studied the Shell Lake Member of Saskatchewan to determine the stratigraphic and temporal relationship between the Winnipegosis and Prairie Formation. Dedolomitization was studied by Fu and others (2008) where overlying Prairie evaporites had been dissolved along the east-central margin of the Elk Point Basin.

CHAPTER II

GEOLOGIC OVERVIEW

Nomenclature and Correlative Units

The first formal name for the marine carbonates exposed along Lake Winnipegosis and Lake Manitoba in Manitoba, Canada was Winnipegosan Formation and was proposed by J.B. Tyrrell (1892). Baillie (1953) proposed the name Winnipegosis to include both the Winnipegosan Formation and the Elm Point Formation due to difficulty in differentiating the two formations in the subsurface. Baillie (1953) also proposed the Elk Point Group in the Williston Basin, composed of the three formations in ascending order: the Ashern, Winnipegosis, and Prairie Formations (Figure 1). Jones (1965) considered the Winnipegosis to be upper Eifelian to middle Givetian Stage spanning a period from 390 to 385 million years before present.

The Winnipegosis Formation is the Middle Devonian carbonate in the subsurface of North Dakota, northeastern Montana, southern and central Saskatchewan, south-central Alberta, and southeastern Manitoba (Figure 7). In Manitoba outcrops, the Winnipegosis includes the Elm Point and Winnipegosis Formations. Correlative equivalents of the Winnipegosis include the Keg River Formation of northern Alberta and British Columbia, the Pine Point and Presqu'ile Formations of the Northwest Territories, and the Headless and Nahanni Formations of southern Yukon and southwestern Northwest Territories.

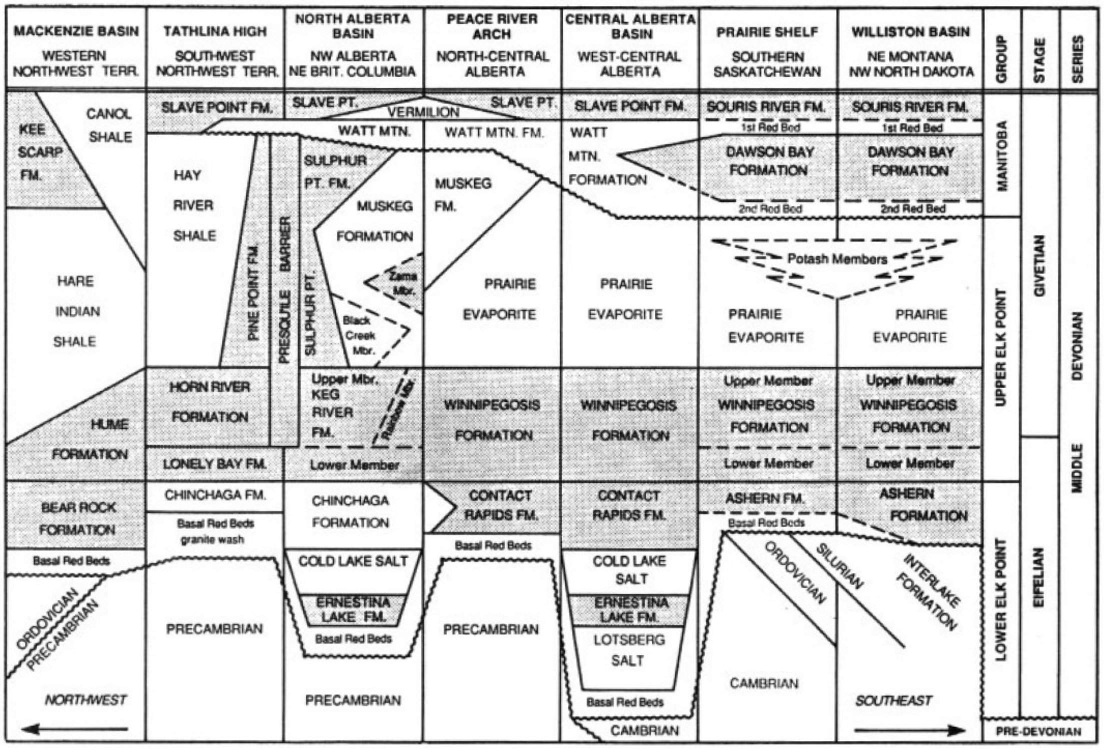

Figure 7. Stratigraphic correlation and nomenclature of the Middle Devonian Formations in the Elk Point Basin. (Ehrets and Kissling, 1987)

Depositional Environments

The Elk Point Basin was thought to be located at approximately 20 degrees south latitude (Figure 2) during the Devonian Period. The first deposits of the Kaskaskia sequence in North Dakota are the Elk Point Group, deposited over a major unconformity at the end of the Silurian (Interlake Formation). Seas transgressed into the Elk Point Basin from the north, depositing the fine-grained red dolomite of the Ashern Formation. A brief hiatus followed Ashern deposition, represented by a zone of brecciation. The seas returned and deposition of the Winnipegosis Formation began. The interpreted three episodes of Winnipegosis deposition and depositional environments are shown below in Figure 8.

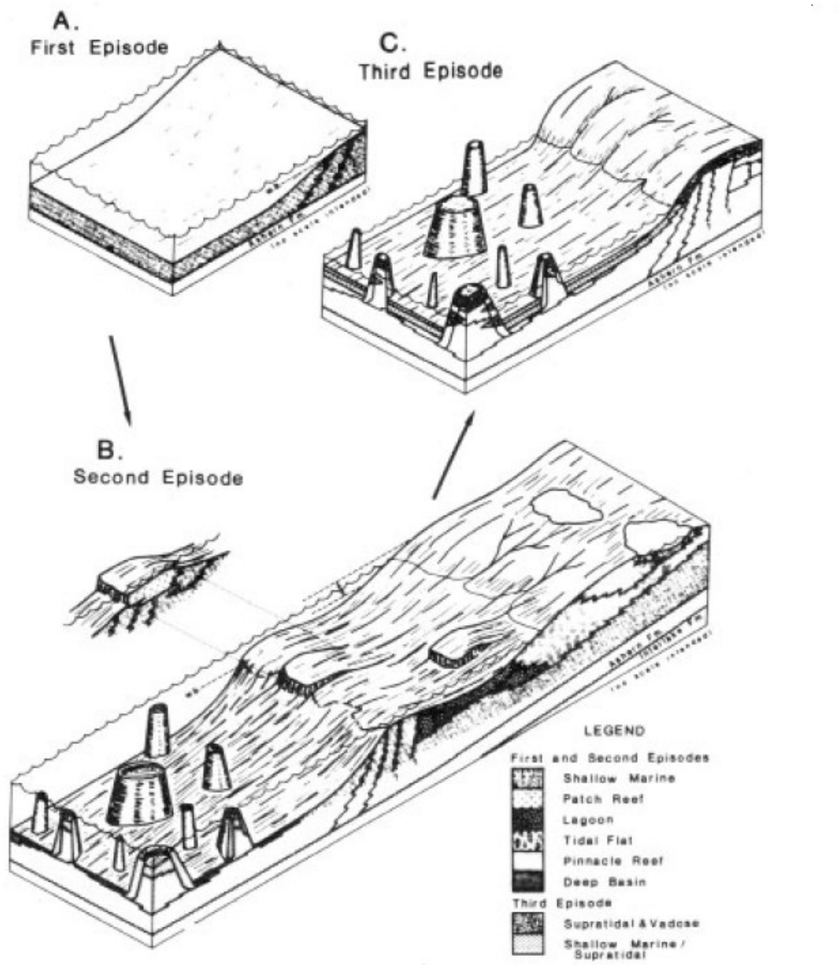

Figure 8. Illustration of Winnipegosis depositional episodes with associated depositional environments. (modified from Perrin, 1982)

In the first depositional episode, a sea spread over a broad region of North Dakota and deposited sediments. The broad ramp setting of the first episode is represented by two lithofacies (brachiopod-crinoid mudstone to packstone and brachiopod packstone/grainstone facies) making up the Lower Winnipegosis Member.

The platform and basin environments were formed during the second episode and represent the Upper Winnipegosis Member. Carbonate platforms and pinnacle reefs were deposited where carbonate production was able to keep pace with the rising sea. The deeper basin had minimal carbonate accumulations. Platform and basin environments in the Elk Point Basin are evident by isopach maps of the formation (Figure 9). The formation thickens gradually from the platform interior to the platform margin where it is 180 to 225 feet thick. The platform margin thins downslope to the basin where average thickness is roughly 60 feet. The platform margin in North Dakota is informally subdivided into eastern, western, and southern platforms.

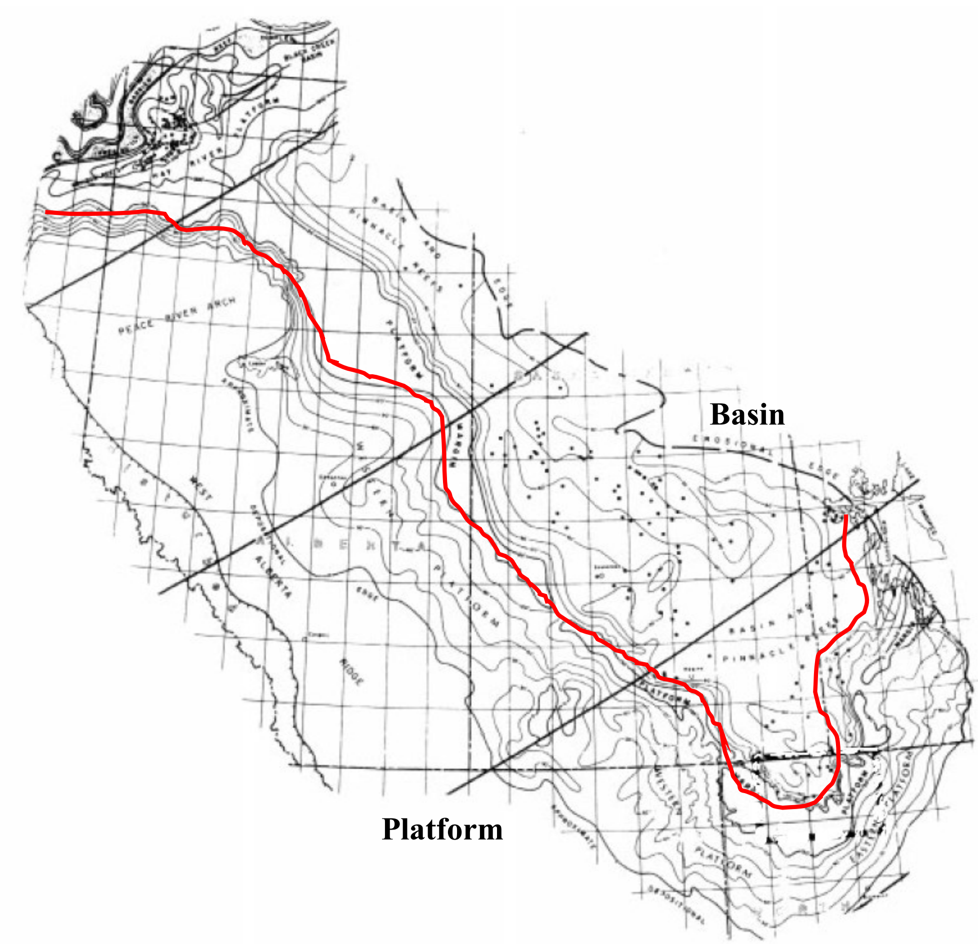

Figure 9. Map of platform and basin environments in the Elk Point Basin. Red line denotes platform margin. (modified from Ehrets and Kissling, 1987)

The platform region is represented by four depositional environments: shallow marine, patch reef, lagoon, and tidal flat. Shallow marine lithofacies from the first episode continued into the second episode. Patch reef environments developed, composed of stromatoporoid-tabulate coral boundstone facies. Lagoon environment deposits included red and blue-green algal packstone, Amphipora- calcisphere wackestone, and ostracode- calcisphere packstone. Swirled anhydrite and dolomitic mudstone along with oolite peloid packstone were deposited in the tidal flat environments.

The deep basin deposits occurred in two depositional environments: pinnacle reefs and deep marine. The pinnacle reefs are composed of a stromatoporoid tabulate coral boundstone and Codeacean algae- calcisphere- peloid packstone lithofacies. Laminated mudstone composes lithofacies in the deep marine environment.

The third episode is represented in the Winnipegosis Formation by a regression of the sea to the northwest. On top of the platform and pinnacle reefs, supratidal deposition took place. Dolomitization took place during the third episode represented by the porous dolomite facies. Allochems of the stromatoporoid boundstone facies of the reef environments were destroyed by dolomitization of the reef facies.

Restriction of the sea at the mouth of the Elk Point Basin led to the deposition of the Prairie Formation evaporites.

Hydrodynamics

The hydrodynamics of the Winnipegosis Formation exhibit a north- northeastern flow trend from the Williston Basin center (Figures 10 and 11). This flow of the formation would allow hydrocarbons to be trapped in any structural or stratigraphic traps in the Winnipegosis Formation.

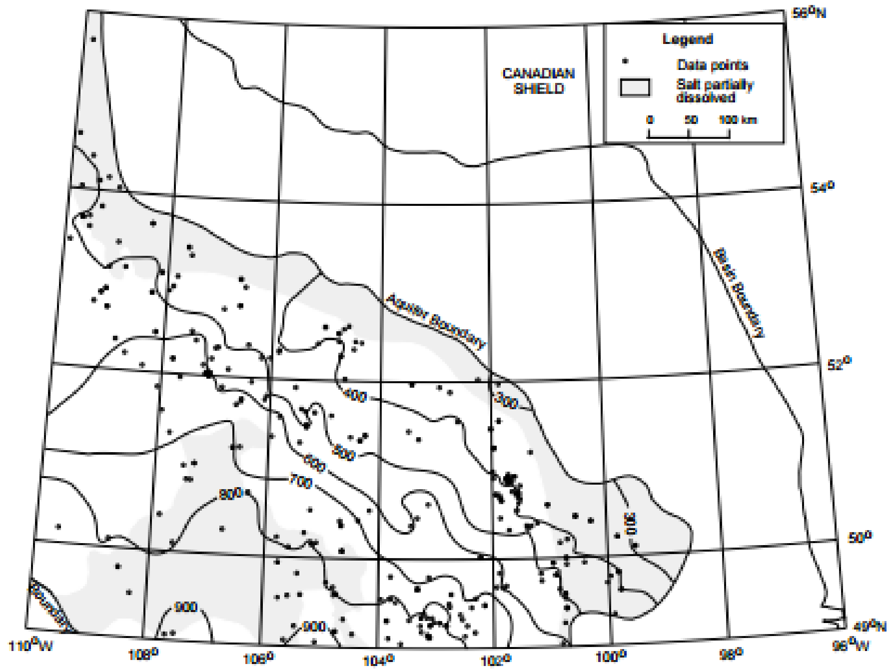

Figure 10. Winnipegosis potentiometric surface, Canada, Williston Basin. (modified from Bachu and Hichon, 1996)

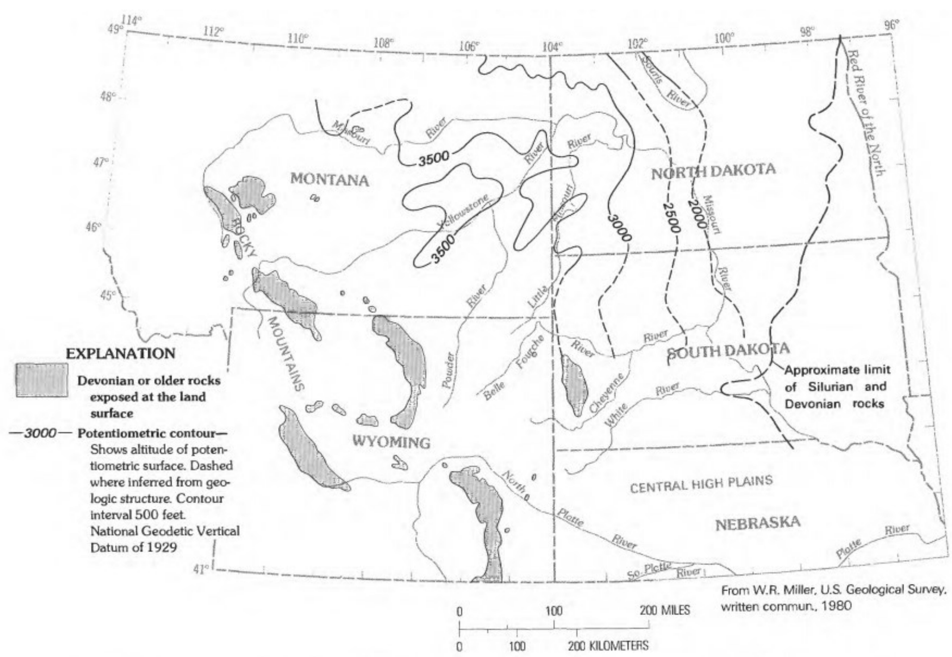

Figure 11. Potentiometric surface of Devonian rocks underlying the Northern Great Plains. (Downey and Dinwiddie, 1988)

History of Oil Production

The main area of interest in the Winnipegosis Formation has been the pinnacle reefs for their potential in hydrocarbon production. These reefs, however, have produced very little hydrocarbons in North Dakota in comparison to similar features in Canada (Fisher and Burke, 1987).

The first Winnipegosis production in the Williston Basin was in Montana in 1956 and then North Dakota in 1968, both producing from interpreted tidal flat deposits (Carlson, 1987). Other Winnipegosis production has occurred in the interpreted platform margin of Temple, Hamlet, and McGregor Fields and in the basin marine deposits of Stoneview Field (Figure 12). Winnipegosis hydrocarbons are thought to be self-sourced according to Osadetz and others (1992), likely from thin organic-rich, deep marine intervals and platform limestones.

Since the first North Dakota production, the Winnipegosis has not been a prolific producer of hydrocarbons in the North Dakota portion of the Williston Basin, with a cumulative oil production of 9.8 million barrels through December 2015 according to the North Dakota Industrial Commission (NDIC). Halite plugging degrades reservoirs in the formation over large portions of the platform margin. An assessment by Anna (2013) determined the success ratio of Winnipegosis oil production to be only one percent within the Williston Basin of the United States.

The platform margin depositional environment of Temple and McGregor Fields in North Dakota represents the most prolific production in the state. The two fields have produced approximately 8 million barrels of oil. Temple Field has produced the majority of the oil from the Winnipegosis in North Dakota, with approximately 6.5 million barrels produced since 1982.

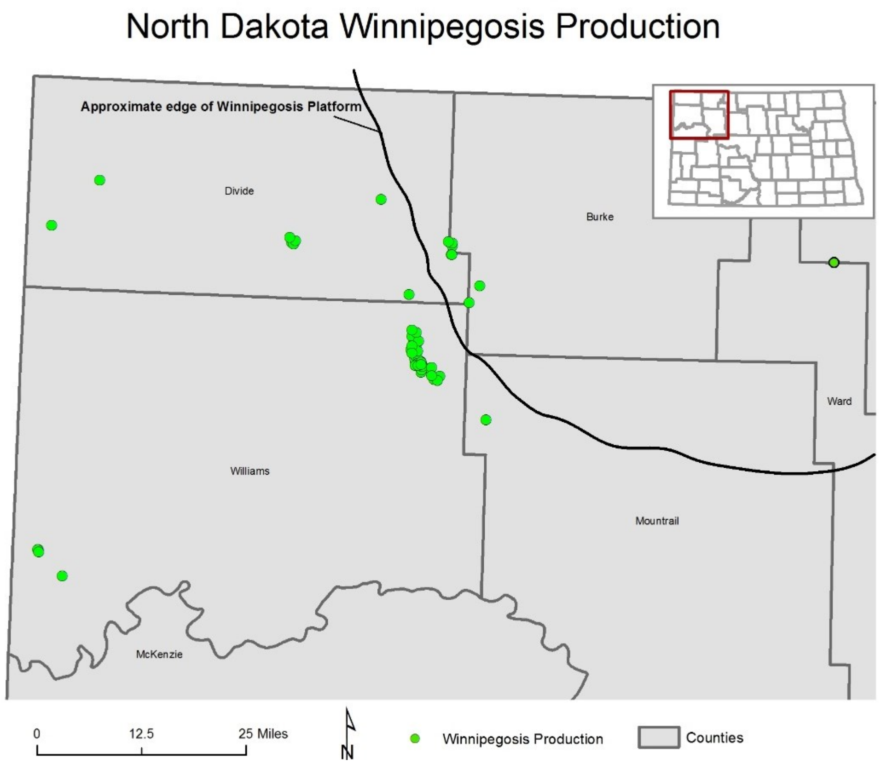

Figure 12. Map of Winnipegosis production in North Dakota.

CHAPTER III

TEMPLE FIELD CHARACTERIZATION

Temple Field is located on the western platform margin environment of the Winnipegosis Formation (Figure 13) and represents the eastern extent of platform progradation. Structural maps of the Prairie, Winnipegosis, and Ashern Formations show the field is located on a small north-south trending subordinate limb of the Nesson Anticline (Figure 14).

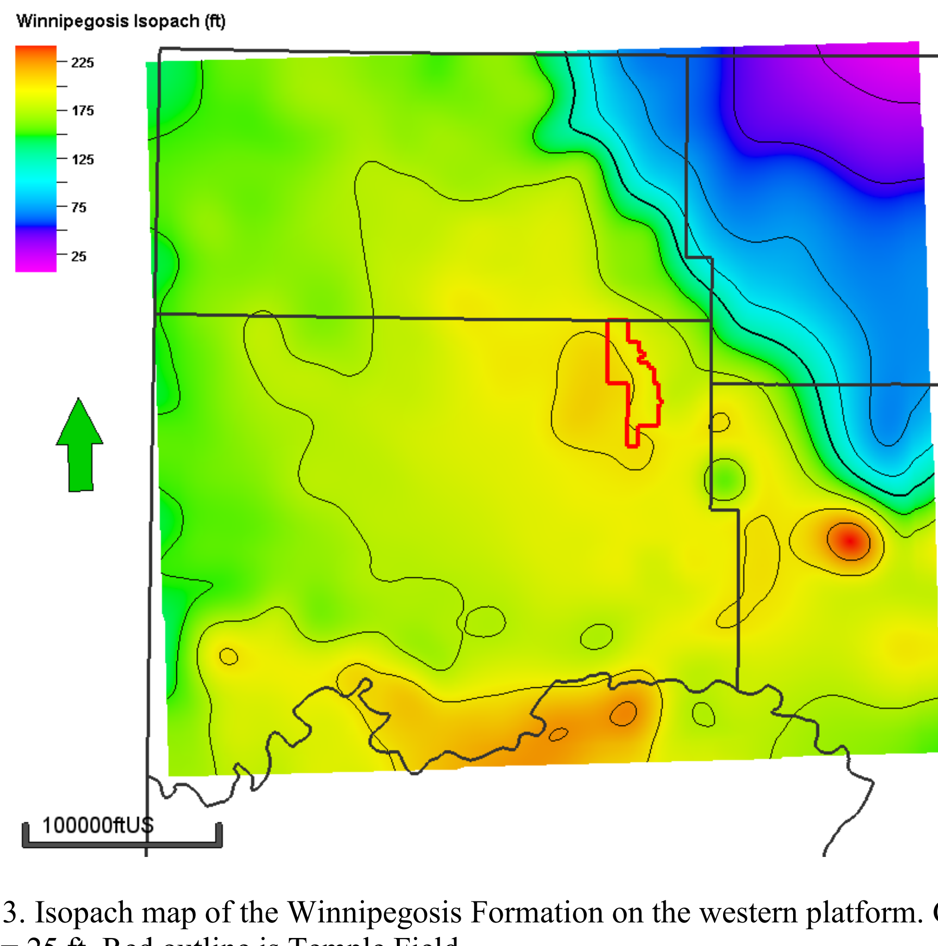

Figure 13. Isopach map of the Winnipegosis Formation on the western platform. Contour interval = 25 ft. Red outline is Temple Field.

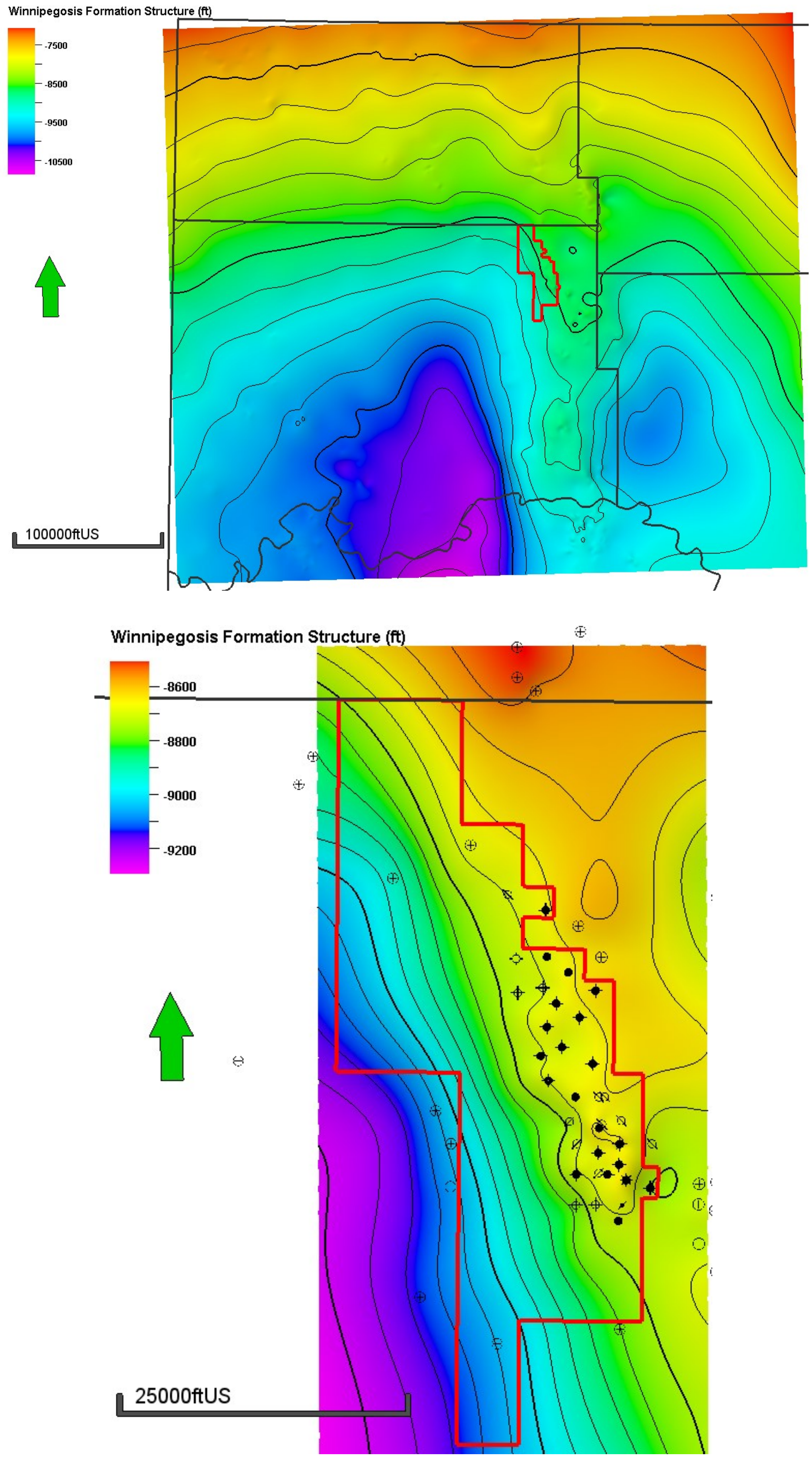

Figure 14. Structure contour maps of the Winnipegosis Formation. Top: Structure across northwestern North Dakota, Contour interval = 250 feet. Bottom: Structure in the study area, Contour interval = 50 ft.

Facies Descriptions

Temple Field has seven vertical cored wells in the Winnipegosis Formation, which were used in this study (Table 1). The cores for this study are all stored at the North Dakota Geological Survey Wilson M. Laird Core and Sample Library at the University of North Dakota. Cores were analyzed and described for facies identification. In addition, porosity and permeability data were used in calibration to petrophysical logs from the field.

Table 1. List of cores examined within Temple Field.

NDIC	Location	Original Operator	Original Well Name	Cored Interval
11893	SWNW 24-159-96	Dekalb Energy Co.	McCoy 12-24	11060-11121
10763	NWNE 23-159-96	Depco, Inc.	Sevre 31-23	11048-11107
10480	SENW 7-158-95	Depco, Inc.	Skarderud 22-7	11098-11205
10396	NENW 25-159-96	Depco, Inc.	Bronson 2-25	11065-11125
10209	SESW 6-158-95	Depco, Inc.	McGinnity 24-6	11082-11142
10059	SENE 1-158-96	Fulton Producing Co.	Grimsrud 1	11107-11159
3055	SENE 25-159-96	Depco, Inc.	Olga Thompson et al 1	11060-11140

The Winnipegosis Formation of Temple Field for this study was divided into nine facies. The uppermost eight facies are all part of the Upper Winnipegosis member and the lowermost facies comprises the Lower Winnipegosis member. The Upper Winnipegosis member within the field contains (in ascending order): Lower Slope, Alpha Marker, Brachiopod Wackestone, Porous Dolostone, Dolomitic Mudstone to Wackestone, Reef, Beta Marker, and Peritidal facies.

The entire vertical thickness of the Winnipegosis Formation has not been sampled by coring efforts within Temple Field. The reservoir facies within the field are located in the upper portion of the Upper Winnipegosis Member, thus cored samples have not been collected in the Lower Member. Facies that were not seen in the available Temple Field core were associated with facies described by Perrin (1987).

A cross section containing wells #10480 and #10396 (Figure 15) displays typical well log signatures for the facies described in this thesis.

Lower Winnipegosis Member

The Lower Winnipegosis Member is not seen in the available Temple Field core samples but has been penetrated by 21 wells in the field and averages 10 feet in thickness (Figure 16). This member is equivalent to Perrin's (1987) First Episode, and is composed of a brachiopod-crinoid mudstone facies. This member was deposited in the ramp setting prior to platform development in the formation.

The Lower Winnipegosis facies is separated from the Upper Winnipegosis by a thin unit possibly equivalent to the Brightholme member (Figure 15) described in Saskatchewan by Jin and Bergman (1999). In their study, Jin and Bergman (1999) described the Brightholme member as a dark brown-to-black, organic-rich shale deposited within deeper marine areas between pinnacle reefs. This facies is distinct in well logs by its increasing gamma ray signature. Within Temple Field, both of these facies are seen in well logs and interpreted as tight, low porosity limestones.

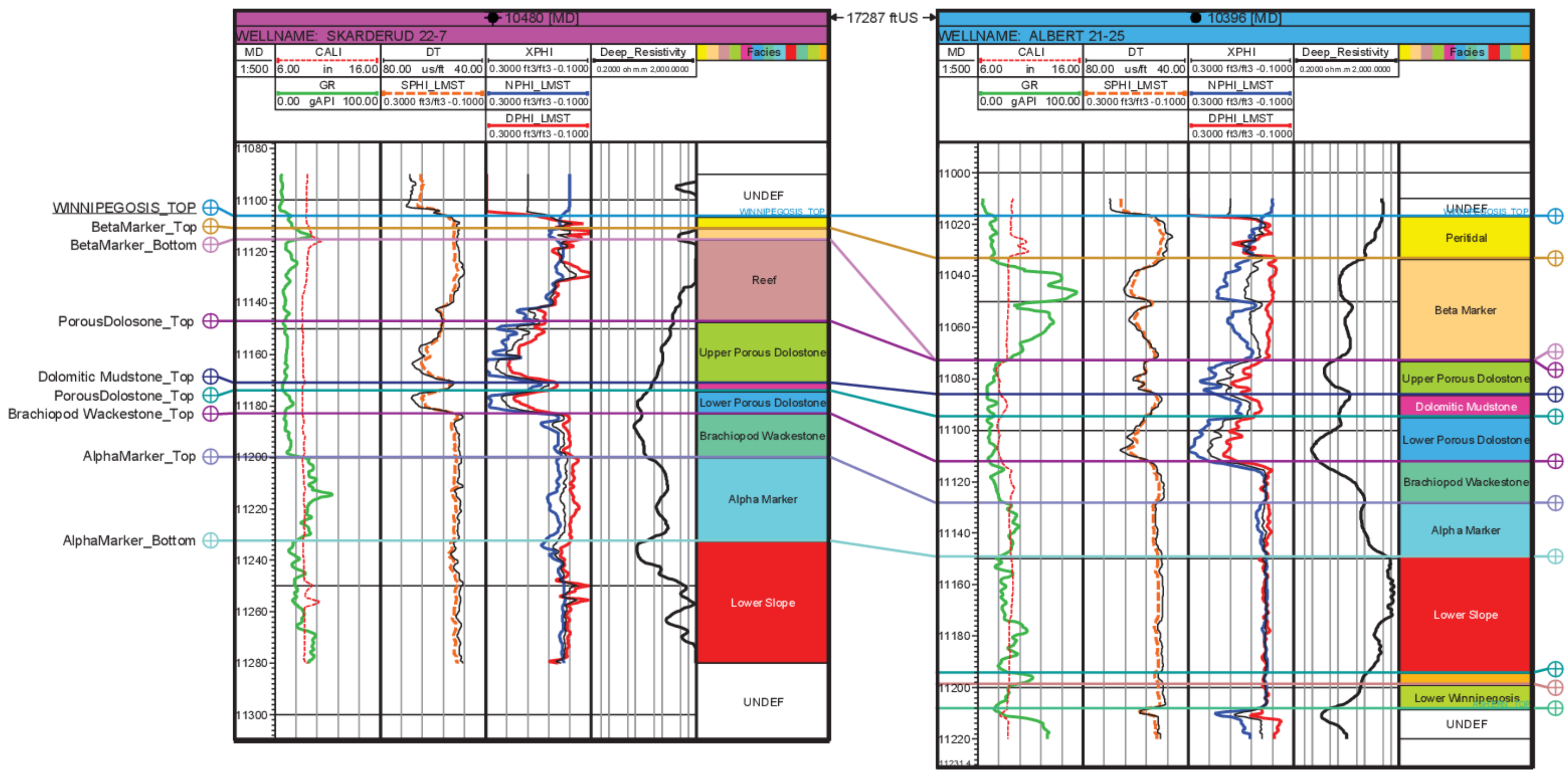

Figure 15. Well log signatures of the described facies within Temple Field.

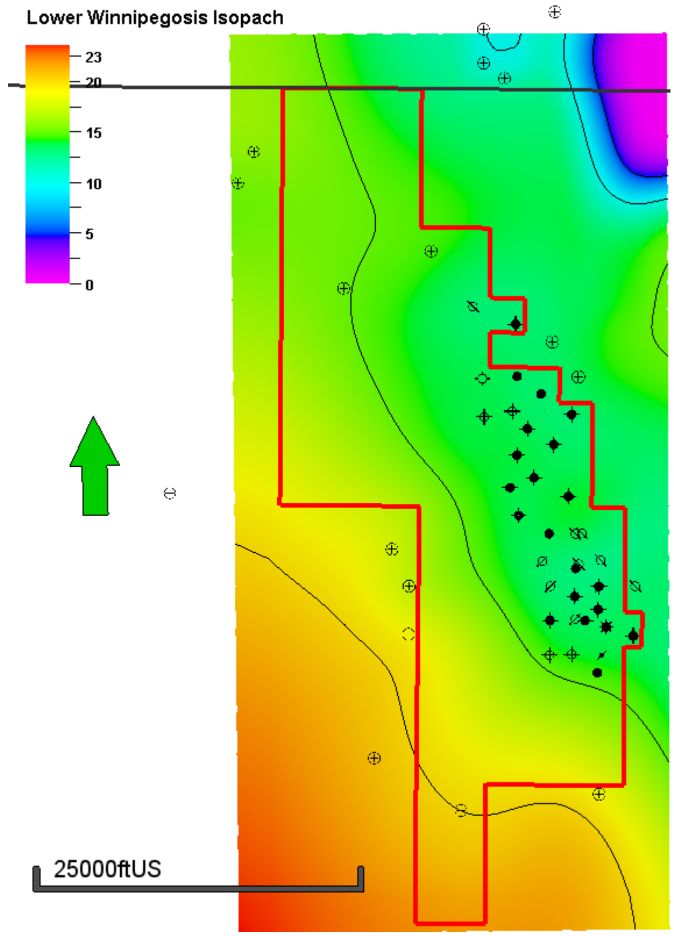

Figure 16. Isopach map of the Lower Winnipegosis Member. Contour interval = 5 ft.

Upper Winnipegosis Member

The Lower Slope facies are not seen in the available Temple Field core. This facies overlies the Lower Winnipegosis Member and is overlain by the Alpha Marker facies. This facies possibly represents the first deposits as the formation developed into a platform according to Perrin (1987) (Figure 17). Ehrets and Kissling (1987) correlate this member to a lower slope interpretation composed of similar fauna and flora to the overlying Alpha Marker. This member is a very tight limestone with little to no porosity in the study area based on well log interpretation (Figure 15).

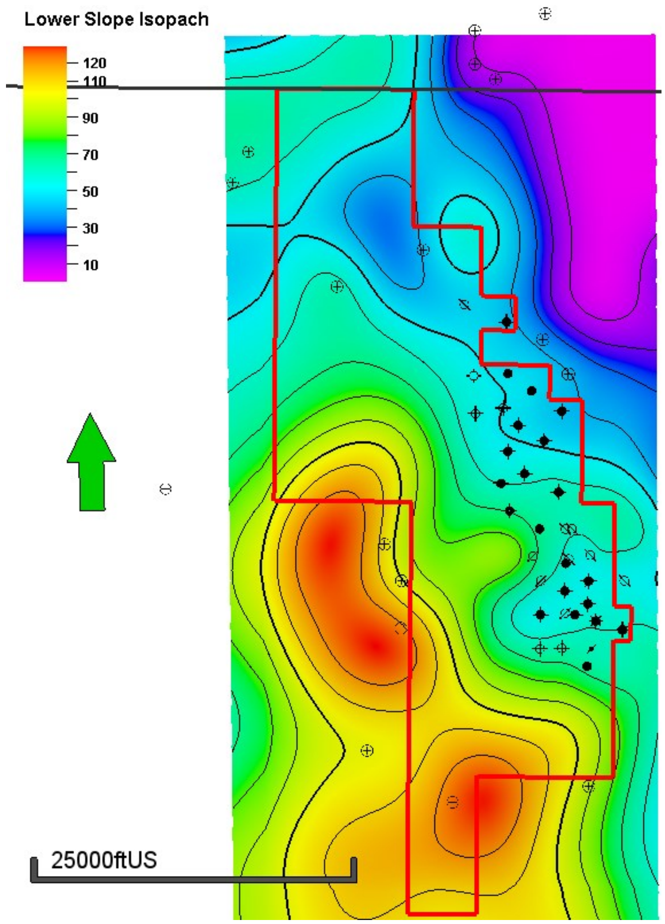

Figure 17. Isopach map of the Lower Slope facies. Contour interval = 10 ft.

The Alpha Marker facies (Figure 18 & 19) overlies the Lower Slope facies and is overlain by the Brachiopod Wackestone facies. The Alpha Marker has an increased argillaceous content compared to the overlying and underlying facies, which is distinguishable on logs by an increasing gamma ray signature and separation of the neutron-porosity and density-porosity logs (Figure 15). The Alpha Marker is a mottled dark gray to black wackestone, packstone to floatstone. Common brachiopod and oncolite intervals and rare corals make up the flora and fauna of the facies. The core porosity of the interval averages 0.8%. The Alpha Marker is one of the informal units known among operators as a “Winnipegosis shale”. This facies is thought to have been deposited during extrinsic events resulting from re-deposition of platform interior unlithified coastal mudflats deposits. Re-deposition of the interior mud was triggered either by slight lowering of sea level or by subtle uplift of the coastal mud flats.

Figure 18. Alpha Marker facies core photograph. (NDIC #10480, Depth: 11,201 ft)

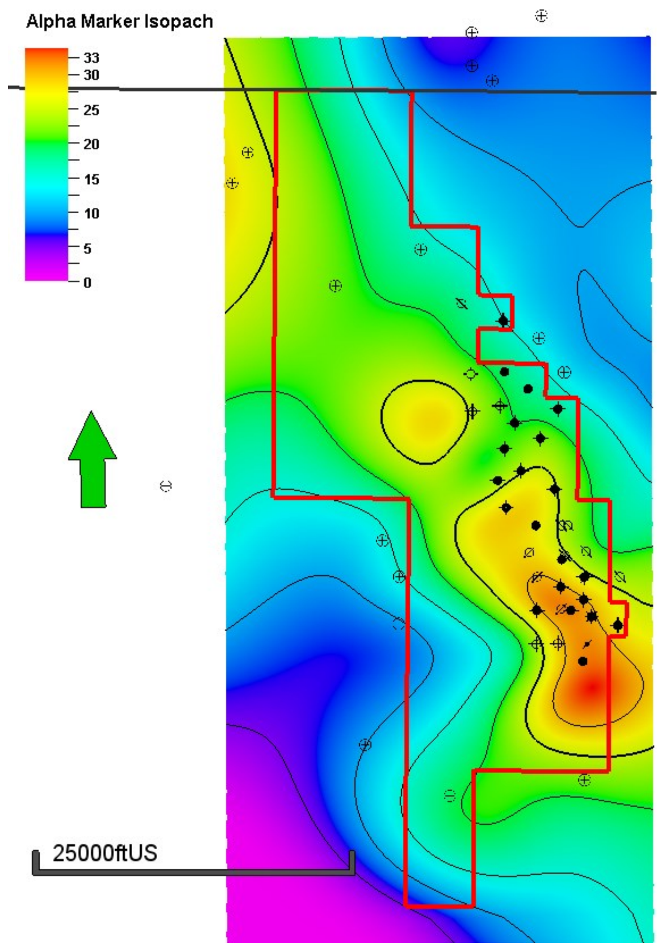

Figure 19. Alpha Marker facies isopach map. Contour interval = 5 ft.

The Brachiopod Wackestone facies (Figure 20) is a tight limestone on well logs (Figure 15). It overlies the Alpha Marker facies and is overlain by the lower Porous Dolostone facies. The Brachiopod Wackestone facies is a medium gray to dark gray wackestone to packstone. The facies has common brachiopods, rare stromatoporoids, rare stylolites, minor crinoids, and muddy laminations. Core measured porosity of the facies averages 2.8%.

Figure 20. Brachiopod Wackestone facies core photograph. Left: (NDIC #10209, Depth: 11,141 ft). Right: (NDIC#10480, Depth: 11,182 ft)

The Porous Dolostone facies (Figure 21 & 22) is the reservoir facies within Temple Field. This facies was divided into upper and lower portions with similar characteristics. The Dolomitic Mudstone to Wackestone facies if present separates the upper and lower Porous Dolostones in some parts of the field. The lower Porous Dolostone overlies the Brachiopod Wackestone facies and is overlain (where present) by the Dolomitic Mudstone to Wackestone facies. The upper Porous Dolostone overlies the Dolomitic Mudstone facies and is overlain by the Reef facies or the Beta Marker facies in the field. Allochems and matrix have been destroyed by dolomitization making them difficult to identify along with original texture.

The Porous Dolostone facies is a medium brown-to-dark brown dolomudstone to dolowackestone. This facies is composed of fine crystalline dolomicrospar-to-rare dolospar. Rare brachiopods, stromatoporoids, and stylolites, and a black rimming texture of organics or argillaceous material characterize the facies. This facies has a significant amount of oil staining and core measured oil saturation.

The dominant pore type is intercrystalline with some fracture porosity. Fractures within the facies contribute to overall permeability within these reservoir facies. Core measured porosity of the facies is variable, with an average of 11.4%.

Figure 21. Porous Dolostone facies core photographs. Left: (NDIC #10480, Depth 11,169 ft) Right: (NDIC #10209, Depth 11,132 ft)

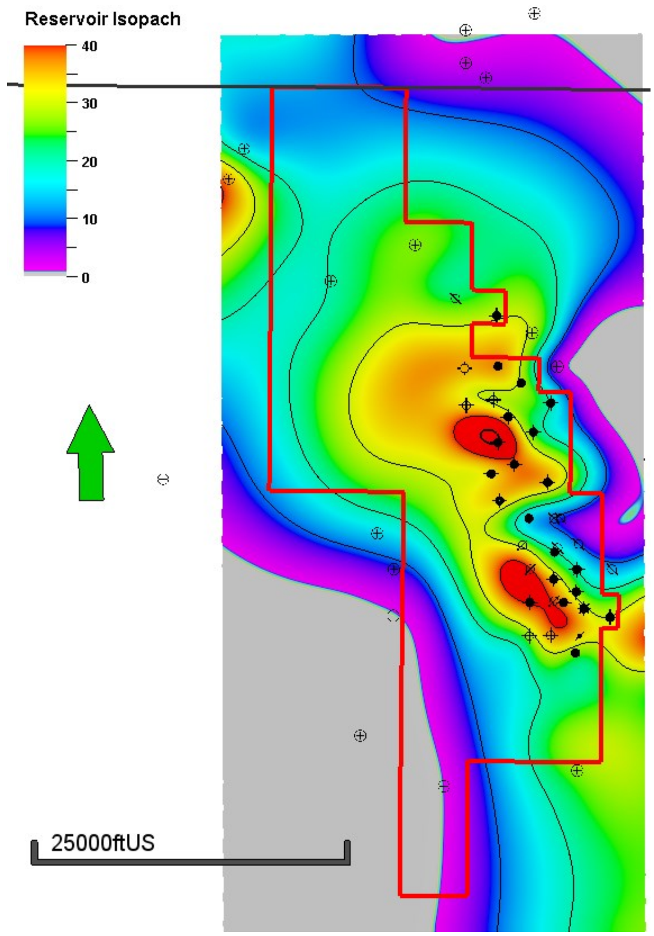

Figure 22. Isopach map of the reservoir facies. Contour interval = 10 ft.

The Dolomitic Mudstone to Wackestone facies (Figure 23) overlies the lower Porous Dolostone facies and is overlain by the upper Porous Dolostone facies. This facies is a medium gray-to-brown mudstone to wackestone. This facies varies in dolomitic content throughout the field and is indistinguishable in some well within the field. Texture of the facies is mottled in dolomitic intervals where fossil content is rare, with an increased fossil assemblage in the less dolomitic intervals. In areas with significant dolomitization, it is associated with the Porous Dolostone facies. Core measured porosity of this facies averages around 7.4%.

Figure 23. Dolomitic Mudstone to Wackestone facies core photograph. (NDIC #10209, Depth: 11,129 ft)

The Reef facies (Figure 24 & 25) overlies the upper Porous Dolostone facies and is overlain by the Beta Marker facies or the Peritidal facies. The Reef facies is mainly composed of a dark gray-to-dark brown stromatoporoid-coral boundstone/floatstone with fossil assemblages decreasing upward into a wackestone. The Reef facies is abundant with stromatoporoids, rugose corals, bryozoans, corals, and rare brachiopods and crinoids. This member was described by Ehrets and Kissling (1987) as a platform margin reef with a reef flat, reef crest, and fore reef. Based on well logs the Reef facies is a very tight limestone with very low porosity, which increases in the lower few feet of the facies (Figure 15). Core samples from Wells #10480 and #10209 contain the reef facies in

Temple Field and show slight oil staining. Halite and anhydrite content is minor in the upper portions of the Reef facies but does increase up section. Core measured porosity within this facies averages 2.5% but can be greater in the lower portion of the facies.

Ehrets and Kissling (1987) interpreted that this member was lithified soon after deposition which allowed it to remain a limestone unit. Early solidification and low porosity of this facies created a caprock for the field above the dolostone reservoir.

Figure 24. Reef facies core photographs. Left: (NIDC #10480, Depth 11,120 ft) Right: (NDIC #10209, Depth 11,105 ft)

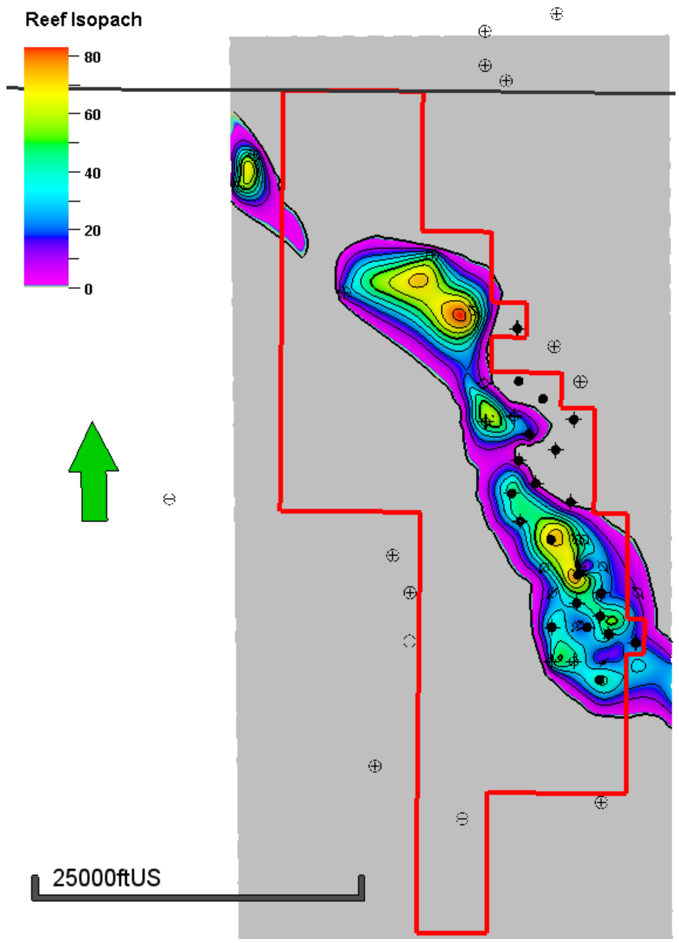

Figure 25. Isopach map of the Reef facies. Contour interval = 10 ft.

The Beta Marker member overlies the upper Porous Dolostone facies or the Reef facies and is overlain by the Peritidal facies. The Beta Marker is distinguishable on well logs by its increasing gamma ray signature and separation of the neutron-porosity and density-porosity logs (Figure 15), similar to the Alpha Marker facies. The Beta Marker facies (Figure 26) lithology varies from a mudstone, wackestone, or packstone facies that is dark gray-to-black in color. This facies is composed of minor brachiopods with brachiopod content increasing towards the bottom of the facies. This facies also has a fissile appearance similar to shale.

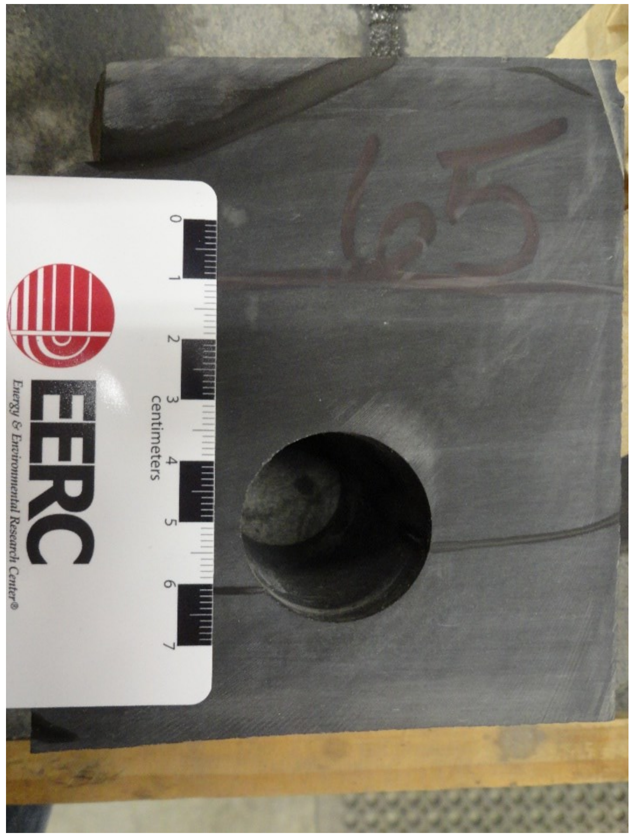

Figure 26. Beta Marker facies core photograph. (NDIC #11893, Depth: 11,065 ft)

The Beta Marker can be found along the platform margin of the western geographic province. This facies was thought to have been deposited in conditions similar to the Alpha Marker (Ehrets and Kissling, 1987). Where the Reef facies is absent on the eastern side of the field, the Beta Marker is the caprock, and overlies the upper Porous Dolostone. This unit is thickest towards the basin and thins moving onto the platform (Figure 27). This facies has also been informally known among operators as a “Winnipegosis shale”. The Beta Marker occurs in cored wells #11893, #3055, #10396, and #10480. Core measured porosity of this facies varies, with an average of 4%.

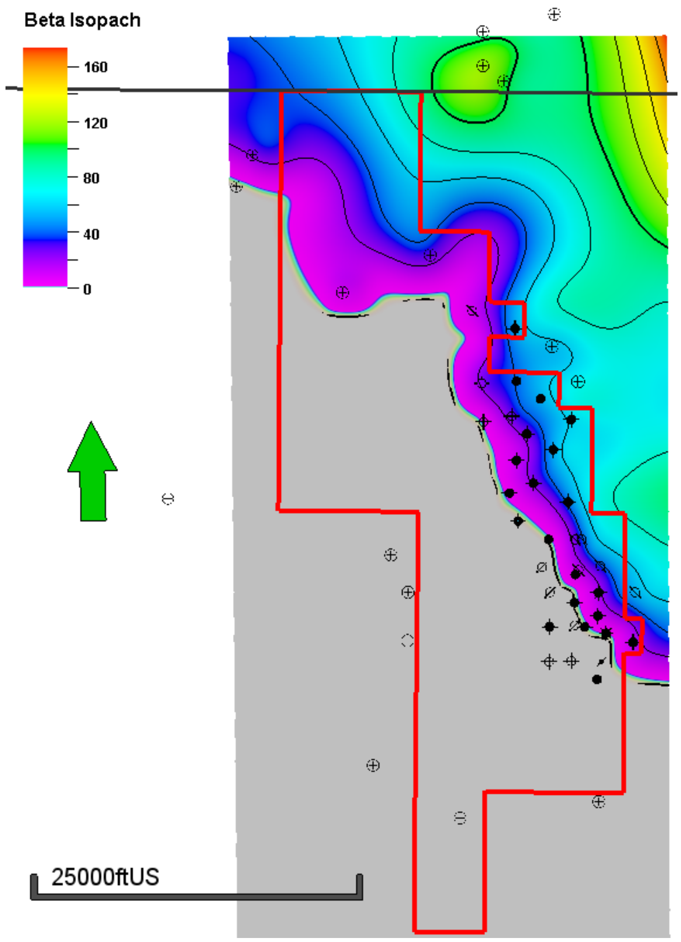

Figure 27. Isopach map of the Beta Marker facies. Contour interval = 20 ft.

The Peritidal facies overlies the Beta Marker facies and the Reef facies and is overlain by the Prairie Formation. The Peritidal facies is a transitional unit within the field between the Winnipegosis Formation and the evaporites of the Prairie Evaporite Formation. This facies thickens from the field toward the platform margin and the deep marine environments (Figure 28). One well within Temple Field contains core from this interval: Well #10480. This facies is a light brown-to-dark brown dolomudstone. This facies is laminated (Figure 29), and has common anhydrite and halite with a minor vuggy porosity. Core measured porosity for this facies averages around 0.9%.

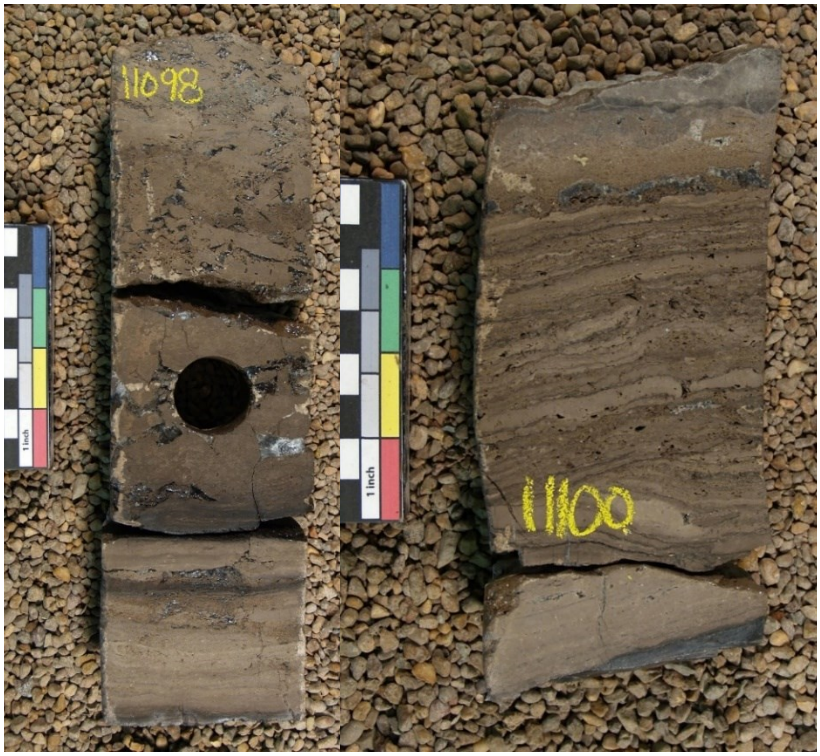

Figure 28. Peritidal facies core photographs. (NDIC #10480, Depth: 11,098 ft & 11,100 ft)

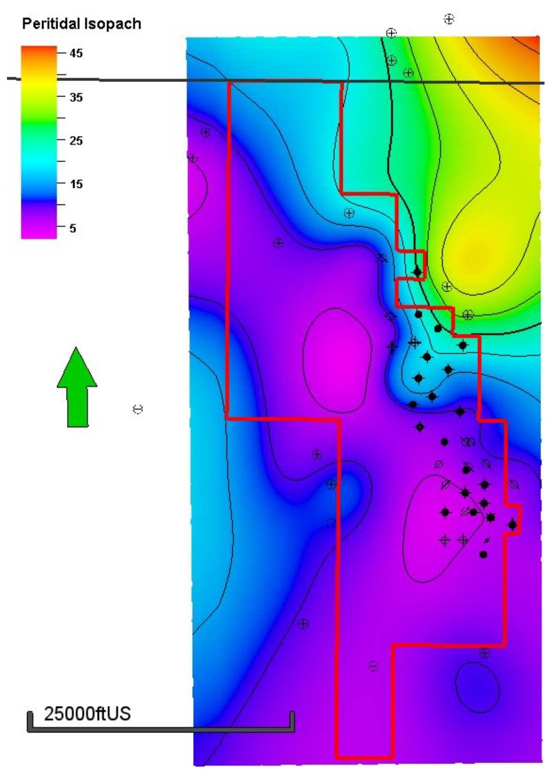

Figure 29. Isopach map of the Peritidal facies. Contour interval = 5 ft.

Reservoir

The reservoir of Temple Field is the dolostone facies of the platform margin. These dolostones are similar to the Porous Dolostones described by Perrin (1987). Porosity within the dolostones in the field trends parallel to the platform margin and pinches out down slope toward the deep marine environment (Figure 30).

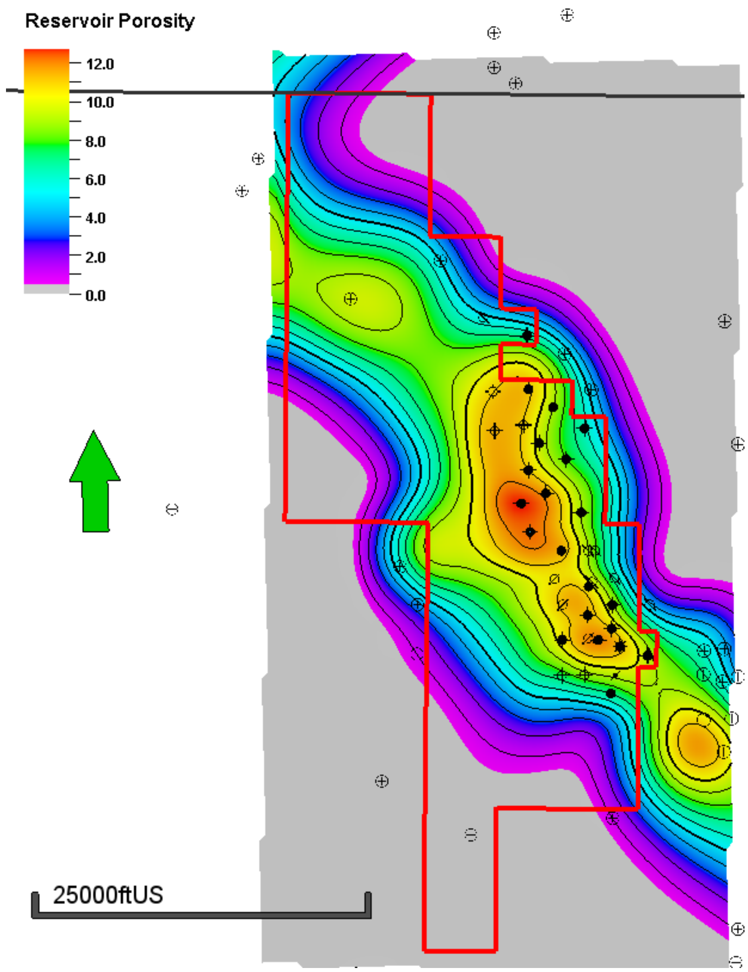

Figure 30. Temple Field reservoir porosity pinchout map. Contour interval = 1%.

Dolomitization of the reservoir took place with the regression of the sea exposing the platform environment. Meteoric water flowed into the deeper basin due to hydraulic head differences between the platform margin and the basin. Early lithification of the reef facies also provided direction for dolomitizing fluids into the slope facies and played a role in limiting the invasion of halite into the reservoir.

Production from the formation in the field is greatest in wells located on the crest of the anticline (Figure 31). The highest porosity values within the field also correlate to the highest production. Wells with low production on the eastern side of the structure are near the porosity pinchout.

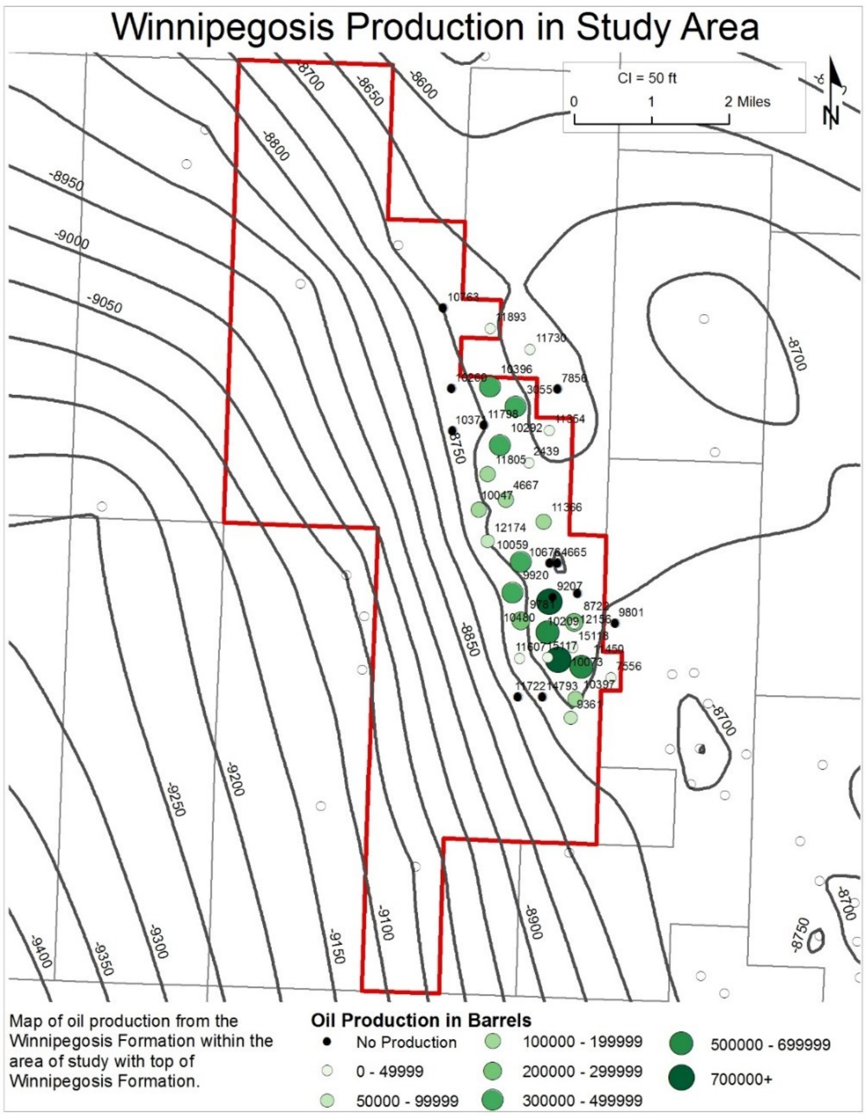

Figure 31. Temple Field production map. Contour lines represent the top of the Winnipegosis Formation.

CHAPTER IV

WELL LOG INTERPRETATION

Forty wells have been drilled into the Winnipegosis Formation of Temple Field, all with vertical penetrations. After determining log availability and data quality of Winnipegosis logs in the study area, 36 wells were chosen from Temple Field for log calculations and interpretation. Additional wells surrounding the study area were also used to minimize edge effects on property distributions.

All the wells used for calculations have logging suites that includes gamma ray, caliper, neutron-density, and resistivity logs. Twenty-five wells also have a sonic log available. Well logs were digitized and formation top were picked for all wells. These data were then input into Petrel to construct geologic maps, create cross sections, and for facies and petrophysical modeling of the Winnipegosis Formation within the study area. Facies logs were also created for all wells.

Petrophysical Analysis

Petrophysical analysis is used to correlate digital well log properties and core measured properties of identified facies. Correlation of core porosity with well log porosity allowed for corrections of well log porosity values based on core analysis measurements, which usually are found to better represent the formation properties. Since well log data were more abundant in the field, they were corrected by core data.

While using well log porosity values it is important to make necessary corrections for accurate petrophysical modeling if laboratory measurements are available.

Core data was available for seven cored wells containing porosity, permeability, oil saturation, and water saturation. Core analysis measurements were digitized and depth shifted to match with their respective wells. In order to be more accurate with permeability analysis, core permeability values, which were associated with fractures, were removed from the data to prevent over estimation of permeability. Core measurements were then plotted with respect to the facies they represent (Figure 32).

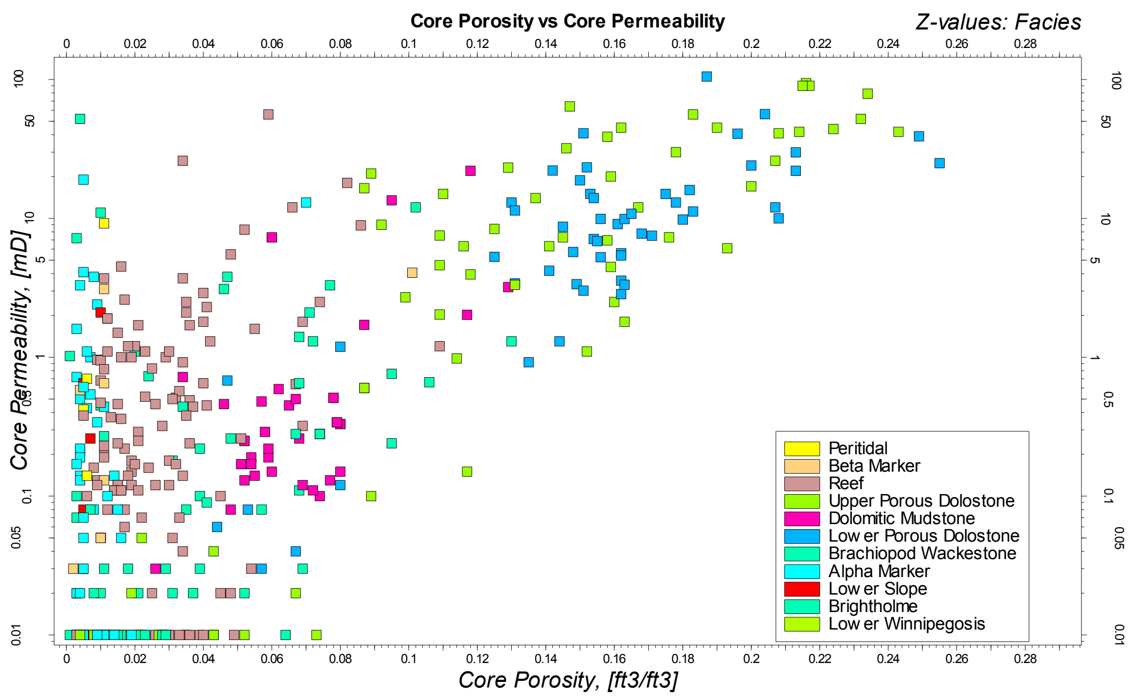

Figure 32. Core porosity and permeability crossplot by facies.

Porosity Corrections

Correcting the log porosity values with core porosity data is very important. All neutron and density porosity logs were referenced in limestone units. The porosities within the dolostone reservoir of Temple Field needed to be corrected based on a dolostone matrix to represent the true porosity values. The neutron porosity and density porosity logs were corrected in the upper and lower Porous Dolostone intervals within Temple Field in order to represent effective porosity values.

The neutron porosity values were corrected based on lithology using the Schlumberger chart Por-5 (Schlumberger, 2013). Density porosity values were corrected using the formation density log and dolostone matrix values. The neutron and density porosity logs were then averaged together to create one porosity log for property modeling. It was found that averaging the neutron and density porosity values gave the best correlation compared to core porosity data (Figure 33).

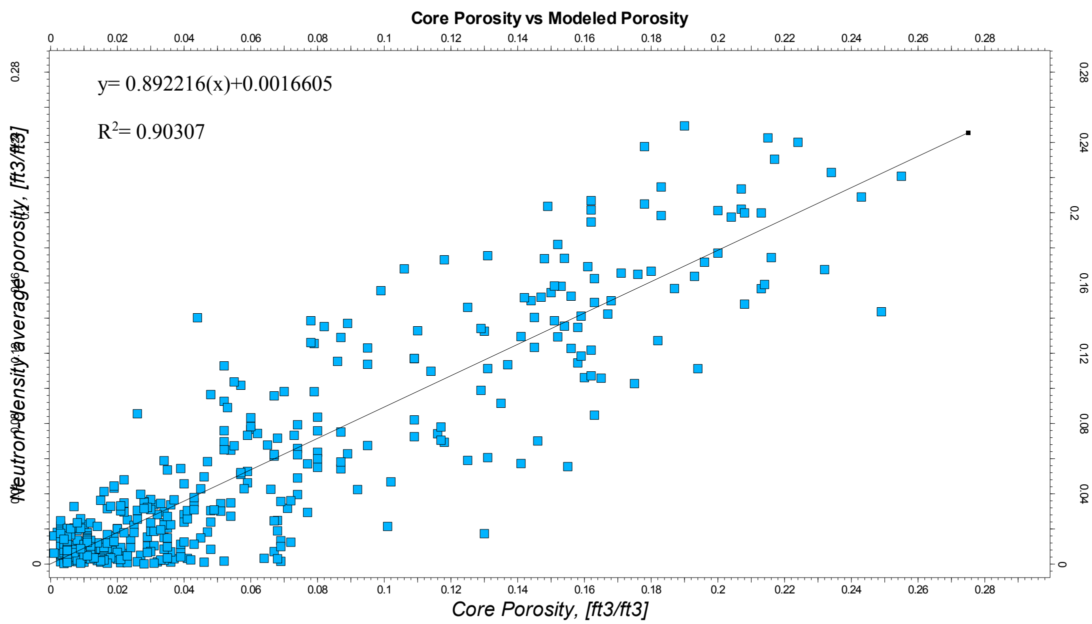

Figure 33. Core porosity and neutron-density average porosity crossplot.

Archie's Water Saturation

Water saturation (Sw) was calculated using the Archie's equation:

$$Sw=\sqrt[n]{\frac{Rw}{\phi^{m}Rt}}$$

Water resistivity (Rw) that was used in the model was set to 0.019 Ω.m and was determined from water analysis from the field in the lab. This value is the corrected water resistivity to the reservoir temperature. Deep resistivity well logs were used to represent the true resistivity (Rt) of the reservoir and neutron-density average porosity (ϕ) of the reservoir in the Archie equation. Based on the industry practice, saturation exponent (n) and cementation factor (m) equal to 2 were used for both.

CHAPTER V

GEOCELLULAR MODELING

Data

Geocellular modeling of the study area was completed with the Schlumberger software Petrel. The first step in modeling was to load all of the available data from the NDIC website. Data included well locations, well names, well identification number (NDIC & API), Kelly bushing elevation, digital well logs, and formation tops. All previously picked formation and facies tops were also input into the program. All wells in the study area are vertical wells so no directional surveys for well trajectory were included.

Grid Development

The structural grid of the model was built using formation structural surfaces of the Winnipegosis and Ashern Formations. The surfaces were then used in creation of the structural model, which included the thickness of the three-dimensional grid of the Winnipegosis Formation (Figure 34). The grid was then used for population of the lithologic and petrophysical properties.

A grid cell size of 100 feet by 100 feet was chosen to accommodate computer runtime and allow accurate results at the same time. Grid spacing can be computationally time and computer memory intensive, if the grid size is too small. The chosen cell size allowed for reasonable computation times and accuracy of the model results.

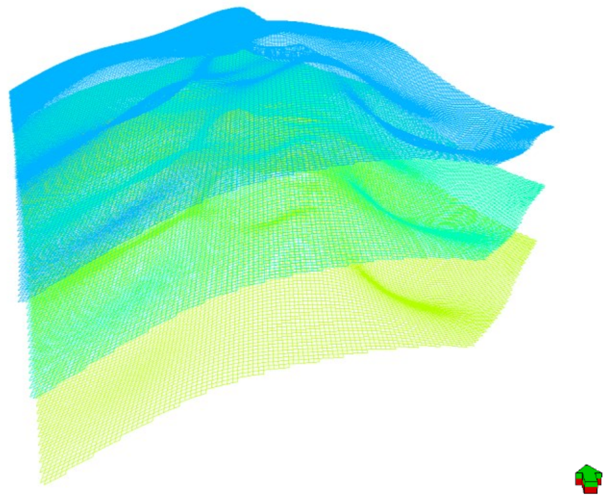

Figure 34. Petrel cellular grid.

After the structural grid was created, several zones were defined to increase the vertical layering resolution of the grid. Each zone in the Winnipegosis Formation was defined with conditioning to facies. Ten zones in total were built proportionally along true vertical thickness from the top of the Winnipegosis Formation to the top of the Ashern Formation (Figure 35).

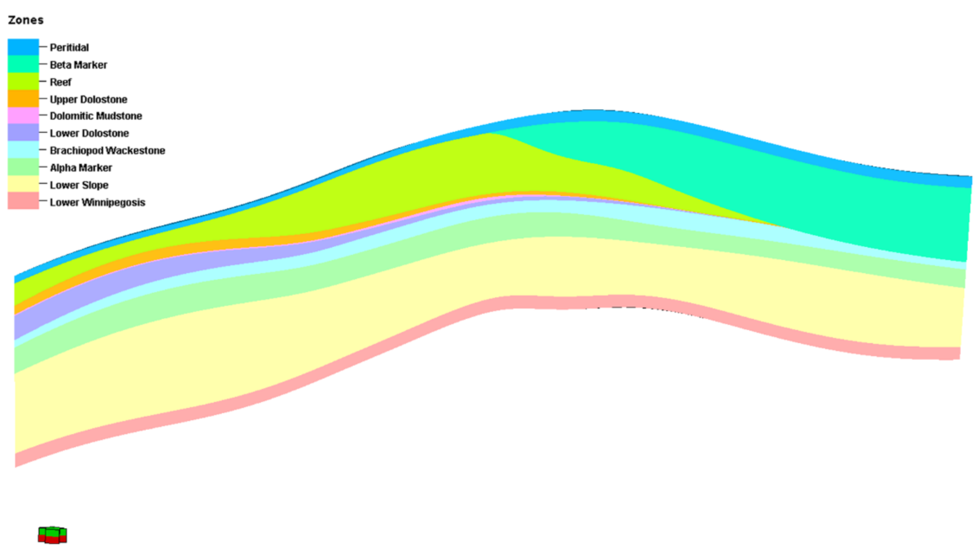

Figure 35. Defined zones in the structural grid.

Layering was the final step in representing the vertical resolution of the grid. Layering was used to divide the zones into smaller cells and define the vertical resolution within each zone. Vertical resolution of the grid and the number of layers in each zone was set to accurately model the vertical heterogeneity of each zone. Zones of importance, such as those that contained hydrocarbons, were given more layers. This allowed for better results in the zones of interest.

Proportional layering was used which divided each zone into a defined number of layers evenly (Table 2 & Figure 36). The most important zones in this study were the Porous Dolostones and the Dolomitic Mudstone due to their importance in being the reservoir zones. Average layer thickness for the reservoir zones was roughly 1.5 feet.

Table 2. Number of layers defined for each zone.

Zone	Number of Layers
Peritidal	10
Beta Marker	10
Reef	18
Upper Porous Dolostone	5
Dolomitic Mudstone	5
Lower Porous Dolostone	5
Brachiopod Wackestone	5
Alpha Marker	5
Lower Slope	12
Lower Winnipegosis	5

Vertical variograms were used to inform a decision of proper layer thickness for each zone based on the methods proposed by Schlumberger (Petrel, 2011). In this model vertical resolution was below half of the interpreted vertical range, which is recommended by Schlumberger.

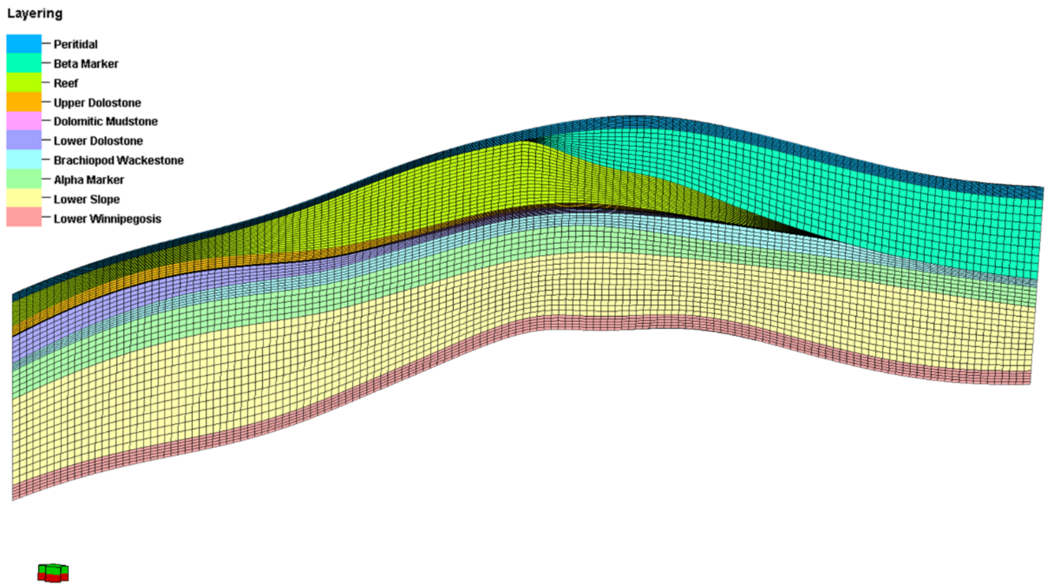

Figure 36. Layering of the model grid.

Facies Modeling

Facies modeling was completed with the previously defined facies of the Winnipegosis Formation based on core analysis. The described cored wells within the field were tied to well log signatures in order to assign facies to each well. Ten facies of the Winnipegosis were defined in the geological modeling of Temple Field. The reservoir facies of the formation were well represented by core in the field, which allowed for greater quality of facies modeling. Non-reservoir facies without core representation were also included in the modeling. These facies were decided based on previous studies of the Winnipegosis Formation. Facies tops for each well were chosen based on core description and well log signatures. Facies logs were then created for each well for the entire Winnipegosis

Formation. Facies top surfaces were then used to define the zones within the model structure and to populate the model with associated facies within each zone (Figure 37).

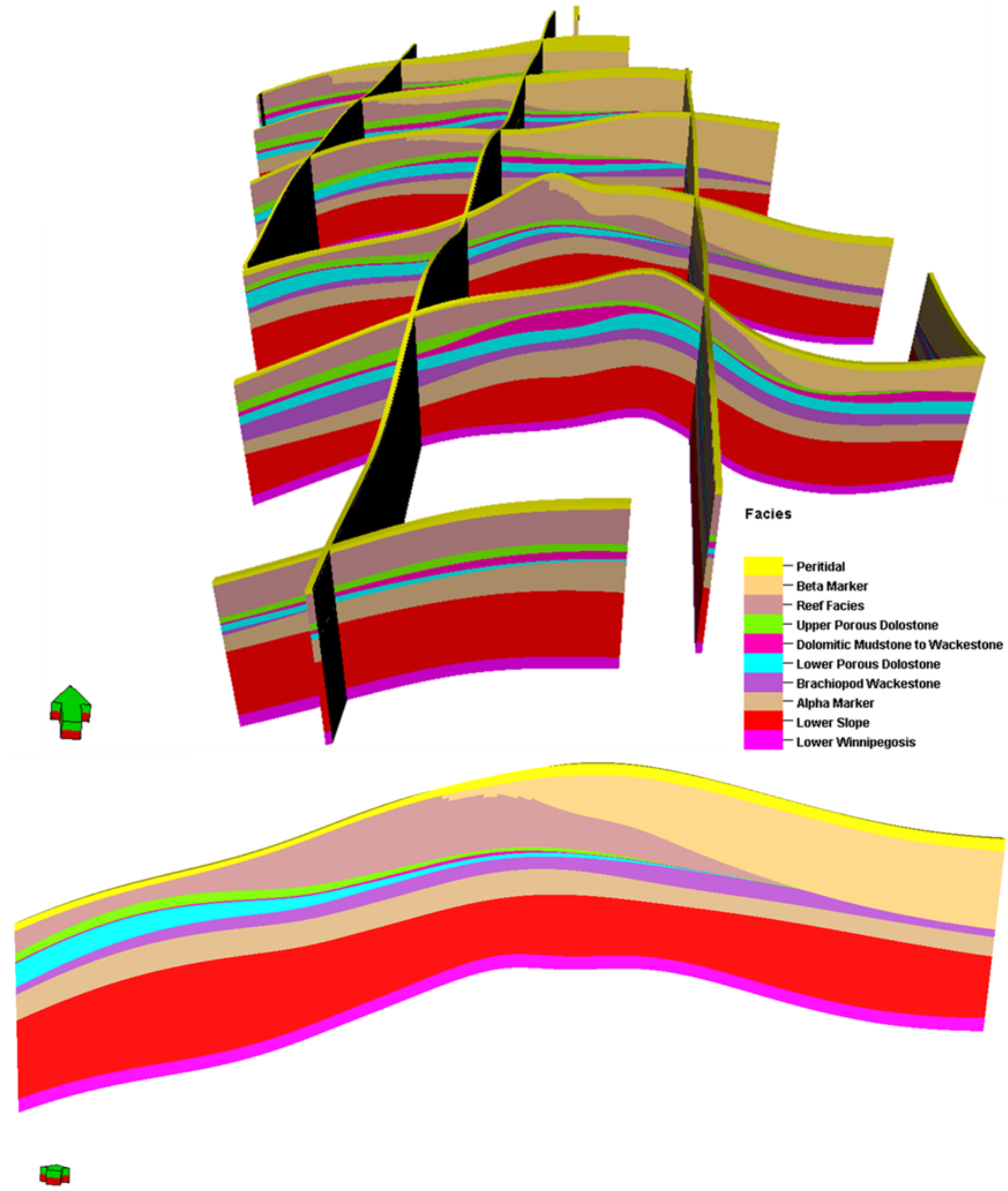

Figure 37. Three-dimensional facies model of the study area.

Petrophysical Modeling

Petrophyscial modeling is the process of filling the cells in the grid with petrophysical properties. The goal of petrophysical modeling is to distribute properties based on mathematical extrapolation between the wells to preserve heterogeneity. The petrophysical properties modeled were porosity and permeability.

Petrophysical modeling may be achieved under deterministic and stochastic algorithms depending on the modeling goals and available data. Deterministic methods work best for dense data sets and create one result from the data. Stochastic methods are best where sparse data is present and can be used to create multiple equally probably realizations. Both the deterministic and stochastic methods use variogram based approaches for property distribution. The variograms allow anisotropy to be introduced into the model based on geostatistical dependencies between the wells. Deterministic and stochastic methods were both used in this study to compare the results obtained from each method. Kriging was used as the deterministic method and Gaussian Random Function Simulation (GRFS) was used as the stochastic method for property modeling.

To distribute the properties in each zone, variogram analysis was performed for each zone in order to understand the variability of each zone. Variogram maps were created in order to determine the major and minor directions for variogram anisotropy. The variogram maps displayed an orientation of roughly 336 degrees, which is similar to the trend along the platform margin. This was expected in this depositional environment, the least amount of variability should be parallel to the platform margin (parallel to depositional strike) and the greatest variability perpendicular to the margin (parallel to depositional dip). Variogram analysis was performed with normal score transformation of the data in each direction (Figure 38). Variograms of each facies can be found in Appendix B. The variogram is used to control the property distribution between known data points. The variograms for each facies all have the same nugget and sill equal to 1 in all directions.

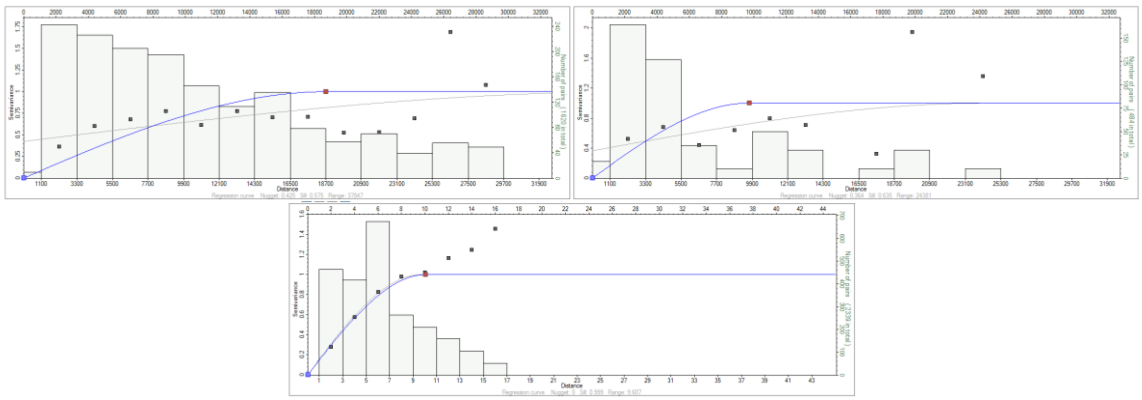

Figure 38. Example variograms in each direction. Left: major. Right: minor. Bottom: vertical.

The next step of petrophysical modeling was to scale up the well logs based on the structural grid. Upscaling of logs is a process in which values are assigned to each cell in the three dimensional grid where the corresponding well is penetrated. Each grid cell is assigned one value based on the averaging method. Porosity was upscaled with the arithmetic mean, using the neighbor cell method. The neighbor cell method assigns one single value to each cell penetrated by the corresponding well path based on the averaged value in that cell. Logs were treated as points, which means only the points inside the cell were input for averaging.

Porosity Model

The porosity model was created using the corrected neutron-density average porosity. Average porosity was upscaled into the grid and distributed using Kriging and

GRFS. Both algorithms were used in order to compare the deterministic and the stochastic method outputs.

The modeled Kriging porosity values varied from 0.1% to 25% with an average of 3.5% for the entire model. Reservoir porosity values in the upper Porous Dolostones were 0.1% to 24% with an average of 10%. Reservoir porosity in the Dolomitic Mudstone ranged from 0.1% to 19% with an average of 7%. The porosity of the lower Porous Dolostone was found to vary from 0.1% to 25% with an average of 11%.

GRFS porosity distribution values ranged from 0.1% to 27% with a mean of 3.5% for the entire model. The upper Porous Dolostone porosity ranged from 0.1% to 26% with an average of 10%. Porosity in the Dolomitic Mudstone ranged from 0.1% to 21% with an average of 7%. The lower Porous Dolostone interval porosity was from 0.1% to 27% with an average of 11%.

GRFS porosity values were slightly higher for each facies. This is due to the fact that GRFS honors the original data more effectively than Kriging and does not create a smooth distribution.

The highest porosity within the field is found within the dolostone reservoir facies as shown in Figure 39 & 40.

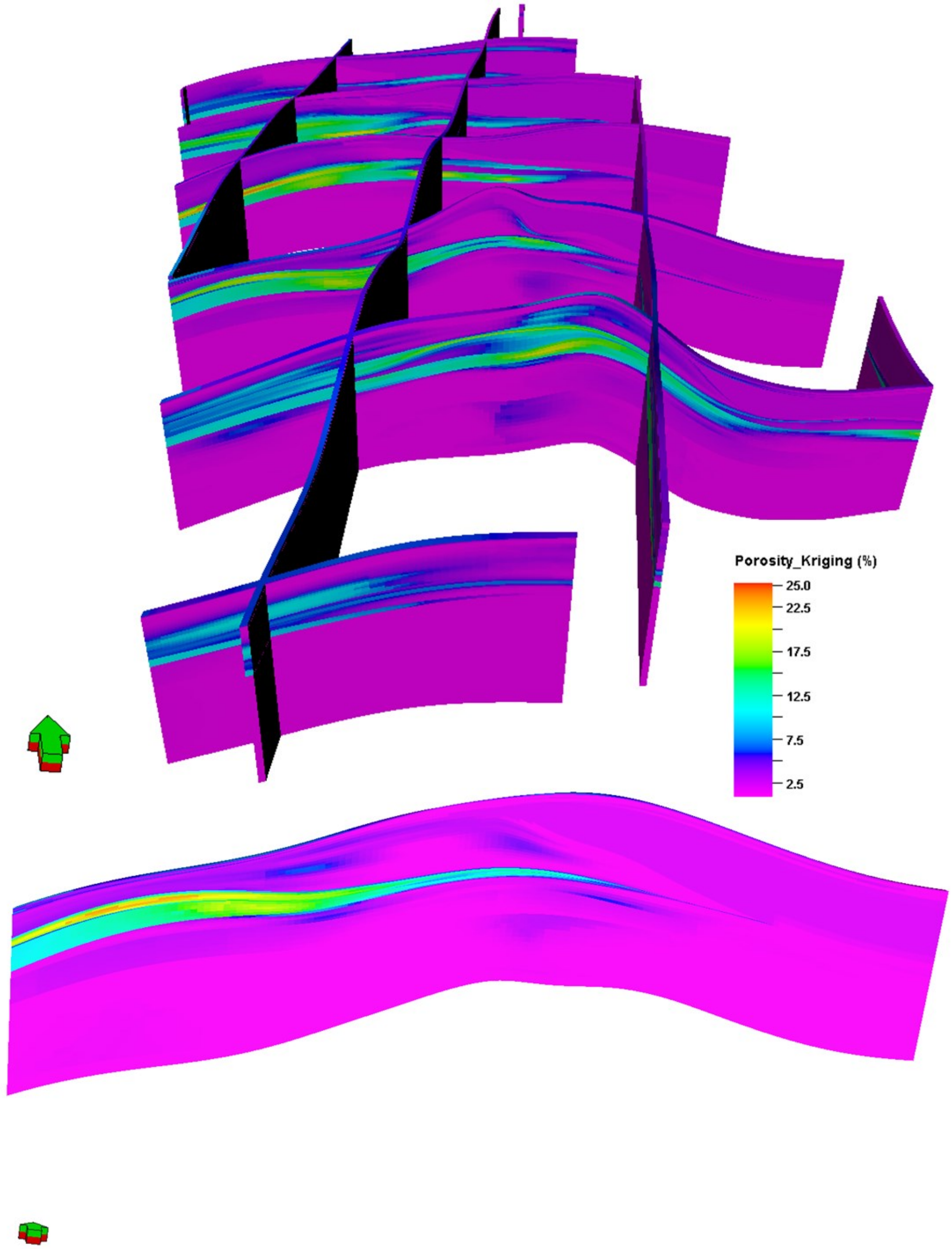

Figure 39. Porosity distribution with Kriging.

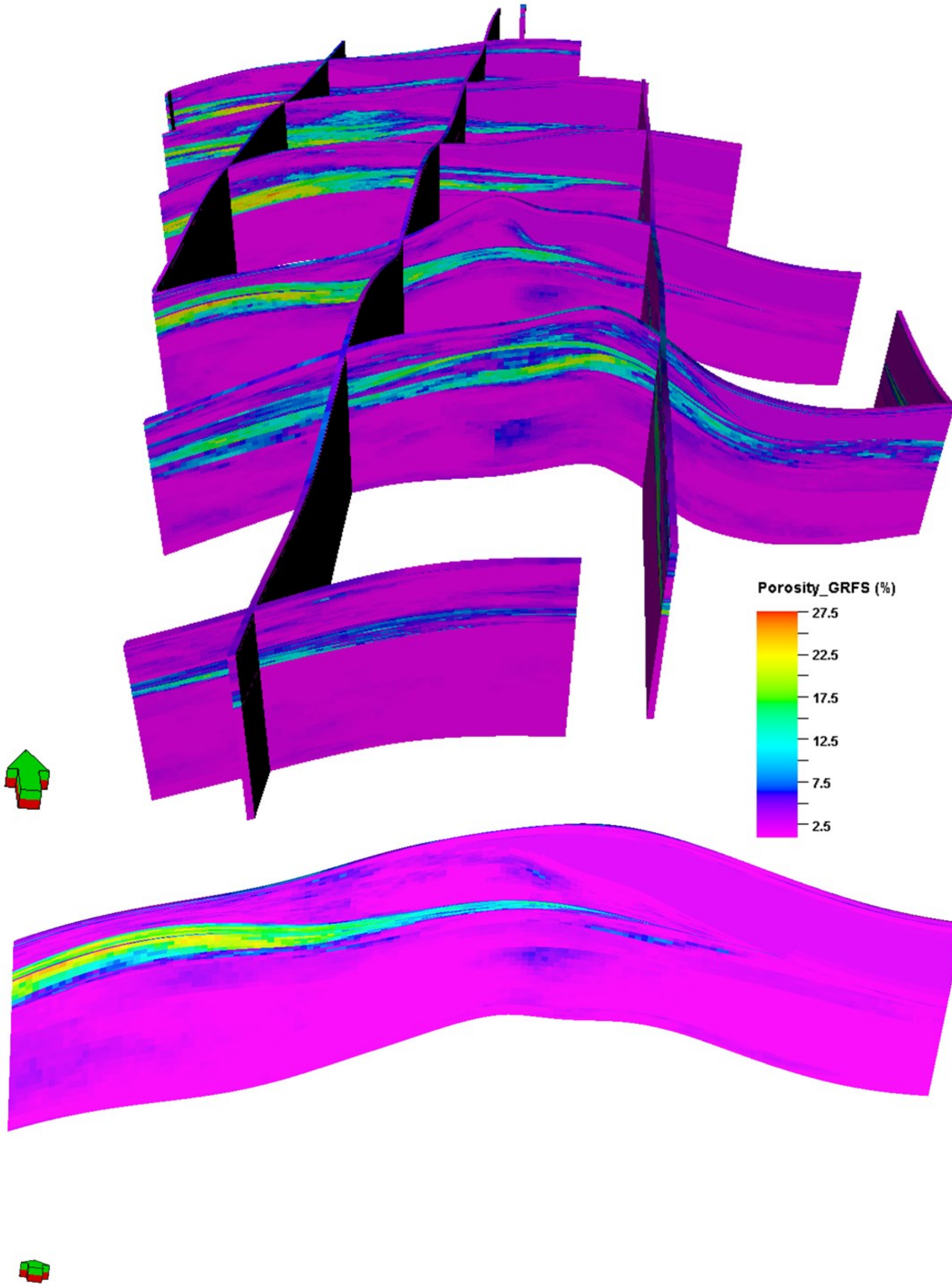

Figure 40. Porosity distribution with GRFS.

Permeability Model

Permeability modeling was completed slightly different than porosity modeling due to the lack of permeability data which was found only in the cored wells.

To model permeability values, the GRFS was used with a bivariate distribution method. Permeability was distributed using the same variograms from the porosity distributions within each facies. The bivariate method used the core measured porosity/permeability crossplot relationships for each facies along with the previously modeled porosity to distribute the permeability property. This method allowed for more heterogeneity to be created in the models than a linear porosity/permeability relationship. Permeability was modeled for the employment of the Kriging porosity distribution (Figure 41) and the GRFS porosity distribution (Figure 42). Crossplots of the modeled porosity and permeability distribution match the core porosity and permeability distributions fairly well (Figure 43).

Water Saturation Modeling

Water saturation was modeled using the upscaled Archie calculated water saturation log. The Kriging algorithm was applied to the data since water saturation should be modeled as a smooth property. Water saturation modeled values were used as input in volumetric calculations for OOIP.

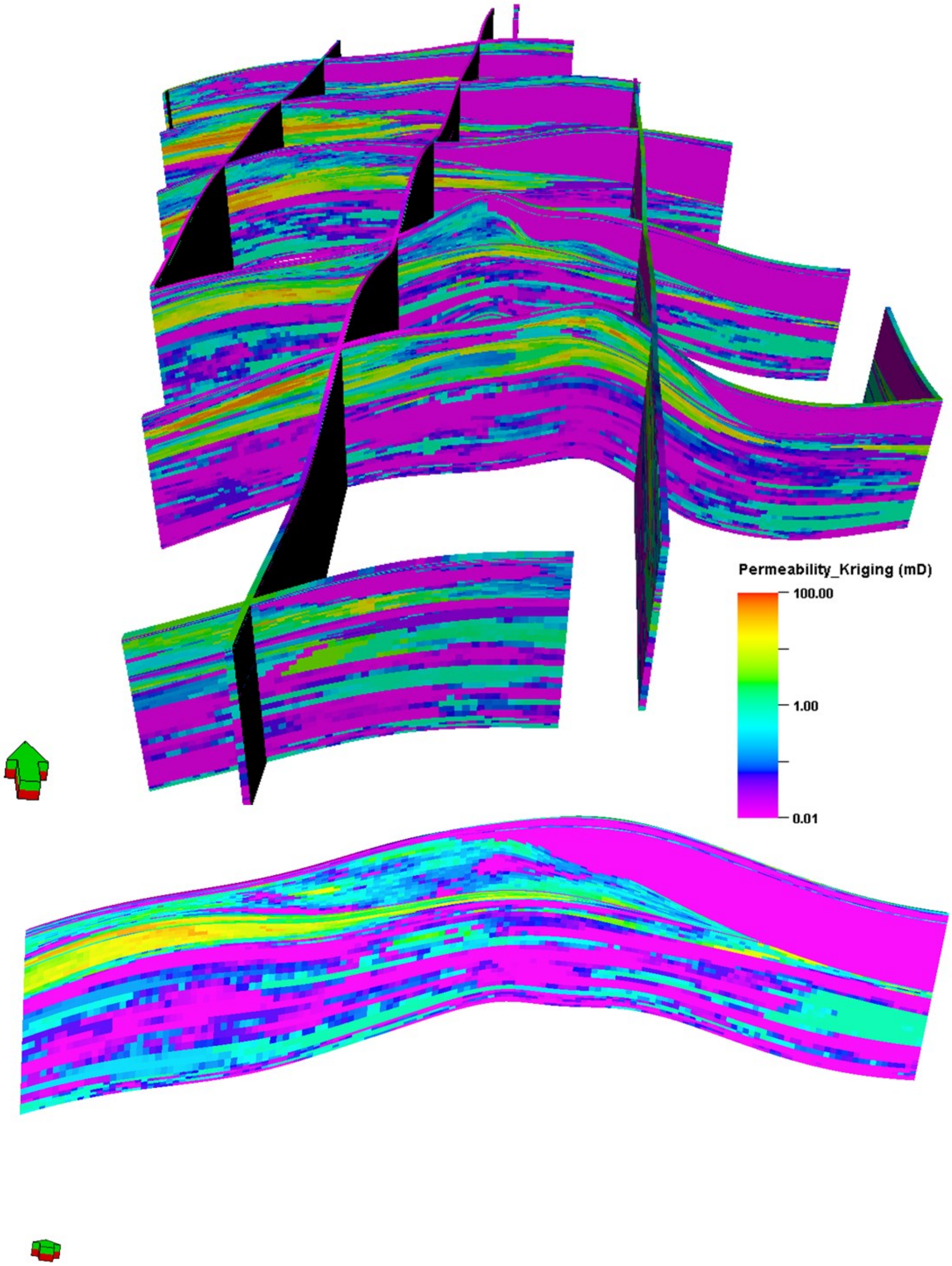

Figure 41. Permeability distribution with Kriging.

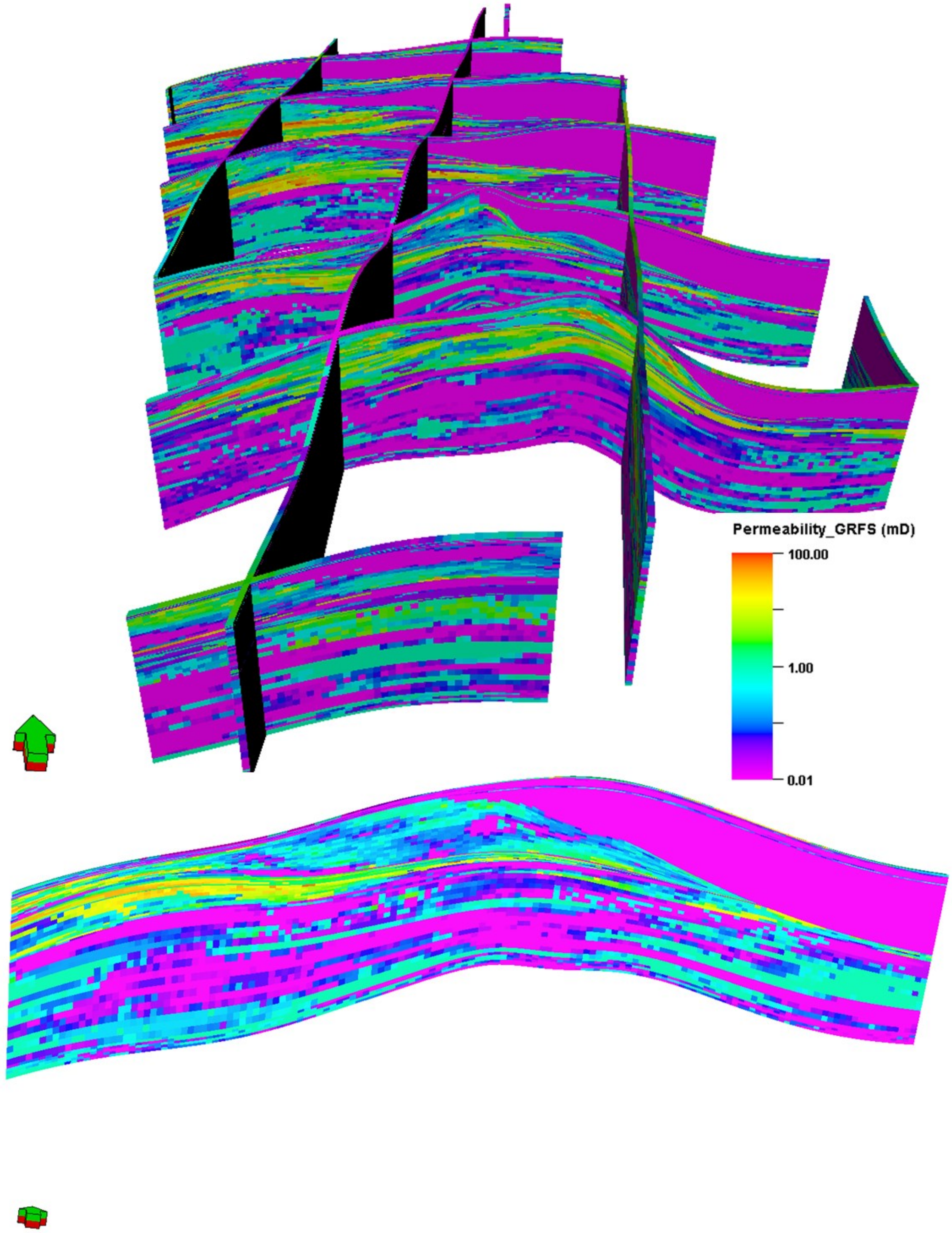

Figure 42. Permeability distribution with GRFS.

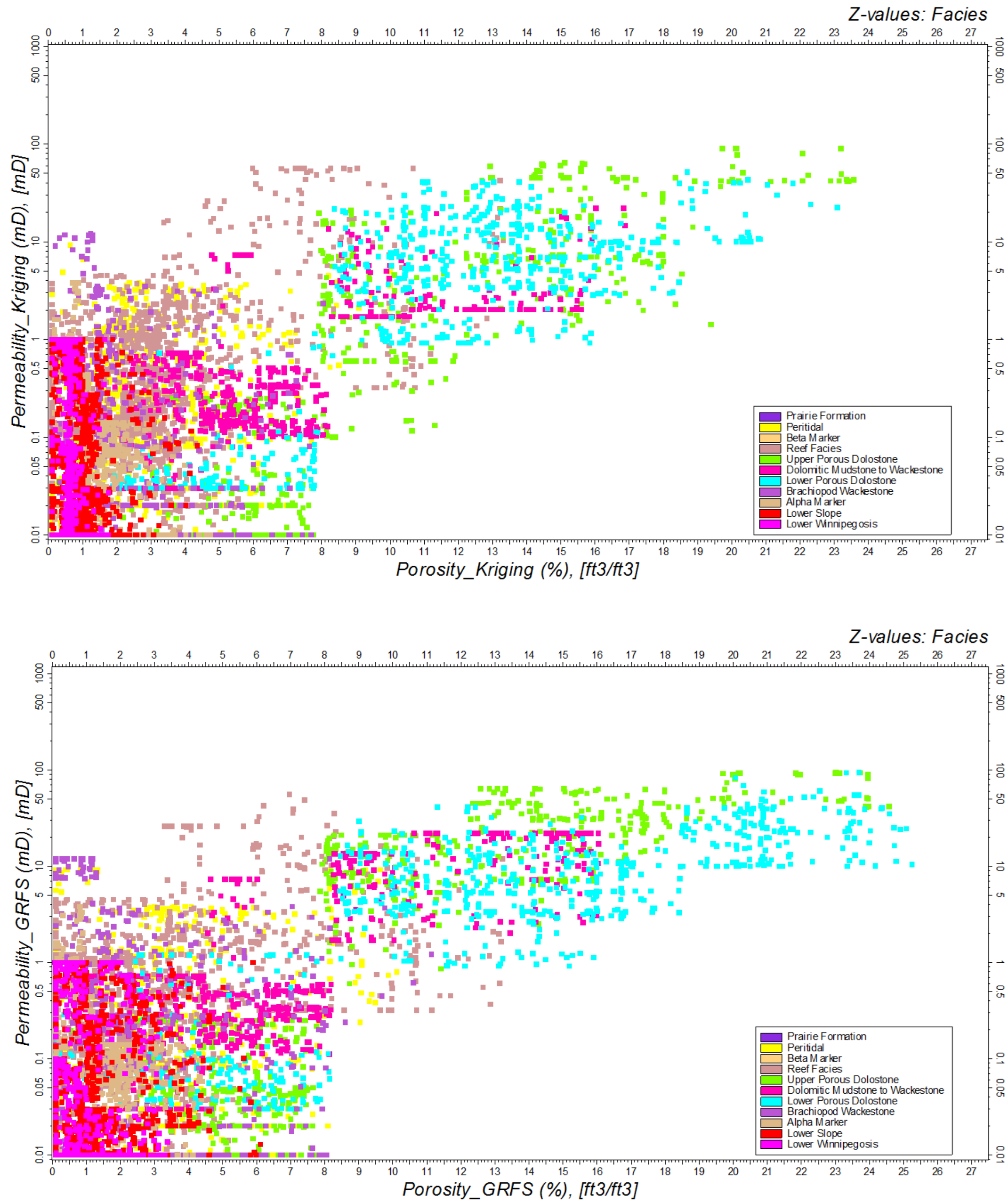

Figure 43. Modeled porosity and permeability crossplots. Top: Kriging porosity and permeability crossplot. Bottom: GRFS porosity and permeability crossplot.

Temperature and Pressure Modeling

Temperature and pressure were both modeled in the study area (Figure 44). Both properties were modeled using a gradient of the pressure and temperature multiplied by a measured depth property that was created for the model.

Temperature in the study area was calculated using gradients calculated from bottom hole temperature values. Temperature was modeled based on an average gradient from the wells in the study area. The surface temperature used was the mean annual surface temperature for Tioga, ND of 41.6 degrees Fahrenheit. Temperature within the field varied from 219 to 236 degrees Fahrenheit.

A pressure gradient was calculated based on the drill stem test data available from the field. Drill stem tests from eight wells were used in calculating the pressure gradient. A gradient of 0.45 psi/foot was found reasonable to be used in the calculation with a surface pressure of 14.7 psi. The final results show the pressure in the reservoir changes from 4874 to 5328 psi.

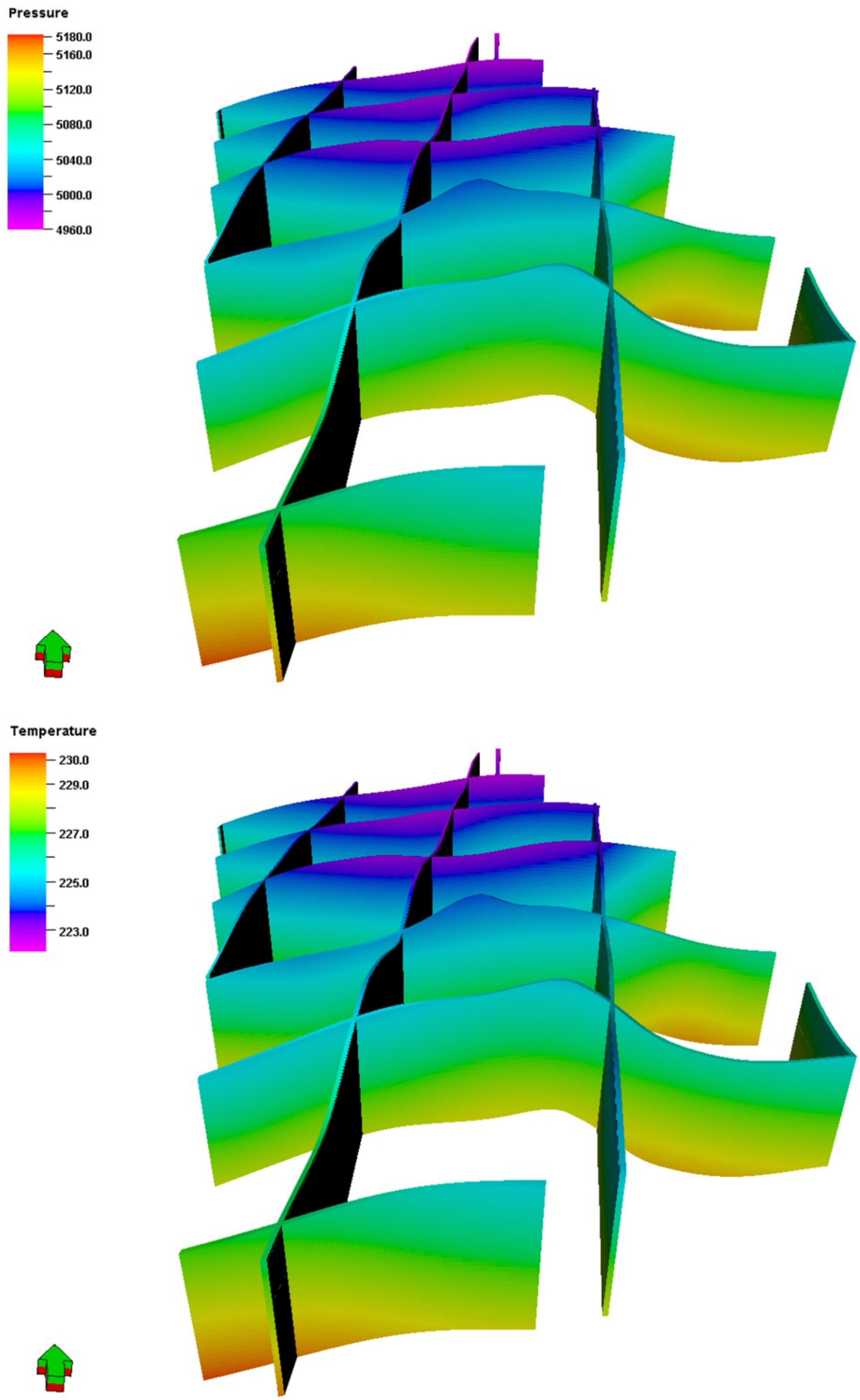

Figure 44. Pressure and temperature distribution. Top: Pressure. Bottom: Temperature.

Volumetric Calculations

Volumetric reservoir estimates were performed for the reservoir facies in Temple Field. The bulk volume for each cell in the field was computed with the geometrical modeling process for use in these calculations. Pore volume was calculated for both the Kriging and GRFS porosity distributions to compare the results.

Original oil in place was calculated using the pore volume, oil saturation and oil shrinkage factor of 1.2 along with a defined oil-water contact. Kriging results presented an OOIP estimate of 24.1 million barrels. This means the field has currently produced 27.5% of the OOIP. The GRFS results gave an OOIP estimate of 21.7 million barrels giving a 30% recovery of the OOIP. Based on both modeling methods the field has produced 27-30% of the OOIP through primary and secondary recovery, which is a reasonable estimate. It should be noted that a gas-oil contact was not designated within the field. Since the field has produced a considerable amount of gas, adding a gas-oil contact to the model is recommended to improve the results.

CHAPTER VI

CONCLUSIONS

Hydrocarbon production from the Winnipegosis Formation platform margin deposits of Temple Field represents the most production from the formation in North Dakota. The field has been producing since the early 1980s through primary and secondary waterflood recovery and is an aging field.

Studying the properties of the Winnipegosis Formation of Temple Field has allowed for a better understanding of the facies and petrophysical property relationships within the field. This information is important for future field development and discovery of other potential Winnipegosis reservoirs along the platform margin.

Analysis of the field's reservoir characteristics has shown the Porous Dolostone facies (underlying the Reef facies and Beta Marker facies) is the productive reservoir. Porosity and permeability crossplot analyses of each facies shows the highest porosity and permeability values occurring in the dolostone facies. Porosity of the dolostone reservoir averaged 11.4% with an average permeability of 8 mD.

The porosity of this dolostone reservoir trends along the platform margin and decreases (pinches out) toward the deep marine basin environment and also onto the platform. The combined anticlinal structure of the field along with the updip porosity pinchout of the dolostone facies create a structural and stratigraphic trap for hydrocarbon accumulation in the field. The highest production from the field is found in wells along the hinge of the anticline which also corresponds to the highest porosity values.

Structural, facies, and petrophyscial models have given a better understanding of the facies and petrophysical property relationships within the field and allowed for an estimation of original oil in place. Similar results for OOIP were derived from porosity models constructed using both Kriging and GRFS. An OOIP of 21.7 to 24.1 million barrels was estimated which makes the current recovery from the field 27-30%.

For future enhanced oil recovery techniques within the field, CO_2 or produced gas EOR may be a viable choice. The overlying impermeable layers along with the overlying evaporites of the Prairie Formation would make a significant seal to contain CO_2 within the formation and the field.

Other reservoirs along the platform margin of the Winnipegosis may exist if a structural trap is present along with overlying impermeable layers to prevent the infiltration of salt into the reservoir facies. McGregor Field to the southeast of Temple Field along the platform margin exhibits more recent production from this depositional environment with production beginning in 2000.

Future efforts could build on this study through completion of numerical simulation efforts including history matching production and predictive simulations of CO_2 EOR. These thesis results could also be used in further modeling of the field. In this study, only one facies distribution was created. Creation and modeling of multiple facies distributions along with the petrophysical property modeling such as porosity and permeability would help to determine the uncertainties existing in the results for better future planning and field development.

APPENDICES

Appendix A

Core and Thin Section Descriptions

The following core descriptions were described from cores at the Wilson M. Laird Core and Sample Library, Grand Forks, ND.

Well 3055 (33-105-00611-00-00)
Williams Co., SWNE 25-159-96
Depco, Inc., Olga Thompson et al 1
KB = 2359 ft
TD = 11250 ft

11060 - 11094 Mudstone: Black w/ dark gray, laminated to nodular, minor brachiopods near bottom, rare fossils, gray intervals w/ black rims, not porous, 11063-11065: halite or anhydrite in matrix, clear crystals, porosity = 0.3%

11094 - 11098 Wackestone to Packstone: Black w/ dark gray, laminated to nodular, gray intervals w/ black rims, brachiopods, crinoids, black laminations, minor stylolites, porosity = 3.18%

11098 - 11100 Mudstone: Medium brown, no fossils, mottled light brown, porosity = 15.6%

11100 - 11103 Dolomudstone: Dark brown to mottled gray layers w/ black rims, limestone in part, oil stained, porosity = 6.95%

11103 - 11108 Wackestone: Light brown to light gray, minor small fossils, crinoids?, corals?, black specs, small muddy laminations, porosity = 6.7%

11108 - 11109 Packstone: Gray to slightly brown, very fossiliferous portions, corals, porosity = 8.0%

11109 - 11114 Wackestone: Light gray to gray, minor fossils, porosity = 7.85%

11114 - 11126 Dolomudstone: Dark brown to medium brown, mottled, muddy, minor stylolites, concolith?, black rims, oil stained, limestone in part, porosity = 16.82%

11126 - 11140 Wackestone to Packstone: Black to Dark gray, brown in part, brachiopods common, light gray between dark laminations, mottled to nodular

Well 10059 (33-105-01059-00-00)
Williams Co., SENE 1-158-96
Fulton Producing Co., Grimsrud 1
KB = 2347 ft
TD = 11170 ft

11107 - 11111 Dolowackestone: Gray to medium brown, limestone in part, common vertical fractures anhydrite filled, minor brachiopods, 11,108- large amplitude stylolite, porosity = 5.7%

-11110 Thin section: fine xtln dolomite, minor calcite, vertical fractures, intercrystalline porosity

11111 - 11118 Wackestone to Packstone: Gray brown to dark brown, mottled, dolomitic in part, minor crinoids and brachiopods, porosity = 1.4%

11118 - 11130 Packstone: Black to dark gray, common brachiopods, minor crinoids, rare corals, porosity = 0.53%

11130 - 11159 Packstone to Floatstone: Dark gray to black. mottled to laminated, common brachiopods, common oncolites in part; alternating brachiopod/oncolite dense intervals in darker matrix w/lighter matrix w/less brachiopods, porosity = 0.58%

Well 10209 (33-105-01076-00-00)
Williams Co., SESW 6-158-95
Depco, Inc., McGinnity 24-6
KB = 2410 ft
TD = 11292 ft

11082 – 11087 Wackestone: Dark gray to dark brown, minor stromatoporoids, codiacean algae texture?, abundant fractures, rare halite inclusions, rare small vuggy porosity, rare corals, slight oil staining, spotted texture, really sparkly look when dry slightly different texture than lower interval, thamnoporoid corals?, rare brachiopods, porosity = 2.6%

11087 – 11115 Stromatoporoid-Coral Boundstone/Floatstone: Dark brown to dark gray, abundant stromatoporoids, domal & tabular, corals, thamnopora?, rugose, bryazoans, branching corals, abundant fractures sealed w/ anhydrite, minor halite, slight oil staining, rare mottled brown in part, rare brachiopods, porosity = 1.7%

11115 – 11126.5 Dolowackestone: Light gray to brown to dark gray, significant limestone & dolostone content, light colored material is dolostone, dark areas limestone rech, abundant stromatoporoids, tabular, wispy texture between dolostone & limestone texture varies greatly, some areas are very dolostone rich, oil stained, rare corals, 11,121 – 11,124 most dolomitic interval, porosity = 8.7%

-11126 Thin section: dolo-mudstone, fine xtln dolomite, slight oil staining, intercrystalline porosity = 10%

11126.5 – 11130 Mudstone to Wackestone: Medium brown, slightly streaked, rare fossils, dolomitic in part, slight oil staining, porosity = 9.4%

11130 - 11133.5 Dolomudstone: Dark brown to black, very fine grained, massive, strong oil staining, brown streaked, no to very rare fossils, slightly swirled/wispy texture, porosity = 13.5%

-11133 Thin section: very fine xtln dolomite, oil stained, intercrystalline porosity: 20-25%

11133.5 - 11142 Packstone to Wackestone: Gray brown, common brachiopods, swirled texture in part, dolomitic in part, dolomite increases upward, large amplitude stylolites (11,136 & 11,137), rare crinoids, slight oil staining, porosity = 4.7%
11133.5-11134 color changes to browner w/ more dolomite
11138-11142 darker color also

Well 10396 (33-105-01089-00-00)
Williams Co., NENW 25-159-96
Depco, Inc., Bronson 2-25
KB = 2334 ft
TD = 11450 ft

11065 - 11067 Mudstone: Dark gray, very fine grained, rare stylolites, minor brachiopods, porosity = 4.6%

11067 - 11070 Mudstone: Medium brown, dolomitic in part, porosity = 11.1%

11070 - 11076 Dolomudstone: Medium brown, mottled w/ black rims, slightly oil stained, porosity = 12.9%

11076 - 11079 Dolomudstone: Dark brown, limestone in part, minor fossils, pinpoint porosity, dark oil stained, porosity = 13.6%

11079 - 11089 Wackestone: Medium gray, dolomitic in part, common fossils, crinoids, corals, mottled in part, oil stained, minor vugs, porosity = 6.7%

11089 - 11098 Dolomudstone: Dark gray to dark brown, mottled in part with light brown, oil stained, minor mud laminations, no fossils, porosity = 16.4%

11098 - 11106 Dolomudstone: Dark brown, similar to above unit with less oil staining, mottled with dark brown, thin black rims between mottles, porosity = 16.0%

11106 - 11109 Mudstone: Medium gray, very rare fossils, muddy, porosity = 7.1%

11109 - 11123 Wackestone to Packstone: Dark gray, massive, mottled gray and light brown, muddy laminations, minor stylolites, wispy look, porosity = 1.2%

11123 - 11125 Wackestone: Gray to dark gray mottled, common brachiopods, oncolites?, porosity = 0.4%

Well 10480 (33-105-01094-00-00)
Williams Co., SENW 7-158-95
Depco, Inc., Skarderud 22-7
KB = 2430 ft
TD = 11307 ft

11098 - 11101 Dolomudstone: Light brown to dark brown, laminated, anhydrite common, halite common, minor vuggy porosity, porosity = 0.7%

11101 - 11110.5 Dolomudstone: Gray brown to dark brown, laminated in part, anhydrite and halite common, white anhydrite, dark black in part, porosity = 1.2%

11110.5 - 11115 Mudstone: Dark brown and dark gray, mottled, dolomitic, vertical fractures, minor halite and anhydrite, porosity = 1.1%

11115 - 11121 Dolowackestone: White to light gray, abundant anhydrite, minor corals, rare stromatoporoids, rare crinoids, porosity = 1.8%

11121 – 11139 Stromatoporoid Packstone to Stromatoporoid Boundstone: Dark brown to dark gray, mottled, laminated in part, dolomitic near the lower contact, abundant stromatoporoids, rare corals and brachiopods, vertical fractures common, porosity = 5.8%

11139 – 11159 Dolomudstone: Medium to dark brown and medium gray, mottled, oil stained, rare brachiopods and stromatoporoids, porosity = 19.5%

-11149.5 Thin section: very fine xtln dolomite, intercrystalline porosity = 10%

-11153 Thin section: fine xtln, sub-euhedral dolomite crystals in part, intercrystalline porosity = 25-30%

11159 – 11163 Dolomudstone: Dark gray, massive, oil stained, large vertical fracture, porosity = 5.9%

-11160 Thin section: very fine xtln, fine xtln in part, sub-euhedral dolomite crystals, intercrystalline porosity = 20%

11163 – 11174 Dolowackestone: Light brown to tan, mottled, rare halite, rare corals, rare stylolites, oil stained, porosity = 14.7%

11174 - 11192 Wackestone: Light brown to medium gray limestone, mottled, abundant brachiopods, rare stylolites, rare stromatoporoids, vertical fractures, porosity = 4.8%

11192- 11205 Mudstone: Dark gray to black limestone, rare corals, common brachiopods, vertical and horizontal fractures; 11202 – 11203 dolowackestone cream limestone with dark gray limestone, offset layers by vertical fractures, porosity = 0.8%

Well 10763 (33-105-01112-00-00)
Williams Co., NWNE 23-159-96
Depco, Inc., Sevre 31-23
KB = 2328 ft
TD = 11551 ft

11048 - 11054 Dolomudstone: Gray, highly fractured, slightly wispy w/ dark black, very fine grained, rare fossils, -11050 large anhydrite inclusion, porosity = 1.1%

11054 - 11056 Dolomudstone: Gray brown, mottled texture in part, oncolite texture?, very fine grained portions, muddy brown blobs in part, porosity = 1.9%

11056 - 11068 Dolowackestone: Gray brown to brown, wispy brown texture, brown algae?, small porosity in brown intervals, rare fossils, rare brachiopods?, minor fractures, rare pyrite, porosity = 3.5%

11068 - 11091 Dolowackestone: Gray brown to brown, wispy brown texture, similar to above interval but with increased fossil content, crinoids common, very rare stromatoporoids, very rare corals, -11174: sponge branch or algae?, porosity = 3.3%

11091 - 11098 Dolomudstone to dolowackestone: Gray, slightly streaked w/ brown algae?, decreased fossil content from above interval, rare fossils, porosity = 4.4%

11098 - 11107 Dolowackestone: Gray to light brown, mottled texture, rare fossils, -11098 allochem rich interval, brachiopods? in intervals, fine wispy texture w/ black wisps, porosity = 3.2%

Well 11893 (33-105-01243-00-00)
Williams Co., SWNW 24-159-96
Dekalb Energy Co., McCoy 12-24
KB = 2354 ft
TD = 11245 ft

11060 - 11073 Mudstone to wackestone: Dark black, shaly look, almost fissile like shale, horizontal fractures, no fossils to rare fossils, rare brachiopods?

11073 – 11078 Wackestone: Dark black, intermixed gray limestone, brachiopods, laminated to mottled dark gray and light gray, porosity = 1.0%

11078 - 11082 Mudstone: Gray to grayish brown limestone, slight mottled texture to minor laminated texture, -11108 stylolite, no fossils, rare gypsum or anhydrite inclusions, porosity = 8.3%

11082 - 11084 Dolomudstone: Dark brown to gray, mottled texture, oil stained, no fossils, slight black wisps, porosity = 12.4%

11084 - 11097 Mudstone to wackestone: Medium gray to gray brown, mottled texture, massive, slightly oil stained, small dark black laminations, rare stylolite, rare fossils, -11094-11097: increasing fossil content, corals?, crinoids?, dolostone in part, porosity = 7.1%

11097 - 11105 Dolomudstone to dolowackestone: Brown, mottled texture, black wisps between mottles, oil stained, no fossils, rare stylolites, -11103: anhydrite inclusion, porosity = 15.6%

11105 - 11121 Mudstone to wackestone: Dark gray, mottled texture increasing downward, mottled light gray and dark gray, brachiopod dense intervals, rare fossils, packstone in part, oncolite floatstone?, slightly fractured, burrows, porosity = 1.7%

Appendix B

Facies Variograms

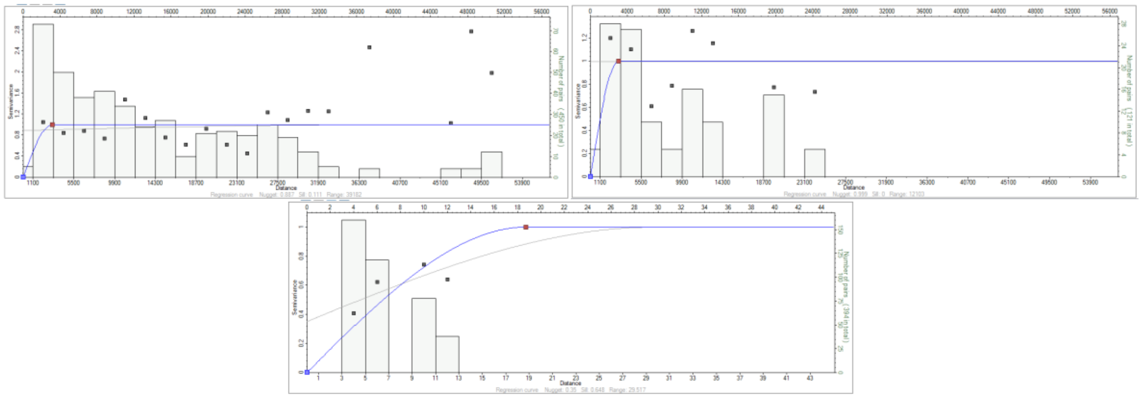

Figure 45. Variograms of the Lower Winnipegosis facies. Left: major. Right: minor. Bottom: vertical.

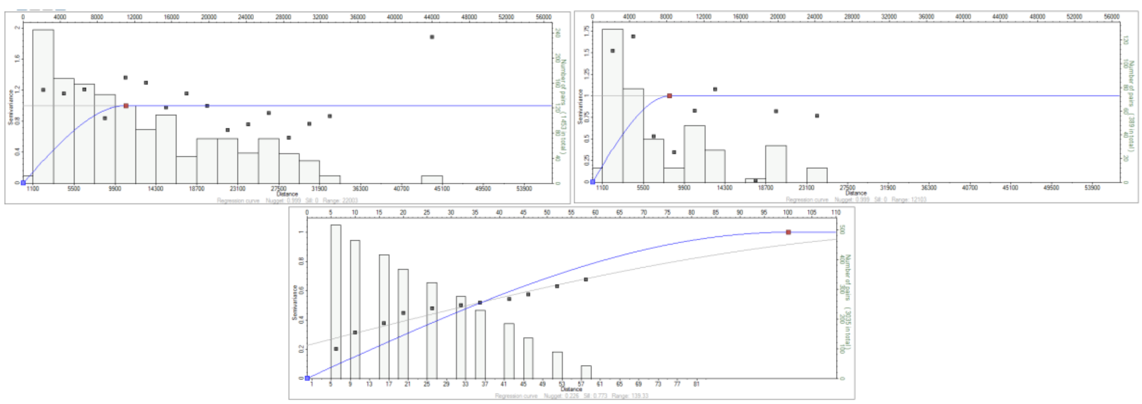

Figure 46. Variograms of the Lower Slope facies. Left: major. Right: minor. Bottom: vertical.

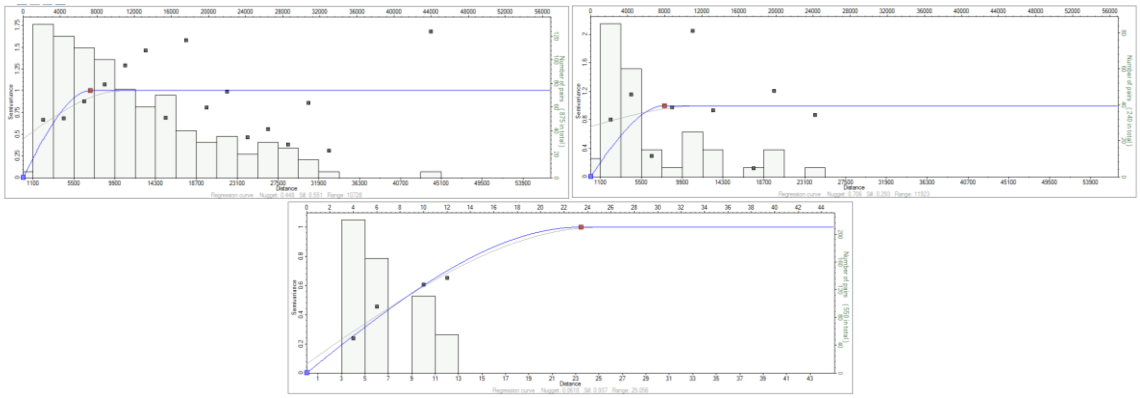

Figure 47. Variograms of the Alpha Marker facies. Left: major. Right: minor. Bottom: vertical.

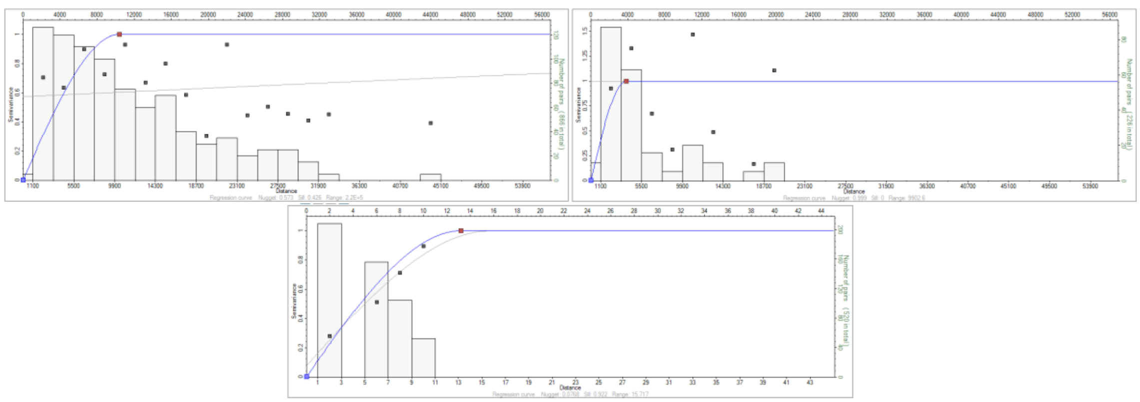

Figure 48. Variograms of the Brachiopod Wackestone facies. Left: major. Right: minor. Bottom: vertical.

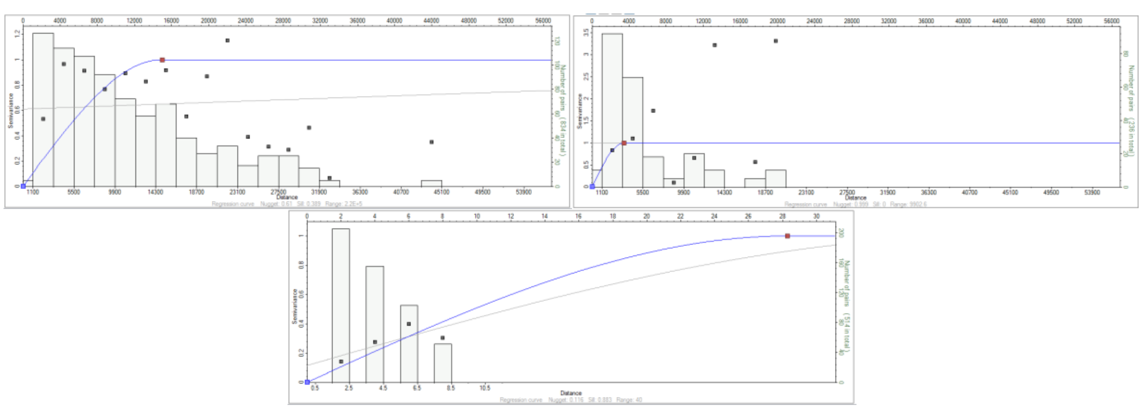

Figure 49. Variograms of the Lower Porous Dolostone facies. Left: major. Right: minor. Bottom: vertical.

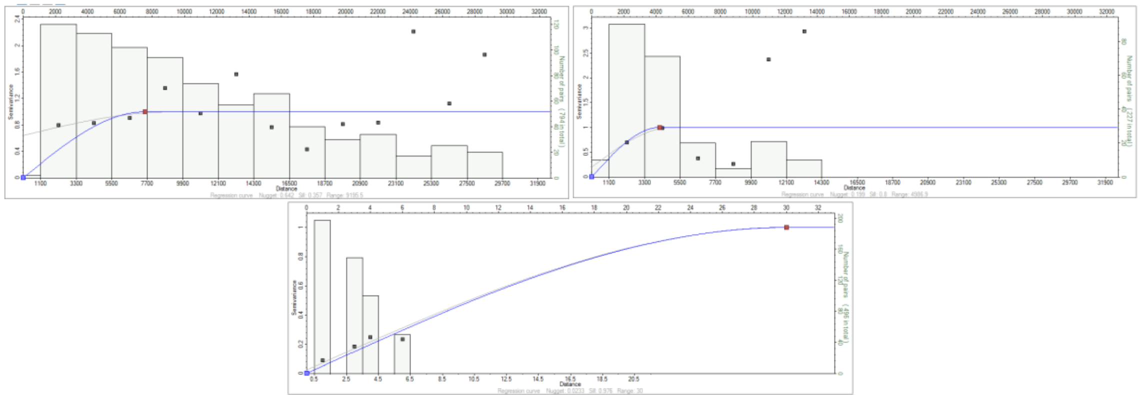

Figure 50. Variograms of the Dolomitic Mudstone to Wackestone facies. Left: major. Right: minor. Bottom: vertical.

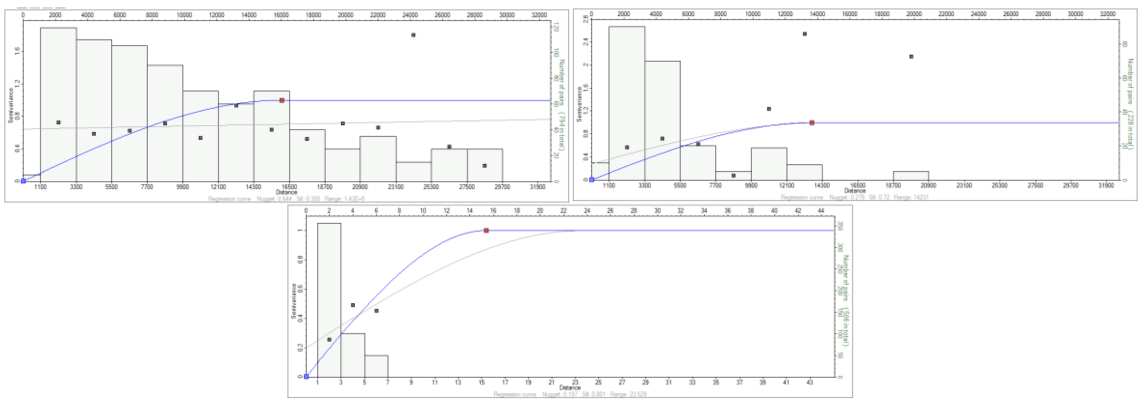

Figure 51. Variograms of the Upper Porous Dolostone facies. Left: major. Right: minor. Bottom: vertical.

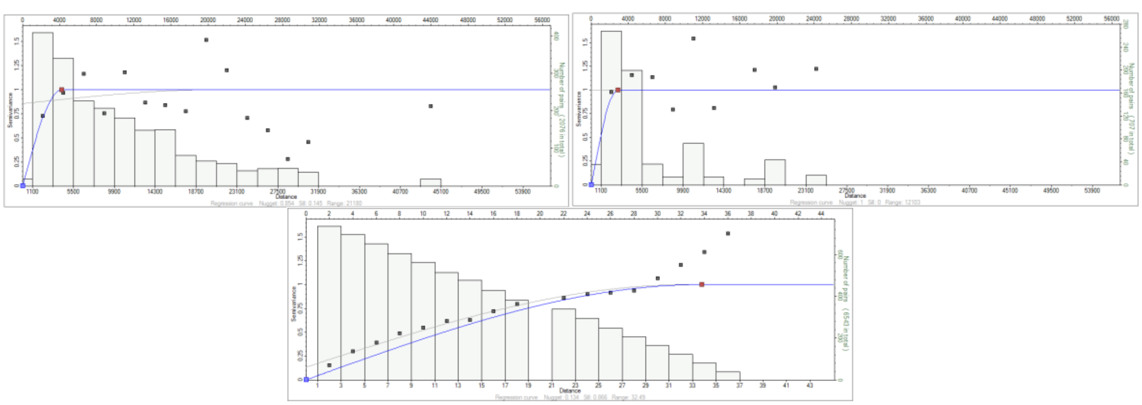

Figure 52. Variograms of the Reef facies. Left: major. Right: minor. Bottom: vertical.

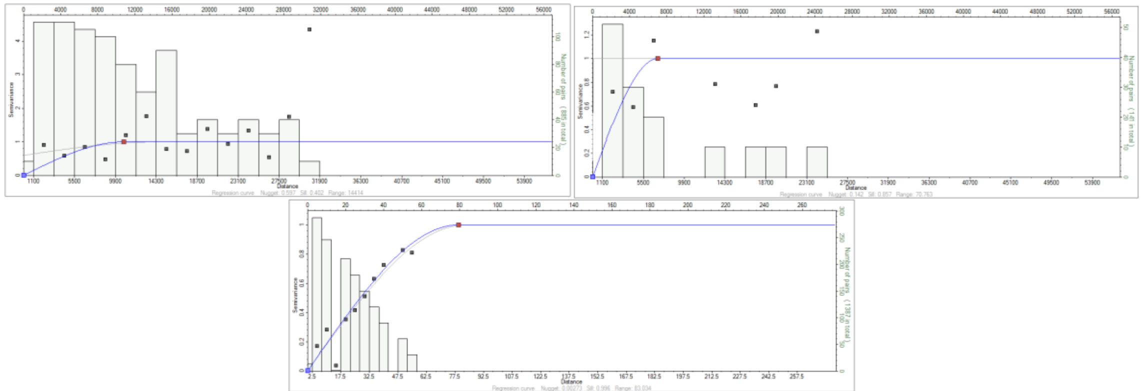

Figure 53. Variograms of the Beta Marker facies. Left: major. Right: minor. Bottom: vertical.

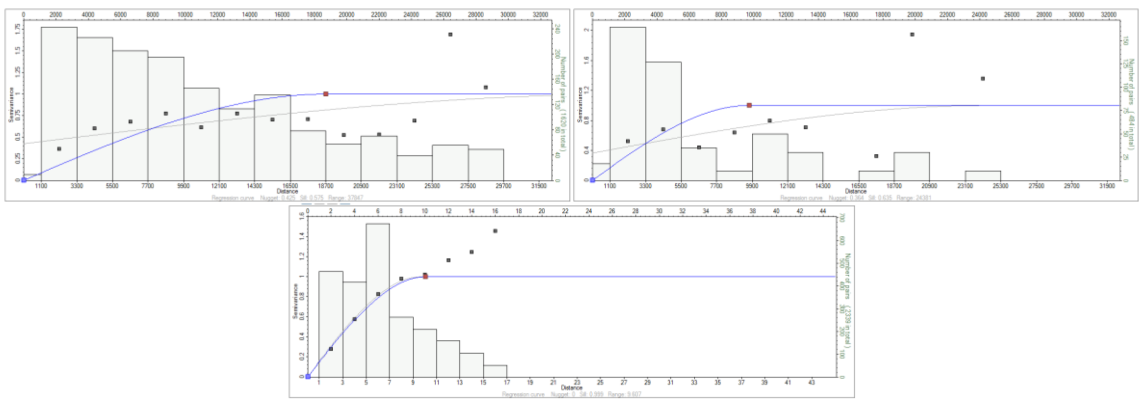

Figure 54. Variograms of the Peritidal facies. Left: major. Right: minor. Bottom: vertical.

Appendix C

Modeled Wells

Table 3. Temple Field wells used in model.

API	NDIC	Well Name	TD	Township	Range	Section
33105010890000	10396	ALBERT 21-25	11450	159 N	96 W	25
33105010870000	10371	BAUMANN 1-26	11344	159 N	96 W	26
33105010380000	9781	BIWER 1	11260	158 N	96 W	12
33105012010000	11607	BIWER 43-12	11250	158 N	96 W	12
33105010780000	10260	BRONSON 1-26	11288	159 N	96 W	26
33105012280000	11798	BRONSON 23-25	11220	159 N	96 W	25
33105006110000	3055	BRONSON 32-25	11250	159 N	96 W	25
33105008260000	7556	CHEEK 1	11270	158 N	95 W	8
33105012160000	11722	EILEEN 41-13	11391	159 N	96 W	13
33105006840000	4665	EUGENE MCGINNITY 1	12819	158 N	95 W	6
33105010800000	10292	FLB-BRONSON 1-25	11250	159 N	96 W	25
33105006850000	4667	GULF STATE 1-36	11260	159 N	96 W	36
33105005710000	2439	GULF-STATE 36-2	11200	159 N	96 W	36
33105011680000	11354	HAMLET UNIT 3	11410	159 N	95 W	30
33105014570000	14793	HOSETH 1-18	11360	158 N	95 W	18
33105012430000	11893	MCCOY 22-24	11245	159 N	96 W	24
33105010450000	9801	MCGINNITY 11-8	12900	158 N	95 W	8
33105009850000	9207	MCGINNITY 14-6	12780	158 N	95 W	6
33105010760000	10209	MCGINNITY 24-6	11292	158 N	95 W	6

Table 3. cont.

API	NDIC	Well Name	TD	Township	Range	Section
33105011260000	11026	MCGINNITY 34-6	12365	158 N	95 W	6
33105010050000	9361	PEDERSON 3	12980	158 N	95 W	18
33105010900000	10397	PEDERSON 4	11308	158 N	95 W	18
33105010520000	9920	SAGASER 1	11275	158 N	96 W	1
33105010590000	10059	SEATON 1	11270	158 N	96 W	1
33105013050000	12174	SEATON 1-2	11225	158 N	96 W	1
33105011690000	11366	SEATON 31-1	11200	159 N	95 W	31
33105011120000	10763	SEVRE 31-23	11551	159 N	96 W	23
33105010620000	10073	SKARDERUD 10-7	12880	158 N	95 W	7
33105015010000	15117	SKARDERUD 13-7	11300	158 N	95 W	7
33105010940000	10480	SKARDERUD 22-7	11307	158 N	95 W	7
33105009390000	8722	SKARDERUD 2-7	12850	158 N	95 W	7
33105013010000	12156	SKARDERUD 2-7R	11350	158 N	95 W	7
33105015020000	15118	SKARDERUD 32-7	11370	158 N	95 W	7
33105011790000	11450	SKARDERUD 33-7	11350	158 N	95 W	7
33105010570000	10047	TOTAL-STATE 1-36	11240	159 N	96 W	36
33105012290000	11805	TOTAL-STATE 22-36	11220	159 N	96 W	36
33105011050000	10676	UNION-MCGINNITY 1-6	12250	158 N	95 W	6

REFERENCES

Anna, L.O., 2013, Geologic Assessment of Undiscovered Oil and Gas Resources of the Williston Basin Provence of North Dakota, Montana, and South Dakota, Chapter 3 of U.S. Geological Survey Williston Basin Province Assessment Team, Assessment of Undiscovered Oil and Gas Resources of the Williston Basin Province, Montana, North Dakota, and South Dakota, 2010 (ver. 1.1, November 2013): U.S. Geological Survey Digital Data Series 69-W, 71 p.

Bachu, S., Hitchon B., 1996, Regional-scale flow of formation water in the Williston Basin, American Association of Petroleum Geologists Bulletin, v. 80, n. 2, p. 248-264.

Baillie, A.D., 1953, Devonian Names and Correlation in Williston Basin Area: American Association of Petroleum Geologists Bulletin v. 37, n. 1, p. 444-447.

Bosshart, N.W., 2014, Characterization, Diagenesis, and Geocullular Modeling of Winnipegosis Formation Pinnacle Reefs in the Williston Basin, North Dakota, M.S. thesis, University of North Dakota, Grand Forks, North Dakota, 152 p.

Carlson, C.G., 1987, Winnipegosis Production in North Dakota, 1987 Field Trip Supplement for 5th International Williston Basin Symposium, p. 9-13.

Downey, J.S., Dinwiddie, G.A., 1988, The Regional Aquifer System Underlying the Northern Great Plains in Parts of Montana, North Dakota, South Dakota, and Wyoming - Summary, United States Geological Survey Professional Paper 1402A, 64 p. Ehrets, J.R., Kissling, D.L., 1987, Winnipegosis Platform Margin and Pinnacle Reef Reservoirs, Northwestern North Dakota: 5th International Williston Basin Symposium, p. 1-31.

Fisher, D.W., Burke, R.B., 1987, A Synoptic Overview of Winnipegosis Pinnacle Reefs in North Dakota, North Dakota Geological Survey MS-68, 17 p.

Fu, O., Qing, H., Bergman, K.M., 2006, Paleokarst in Middle Devonian Winnipegosis mud mounds, subsurface of south-central Saskatchewan, Canada, Bulletin of Canadian Petroleum Geology, v. 54, p. 22-36.

Fu, Q., Qing, H., Bergman, K.M., Yang, C., 2008, Dedolomitization and Calcite Cementation in the Middle Devonian Winnipegosis Formation in Central Saskatchewan, Canada, Sedimentology, v. 55, p. 1623-1642.

Gerhard, L.C., Anderson, S.B., LeFever, J.A., Carlson, C.G., 1982, Geological Development, Origin, and Energy Mineral Resources of Williston Basin, North Dakota, American Association of Petroleum Geologists Bulletin, v. 66, no. 8, p. 989-1020.

Gerhard, L.C., Anderson, S.B., LeFever, J.A., 1987, Structural History of the Nesson Anticline, North Dakota, Williston Basin: Anatomy of a Cratonic Oil Province, p, 337-354.

Jin, J. Bergman, K.M., 1999, Sequence Stratigraphy of the Middle Devonian Winnipegosis Carbonate-Prairie Evaporite Transition, Southern Elk Point Basin, Carbonates and Evaporites, v. 14, p. 64-83.

Jin J. Bergman, K.M., 2001, Revised Stratigraphy of the Middle Devonian (Givetian) Winnipegosis Carbonate-Prairie Evaporite Transition, Elk Point Group, southern Saskatchewan, Bulletin of Canadian Petroleum Geology, v. 49, p. 441-457.

Jones, L., 1965, The Middle Devonian Winnipegosis Formation of Saskatchewan, Saskatchewan Mineral Resources, rpt. 98, 101 p.

Kinard, J.C., Cronoble, W.R., 1969, The Winnipegosis Formation in Northeast Montana, Eastern Montana Symposium: Montana Geol. Soc., 20th Annual Conference 1969, p. 33-44.

Kostelnyk, E., 1998, Dolomite and Dolomitization in the Middle Devonian Winnipegosis Formation, North Dakota, M.S. Thesis, University of Manitoba, Winnipeg, Manitoba, 252 p.

Murphy, E.C., Nordeng, S.H., Juenker, B.J., Hoganson, J.W., 2009, North Dakota Stratigraphic Column, Department of Mineral Resources, North Dakota Geological Survey.

Neuralog Inc, (2010), NeuraLog Version 2010.11, Houston TX.

Osadetz, K.G., Brooks, P.W., Snowdon, L.R., 1992, Oil families and their sources in Canadian Williston Basin, (southeastern Saskatchewan and southwestern Manitoba), Bulletin of Canadian Petroleum Geology, v. 40, p. 254-273.

Perrin, N.A., 1982, Environments of Deposition and Diagenesis of the Winnipegosis Formation (Middle Devonian), Williston Basin, North Dakota: 4th International Williston Basin Symposium, p. 51-66.

Perrin, N.A., Precht, W.F., 1985, Depositional Environments, Paleocology and Diagenesis of Selected Winnipegosis Formation (Middle Devonian) Reef Cores, Williston Basin, North Dakota, Society of Economic Paleontologists and Mineralogists (SEPM), p. 125-182.

Perrin, N.A., 1987, Depositional Environments and Diagenesis, Winnipegosis Formation (Middle Devonian), Williston Basin, North Dakota, Ph.D. dissertation, University of North Dakota, Grand Forks, North Dakota, 583 p.

Petrel 2011; Seismic to Simulation Software, Property Modeling Course, Schlumberger Information Solutions,

Rosenthal, L.R., 1988, The Winnipegosis Formation (Middle Devonian) of the Northeastern Margin of the Williston Basin, Canada, Canadian Society of Petroleum Geologists, mem. 14, p. 463-475.

Schlumberger, Log Interpretation Charts 2013 Edition, Houston, TX., 294 p.

Tyrrell, J. B., 1982, Report on northwestern Manitoba with portions of adjacent districts of Assinibola and Saskatchewan: Canada Geological Survey Annual Report., 1890-91, p. E, 235 p.

Zhang, J., Bergman, K.M., Qing, H., 2004, Stratigraphic relationships between the Middle Devonian Shell Lake Member and the Upper Winnipegosis reef mounds, Saskatchewan Sub-basin, Bulletin of Canadian Petroleum Geology, v. 52, n. 2, p. 156-176.