RESERVOIR QUALITY AND WELL PERFORMANCE ANALYSIS IN THE MIDDLE MEMBER
OF THE LEWIS SHALE, GREATER GREEN RIVER BASIN, WYOMING

by

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ABSTRACT

The Lewis Shale is a turbidite system encompassing sandstones, siltstones, and organic-rich shales, deposited during the last Cretaceous seaway transgression. It is informally subdivided into three members; a lower member (characterized by high clay and organic matter content), a middle member or Dad sandstone member (a mixture of siltstones, shales, and sandstones), and an upper member (with decreasing amounts of sandstone and greenish-grey shales) that can reach up to 2600 ft in thickness. Its lithological characteristics vary depending upon its location within the Lewis Shale depositional basin (eastern Greater Green River Basin).

The present study is in Sweetwater and Carbon counties in Wyoming. Data includes three cores in the Great Divide Basin and one on the Wamsutter Arch provided by MorningStar Partners/Southland Royalty. Cores contain various lithologies, including shales, siltstones, and sandstones, representing the Lewis Shale's lithologic heterogeneity and complexity.

Reservoir quality and diagenesis are intrinsically related. Therefore, high-resolution reservoir characterization must be performed to understand these different intervals and forecast some of the reservoir properties and possible challenges. Measured and sampled core data include X-ray Fluorescence (XRF), X-ray Diffraction (XRD), Field Emission-Scanning Electron Microscope (FE-SEM), and routine core analyses (RCA).

Well-log data obtained from the Wyoming Oil and Gas Conservation Commission (WOGCC) were used to perform correlations, build maps of the different cored intervals, and evaluate its internal characteristics and reservoir quality. Core description and XRF analyses were performed every 0.5 ft. Based on lithology changes, samples for thin sections and XRD were taken in areas of interest.

The objective of this work is to develop a high-resolution reservoir characterization. This analysis is crucial for understanding this play and decreasing uncertainty when planning new well placements. This formation is considered an unconventional reservoir due to its low porosity and permeability and the need
to use hydraulic fracturing to obtain hydrocarbons at commercial rates. In addition, this area around the cores is relatively undeveloped for horizontal wells.

The main concerns of log analyses in tight sandstone reservoirs are porosity estimation, accurate water saturation calculation, permeability determination, and understanding how clay affects log responses. In addition, petrographic thin section, routine, and special core analyses are necessary to develop a reliable petrophysical model. Several authors have mentioned some of the petrophysical properties of the Lewis Shale. However, there are no petrophysical models in the sandstone intervals tying together log and core data to the author’s knowledge.

As in many gas-centered basins, the Greater Green River basin has a high amount of gas shown while drilling with low water production. Production across the area varies greatly, thus suggesting there might be other factors such as rock properties, sweet spots, or different completions and production techniques affecting the production.

The petrophysical characteristics of these four cores displayed the same level of heterogeneity as the facies described. Samples have high variation in water saturation values and, in general, very low porosity and permeability characteristics of these reservoirs. Samples classified as finely laminated silty sandstones displayed better reservoir properties than the other facies, even the clean, massive sandstones. This proves that the cleanest sandstones are not always the best reservoirs. Chlorite and clay content have a high impact on the reservoir properties. For example, Well 1 and Well 2 had lower illite/smectite and higher chlorite content and showed better properties than Well 4, which had higher illite/smectite and lower chlorite content. In this case, chlorite increased the density of the matrix of the sandstones. Thus, affecting the porosity calculation. Chlorite also helped preserve porosity in some of these facies by coating quartz grains. Excess silica correlates with higher porosity and permeability values and correlates with microcrystalline quartz presence.

Wyoming is a large oil and gas producer in the United States, and it is expected to increase in the upcoming years. As a result, drilling operations in the area can significantly affect the wildlife by impacting their habitat and reproduction areas. The Wyoming Game and Fish Commission published
some recommendations to lessen the impact of oil and gas development on the wildlife to mitigate these effects (WG&F, 2007). These efforts include buffers around nests, migration corridors, concentration areas, and non-surface disturbance. Environmental stipulations, restrictions, and pipeline availability have proven to be limiting factors for developing the Lewis Shale in Wyoming. In addition, drilling operations can significantly affect the wildlife by destroying their habitat and reproduction areas. As a result, the Bureau of Land Management (BLM), Wyoming Game and Fish (WG&F), and Wyoming Oil and Gas Conservation Commission (WOGCC) have developed a set of rules that must be followed when applying for a drilling permit. The resulting maps show the areas with better production, fewer environmental concerns, and more pipelines available. The areas with fewer environmental stipulations and are located closer to available pipelines are found towards the Great Divide Basin near the Lost Creek, Red Dessert, Strike, and Siberia Ridge fields. These areas still have some restrictions on drilling times and some buffers present, but restrictions are fewer. These areas on the north also represent the most productive (oil) and prospective areas for well development.

Completion techniques are often one of the most expensive parts of drilling and producing a well. Therefore, the costs of proppant and completion fluid are significant in determining individual well or even field economic viability. A production analysis was made using the volume of proppant, the volume of fluid injected, the number of fracture stimulation stages, and production to infer their effect on production. But it seems there is no correlation between them. Other factors such as the internal reservoir characteristics (such as lithology or bed thickness) could be affecting the production of these wells.
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To Roger Slatt
CHAPTER 1
INTRODUCTION

1.1 Research Motivation and Objectives

The Lewis Shale was deposited during the final transgression of the Western Cretaceous Seaway (WCS) in the eastern Greater Green River Basin in Wyoming, Utah, and Colorado (Hettinger and Roberts, 2005). It is informally subdivided into three members; a lower member (characterized by high clay and organic matter content), a middle member or Dad sandstone member (a mixture of siltstones, shales, and sandstones), and an upper member (with decreasing amounts of sandstone and greenish-grey shales) that can reach up to 2600 ft in thickness. Its lithological characteristics vary depending upon its location within the Lewis depositional basin (eastern Greater Green River Basin). These interbedded sandstones and shales are deposited on a slope to the base-of-slope environment (Asquith, 1970, Young et al., 2003).

It was first described by Cross and Spencer (1899) in southwestern Colorado. Weimer (1960) illustrated that the Lewis shale from Wyoming is younger than the Lewis Shale and Mesaverde described in southern Colorado. Hale (1961) also discussed the discrepancies between the contacts' ages in Wyoming and Colorado identified by the differences in the ages of the fauna found. Hale (1961) also informally named the middle member of the Lewis Shale as the “Dad member.”

Hettinger and Roberts (2005) compiled an oil and gas assessment of the Lewis Total Petroleum System as part of the United States Geological Survey (USGS) program to evaluate different basins and formations. Their study was centered on unconventional reservoir development. They determined that the Lewis Shale's main potential is gas production with some minor potential for liquid hydrocarbons.

Pasternack (2005) measured Total Organic Carbon (TOC), analyzed some of the internal characteristics of the Lewis Shale, specifically in the Asquith Marker, and found the present-day TOC ranging from 1.4-3.2 wt.%. In addition, Pasternack established regional correlations based on the gamma-ray (GR) signature of the Asquith Marker.
Although the Lewis Shale has been produced since the 1960s, production was from vertical wells, and drilling in the area declined rapidly with the decrease in gas prices. Approximately 600 billion cubic feet of gas (BCFG) have been produced from this basin. However, the exact amount produced from the Lewis Shale is unclear due to many of the wells being co-mingled (Hettinger and Roberts, 2005). In addition, about 8.1 million barrels of oil and condensate have been produced from the Lewis Shale, including wells where the production came solely from the Lewis Shale and wells commingled with other formations. The hydrocarbon production from the Lewis Shale comes mainly from the gas reservoirs within the Desert Springs, Hay Reservoir, Wamsutter, Great Divide, Strike Unite, and Siberia Ridge fields (Gonzalez, 2003). Water production is present and variable throughout the basin. In thin-bedded, channel-levee-overbank reservoirs, one of the main issues is the thin-bed continuity (Bracklein, 2000).

Most studies on this formation have been focused mainly on the gas sandstone reservoirs; however, a detailed reservoir analysis is required in field development. In thin-bedded, channel-levee overbank reservoirs, one of the main issues was the thin-bed continuity. Lateral continuity and variations can play an essential role in production, even in high net to gross reservoirs. In thin-bedded reservoirs, production was accomplished by artificially fracturing into the thin beds and shale that could act as fluid barriers.

Turbidites are complex systems that hold great potential for hydrocarbon production. These reservoirs showed depletion as more wells were drilled. Thus, lateral communication was evident. However, vertical production variations showed the possible presence of baffles or permeability variations. Shale units and faults can act as fluid barriers. Thus, consistent reservoir modeling and analysis are essential to identify these barriers. Complexity is always greater than anticipated in turbidite reservoirs (Weimer et al. 1998).

The northern area of the Basin was closer to the shelf area during the time of deposition, and the Lewis Shale displays a progradational pattern towards the south. Consequently, sediment packages more proximal to the basin edge and basin slope have the highest percentage of sandstones from channels and high-density turbidites (Pyles and Slatt, 2000). The sequence stratigraphic framework was developed by Pyles and Slatt (2000, 2007). It is characterized by a third-order progradational highstand systems tract.
(HST), comprising several fourth-order lowstand-highstand (LST, HST) cycles and a shallowing upwards sequence. Its maximum flooding surface is in the lower member and is named the Asquith Marker. It has a maximum thickness of 50 ft within the basin, and it is believed to be a source of hydrocarbons, with TOC values ranging between 0.68% and 3.15% in core and outcrop (Mayorga-Gonzalez, 2016). Figure 1.1 shows the type-log of the Lewis Shale used by Pyles and Slatt (2007) and modified to show the equivalent flooding surfaces used in this study. Most of the cored intervals in this study belong to the Dad Sandstone member and lower member of the Lewis Shale.

This work aims to develop a high-resolution reservoir characterization of the Lewis Shale. This analysis is crucial for understanding this play and decreasing the risk of sand pinch outs, clay swelling, caving, or well instability when planning new well placements. In addition, the Great Divide Basin, specifically where the cores were taken, has not been drilled as extensively as other areas within the Greater Green River Basin. This area is relatively newly developed with horizontal wells. One of the first horizontal wells in the Lewis Shale was drilled in 2012, named Spirit of Radio 7-1H by BP America, and since then, about 226 horizontal wells have been drilled in the Lewis Shale area (WOGCC, 2022). Therefore, these cores can help identify the primary depositional environments for the Great Divide Basin and potentially open a new location for development.

Environmental stipulations, restrictions, and pipeline availability have proven to be limiting factors for developing the Lewis Shale in Wyoming. In addition, drilling operations can significantly affect the wildlife by destroying their habitat and reproduction areas. As a result, the Bureau of Land Management (BLM), Wyoming Game and Fish (WG&F), and Wyoming Oil and Gas Conservation Commission (WOGCC) have developed a set of rules that must be followed when applying for a drilling permit.

Analyzing these limiting factors and identifying the most common well-completion techniques and how they affect well production will help reduce permitting time and provide a more accurate and efficient drilling program. Unfortunately, when looking at the potential to develop a field, factors such as environmental regulations or pipeline availability are often neglected.
Figure 1.1 Type log for the Lewis Shale showing the third-order sequences (retrogradational capped by the Asquith Marker and progradational capped by the Fox Hills Sandstones). Higher-order sequences are found within these third-order sequences separated by flooding surfaces (red lines). These flooding surfaces are correlated to subdivide further each of the members of the Lewis Shale and each of the cored intervals. From Pyles and Slatt, 2007. AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use.

The Lewis Shale has been widely studied, and several authors have mentioned some of the petrophysical properties of the Lewis Shale ((Almon et al., 2001, Almon et al., 2002). For example, Shanley et al. (2004) pointed out that the basin is not gas-saturated everywhere within the basin nor near the irreducible water saturation. Furthermore, water production is highly variable throughout the Basin. But there are no published porosity models or associated saturation models to the author's knowledge. As in many gas-centered basins, the Greater Green River Basin has a high amount of gas shown while drilling with low water production, classifying these reservoirs as continuous accumulations (Shanley et
However, production across the area varies greatly, suggesting there might be other factors such as rock properties, sweet spots, or different completions and production techniques affecting the production. The petrophysical model and production analysis presented in this work address some of these issues.

The Lewis Shale-Greater Green River and San Juan Basins

The Lewis Shale was named by Cross and Spencer (1899) on the shale between the Mesaverde Group and the massive marine sandstone called Picture Cliffs, in exposures near Fort Lewis, Colorado, east of Mesa Verde National Park. In Colorado, the Lewis Shale is Campanian in age, whereas the Lewis Shale in Wyoming is late Maastrichtian (Winn et al. 1987), showing they are not equivalent in these two basins. The Lewis Shale in Colorado is not an extension of the Lewis Shale in Wyoming, and the name was applied due to miscorrelation (Gill et al.,1970).

The Lewis Shale and correlative formations were deposited during the transgression of the Western Interior Seaway, which extended from the Artic Ocean and the present Gulf of Mexico (Manfrino 1984). During the Campanian, the western interior sea regressed to the northeast from the San Juan area. The Picture Cliff sandstones recorded several superimposed transgressive pulses within this regressive system. As a result, these sandstone beds intertongue with coastal plain beds on the southwest side of the shoreline and with marine beds on the northeast of the shoreline (Manfrino 1984).

The Cretaceous Sevier orogenic belt flanked the western margin of the Western Interior Seaway. Episodes of uplift controlled the source of sediments. Deltaic and interdeltaic deposits are present along the western interior shoreline when sandstone sediments swept from the Piceance delta formed the Piceance Cliffs stacked sandstones (Manfrino 1984). The Laramide Orogeny divided the western interior seaway into different intermontane basins and uplifts (the San Juan Basin, Washakie, Sand Wash, and Uinta-Piceance).

In the San Juan Basin, the Lewis Shale consists of sediments that can reach up to 1800 ft thick, and it forms a valley between the underlying Cliff House Sandstone and the overlying Picture Cliffs.
Sandstone. The upper part of the Lewis Shale consists of 148 ft of shale with calcareous concretions interbedded with silty claystone and a “transition” zone consisting of interbedded shale silty claystone and very fine-grained sandstone beds. The Lewis Shale is subdivided into four members: the Ute member, Navajo City member, Chacra member with the Huerfanito Bentonite in between, then Otero (divided into a first and a second bench) in the San Juan basin, each of the members is composed of several coarsening-upward sequences. Cain (1986) studied several cores from the Sand Wash Basin in North Craig and Black Mountain field areas. The Lewis Shale section consists of interbedded sandstone and shale sequences encased within a thick shale unit. Shales observed in cores are dark grey, unfossiliferous, and nonbioturbated. These characteristics suggest that the rocks are deep water in origin.

The Lewis Shale depositional environment in Colorado and Wyoming are both marine, but the paleohighs and subsidence taking place in the Greater Green River Basin creating the embayment ensured a more restricted environment with deeper waters a different source of sediments than those in the San Juan Basin. As a result, the Lewis Shale in Wyoming has a maximum thickness of 2600 ft, whereas the Lewis Shale in the San Juan basin has a maximum thickness of 1800 ft. The Lewis Shale in the Hanna Basin, Wyoming, is divided into three parts and can reach up to 1400 ft in thickness (Gill et al., 1970).
1.2 Synthesis of Dissertation Objectives and Deliverables

This dissertation addresses the reservoir characterization and quality for some sandstone and siltstone intervals primarily within the Dad Member of the Lewis Shale, using a multi-scale approach to identify potential areas for development within the Great Divide and Wamsutter Arch areas. The multi-scale reservoir analysis is then applied to a petrophysical model. Lastly, additional challenges to field development are explored.

1.2.1 Subregional Reservoir Quality Characterization and Challenges

The main objective is to introduce the primary characteristics of the Lewis Shale that might affect the potential for the development of new areas, which will be assessed in Chapters 3 and 4.
First, a core description and facies classification; second, depositional processes correlated with each core facies. Third, a facies laboratory analysis. Fourth, a definition of reservoir quality based on rock analysis, and lastly, a regional evaluation and correlation to architectural elements to help discern any trends or changes that can occur in the area.

1.2.2 Subregional Reservoir Characterization and Potential Based on a Petrophysical Model

Chapter 3 intends to characterize the reservoir quality of the intervals by using well logs and core analysis to define and interpolate the best intervals for development within the basin by developing porosity models and calculating water saturation for each of the cored intervals.

1.2.3 Well Development and Challenges in the Wamsutter Area.

Chapter 4 is an overview of some of the environmental regulations in the area and pipeline availability that could delay the development of the fields. The second part includes an analysis of production and most common completion techniques to define potential areas of development and best completion techniques.

1.3 Dissertation Structure

The results of this study will be presented in three different manuscripts or chapters. Chapter 2 represents an introduction to the types of rocks and the main internal characteristics of each of the intervals. It serves as the foundation for subsequent Chapters 3 and 4. This dissertation represents a comprehensive reservoir characterization of the Lewis Shale from pore to basin-scale that will dramatically increase the understanding of the Lewis Shale in Wyoming.

1.4 References


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CHAPTER 2
HIGH-RESOLUTION RESERVOIR CHARACTERIZATION OF THE LEWIS SHALE, GREATER
GREEN RIVER BASIN, WYOMING

2.1 Abstract

The Lewis Shale is a turbidite system encompassing sandstones, siltstones, and organic-rich shales, deposited during the last Cretaceous seaway transgression. It is informally subdivided into three members; a lower member (characterized by high clay and organic matter content), a middle member or Dad sandstone member (a mixture of siltstones, shales, and sandstones), and an upper member (with decreasing amounts of sandstone and greenish-grey shales) that can reach up to 2600 ft in thickness. Its lithological characteristics vary depending upon its location within the eastern Greater Green River Basin, the depositional basin for the Lewis Shale. The present study is in Sweetwater and Carbon counties in Wyoming. Data includes three core in the Great Divide Basin and one on the Wamsutter Arch provided by MorningStar Partners/Southland Royalty. Cored intervals contain various lithologies, including shales, siltstones, and sandstones, representing the Lewis Shale's lithologic heterogeneity and complexity.

Reservoir quality, facies, and diagenesis are intrinsically related in unconventional reservoirs (Loucks et al., 1984, King et al., 1994, Duarte et al., 2021). High-resolution reservoir characterization will help us to understand reservoir, petrophysical characteristics, and reservoir lithology better; and enable us to forecast possible challenges to production.

Analyses completed on core include X-ray Fluorescence (XRF), X-ray Diffraction (XRD), Field Emission-Scanning Electron Microscope (FE-SEM), and routine core analyses (RCA).

Well-log data obtained from the Wyoming Oil and Gas Conservation Commission (WOGCC) were used to perform correlations, build structural and isopach maps of the different cored intervals, and evaluate each reservoir's internal characteristics and quality. Core description and XRF analyses were performed every 0.5 ft. Based on lithology changes, samples for thin sections and XRD were taken in areas of interest.
The objective of this work is to develop a high-resolution reservoir characterization. This analysis is crucial for understanding this play and decreasing uncertainty when planning new well placements. In addition, the Great Divide Basin, specifically where the cores are taken, has not been drilled as extensively as other areas within the Greater Green River Basin. Therefore, these cores can help identify the primary depositional environments for the Great Divide Basin and open new areas for development.

Correlations helped identify the heterogeneity and possible complications these turbiditic reservoirs can present, such as target pinch out or an increase in clay content that could cause swelling or instability in the wellbore, resulting in either losing the well or having to drill a side-track. Furthermore, this variability was also evidenced in the petrographic thin sections, XRD, and XRF analyses showing mineralogical variations down to the inch scale, which is lower than the well-log resolution, making it challenging to identify.

The overall composition of all the intervals is very consistent with high quartz content, followed by clay and carbonate content. An approximation of a rock’s brittleness can be based on the principle that the higher the percentage of quartz and dolomite, the higher the brittleness index. When the calcite percentage is high, it can act as a brittle mineral. Dolomite is found as grains and cement, augmenting the rock's brittleness, but it can also decrease its porosity and permeability.

In general, the high quartz, calcite, dolomite, and plagioclase content in all the cored intervals makes them particularly brittle, thus facilitating hydraulic fracturing. Chlorite was identified in thin section description, XRD analyses, and FE-SEM analyses. Chlorite can help the reservoir quality by coating grains and preserving porosity in these tight reservoirs, as found in these samples.

The isopach maps reflect the change in depositional environments in the Basin from north to south and the general progradation of the Formation into the southern portion of the Basin.

These analyses also helped identify the main architectural elements present in these intervals; channel complexes and levee-overbank deposits. Channelized features showed lateral pinch-outs, whereas the levee-overbank deposits are more continuous in thickness and lateral distribution. The architectural
issues have implications for correlation, fluid connectivity, and geosteering accuracy during drilling. In addition, levee overbank deposits are also more homogeneous and have high quartz, dolomite, calcite, and plagioclase, minerals usually correlated with a higher brittleness index (BI). However, the higher clay content in these levee overbank deposits have implications for the net reservoir. Drilling and geosteering can be notably easier in siltstone levees, such as in the siltstone interval, due to the intervals’ increased thickness (e.g., a maximum thickness of 400 ft) and the intervals’ continuity. However, the higher clay content may decrease porosity and permeability and increase water saturation. However, in some cases, the higher clay content may decrease porosity and permeability and increase water saturation.

2.2 Introduction

This work aims to develop a high-resolution reservoir characterization of the Lewis Shale using core and logs. Such an improved characterization will help understand this highly complex play, reduce risk, and help make the geosteering process faster.

Herein, I summarize the methods used to assess the reservoir characteristics of four cored intervals of the Lewis Shale. The study is located in Wyoming's Sweetwater and Carbon counties. Data include four core (three collected in the Great Divide Basin and one collected in the Wamsutter Arch), well-logs, core data such as x-ray fluorescence (XRF), x-ray diffraction (XRD), total organic carbon (TOC), routine core analyses (RCA), and field emission scanning electron microscopy (FE-SEM). With the well-log and core data obtained, correlations and maps were constructed, and their internal characteristics identified, such as mechanical compaction and clay content, minerals present, and thus, their reservoir quality is inferred (Figure 2.1).
Figure 2.1 Location of the study area and the cored wells on this study. The red dot is the location of the type log used by Pyles and Slatt (2007) to display the sequence stratigraphic framework of the Lewis Shale.

The Great Divide Basin, specifically where the core were taken, has not been drilled as extensively as other areas within the Greater Green River Basin. This core are critical information in determining the facies, facies architecture, and petrophysical character of these elements. These core interpretations are tied to logs accompanying the cored intervals, and the petrophysical and facies nature extrapolated across a large area of the basin using log motif similarity. The resultant new reservoir framework has the potential to help workers identify new development areas. The Lewis Shale has been produced for hydrocarbons since the 1960s. Production was from vertical wells, with most studies in this formation focusing on the sandstones gas reservoirs and associated with vertical well completion and production. Drilling in the Lewis declined rapidly with the decrease in gas prices. This study will provide several advances in analysis and understanding of the Lewis Shale with the hope of regenerating opportunities in the Lewis. These include:

1. Although several studies identify the primary minerals and analyze the reservoir quality of some intervals of the Lewis Shale, none have been a high-resolution study combining XRF data,
2. This study will be the first where the results are oriented to horizontal drilling and unconventional reservoirs (Thyne et al., 2003; Pasternack, 2005, Sapardina, 2012).

3.Brittleness of the Lewis Shale will be a focus of this study. The brittleness of rock or fracability is critical when evaluating unconventional reservoirs, and several factors such as strength, lithology, texture, effective stress, temperature, fluid type diagenesis, and Total Organic Carbon (TOC) play an essential role in it. The brittleness index helps quantify some of these factors based on the mineral composition and diagenesis of the rock without calculating Young's and Poisson’s moduli. Minerals that affect this index the most are quartz (the higher the quartz content, the higher the brittleness) and carbonate, clay, and TOC content (these decrease the brittleness index) (Jarvie, 2005). Wang and Gale (2009) also included dolomite as a brittle mineral.

**Previous Works**

The Lewis Shale was deposited during the final transgression of the Western Cretaceous Seaway in the eastern Greater Green River Basin in Wyoming, Utah, and Colorado (Hettinger and Roberts, 2005). This study centers in Wyoming, where oil and gas are produced from the Lewis Shale.

The Lewis units were first described by Cross and Spencer (1899) in southwestern Colorado. It is informally subdivided into three members; lower (characterized by high clay and organic matter content), middle member or Dad sandstone member (a mixture of siltstones, shales, and sandstones), and an upper member (with decreasing amounts of sandstone and greenish-grey shales) that can reach up to 2600 ft thick (Almon, 2002). Each member has variable amounts of sands, siltstones, and shales, depending on their location within the Lewis depositional basin.

Approximately 600 billion cubic feet of gas (BCFG) have been produced from this basin, although the exact amount produced from the Lewis Shale is unclear due to the wells’ production being co-mingled (Hettinger and Roberts, 2005). In addition, about 8.1 million barrels of oil and condensate have been produced from the Lewis Shale, including wells where the production came solely from the Lewis Shale and wells commingled with other formations (Hettinger and Roberts, 2005).
The Lewis Shale includes continuous and conventional accumulations (Suryanto, 2003). The conventional accumulations are located in the shallower regions of the Basin where hydrocarbons from the deeper and over-pressured areas have migrated. These overpressured areas were identified by Law (1984) and Surdam et al. (1995) and are believed to affect the chances of oil generation of the rock, cracking the oil into gas in areas of overpressure.

Suryanto (2003) determined gas-in-place estimates, based on assumed hydrocarbon saturation of 45, 50, and 60%, with values ranging from 46.5 to 82.9 TCFG (trillion standard cubic ft). This estimate was based on conventional vertical wells, and the reduced relative permeabilities in tight-gas sandstones may lower the economic recovery of this play. However, this number can come close to reality (Suryanto, 2003) with horizontal development and modern stimulation.

Hettinger and Roberts (2005) compiled an oil and gas assessment of the Lewis Total Petroleum System as part of the United States Geological Survey (USGS) program to evaluate different basins and formations. Their study was centered on unconventional reservoir development. They determined that the Lewis Shale's main potential is gas production with some minor potential for liquid hydrocarbons.

Pasternack (2005) measured Total Organic Carbon (TOC), analyzed some of the internal characteristics of the Lewis Shale, specifically in the Asquith Marker, and found the present-day TOC ranging from 1.4-3.2 wt.%. In addition, Pasternack established regional correlations based on the gamma-ray (GR) signature of the Asquith Marker.

In mature fields, the production history was very different from predicted, with many unforeseen circumstances, such as earlier-than-prognosed water breakthroughs. In thin-bedded, channel-levee-overbank reservoirs, one of the main issues was the thin-bed continuity. These reservoirs showed pressure drawdowns (pressure depletion) as more wells were drilled. Thus, lateral communication and widespread depletion were evident. However, vertical production variations showed the possible presence of baffles or permeability variations.

Differences in fluid contact elevation on opposing channels implied that flanking levees are partially or entirely separated by mudstone channel fill. Development plans for many fields should be based on
past experiences in more mature fields. Close reservoir surveillance is required, as there will be unexpected reservoir performance characteristics through time, and a good infill program should be planned and updated as more wells are being drilled.

Lateral continuity and variations can play an essential role in production, even those with a high net to gross ratio. Shale units and faults can act as a fluid barrier. Thus, consistent reservoir modeling and surveillance are essential to identify these barriers. In thin-bedded reservoirs, production was accomplished by artificially fracturing into the thin beds and shales that could act as barriers. Complexity is always greater than anticipated in turbidite reservoirs (Weimer et al. 1998).

The northern area of the Basin was closer to the shelf area during the time of deposition, and the Lewis Shale displays a progradational pattern towards the south. Consequently, depositional packages more proximal to the basin edge and basin slope have the highest percentage of sandstones (Figure 2.2) related to channels and high-density turbidites (Pyles and Slatt, 2000).

Figure 2.2 shows the type-log of the Lewis Shale used by Pyles and Slatt (2007) and modified to show the mappable flooding surfaces used in this study. Most of the intervals of this study belong to the Dad Sandstone Member and Lower Member of the Lewis Shale. The Lewis Shale includes seals, reservoirs, and source rocks, making it ideal for unconventional development. More than half of the production of the Lewis Shales has been from fields in the Great Divide Basin and Wamsutter Arch areas (Pasternack, 2005). Reservoirs in these areas are sandstones sealed by shales deposited as submarine fans with lobe-shaped geometries usually restricted to the paleo-basin floor and toe of the slope depositional environments (Cain, 1986; Van Horn and Shannon, 1989; Hendricks, 2001) within the Dad Sandstone Member. In their study, Muller and Wirnkar (2004) included sandstone bodies from basin floor fans and slope fans.

The variations in vertical well productivity can reflect sandstone thickness variations typical of these environments and a gas water contact that establishes the eastern production limits. Thinner sandstone intervals have lower productivity (Thyne et al., 2003). Some of these characteristics identified
in vertical wells can also apply to horizontal drilling, such as sandstone thickness variations, but this does not consider the shale and siltstone reservoir quality nor evaluate them as unconventional reservoirs.

Reservoir quality in turbidite systems is controlled by grain size, sorting, the thickness of the reservoir, and distribution. In addition, porosity and permeability are controlled by grain size, sediment burial history, diagenesis, and the deformation processes the rock has suffered (Weimer and Link, 2013).

Some of the best reservoirs in turbidite systems are those with medium to coarse grain size, well-sorted, low cementation, and low diagenetic processes. By contrast, silt and fine-grained material, and coarse debris have low reservoir quality (Weimer and Link, 2013).

The best reservoirs are usually classified as the high-density turbidites from the lobes due to their areal extension and moderate grain sorting, although all the architectural elements within the turbidite system can generate hydrocarbons (Weimer and Link, 2013).
Figure 2.2 Type log for the Lewis Shale in the Washakie Basin, the location of the Asquith Marker (which is believed to be one of the source rocks in the area), with third and fourth-order sequences identified by Pyles and Slatt, 2007. Progradation direction and evolution of each of the clinoforms within the Lewis Shale. “Modified from Pyles and Slatt (2007). AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use”.

Mfs
TOC: 0.5-3.89%
Ro%: 0.72-1.25
2.2.1 Geological Setting

The Lewis Shale is a turbidite system encompassing sandstones, siltstones, and organic-rich shales, deposited during the last Cretaceous seaway transgression. The Lewis Shale is considered a complete petroleum system containing source rock (Asquith Marker), reservoir rock, seal, and different trapping mechanisms throughout the entire basin resulting in structural, stratigraphic, and basin-centered gas plays (Zainal, 2001).

The Lewis Shale in the study area was deposited as a series of southward-prograding clinoforms whose source of sediments were various submarine fans (Young et al., 2003). The subaqueous deltas prograded initially from the northeast but later issued from the south (Winn et al., 1985) as the different uplifts in the area started to lift at different times during the Laramide Orogeny (the Sierra Madre, Lost Soldier anticline, and Rock Springs Uplift). The geometry of the clinoforms with the uplifting of the Lost Soldier Anticline located in the northeast of the Great Divide Basin created a well-defined shelf-slope basin floor topography with slopes between 0.6 and 1 degree (Minken, 2004).

The progradation direction suggests some structural influence during the deposition of the Dad Sandstone Member of the Lewis Shale. Several studies (Perman, 1990, MacMillen and Winn, 1991, Gonzalez, 2003, Pyles, 2000, Pyles and Slatt, 2007) have been conducted on the shape of the clinoforms and the processes associated with them. They determined that the slope within the clinoforms are areas of constant changes in thickness. In addition, the sediments show slight bioturbation to no bioturbation, identifying periods of anaerobic and dysaerobic conditions with water depths between 500-650 ft (Winn et al., 1983). In Wyoming, the Lewis Shale intertongues throughout the entire basin with the overlying Fox Hills Formation and underlying Mesaverde Group (Gonzalez, 2003) (Figure 2.3).
Figure 2.3 Stratigraphic column of the Lewis Shale and adjacent units in Wyoming. From Hettinger and Roberts, 2005.
The main architectural elements include channels, sheet sands, mass transport deposits, and flooding surfaces. The Dad Sandstone Member has a maximum thickness of 1400 ft in the eastern Washakie Basin and thins towards the Basin's edges when it becomes the laterally equivalent formations (i.e., Fox Hills Sandstone) (Hettinger and Roberts, 2005).

It comprises interbedded sandstones and shales deposited on a slope to the base-of-slope environment (Asquith, 1970, Young et al., 2003, Bracklein, 2000). The upper and lower member are composed of several hundred feet of siltstones, sandstones, and shale intercalations.

The sequence stratigraphic framework for the Lewis Shale was developed by Pyles and Slatt (2000, 2007). It is characterized by third-order progradational highstand systems tracts, comprising several fourth-order lowstand-highstand cycles and a shallowing upwards sequence (Figure 2.4).

The maximum flooding surface is located in the lower member, named the Asquith Marker (Figure 2.4). It has a maximum thickness of 100 ft within the Basin (Pyles and Slatt, 2000), and it is believed to be a source of hydrocarbons, with TOC values ranging between 0.68% and 3.89% in core and outcrop and Ro values between 0.72% and 1.25% (Mayorga-Gonzalez, 2016). In addition, according to source rock and biomarker analyses, it has a high potential to generate liquid hydrocarbons from a Type II/III kerogen (Mayorga-Gonzalez, 2016).

The Lewis Shale comprises different depositional environments within the deep-water system, including turbidite channels, sheet sands, and mass transport deposits. Deeper depositional areas are located towards the south and transition to shallower regions towards the north (Pyles and Slatt, 2000, Sapardina, 2012). The processes that occur during the deposition of the Lewis Shale include sediment gravity flows, such as debrites and high-density turbidites (Haughton et al., 2009).
Figure 2.4 Type log for the Lewis Shale in Wyoming showing the retrogradational sequence capped by the Asquith Marker and the progradational sequence capped by the Fox Hills Sandstones. The sequence stratigraphic framework was developed by Pyles and Slatt (2007). AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use.
The Upper Cretaceous Lewis rocks were deformed in intermontane basins formed during the Laramide Orogeny. During this time, the Sierra Madre, Rawlins, Cherokee, Rock Springs Uplifts, and Lost Soldier Anticline developed and served as a sediment source for the Lewis Shale (Pyles and Slatt, 2000). In addition, McMillen and Winn (1991), McGookey et al. (1972), and Hamilton (2006) identified submarine fan sandstones from several directions matching the placement of the other uplifts of the time.

The Lewis Shale was deposited during a subsidence period within the Greater Green River Basin from the Late Cretaceous through the earliest Tertiary (Surdam et al., 1995). The unconformities present in the Tertiary section suggest some periods of uplift and erosion, but there is no evidence of a significant loss of section or that the burial took place at a deeper depth than the present-day (Thyne et al., 2003). Instead, processes of tectonism and eustacy controlled the Lewis’ Shale sedimentation.

The late Absaroka thrusting, and subsidence triggered a sea-level rise (Luo and Nummedal, 2010). As a result, the Basin subsided faster than sedimentation (Winn et al., 1987, Luo and Nummedal, 2010). The subsidence submerged areas of the northeastern delta. These processes created an embayment deep enough to allow the deposition of this turbidite system and sufficient restriction to preserve organic matter.

Each of the clinoforms, intervals divided by flooding surfaces, show differences in the topography by sediment entry points and a distributary channel trend (Gonzalez, 2003). The location of the lobes reflects a compensational character filling (new turbidites fill topographic lows) rather than a reflection of the paleotopography of the seafloor (Hamzah, 2001).

2.3 Methods

2.3.1 Core

The core description was completed for 816 ft of core, from four core covering different intervals of the middle (Dad) Sandstone Member of the Lewis Shale. The core change lithologies reflect the depositional complexity of the Lewis Shale. Descriptions provided herein annotate the main sedimentary structures, grains, bioturbation, fossils, and observable diagenetic characteristics of the rock. Several core
has been described from the Lewis Shale in other areas of the Greater Green River Basin (Winn et al., 1985, Winn et al., 1987, Gonzalez, 2003, Pasternack, 2005, Sapardina, 2012).

The sedimentary structures seen in the core descriptions include parallel lamination, ripples, climbing ripples, and convoluted beds (Van Dyke, 2003, Slatt et al., 2009, Boyce, 2006). In addition, the core contain structureless sandstones and cryptobioturbated sandstones (Winn et al., 1985, Winn et al., 1987, Gonzalez, 2003, Pasternack, 2005, Sapardina, 2012). Fossils see in the core. Include shells, shell debris, foraminifera, and trace fossils found, include dominantly *Ophiomorpha*, *Schaubcylinndrichmus*, and *Phycosiphon*.

2.3.1.1 Sediment gravity-flow classification

Sediment gravity flows are flows in which the sediment moves due to gravity and due to differences in density between the fluidized sediment and the surrounding fluids. Gravity flow deposits are typically described using their internal characteristics (i.e., cohesion), their rheology, and the duration of each depositional event. They can exhibit laminar, mixed, or turbulent behavior, giving rise to deposits with a characteristic geometry, texture, and internal structures.

The inferred turbulence state and rheology can vary spatially or temporally during a single transport event (Haughton et al., 2009). Therefore, they can be classified as dense, laminar cohesive flows that include debris flows and mudflows to dilute, fully turbulent flows such as high and low-density turbidity currents.

At some point, some flows display a mixed behavior (e.g., composite flows). For example, debris flows commonly evolve to become turbidity currents due to flow transformations traveling basinward. Consequently, upslope debrites can be lateral to turbidites down-dip (Haughton et al., 2009). The classification of flows that mix characteristics are complex because they are difficult to observe, and flow characteristics must be inferred from the sediment record (Haughton et al., 2009).

Sediment gravity flows are differentiated by sliding or slumping based on the degree of internal deformation and the degree of displacement, which is extensive on flows, slight in slides, and intermediate in slumps (Middleton and Hampton, 1973). The primary mechanism supporting the sediment
is turbulence. The movement that causes turbulence is the sediment contained in the flow, making it denser than the surrounding water. The rate of deposition from turbidity currents is highly variable. For example, there might be rapid deposition by suspension in proximal regions due to a decrease in the flow initiation energy. It can also occur due to a reduction in the slope (such as the toe of the slope).

Overbank flow can dissipate part of the energy from the discharge or spread onto the lower part of the fan on the basin floor. In these cases, the sediment is buried almost as soon as it is deposited, causing the sediments to be deposited without any sedimentary structures or faint lamination. However, slow sedimentation can develop flutes and scour surfaces (Middleton and Hampton, 1973).

Turbidity currents and turbidites are a type of sediment gravity flow characterized by fluidal rheology, in which sediment is supported mainly by the upward component of fluid turbulence. They are usually divided into head, body, and tail. Sediment concentration profiles vary depending on the erosion and transport processes and the sediment concentration in the near-bed area (Weimer and Slatt, 2007).

Most turbidity currents appear to be surges initiated by some event (that could be catastrophic), and they move downslope away from their source. In addition, they can erode the substrate. Thus, sediment can be continually fed into the head as the body and tail deposit (Weimer and Slatt, 2007). Water can also enter and leave the system. Hence, the flow concentration can increase and decrease in a non-systematic way.

Turbidites have an “idealized” sequence created by Bouma (1962) (Figure 2.5). Structures are usually in series and go from massive (Ta), planar laminated (Tb), cross-laminated or convoluted (Tc), planar laminated (Td), and laminated shale (Te). This sequence might be incomplete in some deposits, but they usually follow that order. There are several types of structures, such as sole marks, tool marks, organic marks, and load structures. Sole marks include scouring marks. Scour marks are flutes formed by the erosion of a cohesive bed by flow separation preserved due to rapid sedimentation processes.

Flutes are classified as bulbous and are present at the base of Ta. Tool marks include grooves (mud clasts), bounce marks, etc. Organic marks and load structures occur when the sediment deposited (sand) is denser than the sediment in which is being deposited (mud), causing the deformation of the mud
previously deposited (Middleton and Hampton, 1973). Thus, there is slow deposition with beds showing well-developed lamination or cross-lamination and “saltation” (by the transport of clasts), with brush marks left by the impact of the mud clasts while they are transported.

Other structures are formed by liquefaction when sand beds are deposited rapidly on top of a soft, less dense sediment. The unstable fabric causes “liquefaction” and creates convoluted beds (usually found in Tc in Bouma’s division).

The rapid nature of the event and the “liquefaction” of the sediments prevents the formation of any laminations. Therefore, grading seems to be expected in turbidites. Coarser sediments are located at the bottom of the sequence, and they decrease in size up to the top of the sequence. This grading is given by the decrease in energy from the head to the tail of the flow. Reverse grading correlates with high concentration flows (debris flows).

Not all turbidity currents behave the same way in deep water environments. Concentrations and velocities may vary at different moments, creating different Bouma divisions both vertically and horizontally.

![Bouma divisions (1962)](image)

**Figure 2.5** Bouma sequence showing the turbidite processes and associated facies. From Middleton and Hampton, 1973. Published with permission of ELSEVIER LTD.
High-density and low-density turbidity currents are differentiated by the concentration of sediments, silt, clay, and fine- to medium-grained sands within the flow. High-density turbidity currents are defined as a sediment concentration between 6- and 44%, whereas low-density turbidity currents have sediment concentrations between 1- and 23%. This overlap in values illustrates the difficulty in classification between these flows. Some have suggested that high-density turbidites should be classified as sandy debrites if they are ungraded (Shanmugam, 1996, 1997).

Slurry currents were identified by Lowe and Guy (2000) as a type of flow that is transitional between turbidity currents and debris flows. In slurry flows, mud particles are rigid and behave as rigid sand- and silt-size quartz. When the energy decreases and the mud particles displace towards the bottom of the flow, these particles collide with more rigid particles and disintegrate into the mud, transforming the flow into a mud-rich basal flow. Fluid escape structures with ripped-up clasts are characteristic of this sediment flow (Weimer and Slatt, 2007).

Lowe (1982) classified intermediate flows as three distinct flows based on the mechanism for sediment support: 1) fluidized and liquified sediment flows, 2) gravity flows, and 3) debris flows. Fluidized and liquified sediment flows occur when the upward flow of fluid escaping between the grains as gravity settles the grains and supports the sediment. Typical sedimentary structures seen in these deposits include sills, fluid escape structures, dykes, and related injection phenomena.

Gravity flows are grain flows, where direct grain-to-grain interactions support the sediment. Beds are usually massive and ungraded, but dish structures and diffuse parallel laminations and clasts are also found. Identification of these kinds of flows is still tricky because all the characteristics of grain flows can also be produced by other transport processes (Middleton and Hampton, 1973).

Debris flows and debrites occur when the larger grains are supported by fluid and fine sediment matrix. They can transport large objects while moving sluggishly, such as clasts. Debris flows are composed of clay minerals, granular solids, and water. The clays and water are mixed as single fluids within the flow with finite cohesion. This cohesion support distinguishes “true” debris flows from grain flows and turbidity-current flows. Within these flows, grains are supported by strength and buoyancy.
Deposition occurs as mass emplacement when the driving stress of gravity decreases below the strength of the debris. As a result, there are lateral deposits on the sides of the channel, or they form adjacent to the channel as levees.

Debris flows usually do not have structures, and boulders are set randomly in a fine-grained matrix (Middleton and Hampton, 1973), but the slide and deformations structures may be present. Figure 2.6 summarizes the processes and types of flows discussed above.

Hybrid events occur when the flow goes from non-cohesive to debris flows, either by erosion and adding mud and mudclasts to the flow or by the rapid transformation of the debris flow into a turbidite current (Haughton et al., 2009). Three types of subaqueous gravity beds deposited under mixed flow conditions have been defined (Haughton et al., 2009). The first type is beds that show an upward change from cohesive to non-cohesive fluid. The second type are the debrite -turbidite type of beds, which usually record significant magnitude events within a normal gravity current deposition (Haughton et al., 2009, Southern et al., 2017). The third bed types show an upward change from non-cohesive to cohesive behavior (Figures 2.7, 2.8). Non-cohesive types of beds can cap them. Moreover, the third type is beds that record more complex cyclical alternations between more and less cohesive flow (Haughton et al., 2009).

Hybrid event beds contain up to five internal divisions: argillaceous and commonly mud clast-bearing sandstones (linked debrite H3), overlain by banded sandstones (transitional flow deposits, H2), and structureless sandstones that can show structures such as dewatering, dishes, or commonly dewatering sheets (high-density turbidity currents, H1). In addition, many hybrid event beds are capped by a relatively thin, well-structured, and a graded sand-mud couplet (trailing low-density turbulent cloud H4 and mud suspension fallout H5) (Figure 2.9).
<table>
<thead>
<tr>
<th>Type of flow</th>
<th>Process</th>
<th>Structures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-cohesive Turbidity currents</td>
<td>High-density Turbidity currents</td>
<td>High concentration of sediment</td>
</tr>
<tr>
<td>Low Density Turbidity currents</td>
<td>Low concentration of sediment</td>
<td>Bouma Sequence. Sandy, parallel laminated bed (Tb), Beds with ripple/ climbing ripples to laminated or convoluted (Tc). Parallel laminated to massive, silty beds (Td)</td>
</tr>
<tr>
<td>Transitional between turbidity current and debris flow</td>
<td>Slurry bed</td>
<td>A transitional flow between turbidity currents and debris flows. Mud particles behaved rigidly at the beginning and then become a mud-rich basal flow</td>
</tr>
<tr>
<td>Cohesive</td>
<td>Fluidized and liquified sediment flows</td>
<td>Sediment is supported by fluid scaping upward as gravity sets the grains.</td>
</tr>
<tr>
<td>Grain flows</td>
<td>Direct grain-to-grain support the sediment.</td>
<td>The beds are massive and ungraded. Dish structures and diffuse parallel laminations and clasts are found.</td>
</tr>
<tr>
<td>Debris flows and Debrites</td>
<td>Large cohesion flow. Composed of clay, granular solids, and water. Grains are supported by strength and buoyancy.</td>
<td>No structures with clasts are set randomly in a fine matrix. There might be some slide and deformation structures.</td>
</tr>
</tbody>
</table>

Figure 2.6 Summary of sediment gravity flows, the main processes associated with them, and main sedimentary structures found within their deposits.
Figure 2.7 Sediment gravity-flow classification as debris flows, composite co-genetic flows, high-density turbidites, and low-density turbidites, and their sediment record characteristics upward and onward in the basin. (Haughton et al., 2009) Published with the permission of ELSEVIER LTD.

Figure 2.8 Flow transformation from beginning to end and deposits. One shows the typical development of a classic "Bouma" style sequence. 2. Shows the development of hybrid event beds and possible configurations (Haughton et al., 2009). Published with the permission of ELSEVIER LTD.
Figure 2.9 Hybrid event bed classification, lithology, and associated processes. Modified from Haughton et al., 2009. Published with the permission of ELSEVIER LTD.
Hybrid event beds are preserved in the lateral or distal edges of systems commonly dominated by turbulent flow processes. As a result, hybrid sediment gravity flows usually display a clean sandy interval at the bottom and darker, poorly sorted, chaotic laminations, muddy sandstones, or sandy mud divisions at the top, which differs from a “regular” turbidite, where clays are deposited by suspension as a mud cap.

2.3.2 Petrographic Analyses

Facies were defined based on their characteristics observed in the core and later refined by petrology and geochemistry. Forty-two petrographic thin sections were analyzed for intra-, and extrabasinal grain components, texture, fabric, and authigenic mineral changes highlighted in each identified facies. Thin sections were prepared at Stratum Reservoir and Colorado School of Mines, stained for carbonates and feldspars, and analyzed at the Colorado School of Mines.

By integrating log, core, thin sections, and laboratory data, it was possible to identify different lithofacies and thus their associated architectural elements. In deep water deposits, the architectural elements are the different bodies or groups of bodies with lower and upper confining boundaries genetically related to each other and generated in a common depositional setting (Slatt et al., 2009).

Previous studies (Slatt et al., 2009, Thyne et al., 2003) described the Lewis Shale's Dad Sandstones as fine- to medium-grained. Grains are angular to subangular, moderately to poorly sorted, and grain supported. Their composition is mainly from the detrital origin (Slatt et al., 2009), with a minor amount of mica, organic matter, and lithic crystals. The matrix comprises clays, and the most common types of cement, although scarce, are calcite, quartz, dolomite, and clay (in order of abundance).

2.3.3 Chemostratigraphy

X-ray Fluorescence spectroscopy (XRF) analyses were performed every 0.5 ft using the Niton XL3 energy-dispersive X-ray fluorescence (ED-XRF) analyzer that belongs to the MUDTOC Consortia at the Colorado School of Mines. This instrument measures the elemental composition of rocks.

XRF provides elemental concentrations for major elements heavier than Sodium (Na) (Si, Ti, Al, Fe, Mn, Mg, Ca, K, P, S) and trace elements (Ba, V, Cr, Cu, Zn, Rb, Sr, Zr, Nb, Mo, Th, and U).
Measurements were taken at selected intervals by placing the Niton XL3 on slabbed core samples in the TestAll Geo mode for 180-seconds.

The ED-XRF instrument was calibrated to a reference material with known elemental concentrations before testing and periodically during data collection to resolve drift in the data and ensure its validity. In this case, a shale sample was used as the reference material. The elemental composition can correlate intervals, identify changes in depositional environments, and estimate the organic richness of intervals.

Certain elements have more affinity with detrital sediments (Turner et al., 2015). Some of the detrital proxies are:

- Chromium (Cr): can be transported to sediment by a land-derived clastic fraction (clay minerals, ferromagnesian minerals).
- Aluminum (Al): associated with the detrital clay fraction. It is commonly found in fluvial and eolian sediments (Brumsac, 2006).
- Titanium (Ti): is often found within clays as wind-blown silt particles (Turner et al., 2015).
- Potassium (K): found in mudrocks, clay minerals, and feldspars.
- Zirconium (Zr): rarely authigenic, from detrital silts, reworked bentonites.
- Silicon (Si): it can be found in clays and quartz (authigenic and biogenic). The ratio of silicon with the main detrital proxies can help identify authigenic or biogenic quartz zones.
- Several proxies are the most widely used as redox indicators.
- Molybdenum (Mo): is present in seawater as the molybdate anion (MoO42-). It precipitates out of the solution and is locked into the sediment-water interface if there are oxygen-poor conditions and enough free H2S. It correlates with TOC (Algeo and Maynard, 2004).
• Vanadium (V): it is highly mobile under oxidizing conditions. It does not require sulfur to precipitate if anoxic conditions are present (Algeo and Maynard, 2004).

• Uranium (U): its precipitation is catalyzed by reactions at sediment redox boundaries. It is not influenced by Mn and Fe redox cycling in the water column. On the handheld XRF, Uranium can present some inconsistencies due to tool capabilities (Algeo and Maynard, 2004).

These proxies’ trends can infer other relationships, such as sequence stratigraphy. For example, if there is a general increasing trend in detrital proxies’ signals (Ti, Al, Zr, K), the system might be in a lowstand system tract (LST) (Zou et al., 2017). In this case, Al and K are associated more with feldspars, and in some isolated basins, there might be some degree of anoxia showing high concentrations of Mo and V (Zou et al. 2017).

A transgressive system tract (TST) might be inferred if there is a general decrease in the continental proxies (Ti and Zr). Al and K become more associated with the clay fraction and still have higher concentrations than Ti and Zr. High stand system tract (HST) is characterized by the decline in restriction levels (V and Mo) and an increase in the detrital proxies’ trend. A carbonate environment has high Ca, Sr, and Mg (Zou et al., 2017).

2.3.4 Mineralogical Model

The model used is the one Nance and Rowe (2015) described using only calcite, quartz, and clay. This model uses a stoichiometric relationship between the elements and the minerals from average values of Si and K in published illite analyses. XRF provides element concentration data that are easy to convert to mineral content. This method requires comparing the XRF-elemental data with XRD data and then developing calibration curves and regression equations for the curves from which to calculate mineral abundances from elemental data.

Nance and Rowe (2015) use the main constituents of the Bone Spring Formation, which are calcite, quartz, and illite. From the content of clay, they calculate analytical values for K and Si acquired from
illite samples analyzed with XRD and estimate the mineral abundances based on Weaver (1965) and Mermut and Cano (2001).

Calculations show that strongly bonded illite-like layers commonly have 9% to 10% of K$_2$O. If the percentage is more than 10%, it suggests the presence of non-illite layers. Nance and Rowe (2015) use the following relationships:

- Calcite: Ca is 40% of CaCO$_3$, then %calcite = 2.5Ca (assuming no other carbonate phases are present).
- Illite: K is present in an average of 6% in Illite (based on Weaver, 1965), so %illite = 16.58 K.
- Si in Illite: Si averages 25% of illite, (Mermut and Cano 2001), which must be subtracted from total Si before % quartz is calculated. Si$_{illite}$ = %illite * 0.25
- Quartz: Si is 47% of SiO$_2$ (quartz), then %quartz = (%Si$_{Total}$ - %Si$_{illite}$) * 2.14

2.3.5 X-Ray Diffraction (XRD)

The main minerals were identified from the petrographic thin section and XRD analyses. XRD samples were selected based on lithology, sedimentary structure changes, and GR responses. Samples were analyzed for bulk mineralogy and, when possible, clay differentiation at Corelab Laboratories or Stratum Reservoir. The brittleness of rock or fracability is controlled by several factors such as strength, lithology, texture, effective stress, temperature, fluid type diagenesis, and TOC (Wang and Gale, 2009). The brittleness index helps quantify some of these factors based on the mineral composition and diagenesis of the rock. It is an approximation without calculating Young's and Poisson moduli. Minerals that affect this index the most are quartz and carbonates, which increase the brittleness index, and clay, and TOC content, which decrease it (Jarvie, 2007).

Wang and Gale (2009) also included dolomite as a brittle mineral. However, the brittleness index was not calculated for all these cores due to the scarcity of TOC measurements, preventing calculation. Instead, an approximation of brittleness was determined based on the formula's principle. The higher the percentage of quartz and dolomite, the higher the brittleness index. When calcite percentage is high, it can
act as a brittle mineral. Dolomite is found as grains and cement, augmenting the rock's brittleness and decreasing its porosity and permeability. However, in general, the high quartz, calcite, dolomite, and plagioclase content in all the cored intervals makes them particularly brittle, thus facilitating hydraulic fracturing and drilling. Depth can affect the brittleness of a rock as it affects pressures, temperature, TOC, and diagenesis. Depth positively correlates with temperature, pressure, and diagenesis and negatively correlates with TOC (Wang and Gale, 2009). Silica tends to increase with increasing depth due to the Smectite to Illite conversion, thus increasing the brittleness of the rock (Wells, 2004; Wang and Gale, 2009).

2.3.6 Field-Emission Scanning Electron Microscope (FE-SEM)

FE-SEM is a non-destructive technique that allows the visualization of samples from 10x to about 300,000x magnification. FE-SEM analyses were performed using a TESCAN MIRA3 LMH Schottky Field Emission SEM at the Colorado School of Mines. This instrument has capabilities of topography contrast (using secondary electron imaging (SE)), phase contrast (Backscatter electron imaging (BSE)), and compositional analysis (using Energy-dispersive X-ray spectroscopy (EDS)). SE images provide topographical information about the sample. In this analysis, the k-shell ejects secondary electrons by inelastic interaction with the beam electrons. Thus, the signal's brightness depends on the number of secondary electrons reaching the detector, providing topography contrast. In addition, BSE gives information about the presence and distribution of the elements within the sample.

The phase-contrast consists of back-scattered electrons from the specimen interaction volume by elastic scattering interactions with specimen atoms. It detects contrast between areas with different chemical compositions since high atomic-numbers backscatter electrons more strongly than elements with low atomic numbers and, therefore, appear brighter in the image. EDS measures the X-rays emitted from the sample, thus, allowing a semi-quantitative analysis of the elemental composition of the area analyzed. Analyses can be shown as a composition map displaying the main elemental composition of an entire image taken on the FE-SE or selecting a spot for analysis. High-resolution images were obtained using six...
thin sections and three rock samples that were oriented perpendicular to the bedding plane and coated with carbon.

### 2.3.7 Organic Geochemistry

Pyrolysis analyses are performed on rocks to evaluate their potential to generate hydrocarbons and determine thermal maturity. Therefore, TOC and pyrolysis were performed on the shales and siltstones to assess their potential as a source of hydrocarbons. A total of 45 samples were analyzed for TOC, and from those, 29 were used for pyrolysis analysis. Plants, zooplankton, phytoplankton, and algae are the primary sources of organic matter (Jarvie, 1991). The source determines the type of kerogen and, thus, the type of hydrocarbon generated and influences the present-day thermal maturity (Jarvie, 1991). The organic carbon content, including kerogen and bitumen in a rock sample, is minimal, including kerogen and bitumen (Peters and Cassa, 1994). Total organic carbon (TOC) measures the organic richness of the sedimentary rock. The higher the content, the higher the potential to generate hydrocarbons (Figure 2.10). Hence, TOC screening is one of the most used techniques to evaluate source rocks (Jarvie, 1991). After this, additional analyses (pyrolysis, vitrinite reflectance) determine the source potential of the rock. The TOC value and TOC composition are significant in determining the potential of a source rock and the type of hydrocarbon the rock is more likely to produce.

<table>
<thead>
<tr>
<th>Quantity</th>
<th>TOC (wt. %)</th>
<th>S1 (mg HC/g rock)</th>
<th>S2 (mg HC/g rock)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poor</td>
<td>0-0.5</td>
<td>0-0.5</td>
<td>0-2.5</td>
</tr>
<tr>
<td>Fair</td>
<td>0.5-1</td>
<td>0.5-1</td>
<td>2.5-5</td>
</tr>
<tr>
<td>Good</td>
<td>1-2</td>
<td>1-2</td>
<td>5-10</td>
</tr>
<tr>
<td>Very Good</td>
<td>2+</td>
<td>2+</td>
<td>10+</td>
</tr>
</tbody>
</table>

Figure 2.10 Source rock potential from TOC and SRA. Most of the samples from this study fall within poor to fair potential. From Peters, 1986. AAPG©[1985], and the phrase “reprinted by permission of the AAPG whose permission is required for further use.

Pyrolysis helps determine the potential to generate hydrocarbons and the thermal maturity of the sample (Peters, 1986). Pyrolysis analysis provides S1, S2, S3, HI, OI and Tmax values, given in mgHC/g of rock and °C (Tmax). S1 represents the hydrocarbon present in the sample. A High S1 peak indicates
that the sample is mature and has generated hydrocarbons (Peters, 1986, McCarthy et al., 2011). S2 peak represents the remaining potential for the rock to produce hydrocarbons once the sample is subject to the processes of burial and increased temperatures. The third peak (S3) represents the carbon dioxide generated during programmed heating up to 390°C from the kerogen before releasing the earliest inorganic carbon dioxide (Peters, 1986, Hart and Steen, 2015) (Figure 2.11).

Hydrogen index (HI) values can help identify the type of hydrocarbon generated. Values between 0-150 mg HC/g Corg generate gas, between 150-300 can generate gas and oil, and values greater than 300 generate oil. Tmax values can help determine the thermal maturity of the samples; values between 435-445°C represent samples in the early oil window, whereas samples with values of more than 470°C are in the gas window (Peters, 1986).

Well 2 and 3 were analyzed at Stratum Reservoir using Rock-Eval equipment. In addition, well 1 and 4 samples were analyzed using the Source rock analyzer TM (SRA-TPH/TOC Version 1.0) at the Colorado School of Mines.

![Figure 2.11 A) Typical pyrogram obtained from pyrolysis showing the main peaks and their significance. B) Type of Hydrocarbon generated based on HI. C) Thermal maturity derived from Tmax and Ro. Modified from Hart and Steen, 2015(A) and Peters, 1986 (B, C). AAPG©[1985], and the phrase “reprinted by permission of the AAPG whose permission is required for further use.

Vitrinite Reflectance was initially developed to measure coal rank by measuring the percentage of light reflected off the vitrinite maceral at 500x magnification in oil immersion (Cardott, 2012). Vitrinite
reflectance is also used to determine a rock's thermal maturity. The percentage of reflected light varies with thermal maturity. Vitrinite reflectance analyses were performed in four samples from well 3.

This analysis helps determine the type of organic matter present in the rock, therefore helping identify the type of kerogen present (McCarthy et al., 2011). Figure 2.12 shows the reflectance percentage and the thermal maturity expected for each percentage of reflected light.

![Figure 2.12](image.png)

Figure 2.12 Thermal maturity from Vitrinite reflectance. From Tissot and Welte, 1984. Used with the permission of SPRINGER-VERLAG NEW YORK INC.

Vitrinite is a maceral from woody material (Tissot and Welte, 1984). To find this maceral in a marine environment, Woody particles have to be small enough to be transported by water or by the wind away from their continental source. Therefore, sometimes it is challenging to identify vitrinite in marine rocks due to the distance between the source of the vitrinite and the formation of these rocks. Also, the similar appearance of vitrinite to bitumen makes it especially difficult to detect and measure using the microscope (Cardott, 2012).
Solid bitumen is the main organic matter in high-temperature thermally mature gas systems. Type I/II kerogens are diminished at higher maturities in shales because they have converted into hydrocarbons, either from other sources or in situ (Wood et al., 2015). Type III/IV kerogen (vitrinite and inertinite) are preserved in shale gas reservoirs, changing very little. Gas from reservoirs with solid bitumen is present as free gas or sorbed gas or dissolved (absorbed) in the solid bitumen (Hackley, 2017).

The Vitrinite Reflectance Equivalent (VRE) value may be used as a thermal maturity indicator when vitrinite is absent or to verify the vitrinite-reflectance value. Solid hydrocarbons in sedimentary rocks change with thermal maturity as macerals do (Landis and Castaño, 1995). Thus, solid bitumen can be a good tool for thermal maturity calculation. In addition, the existence of bitumen and solid hydrocarbons is visual proof that the rock has generated liquid hydrocarbons (Cardott et al., 2015).

2.3.8 Well-log Analysis and Subsurface mapping

Well-logs obtained from the Wyoming Oil and Gas Conservation Commission (WOGCC) and TGS were correlated using the gamma-ray (GR) signature for the Lewis Shale in the Wamsutter Field. Since the Lewis Shale is a very thick unit, the three-member division is insufficient to correlate specific sand packages. For this reason, correlated intervals are separated by different flooding surfaces that show higher GR values and can be followed throughout the basin. Similar to that used by Pyles and Slatt (2000) and Pasternack (2005) (Figures 2.13, 2.14).

Correlations were centered in areas surrounding the four cores. Based on these correlations, the placement of each of the cores is in different packages separated by the fourth-order flooding surfaces. Correlations for these specific cored packages were extended to the surrounding wells. Then, isopach and structural maps were built for each cored package from these correlations. These correlations also show the different heights and lengths of the clinoforms that form the Lewis Shale.
Figure 2.13 Regional Stratigraphic cross-section of the Lewis Shale, lateral equivalent formations, and underlying Almond Formation. It shows the different depositional environments, location of the shelf edge, and general progradation of the Lewis towards the south. (From Pyles and Slatt, 2000). AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use.
Figure 2.14 Type log of the Lewis Shale with the equivalent flooding surfaces used in this study. This well is located in the Washakie Basin, south of all of the cores in this study. (Modified from Pyles and Slatt, 2000). AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use.
Clinoforms are the inclined subaqueous depositional plane extending from the outer edge of the undaform down to the fondo form level of the water body. The length of a clinoform is given by the distance between the wave base and the bottom of the seafloor and the angle of inclination (Rich, 1951). They are usually separated by datums which usually are flooding surfaces.

2.3.9 Architectural Elements

The main architectural elements within the Lewis Shale include channels, levee deposits, lobes, mass transport deposits, and flooding surfaces. Most of the wells in this area are drilled in the sandstone bodies, usually associated with channel fill and high-density turbidite deposits from the Dad Sandstone and Lower Member (Slatt et al., 2009). Channels have erosional bases; the channel's top may be erosional or gradational. They have several events of filling and erosion surfaces bound each one. When the channel width increases the slope of the margins, narrow channels can have margins with slopes that can reach up to 45°. Channels with gentle slopes have a sheet-like geometry and almost non-discriminable margins (Miall, 1985). Channels are elements where sediments are constantly bypassing, maintained by the turbidity-current flow depositional processes or erosional events determining their shape (Weimer et al., 2007).

The sediment filling the channels varies greatly in lithology, including gravel, sand, mud, and mixed fills, controlled by tectonism, sediment influx, or climate. These also control the nature of filling, such as gravity flows (turbidites or debrites) or hemipelagic suspension fallout (Weimer et al., 2007). These elements can be found in the lobes' proximal and central areas. In addition, there is an upward tendency due to the change from amalgamated channels to levee channels. By contrast, distal lobes have an excellent continuity with lesser amounts of shales and siltstones. They vary laterally from amalgamated to layered, but this change occurs over long distances.

Well-log responses include blocky sands that thin upwards and fining upward patterns separated by shales (Figure 2.15). Individual channel-fill reservoirs are 16–50 ft. thick and can reach higher thicknesses when these are amalgamated.
A marked grain contrast occurs between the channel-fill sediments and the adjacent slope system in many basins. The overbank sediments are mud and silt-dominated. Differentiating sandstone bodies from channel fill versus high-density turbidites is a difficult task. Using limited log data can prove problematic due to their vertical and laterally variability.

The percentage of sandstone versus siltstones and mudstones often changes from the channel axis to its margins being higher towards its axis, which is reflected in the well-log signature (Figure 2.16, 2.17). If, for example, a GR log has changed in its signature over short distances, the sediment is identified as a channel-fill element (Weimer et al. 2007).

Figure 2.15 Log signature, sedimentary characteristics, and their associated architectural elements. This helps classify each of the cored intervals. From Koo et al., 2016. Published with permission of the Journal of sedimentary research.
Figure 2.16 Architectural elements and their associated log signature. From Koo et al., 2016. Published with permission of the Journal of sedimentary research.

Figure 2.17 Log signature and lateral variation of the channelized elements within lobes. Similar to those seen in the correlations of the cored intervals. (See mapping and correlations section). From Koo et al., 2016. Published with permission of the Journal of sedimentary research.
Some elements associated with channels and frequently overlooked are the levee-overbank deposits. In the well-log response, these thin-bedded zones look like shaly or "ratty" intervals. This signature is because they are thin-bedded and are usually below the well-log resolution. However, some thin sandstone beds can be present (Weimer et al., 2007).

2.4 Results

2.4.1 Core Analysis

The cored interval on Well 1 is 457 ft. It consists of beds of sandstones intercalated with siltstones and shales (Figure 2.18). Sedimentary structures include fine laminations, soft-sediment deformation, flame-up structures, ripples, convoluted beds, scour surfaces, rip-up clasts, burrows, and bioturbation. There are also some structureless sandstones present. This core displays several changes in depositional events, and incomplete Bouma sequences can be found as a mix of debris flows and high-density turbidites. Carbonaceous materials, such as leaves and shells, are pervasive throughout the core. The fine-grain deposits interbedded with the sandstone represented bypass intervals or extended periods when no sandstone was deposited. Bioturbation includes *Ophiomorpha, Phycosiphon*, and *Schaubcylindrichnus*.

These ichnofacies indicate relatively high wave or current energy levels. It is typically developed in muddy to clean sand-prone environments with moderately sorted to well-sorted particles. These environments are generally subject to changes in the rate of deposition, erosion, and reworking, reflecting changes in the system's energy. These changes cause reworking, in some cases erasing the biogenic structures and preserving the sedimentary ones (MacEachern, 2009).

The cored interval for Well 2 was 93 ft. It consists of very fine- to fine-grained, light grey sandstone (Figure 2.19). It goes from structureless to fine-laminated, ripples, rip-up clasts, mudclasts, soft-sediment deformation, and erosional surfaces. Some black crystals seem to be muscovite. Towards the bottom of the interval, there is a shale interval of about 2.5 ft thick. There are no fossils present, and the structureless sandstones have some crypto bioturbation. It is interpreted to be deposited as a high-density turbidity current.
The third well-cored interval has 177 ft. It was taken from the F interval (Figure 2.20) and dark grey siltstones with burrows. *Schaubcylindrichnus* and *Phycosiphon* trace fossils were present. Laminations are not easy to identify due to the high levels of bioturbation. However, the bioturbation decreases, and laminations are more readily visible towards the bottom of the core.

The interval cored for Well 4 has 90 ft. It consists of beds of sandstones (Figure 2.21) intercalated with siltstones and shales. Sedimentary structures include fine laminations, soft-sediment deformation, flame-up structures, ripples, convoluted beds, scour surfaces, rip-up clasts, burrows, bioturbation, and structureless sandstones.

### 2.4.1.1 Sediment Gravity-flows

Each core was examined for the occurrence of sediment gravity flow hybrid event beds which contain up to five internal divisions such as argillaceous and commonly mud clast-bearing sandstones (linked debrite H3), overlain by banded sandstones (transitional flow deposits, H2), and structureless sandstones that can show structures such as dewatering, dishes, or commonly dewatering sheets (high-density turbidity currents, H1). In addition, many hybrid event beds are capped by a relatively thin, well-structured, and graded sand-mud couplet (trailing low-density turbulent cloud H4 and mud suspension fallout H5. Although Haughton and Middleton proposed a specific facies assemblage from H1 to H5 and stacking pattern defining hybrid events, our observations in the Lewis suggest that, although these facies occur, they rarely follow the classic pattern defined by Haughton and Middleton (1973) (Figure 2.22).

This core shows the rapid changes in the density of the flows, rapid deposition of the sediments, and reworking in these environments.
Figure 2.18 Core description for well 1. Bioturbation is pervasive through the entire core. The mineralogical model shows high quartz content. There are several coarsening-upwards sequences and two flooding surfaces recognizable in this core. On the right are some of the sedimentary structures that can be found on this core. See appendix for core description.
Figure 2.19 Core description for well 2. It is mainly composed of sandstone that varies from structureless to fine laminated with ripples. Towards the bottom of the core is a small shale break that could belong to a small levee from another channel. See appendix for core description.
Figure 2.20 Core description for Well 3. The main variation in this core corresponds to levels of bioturbation. It consists of bioturbated sandy siltstones. Bioturbation decreases towards the bottom of the core. See appendix for core description.

Sedimentary Structures:
- Soft sediment deformation
- Climbing up ripples
- Planar lamination
- Schaubcylindrichnus, Phycosiphon
Figure 2.21 Core description for Well 4. This core displays several events with changes from cohesive to non-cohesive to mixed events. It mainly consists of bioturbated sandstones and siltstones. See appendix for core description.
Well 2 core includes H1, H2, and H5 type of beds. Beds usually follow H1 or H2, but in some cases, the sequence is incomplete (i.e., H2, H5) (Figure 2.23 B). H1 beds are structureless sandstones that can have a structure such as dewatering, dishes, or commonly dewatering sheets. H2 is overlain by banded sandstones, corresponding to a transitional flow deposit with intermittent turbulence suppression due to near-bed dispersed clay and internal shearing.

This facies suggests a significant amount of sediment bypassed this proximal part of the axial channel belt. The fine-grain deposits interbedded with the sandstone represented bypass intervals or extended periods when no sandstone was deposited.

There was a rapid change between high-density turbidity to low-density turbidity current. The general lack of structures in the Well 2 core containing dewatering structures (in all the cored intervals) is interpreted to be due to rapid deposition by sediment gravity flows.

Well 3 core has mainly H4 and H5 types of beds. This core is primarily composed of silt and mud. Most of the sedimentary structures are obscured by the bioturbation present (Figure 2.24).

Well 4 core is a very heterogeneous core with several hybrid events that include high-density turbidites (H1), transitional flows (H2), cohesive debris with injectites (H3), and traction by dilute turbulent wake (H4), suspension fallout with shearing (H5) (Figure 2.25).

Reservoir Quality

The deposition of the hemipelagic and pelagic sediments and debrites can act as seals in these reservoirs. They can help the reservoir, sealing the hydrocarbons within and as migration barriers.

Some sedimentary structures such as injectites and burrows can serve as migration pathways for hydrocarbons into the reservoir. In most of the intervals, the presence of clay was evident. Thus, thin section, XRD, XRF, and FE-SEM analysis was crucial to identify the type of clays present and determine their role in the reservoir quality of these intervals.
Figure 2.22 Some of the hybrid events found on well 1. This core shows several interbedded high-density turbidites, low-density turbidites, and debrites that reflect episodes of energy change in the system.
Figure 2.23 Hybrid events sequence and some examples from Well 2 core. Most of this core has structureless sandstones with a few planar laminations present.
Figure 2.24 Hybrid events found on Well 3. Ripples and planar laminations are frequently found. Bioturbation levels obscure the sedimentary structures present.
Figure 2.25 Hybrid events sequence and some examples from the Well 4 core. This core has a high abundance of sedimentary structures, from ripples to flame-up structures, convoluted beds, erosional surfaces, and several types of bioturbation.

Sedimentary Structures:
- Bioturbation
- Planar laminations
- Rip up clast
- Climbing ripples
- “Massive” beds
- Erosional surface
- Soft sediment deformation
- Convoluted beds
2.4.2  Facies Analyses

Detailed core, thin section, and geochemical analyses were used to identify sedimentary facies. Facies were classified based on lithologic assemblage, sedimentary structures, and biologic structures.

Table 1 illustrates the seven sedimentary facies identified in all the cores, listing main characteristics and image examples. Classification of sedimentary rocks, especially sandstones, includes textural and mineralogical characteristics.

The Folk classification ternary diagram (Folk, 1954) gives essential information about provenance, with the name reflecting the details of its composition. In addition, the QFR (quartz, feldspar, rock fragments) ternary diagrams have effectively the relationship between plate tectonic settings and sandstone compositions. Finally, facies were classified using Folk’s sedimentary diagram (Folk, 1954) (Figure 2.26).

![Folk diagram classification for sedimentary rocks based on the composition used to classify rocks in this study. Q (Quartz) includes all mono and polycrystalline quartz, F (Feldspar Grains) include feldspars and gneiss and granite lithic grains, R (Rock Fragments) include lithic grains such as chert, sedimentary rocks, schist, shale, slate, and all carbonates, M (Metamorphic Rock Fragments) includes low-grade metamorphic rocks, V (Volcanic Rock Fragments).](image-url)
The detrital fraction comprises silica as quartz (with undulated and non-undulated extinction) and chert. Feldspars are mostly plagioclase, and K-feldspars are found in less quantity. Lithic grains are also present as detrital carbonate, rock fragments, micas, organic matter, and clay minerals. In some cases, grains are altered either to chlorite or clay, complicating their identification (Figure 2.27 D). Thus, potentially decreasing the porosity and permeability of the rock by the pores that are present, although some of the chlorites seem to be coating quartz and could potentially preserve some of the porosity and permeability. The matrix comprises clay minerals, micas, organic matter, silt-sized quartz, and microcrystalline quartz for matrix-supported samples, although they often are too small to be identifiable (Figure 2.27 C). Physical compaction was evident in most samples, especially in the stratigraphically deeper ones, as evidenced by clay minerals’ deformation, a higher abundance of sutured contacts, and higher contact indexes. All elements act to reduce porosity and permeability. Calcite and dolomite are present as cement and detrital grains, decreasing the porosity and permeability of the rock. All the core effervesced when in contact with hydrochloric acid. These findings are similar to those made by D'agostino (2004) and Thyne et al. (2003).

Porosity data show some positive correlation with the percentage of quartz in the system, and permeability decreases with increasing carbonate content—both porosity and permeability decrease in areas with higher amounts of clays. Quartz cement is limited by compaction that has forced quartz grains into contact with clays. Altered foraminifera replaced by calcite are also present but in low quantities.
Figure 2.27 Thin section photomicrographs for the main facies showing the main components and characteristics. A) F2; Bioturbated Sandy Siltstone. B) F3; Finely Laminated sandy siltstone. C) F4; Finely laminated bioturbated siltstone. D) F5; Bioturbated silty sandstone. E) F6; Massive sandstone, F) F7; Finely laminated silty sandstone. Bioturbated Shale and convoluted bed facies did not have thin sections, and classification was made from the core description.
Figure 2.27 continued.
Eight facies (F1-F8) were defined in the Lewis core and are detailed below. They include bioturbated siliceous mudstone (F1), bioturbated sandy siltstone (F2), finely laminated sandy siltstone (F3), finely laminated bioturbated siltstone (F4), bioturbated silty sandstone (F5), massive sandstone (F6), finely laminated silty sandstone and contorted beds (F8).

Facies 1 Bioturbated siliceous mudstone

Due to the high levels of bioturbation, samples from these facies do not display clear laminations, or they are faint. Instead, samples from this facies are dark grey to black, with mud-silt size grains, abundant particles of organic matter, and fossil fragments. Bioturbation types include *Schaubcylinrichnus* and *Phycosiphon*.

Facies 2 Bioturbated sandy siltstone

This facies appears as dark grey with light grey wisps of very-fine sandstone impacted by bioturbation. In the thin section, the rock is grain-supported and, in some areas, matrix-supported. Thin sections are composed of (from most abundant to least abundant) quartz (chert, monocrystalline quartz), lithics (some unrecognizable and are volcanic rock fragments), and feldspars (plagioclase and K-feldspars), dolomite, and calcite (Figure 2.28). The main secondary minerals present are biotite and muscovite. In addition, alteration to chlorite and sericite is present and abundant. Grains usually have sutured contacts and point contacts with very low to non-existent porosity. The compositional classification is calcareous subarkose, lithic arkose, feldspathic litharenite, and litharenite. The most common being lithic arkose and feldspathic litharenite.
Facies 3 Finely laminated sandy siltstone.

This facies appears dark grey with fine laminations; bioturbation is lower than previous facies. The thin section shows that the rock is grain supported with detrital grains (Figure 2.29). The grain size is coarse siltstone. Silica is present as monocrystalline quartz and chert, lithics, feldspars, calcite, and dolomite as grains and contains the accessories, chlorite, biotite, muscovite, and sericite. Grain contacts are point and floating. There is a high organic matter content, and chlorite clay coatings are present. Compositionally this facies can be classified as feldspathic litharenite.
Facies 4 Finely laminated bioturbated siltstone

This facies occurs as light grey to medium grey, bioturbation is high, destroying any possible laminations. Bioturbation includes *Ophiomorpha*, *Schaubcyclindrichnus*, and *Phycosiphon*. Silica is abundant, followed by lithic fragments (mainly volcanic fragments), feldspars, dolomite, and calcite (Figure 2.30). Secondary grains are muscovite and biotite, with some altered to chlorite and sericite. Compositional, these thin sections were classified as calcareous litharenite, feldspathic litharenite, lithic arkose, and feldspathic litharenite.

![Figure 2.30 Finely laminated bioturbated siltstone. Observe the faint on the first image. Compositionally it is similar to the other facies with high quartz content, micas, feldspars, and chlorite.](image-url)
Facies 5 Bioturbated silty sandstone

This facies appears as a light grey rock. Bioturbation has altered the beds giving them a wispy look. Some of the bioturbation present is identified as *Schaubcylindrichnus* and *Phycosiphon*. There is some carbonaceous material present, seen as plant leaves and fragments. As in the other facies, silica is abundant and can be found as chert and quartz. There is abundant chlorite growing on top of crystals and coating quartz grains. There are some shell fragments present in the thin sections. Calcite and dolomite are present as crystals and cement (Figure 2.31).

![Figure 2.31 Bioturbated Silty Sandstone facies. It is mainly composed of quartz and plagioclases altering to sericite. Chlorite is present between grains, probably preserving some porosity and, in other cases, as a grain alteration.](image)

Facies 6 Massive sandstone

Samples from this facies are light grey with black wisps identified as phosphates in the thin section. It is grain supported with fine to medium grain size. It has a high silica content seen as monocrystalline quartz and chert, followed by lithics, feldspars, and carbonates represented by dolomite and calcite. Biotite is found as an accessory mineral, and some grains are altered to chlorite and sericite (Figure 2.32). Some grains seem to be phosphates and oxides. Crystals are very close together and, in most cases, have sutured and convex/concave contact between them.
Figure 2.32 Massive sandstone photomicrograph. Note the sutured, presence of lithic fragments, and abundance of quartz and chert.

Facies 7 Finely laminated silty sandstone

Samples from this facies are light grey with fine laminations of dark silt. In some instances, the laminations form sedimentary structures such as ripples, climbing ripples, and convoluted beds. Thin sections display approximately the same composition as the previous facies except for higher silica content (50%-60%). There is also a high content of feldspars, lithics, and carbonates. Carbonates can be found as cements (calcite and ferroan calcite) (Figure 2.33). In some samples, mechanical compaction is evident by the deformation of biotite. Alterations include sericitization and chlorite. Compositionally thin sections belonging to this facies are calcareous litharenite, feldspathic litharenite, or lithic arkose.
Figure 2.33 Finely laminated silty sandstone photomicrograph with calcite cement (pink on the first photo) and abundant feldspars and quartz. There is also evidence of alteration in several grains to sericite and chlorite.

Facies 8 Contorted beds

Facies 8 is characterized by beds that are contorted, which can initially be similar to any of the other facies but has been subjected to soft-sediment deformation and transport typical of turbidite systems.

Reservoir Quality

Changes in flow regime in turbidite currents resulted in variations in rock texture and sedimentary structures (Thyne et al. 1989). Porosity can come from the partial dissolution of grains, including lithic grains, chert, and clay clasts in pores, and dissolution along grain boundaries. There is also the partial dissolution of carbonate cement. However, mechanical compaction seems to be the primary control on porosity. These samples have a high silica content, represented by detrital quartz, chert, and quartz overgrowths. The main factors controlling the solution and precipitation of silica are pH, temperature, presence of CO$_2$, and water turbulence (Laschet, 1984). In addition, paleoclimatic conditions and ferralitic weathering control the rate of silica sourced. When these conditions have been met, the solubility of silica is higher, and the solubility of Al is low. As a result, the residual Al is supplied to the oceans, increasing the AI/Si ratios in the water composition. These also increase the productivity of silica secreting organisms (Laschet, 1984).
The litharenites and quartzarenites in the Kekituk Formation from the Mississippian North Slope of Alaska follow this diagenetic sequence (Bloch and McGowen, 1994): precipitation of early quartz cement, formation of authigenic siderite, at least one episode of limited siderite dissolution, precipitation of ankerite, pressure solution, late quartz cementation, some dissolution of chert, precipitation of kaolinite, emplacement of hydrocarbons, local formation of asphalts.

These processes could also occur within the Lewis shale due to the high percentage of silica as chert and monocrystalline quartz. Some quartz grains seem to have ghost boundaries (Figure 2.34). However, the presence of chlorite inhibits some of the quartz overgrowths. Kaolinite is absent in most samples or in very low quantities (in just one core, Well 4).

![Figure 2.34 Example of ghost boundaries in quartz grains (red circles).](image)

Processes of dissolution of the silica, feldspars, other grains, and chlorite grain coatings can increase the porosity. For example, Do, (2018), in her study of clays and architectural elements, found that sediments from the channel axis have a higher content of micas that create orientation in the samples. She also found higher chlorite in the proximal channel vs. distal margin channels. The deposition of high-density turbidity currents allows the fractionation of the minerals and the sedimentation of rounder and larger grains of quartz and plagioclase. There was a lack of clay minerals in these settings. It is believed that the finer grains were transported into distal parts of the system (Do, 2018).
Samples from Well 2 had fewer clays and larger detrital grains of quartz crystals. These changes in size would indicate that the cleanest part of the core being in the channel axis and that the axis migrated with time, and then margin sediments were deposited. As a result, there is an increase in clay content, and the grain size decreases.

2.4.3 Chemostratigraphic Analysis

The fundamental ratios between the main detrital proxies and silica were plotted to analyze the amount of detrital input (Si/Zr, Si/Al, Si/Ti) and plots for the primary carbonate and redox environments proxies (Figure 2.35, 2.36). These ratios are usually performed as silica is one of the most abundant elements and can be found in clays and quartz to help differentiate areas of possible biogenic or authigenic quartz from clay-rich intervals (Tribovillard et al., 2006). For example, where aluminum is low, and silica content is high, it can indicate biogenic quartz or authigenic quartz.

The different peaks observed in these ratios represent areas where biogenic or authigenic quartz can be present. Zirconium (Zr) can be found in igneous rocks, thus associated with continentally derived sediments. Titanium (Ti) can only be transported from the continent by the wind. Therefore, titanium and zirconium have a strong affinity for coarser grain sediments.

The increase in the Ti/Al ratio suggests more wind-transported sediment since eolian silt grains have more heavy Ti-bearing minerals than purely detrital clay material (Yarincik, 2000). Aluminum (Al) is associated with the detrital clay fraction (Driskill et al., 2018).
Table 2.1 Facies' main characteristics are based on the core description and thin section analysis.

<table>
<thead>
<tr>
<th>Facies</th>
<th>Composition</th>
<th>Sedimentary Structures</th>
<th>Biogenic Structures</th>
<th>Diagenetic Components</th>
<th>Well where can be found</th>
<th>Pictures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bioturbated Siliceous Mudstone. (Facies 1)</td>
<td>Illite-Smectite, detrital mudsize quartz grains. Minor amounts of other grains such as Feldspars, Calcite, Dolomite, Phlogopite, Chlorite and Biothe.</td>
<td>Finely laminated.</td>
<td>Schauberkeritic and Phycocyanin trace fossils are present. Shell fragments.</td>
<td>Mechanical compaction, High Organic matter content. Matrix supported.</td>
<td>Well 1, Well 4.</td>
<td><img src="image1.png" alt="Image" /></td>
</tr>
<tr>
<td>Bioturbated sandy Siltstone. (Facies 2)</td>
<td>Same as previous.</td>
<td>Finely laminated, sand lenses.</td>
<td>Shell fragments. Phycocyanin.</td>
<td>Matrix supported.</td>
<td>Well 1, Well 3, Well 4.</td>
<td><img src="image2.png" alt="Image" /></td>
</tr>
<tr>
<td>Finely laminated Sandy Siltstone. (Facies 3)</td>
<td>Detrital quartz, Feldspars, Calcite, Dolomite, Phlogopite, Chlorite and Biothe.</td>
<td>Finely laminations none</td>
<td></td>
<td>Matrix supported</td>
<td>Well 2</td>
<td><img src="image3.png" alt="Image" /></td>
</tr>
<tr>
<td>Bioturbated Silty Sandstone. (Facies 5)</td>
<td>Quartz, chert, minor amounts of other grains such as Micas, Dolomite, Calcite</td>
<td>Feathertem laminae</td>
<td>Schauberkeritic and phycocyanin trace fossils present. Shell fragments.</td>
<td>Calcite cement</td>
<td>Well 1, Well 3, Well 4.</td>
<td><img src="image5.png" alt="Image" /></td>
</tr>
<tr>
<td>Massive Sandstone. (Facies 6)</td>
<td>Illite-Smectite detrital mudsize quartz grains. Minor amounts of other grains such as Feldspars, Calcite, Dolomite, Phlogopite, Chlorite and Biothe.</td>
<td>Non observed due to bioturbation</td>
<td>Altered forams.</td>
<td>Calcite cement, Clay coatings, chert cement and grains, quartz overgrowth</td>
<td>Well 1, Well 2, Well 4.</td>
<td><img src="image6.png" alt="Image" /></td>
</tr>
<tr>
<td>Finely laminated Silty Sandstone. (Facies 7)</td>
<td>Illite-Smectite, Biogenic and detrital mudsize quartz grains. Minor amounts of other grains such as Feldspars, Calcite, Dolomite, Phlogopite, Chlorite and Biothe.</td>
<td>Fine laminations, ripples, flame up structures.</td>
<td>None visible.</td>
<td>Quartz overgrowth, Clay coatings, Higher Biothe content.</td>
<td>Well 1, Well 2, Well 4.</td>
<td><img src="image7.png" alt="Image" /></td>
</tr>
<tr>
<td>Contorted beds. (Facies 8)</td>
<td>High silica, Al and K content.</td>
<td>Soft sediment deformation, rip up clasts, flame up structures.</td>
<td>None observed.</td>
<td></td>
<td>Well 1, Well 2, Well 4.</td>
<td><img src="image8.png" alt="Image" /></td>
</tr>
</tbody>
</table>
Molybdenum (Mo) is a highly mobile element under oxidizing conditions and precipitates out of solution under anoxic conditions. Under oxidizing conditions, Molybdenum is in solution as the Molybdate anion (MoO$_4^{2-}$). However, molybdenum falls out of solution under oxygen-poor conditions with sufficient concentrations of sulfur, euxinic conditions, which forms thiomolybdates.

Well 1

Chemoostratigraphic analysis shows the main proxies for detrital, carbonate, and redox environments. This interval has a considerable amount of silica (up to 70%). It appears that the upper section of the core (11730-11880 ft) has a higher authigenic quartz content than can be correlated with the amount of chert and microcrystalline quartz found in the thin sections (blue circles) (Figure 2.35, Figure 2.36). Calcium (Ca) and magnesium (Mg) is present as calcite (cement and grains) and dolomite (cement and grains, as shown previously on the petrographic analyses). It seems porosity and permeability increase where more excess silica is present due to dissolution and preservation of the pores. This excess silica can be authigenic or biogenic.

The middle of the core (11880-12000 ft) has a higher GR signature accompanied by a slight increase in clay proxies and clay content, as well as an increase in the anoxic proxies such as vanadium (V) and euxinic environments (nickel (Ni)). An increase in clay content also coincides with a glauconite bed, indicating a possible sediment starvation event and the top of the flooding surface. The presence of biogenic or authigenic quartz is scarce to non-existent.

The lowermost part of the core (12000-12143 ft) has higher aluminum (Al) and potassium (K) content, as well as an increase in biogenic or authigenic quartz. Detrital proxies and marine anoxic-euxinic environment proxies illustrate these mixed environments' high heterogeneity and complexity.
Figure 2.35 XRF profile with detrital, anoxic, and marine environment main proxies for Well 1. Blue circles are areas where excess silica is found. Higher clay proxies coincide with areas identified as flooding surfaces.
Figure 2.36 Excess silica provenance for Well 1. As shown in the plot with the ratios, it has a high abundance of silica that does not seem to have a detrital origin. According to this plot, silica could be either authigenic or biogenic. But it is possible that the cloud also includes detrital silica from cherts. For more explanation see Figure 2.43 (A,B,C,D)
Well 2

The source of the material is mainly detrital, as evidenced by the increase in all of the detrital proxies, such as Zr, Ti, Al, and K (Figure 2.37). In addition, there seems to be some authigenic quartz present, as noted by the peaks on the different ratios with Si, especially Si/Zr and Si/Ti, highlighted by blue circles and shown in the plot of Zr vs. SiO2 (Figure 2.38).

The middle area (~11612 ft) has more calcium, corroborated by the XRD data, and is mainly calcite cement from thin-section analyses. Porosity and permeability appear to be positively correlated with authigenic/biogenic quartz content. Lower porosity correlates with increases in calcite cement, which can be seen in some of the higher calcite peaks in the track where porosity decreases (Cain, 1986). A sharp increase in clay content from the XRD analyses, also identified in the XRF detrital proxies, correlates well with the rise in GR values and a small flooding surface. In general, this interval has high quartz content with dolomite and plagioclase, which would increase its brittleness index (BI). In addition, some porosity is observed in the thin sections and confirmed by the Routine Core Analyses (RCA).

Well 3

In general, the Well 3 core seems to have a detrital control on sedimentation, although it decreases towards the bottom of the core (11562-11585 ft) as marked by the detrital proxies. A few spots of possible authigenic quartz are highlighted by blue circles on the ratios between silica and the main detrital proxies (Figure 2.39). The cross plot between Zr vs. SiO2 shows a high abundance of authigenic or biogenic excess silica (Figure 2.40). V and Ni are positively correlated, increasing towards the bottom of the core, indicating more anoxic environments (green circles).

Al correlates with higher GR values and higher clay content. P is related to the organic richness, and it increases with increasing conditions of retrogradation (orange circle). It also correlates with core observations of less bioturbation and the darker color of the rock. Porosity increases towards the bottom of the core, but permeability decreases; this could be due to higher organic matter and clay content. This core has the lowest porosity of all the intervals.
Calcite and dolomite content is lower in this core but still pervasive throughout the interval. In addition, carbonate cement is identified in some of the thin sections. This core has the least amount of variations on the proxies. It shows there were very few changes in the environment during its deposition. Well 4

The elemental variations for this core reflect the observations in the core. There is a detrital control with a high abundance of silica and authigenic quartz (blue circles) (Figure 2.41), as also shown on the plot of Zr versus SiO$_2$ (Figure 2.42). Vanadium (V) is high at the top of the core (green circle) but is absent towards the bottom of the core, where more vertical bioturbation was observed. Together, they indicate more oxygenated waters and less preservation of organic matter. Uranium, which is a redox environment proxy appears where the other anoxic and redox proxies disappear (V, Ni, Co). Carbonate content is not increasing based on the XRD and elemental data. Furthermore, the vertical bioturbation and other proxies show preservation of Uranium would be impossible, which highlights one of the pitfalls of using just one proxy, especially Uranium. Calcite is present throughout the core and can be seen as detrital grains and authigenic cement. Permeability from routine core analyses is lower than in the other cores. However, porosity is higher, which could be due to more burrows.
Figure 2.37 XRF profile with detrital, anoxic, and marine environments main proxies for Well 2. Blue circles highlight areas of excess silica in the core.
Figure 2.38 Excess silica provenance for Well 2. As shown in the plot with the ratios, it has a high abundance of silica that does not seem to have a detrital origin. According to this plot, silica could be either authigenic or biogenic. But it is possible that the cloud also includes detrital silica from cherts. For more explanation see Figure 2.43 (A,B,C,D).
Figure 2.39 XRF profile with detrital, anoxic, and marine environment main proxies for Well 3. Blue circles represent areas in the core where excess silica is found. The bottom of this core displays less bioturbation and more planar laminations than the upper section. There is also an increase in the organic-rich proxies and redox proxies that coincide with these changes, indicating more anoxic environments and preservation of organic matter.
Figure 2.40 Excess silica provenance for Well 3. As shown in the plot with the ratios, it has a high abundance of silica that does not seem to have a detrital origin. According to this plot, silica could be either authigenic or biogenic. But it is possible that the cloud also includes detrital silica from cherts. For more explanation, see Figure 2.43 (A, B, C, D)
Figure 2.41 XRF profile with detrital, anoxic, and marine environment main proxies for Well 4. Blue circles highlight areas of possible excess silica. Towards the middle of the core, the redox proxies disappear entirely. This is correlated with the appearance of more vertical bioturbation, indicating more oxygenated waters. The red circle highlights some of the pitfalls of using Uranium as the only proxy (where the other redox proxies are not present, Uranium is). Thus, using several proxies for redox, organic richness, or detrital control is essential.
Figure 2.42 Excess silica provenance for Well 4. As shown in the plot with the ratios, it has a high abundance of silica that does not seem to have a detrital origin. According to this plot, silica could be either authigenic or biogenic. But it is possible that the cloud also includes detrital silica from cherts. For more explanation, see Figure 2.43 (A, B, C, D).
Figure 2.43 A) Cross plot of Zr vs. TiO$_2$ detrital proxies shows a detrital control in the sediments. Although when plotting SiO$_2$ vs. any of the detrital proxies (Zr (B), TiO$_2$ (C), or Al (D)), it seems there is no linear fit, and it seems most of the silica is authigenic or biogenic.
Figure 2.43 A shows the cross plots of Zr vs. TiO$_2$; both are detrital proxies and should have a linear fit. Samples that fall directly on the line are considered to have a detrital control (highlighted in green).

Samples that are away from the trend might be authigenic or biogenic (highlighted in bright pink). Figure 2.43 B, C, and D show SiO$_2$ versus detrital proxies. If the silica was entirely detrital, samples would have a direct correlation. However, these plots and the other wells' plots mistakenly indicate that all the silica is authigenic or biogenic (Figures 2.36, 2.38, 2.40, 2.42, 2.43B, C, D).

But, looking at the highlighted detrital points from Figure 2.43A (green outline) and the authigenic/biogenic silica (bright pink), they both are in the same cloud of points on the other plots (Figure 2.4B, C, D). Thin sections showed a high abundance of chert, as well as quartz. The chert can be sourced from Paleozoic carbonates (Phosphoria Formation, Bighorn limestones, Amsden Formation, Gallatin Limestone, among others (Law, 1996), which would explain why the silica does not correlate with the detrital proxies. All the wells showed the same trends as the ones shown above, and it is believed that the cloud of points includes detrital, biogenic, and authigenic silica.

The rapid deposition and high energy of these sediments makes the use of elemental data more challenging to interpret. In most cases, the organic enrichment factors or redox proxies are within the organic matter. In these sediments, the organic matter has been diluted and oxidized by the coarse grain and high energy of the system.

### 2.4.4 Mineralogical Analysis

The mineralogical model for these intervals was calculated from the elemental data obtained by XRF analyses. The model used is the one Nance and Rowe (2015) described using only calcite, quartz, and clay. They used stoichiometric relationships between the elements and the minerals and from average values of Si and K in published illite analyses. One of the pitfalls of this method is that the XRD and the XRF data must come from precisely the same points in the rock and the fact that it assumes ideal stoichiometric relationships between the elemental data from XRF mineralogical data from XRD analysis. The following formulas and relationships were used to calculate the minerals from the elemental data.
For Calcite: Ca is 40% of CaCO$_3$, then %calcite = 2.5Ca (assuming no other carbonate phases are present).

For Illite: K is present in an average of 6% in Illite (based on Weaver, 1965), so %illite = 16.58 K.

Si in Illite averages 25% of Illite, which must be subtracted from total Si before % quartz is calculated.

\[ \text{Si}_{\text{illite}} = \% \text{illite} \times 0.25 \] (Mermut and Cano, 2001).

For quartz: Si is 47% of SiO$_2$ (quartz), then %quartz = (\%Si$_{\text{Total}}$ - \%Si$_{\text{illite}}$) * 2.14

Final values are normalized so that calcite + quartz + illite = 100%

Some potentially significant minerals are not considered in this model, such as dolomite, feldspars, pyrite, accessory minerals, and TOC. Their XRD analyses and the present study show that feldspars are less than 10%. Pyrite is less than 4%. Although in the case of dolomite, their abundances are less than calcite. In samples from this study, dolomite abundance is either close to or higher than the calcite content. Thus, this method underestimates the carbonate fraction because the Ca content in dolomite (CaMg(CO$_3$)) is less than the molar value of calcite (CaCO$_3$), thus, inflating estimates of noncarbonate abundances.

Linear best fit calibration cross plots were performed for Ca and calcite, K and illite, Al and illite, and Si and quartz, covering the minerals that the mineralogical model estimates (Figures 2.44, 2.45). Some of these lines do not fit the trend, but it could be because the points are not precisely the same.
Figure 2.44 Linear relationships between A) SiO2 vs. quartz, B) Ca, and calcite. These plots cover the minerals that the mineralogical model estimates. However, there is not much linear correlation between these samples due to differences in sampling points where the XRF and XRD analyses were performed.

Although this model does not consider other mineral phases present in the samples and final percentages are very different from the ones obtained from X-ray diffraction analysis, they show mineral stratigraphy trends that can help identify areas with higher clay content or higher carbonate content. When available, the mineralogical model was compared to the XRD data, showing the same trends (Figures 2.47, 2.48).
Figure 2.45 A) Aluminum vs. mixed I/s, B) potassium vs. illite, and C) aluminum vs. illite. There is not much linear correlation between these samples. This could be due to sampling areas and point areas where the XRF analysis was performed.
2.4.5 X-Ray Diffraction (XRD)

XRD analyses were performed for bulk and clay differentiation at Stratum laboratories.

Unfortunately, not all the wells were sampled for XRD analyses due to budget constrictions. Therefore, Well 1 was not analyzed.

Well 2 had 20 samples analyzed with XRD. Figure 2.46 shows the distribution of dolomite, kaolinite, calcite, siderite (when present), quartz, pyrite, plagioclase, mixed I/S, illite/mica, and chlorite. The average quartz content for this well is 56.1%, calcite is 2.49%, dolomite 2.53%, illite/mica 5.54%, and I/S is 5.11%, plagioclase is 18.54%, chlorite 7.05% and k-feldspar 2.05%. There is no kaolinite or siderite in these samples. The absence of kaolinite probably indicates a marine environment of deposition (Weaver, 1961).

Figure 2.46 XRD analyses for Well 2 show the distribution of dolomite, kaolinite, calcite, siderite, quartz, pyrite, plagioclase, illite/micas, illite/smectite, and chlorite.
Thirty-eight samples were analyzed from Well 3. Figure 2.47 shows the distribution of the main minerals found in the samples, which are the same as found in Well 2. The average quartz content for this well is 44.1%, calcite is 2.69%, dolomite 7.89%, Illite Mica 11.8%, I/S is 9.42%, plagioclase is 11.9%, chlorite 7.84%, and K-feldspars 2.8%.

Figure 2.47 XRD analyses for Well 3 show the distribution of dolomite, kaolinite, calcite, siderite, quartz, pyrite, plagioclase, illite/micas, illite/smectite, and chlorite and their averages throughout the entire core.
Five samples were analyzed from Well 4. Figure 2.48 shows the distribution of the main minerals found in the samples, which are the same as found in Well 2 and Well 3. The average quartz content for this well is 52%, calcite is 3.4%, dolomite 5%, illite/mica 9.52%, i/s is 8%, plagioclase is 12%, chlorite 3%, and K-feldspars 3.58%. Chlorite content is lower in this well than in the other two wells analyzed. Chlorite usually forms from the transformation of smectite into illite. The transformation usually requires increasing temperature and pressure by increasing depth. However, this interval is the shallowest. All the smectite might not have been transformed into illite and released the silica to form chlorite.

Reservoir quality

Permeability changes show considerable scatter and a relationship to calcite cement. One explanation for this variation among samples is that calcite cement is distributed locally irregularly in the
cores, and as a result, the percent of cement may be highly variable within small core intervals. A second explanation, supported by petrographic evidence, suggests that although the matrix may influence porosity and permeability, its effect is not systematic (see last two columns on elemental data profiles) (Cain, 1986).

There is grain replacement by alteration, such as chlorite and sericite and silica and calcite replacement of fossils. Microcrystalline quartz is found in all the samples analyzed, defined as grains less than 20µm and at least 0.5µm by French et al. 2012 and Olson and Milliken, 2017.

In these samples, microcrystalline quartz can be found as dispersed grains (Figure 2.49A) within the clay matrix, chert-like grains of microcrystalline quartz (Figure 2.49B), or amorphous masses growing on top of chlorite (Figure 2.49C).

Excess Silica

Microcrystalline quartz constitutes a significant portion of the samples' minerals, explaining the amount of excess silica interpreted from the XRF elemental data. There are several potential sources of silica precipitation: biogenic opal, volcanic glass, and illitization of smectite (Milliken and Olson, 2017). XRD data showed the presence of mixed layer illite-smectite. However, the smectite transformation does not seem to be able to provide enough silica to precipitate the amount of excess silica present in these samples. Other potential sources include precipitation from the volcanic glass during early diagenesis and the replacement of organisms. However, the coarse nature of most of the samples analyzed, indicating high energy environments, might indicate that some of the organism fragments were broken, thus making it difficult to identify them.
Figure 2.49 A) Microcrystalline quartz dispersed in the matrix. B) Microcrystalline quartz in a chert-like grain. C) Microcrystalline quartz growing on top of chlorite. Colored pictures represent the composition of the samples. Si is red, Al is green, Fe is yellow, K is orange, Na is teal, and Ca is dark blue. Composition maps confirm the composition of the minerals. High silica content, calcite, and dolomite are usually found as crystals and chlorite as coating grains.

Frequently quartz precipitation after compaction can be a significant factor in porosity loss. Additionally, microcrystalline quartz can preserve porosity when it grows early during low-temperature diagenesis and parallel to the surface of the host grain (French et al., 2012). Finally, chert from the different Paleozoic carbonates in the area can also contribute to excess silica, which is not correlated to the detrital proxies. Intergranular pores are the dominant pores in these samples, especially within the
sandstone facies. In addition, some organic matter pores are present but are minor and only identified in one sample.

Brittleness Index:

The brittleness index is one of the most critical parameters to screen unconventional systems. It is a function of mineral composition and diagenesis. For example, the presence of quartz and dolomite increases the brittleness of rocks, and organic matter increases ductility (Walles, 2004). Wang and Gale (2009) modified the original formula to add dolomite.

$$BI = \frac{Q+\text{Dol}}{(Q+\text{Dol}+\text{Lm}+\text{Cl}+\text{TOC})}$$  \hspace{1cm} (2.1)

Dol: Dolomite
Lm: Limestone
TOC: Total Organic Carbon
Cl: Clay
Q: Quartz

Not all wells were analyzed for TOC content or contained enough clay to be evaluated for the brittleness index. However, Well 3 had enough information to evaluate the brittleness index.

Results are shown in Figure 2.50, in which most of the samples fall within the brittle part due to their high quartz content.
Figure 2.50 Britleness Index calculation for Well 3. Results show that most of the samples are brittle in this interval.

Chlorite

Chlorite can be detrital or authigenic. Detrital chlorite includes mineral grains, components of mineral grains, and matrix. Authigenic chlorite can be grain-coating, pore filling, or grain-replacing. Grain coating chlorite is the dominant chlorite that can improve reservoir quality by inhibiting quartz cementation. It forms because of high chlorite levels, supersaturation in the pore waters, and rapid indiscriminate nucleation, which allows the growth of well-formed and oriented crystals (Worden et al., 2020). Grain coating chlorite probably comes from closed systems diagenesis at the bed scale. The specific origin of chlorite controls its composition. It can come from the transformation of Fe-rich berthierine or transformation of Mg-rich smectite, kaolinite reactions with Fe sources, or a breakdown of volcanic grains. Chlorite in marine sandstones usually has a berthierine origin, whereas continental sandstones have smectite-originated chlorite which is the more commonly found chlorite in marginal marine sandstones (Worden et al., 2020). At 80-100°C, sandstones with grain coats have relatively higher
porosity than those without them. This anomalous porosity occurs because the grain coats inhibit the growth of syntaxial quartz. Microquartz can also inhibit this growth (Aase et al., 1996, Ramm et al., 1997, Jahren and Ramm, 2000, Bloch et al., 1990) and it seems to be helping reserving porosity and permeability as shown on the elemental data profiles where the excess silica is correlated with higher values of porosity and permeability.

Chlorite is a clay mineral that typically contains high Fe and Mg. Chlorite is a common weathering product transported into the oceans from the continent (Worden et al., 2020). When chlorite coating grains are absent, there are no other natural mechanisms to inhibit quartz cement besides microquartz grain coats or early overpressure development; hence quartz cement grows in deeply buried sandstones, and porosity and permeability are very low.

Although, contrary to what many think, the cleaner sandstone is not always the best reservoir, a small amount of clay such as chlorite coating grains can increase the reservoir quality by preserving pores and pore throats (Worden et al., 2020). However, not all chlorite is beneficial for the reservoir; chlorite's physical position and overall volume in the pore network are essential to analyze.

Chlorite does not contain Th, U, or K; hence, it does not increase the GR or spectral GR responses; thus, GR should not be used to identify chlorite. However, detrital chlorite can begin to coat the quartz grains and act as a nucleation site from which authigenic chlorite with well-formed crystals can begin to form (Figure 2.51) (Worden et al., 2020).
These detrital chlorite coatings early in the deposition of the sandstones can account for the angularity of the grains since the coatings would decrease the contact and compaction and be rounded by abrasion. Chlorite coatings in fine-grained sandstones can occlude the pores and restrict fluid flow, but when present in the medium to coarse-grained sandstones, they can preserve porosity and permeability since there are fewer grain-to-grain contacts. Therefore, it is essential to differentiate between pore-filling chlorite and grain coating or pore preserving chlorite (Worden et al., 2020).

One of the methods used to identify chlorite is the petrographic microscope, where chlorite can be detected by its characteristic pleochroic green color or the anomalous birefringence (berlin blue) in cross-polarized light. Thin coats of chlorite on sands grains might be challenging to identify versus pore-filling chlorite. However, chlorite coats can usually be identified due to their color compared to illite (which has
higher-order birefringence colors) and kaolinite which is colorless. In addition, the coat is composed of somewhat perpendicular crystals to the grain surface, and the outer margins of the coat typically appear to be made up of small, bladed crystals (Worden et al., 2020). Usually, the best way to identify chlorite is by XRD analysis or FE-SEM analysis.

Figure 2.52 Porosity in sandstones and closeup of the pores B, C, D, E) Chlorite coating grains preserving porosity. Colored pictures represent the elemental composition of the samples. Si is red, Al is green, Fe is yellow, K is orange, Na is teal, and Ca is dark blue. In all of the images, chlorite can be seen growing parallel to the surface of the grain and preserving porosity and pore throats. Microcrystalline quartz is observed dispersed in the matrix (C, D).
Chlorite can help improve the reservoir quality by coating sandstone grains, which covers the nucleation sites, thus preventing the growth of quartz cement. By contrast, it can decrease reservoir quality if it is found in excess clay-rich siltstone and sandstones, decreasing pore throats, and thus reducing permeability (Worden et al., 2020).

Chlorite with a higher Fe: Mg ratio is usually grain coating instead of pore filling chlorite. There is a strong lithic provenance control on the developing chlorite grain coats (Worden et al., 2020). In addition, chlorites that inhibit the growth of quartz cement have been shown to grow on top of another clay mineral. Chlorites form in alkaline environments with high pH and a high content of Fe ions (Guoyun et al., 2011). However, XRD analyses show a low content of smectite in these samples. Thus, the presence of chlorite can be explained by the transformation of smectite to illite, which releases silica into the system, and the dissolution of feldspars that provide the materials necessary for chlorite formation. Chlorite cement can be formed in different ways, such as releasing Fe and Mg ions during the alteration of ferromagnesian minerals such as biotite, amphiboles, feldspars, and volcanic rock fragments (Guoyun et al., 2011). This absence also coincides with the observations made by Weaver (1961), who found that rocks in the Lewis Shale had a decrease in smectite content when buried to depths greater than 10,000 ft. There is no direct correlation between porosity vs. chlorite when plotted. Likewise, there is no apparent correlation between calcite and porosity, quartz and porosity, or clay and porosity. However, in some cases, the presence of chlorite is seen to preserve porosity in these tight sands.

Figure 2.52 shows FE-SEM images of the massive and finely laminated silty sandstone facies where chlorite coatings preserved porosity. Figure 2.52 A, B, and C images were taken from thin section samples, whereas D and E were taken from rock chips.

2.4.6 FE-SEM and BSE analyses

Nine samples were selected for these analyses to identify the main mineral component, fabric configuration, composition of the cement, and other minerals challenging to identify using thin-section analyses.
These samples show low porosity with high silica (mainly quartz) and sodium (usually correlated with clay content). There is also evidence of calcite and dolomite (mainly cement).

All the analyses have shown that the samples are compositionally very similar. The FE-SEM analyses also helped identify grain configuration, porosity, cement, and clay types. In addition, BSE and SE enabled the identification of some of the major minerals, and minor minerals found (Figures 2.53, 2.54).

Some fractures are filled with organic matter (Figure 2.53 A, C, D). Quartz crystals have clay rims and, in some cases, are coated with chlorite (Figure 2.53B, 2.53 E). Pyrite frambooids are also present in low quantities (Figure 2.53 E, 2.53 C). Microporosity is evident in several samples, due to the dissolution of feldspars and intragranular porosity between quartz grains (Figure 2.53 F, G). The high abundance of clay minerals is evident in all of the images. (Figure 2.53 A, B, C, D, E, F, G, H).

In some cases, the matrix composition was difficult to differentiate. Therefore, EDS was a crucial tool for identifying the composition of the matrix and some of the main minerals present. For example, Figures 2.53 and 2.54 show that the matrix comprises mostly clays, whereas some of the main grains are calcite, feldspars, pyrite, and quartz. Other minerals found include muscovite, pyrite frambooids, apatite, and calcite.

FE-SEM and EDS were crucial tools to identify chlorite and microcrystalline quartz (Figure 2.55 A, B). Samples analyzed using the FE-SEM revealed a high abundance of microcrystalline quartz, and in some sandstone samples, most of the quartz crystals were coated with chlorite (Figure 2.52). EDS proved to be crucial in differentiating between chlorite and illite, due to the similarity in their morphology. In this case, chlorite was identified due to the high content of iron since illite does not contain iron (Figure 2.56).
Figure 2.53 FE-SEM and BSE pictures with some of the main characteristics found on these samples. A) BSE photo showing organic matter and pyrite within a clay matrix, B) BSE image showing a quartz grain, Illite, and chlorite. C) and D) organic matter filling a fracture, E) pyrite framboid in a clay matrix, F) feldspar dissolution creating secondary porosity, G) intragranular porosity in microcrystalline quartz, H) mica crystal within a clay matrix.
Figure 2.54 BSE picture with the main minerals in all of the samples. Three calcite crystals can be seen aligned in a clay and silica matrix. A) sample showing high quartz content within a clay matrix. Feldspars, calcite, and dolomite crystals are present, which corroborates the observations made with the petrographic microscope. B) Calcite crystals dissolving within clay and microcrystalline quartz matrix. C) Pyrite frambooids surrounded by quartz crystals and calcite. D) photomicrograph showing two of the main minerals found in these samples. They are characterized by high quartz content, with dolomite, feldspars, and clay matrix. E) Quartz coated by chlorite. F) Biotite illustrating the mechanical compaction present in these samples.
Figure 2.55 FE-SEM and EDS show the chlorite composition and microcrystalline quartz (A and B). Color represents the composition of the minerals. For example, Si is red, Al is green, Fe is yellow, K is orange, Na is teal, and Ca is dark blue.
2.4.7 Organic Geochemistry

2.4.7.1 Total Organic Carbon (TOC), Source Rock Analysis (SRA), and Vitrinite Reflectance ($R_o$)

Well 1

Samples were collected from fine-grained lithologies that reflected the highest GR values. The TOC for these samples ranged from fair to good, with a maximum TOC of 1.5% (Figure 2.56-2.58). In addition, hydrogen index values suggest that these samples fall within the gas window.

Figure 2.56 The table shows the range of total organic carbon and the indication for source rock quality as defined by Jarvie (1991). Most of the samples from this study showed poor to fair TOC values suggesting little source rock potential. Modified from Peters, 1986. AAPG©[1985], “reprinted by permission of the AAPG whose permission is required for further use.”

<table>
<thead>
<tr>
<th>Type</th>
<th>HI (mg HC/g Rock)</th>
<th>S2/S3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas</td>
<td>0-150</td>
<td>0-3</td>
</tr>
<tr>
<td>Gas and Oil</td>
<td>150-300</td>
<td>3-5</td>
</tr>
<tr>
<td>Oil</td>
<td>300+</td>
<td>5+</td>
</tr>
</tbody>
</table>

Figure 2.57 Hydrocarbon potential from Hydrogen Index. Modified from Peters, 1986. AAPG©[1985], “Reprinted by permission of the AAPG whose permission is required for further use.”. AAPG©[1985], and the phrase “reprinted by permission of the AAPG whose permission is required for further use.”
Figure 2.58 TOC and SRA analysis results for Well 1. Most samples show gas potential and fair to good potential to generate hydrocarbons.

Two samples from Well 2 were analyzed for TOC. Well 2 core comprises sandstones with some clay content, a lithology not typically indicative of good source rock potential. Therefore, no additional samples were analyzed. As expected, the TOC values for the two samples in this well were low, and the source potential was poor (Figure 2.59).
Figure 2.59 XRD, Mineralogical model, and TOC analyses for Well 2. XRD analyses the distribution of dolomite, kaolinite, calcite, siderite, quartz, pyrite, plagioclase, illite/micas, illite/smectite, and chlorite and their averages throughout the entire core.

Well 3 had nine samples analyzed for TOC. The maximum TOC for these samples was 1.09%, but the potential to generate hydrocarbon was low based on TOC potential (Figure 2.56). Hydrogen index values indicate that these samples are in the gas window (Figure 2.56 2.57 ). The core's low TOC values and lithology analysis suggested that the siltstone interval in this core is not a source rock, nor are these rocks of high reservoir quality due to the high clay content and low porosity and permeability observed petrographic analyses (Figure 2.60).
Figure 2.60 XRD, Mineralogical model, and TOC analyses for Well 3. XRD analyses show the distribution of dolomite, kaolinite, calcite, siderite, quartz, pyrite, plagioclase, illite/micas, illite/smectite, and chlorite and their averages throughout the entire core.

Three samples from Well 4 were analyzed for TOC. TOC values for these samples were very low and showed low potential for hydrocarbon generation (Figure 2.63). Due to the low potential, no further analyses were performed in these samples.
Mineralogical model and TOC analyses for Well 4. TOC values are very low and show a low potential to generate hydrocarbons.

**Maturation Analysis using Vitrite reflectance and bitumen analysis**

Vitrite reflectance analyses were performed in samples with higher TOC values to determine the presence and type of macerals. Unfortunately, no macerals were observed, so the type of kerogen is indeterminate and thermal maturity based on these samples was impossible to determine.
Figure 2.62 Bitumen particle was used to calculate the Vitrinite reflectance equivalence

The values of bitumen (1.25%) shown in Figure 2.61 were measured on bitumen. The vitrinite reflectance equivalence (VRo-eq) is estimated to be 1.17% using the Jacob (1989) formula (Rvit = Rbit * 0.618 + 0.4) (where Rvit is the vitrinite reflectance equivalence and Rbit is bitumen reflectance), is calculated to be 1.25%. The other samples analyzed showed similar values of 1.12%, 1.24%, and 1.13%. Based on this analysis, these samples were determined to have matured to a wet gas window (Figure 2.62).

The Montney Formation (another reservoir produced from tight siltstones such as this F interval) was charged by external source rocks. As a result, there is a predominance of solid bitumen as the main organic matter (Hackley, 2017). This solid bitumen is thought to be the remnant of oils. This organic matter affected the wettability of the rock creating a more hydrophobic pore space. Therefore, this solid bitumen could indicate hydrocarbon migration through this F siltstone interval. Furthermore, the presence of solid bitumen and grain size in this interval represents a certain energy level that would not allow the deposition of light kerogen particles nor the preservation of organic matter under these oxidizing conditions. Solid bitumen can be allochthonous or autochthonous. It forms when liquid hydrocarbons are present and crack onto gas and condensate with increasing depth and temperature. Defining if it is formed
in situ can be based on thin section and SEM analyses and how it fills cavities. According to the laboratory, these solid bitumen particles appear to be formed after migrated hydrocarbons crack into gas and condensate.

Figure 2.63 Vitrinite Reflectance values and thermal maturity are based on the values. The orange rectangle highlights the areas where the samples fall. All samples fall within the beginning of the wet gas window. Modified from Tissot and Welte, 1984. Used with the permission of SPRINGER-VERLAG NEW YORK INC.

Well 4

Three samples were analyzed for TOC and SRA. TOC values for these samples were very low and showed low potential for hydrocarbon generation (Figure 2.63). Due to the low potential, no further analyses were performed on these samples.
Figure 2.64 Mineralogical model and TOC analyses for Well 4. TOC values are very low and show a low potential to generate hydrocarbons.

2.4.8 Well-log Analysis and Subsurface Mapping

Figure 2.64 shows a stratigraphic correlation for the four cored wells. These wells range from ~7000 ft. depth to ~12000 ft. depth, covering several stratigraphic intervals and documenting lithologies that can help identify the characteristics and reservoir quality of fourth-order sequences in the basin. Eight key flooding surfaces were identified across the area; A to H and are youngest to oldest, respectively. These key surfaces were used to create an east-to-west correlation parallel to the shelf edge and perpendicular to gravity flow deposition's primary downslope direction.

Top structure maps were built for each 4th order flooding surface, and each flooding event bounded sequence was isopached to show constructed thickness and variability within the area. Additionally, net sand (using GR values between 0-85 API) and net silt maps (using GR values between 85-165 API) were constructed for wells 2 and 3. These two wells core the same F interval. However, Well 2 cored interval predominantly comprises sandstones, whereas Well 3 cored interval is mostly siltstones.
All the structural maps were mapped and compared to the structural map at the top of the Asquith Marker as no significant changes in structure are expected to be present between the Asquith Marker and the other intervals. Figure 2.65 shows the structural map for the Asquith Marker.

Figure 2.65 Correlation of the cored wells in the area based on their GR response. Lines correspond to the flooding surfaces identified by the high GR signature, followed throughout the basin.
Figure 2.66 Structural map on top of the Asquith Marker and the location of the four cored wells used in this study. 1917 wells were used to construct this map.

Observations on wells correlations

Well 1

Data available for Well 1 comprises 457 ft of whole slabbed core, well-logs, and data from laboratory samples analyses. Lithologies consist of sandstones, siltstones, and shales with variable amounts of clays and pervasive bioturbation. Correlations in Figure 2.66 around well 1 cover an area of
12 miles exhibiting lateral changes of the sands, siltstones, and shales within the cored interval, between the flooding surfaces, denoted as E1 and E2, where sandstone packages vary in thickness and, in some cases, pinch-out, demonstrating the high heterogeneity of this package. The yellow and green filling highlight two different sand packages separated by a small shale break and pinch out toward the east of the correlation.

This core encompasses two fourth-order cycles separated by the E2 flooding surface and starts at the top with the E1 flooding surface. The isopach maps cover an approximate distance of 54 miles by 54 miles to show a more general distribution of the sand packages within the basin. The isopach maps reflect a change in the progradation in the basin from North to South (Figure 2.67). Flooding surfaces E1 and E2 thin towards the Washakie Basin on the south at the base of the clinoforms. Eventually, E2 amalgamates onto the deeper flooding surfaces (F, G, and Asquith Marker) to the South of the Wamsutter Arch), the blocky pattern on the sands on the logs, and the intercalation between shales, siltstones, sandstones, and lateral variability point to amalgamated channels and levee channel deposits depositional environment. Well 2

Correlations across this cored interval with surrounding wells with log data available show high lithology variations, and this sand package pinches out laterally within the span of hundreds of feet (zone highlighted in the yellow filling). The depositional environment is likely to be channel deposits and levee channels (Figure 2.68). The isopach maps cover an approximate distance of 54 miles by 54 miles. The isopach map for this well shows a thinning of this interval towards the Wamsutter Arch, where, as with the previous intervals, it amalgamates on top of the deeper flooding surfaces (G and Asquith Marker) (Figure 2.69). Since this core only covers one of the sand intervals, a net sand map for the F interval was constructed. Sand bodies in this area seem to pinch out over short distances, supporting the interpretation of channel deposits and levee channels. The maximum thickness for this sandstone body is ~75 ft, estimated from the net sand map. The isopach maps cover an approximate distance of 54 miles by 54 miles.
Well 3

This well was also cored in the F interval but comprised siltstone rather than sandstone. The correlations show that this silty interval is prevalent laterally in the nearby wells (Figure 2.70). An isopach map shows a thinning of the F interval towards the Wamsutter Arch, where, as with the previous cored intervals, it amalgamates on top of the deeper flooding surfaces (G and Asquith Marker). Since this core is restricted to the siltstone lithology, a net siltstone map for GR values between 85-164 API was constructed, closely following the same trend as the entire interval isopach map (Figure 2.71). The maximum thickness for this siltstone interval is ~400 ft, estimated from the net silt map. The wireline-log response of channel-fill strata is highly variable, indicating the broad spectrum of stratal grain sizes and the complex and varying styles of channel fill. This interval's "ratty" signature, the presence of some thin sandstone beds on the surrounding wells, and the presence of channel deposits below and above this interval helped classify this core's depositional environment as a levee-overbank deposit. The isopach maps cover an approximate distance of 54 miles by 54 miles.

Well 4

This well is located in the Wamsutter Arch, and it is the shallowest well of the set. Although this core is only 90 ft thick, it displays all the same lithological and sedimentary characteristics as Well 1. In addition, correlations illustrate lateral variations within this interval and significant thickness variations of the sandstone packages, both laterally and vertically (Figure 2.72, 2.73). Some muddy convoluted beds could be classified as slumps towards the end of the core. They can occur when sediments along the channel margin slump towards the center of the channel and can form a low permeable material in the channel fill. The isopach maps cover an approximate distance of 54 miles by 54 miles.
Figure 2.67 Location of Well 1 (A), (B), and (C) Correlation of the interval around the first cored well. The cored area is highlighted in pink. Filled polygons represent amalgamated channels. The different colors represent different intervals. The yellow interval illustrates an example of an individual sand package's variation in the correlated area. The correlation is flattened onto the E1 flooding surface to illustrate the channel-like feature during deposition.
Figure 2.68 Isopach maps for the E1 and E2 intervals on the Lewis Shale. These intervals thin until they onlap onto the deeper flooding surfaces to the South of the Wamsutter Arch. Thickness is in feet. The area is approximately 54 miles by 54 miles. Approximately 1500 wells were correlated for the E1 and E2 intervals.
Figure 2.69 Location of Well 2 (A), (B), and (C) correlation of the Well 2 area. Cored interval is highlighted in pink. This sand body thins to the East and West. The yellow filling indicates the cored section and its correlation with the nearby wells to illustrate its lateral changes. The correlation is flattened onto the top of the sandstone cored interval to illustrate the shape of the channelized feature.
Figure 2.70 Isopach map of F interval and net sand map in feet, based on GR values between 0-85 API. The F interval follows the same trend as the shallower E1 and E2 intervals and thins until it onlaps onto the G and Asquith Marker Flooding Surfaces in the Wamsutter Arch. The net sand map depicts the short distances these sand bodies pinch out. Thickness is in feet. The area is approximately 54 miles by 54 miles. Approximately 1800 wells were correlated on the F interval.
Figure 2.71 Location of Well 3 (A), (B), and (C) Correlation for Well 3 area. Cored interval is highlighted in pink.
Figure 2.72 Isopach map for the F interval and net map for the cored siltstone interval with GR values between 85-165 API. These siltstone intervals are more continuous in thickness and lateral distribution, as evidenced by the correlations in Figure 2.64. The net silt map closely resembles the F interval isopach map. Thickness is in feet. The area is approximately 54 miles by 54 miles. Approximately 1800 wells were correlated on the F interval.
Figure 2.73 Location of Well 4 (A), (B), and (C) correlation area. Cored interval is highlighted in pink. The yellow filling indicates the cored section and its correlation with the nearby wells to illustrate its lateral changes.
Figure 2.74 Isopach map for the C2 interval in Well 4. C2 is the shallowest interval from all the cores and reflects the progradation of the basin by thinning closer to the Washakie Basin. It also correlated with its maximum thickness at the Wamsutter Arch, where the Slope and base of the Slope would be located at the time of deposition. Thickness is in feet. The area is approximately 54 miles by 54 miles. About 1200 wells were correlated for this map.
2.4.9 Architectural Elements

Figures 2.74 and 2.75 show the log signature, depositional environments, and correlation with the cored intervals. For example, the Well 1 log signature has an upward decreasing and thickening GR. In addition, it shows characteristics similar to the log motif C, which corresponds to lobe margin to lobe center of the lobe, some of the log responses within the cored interval, and the lateral variations on some of the sandstone intervals suggest channelized features within lobes similar to those in Well 2.

Figure 2.75 Log motif signature from cored intervals (left) and those shown by Koo et al., 2016, and the main architectural elements related to them. Modified from Koo et al., 2016. Published with permission of the Journal of sedimentary research.
Well 2 log signatures have a blocky pattern with low GR values with increasing GR towards the top. This type of log shows characteristics similar to the log motif B, which corresponds to amalgamated channels, dominant in the proximal and center of the lobe.

Well 3 has a relatively sharp base with a fining upward log signature. There is an erosional surface overlain by fine sandstones and underlain by mud. This log signature usually belongs to slope channels and overbank deposits (Koo et al., 2003).

Well 4 shows GR signatures with an upward decreasing and thickening GR. In addition, it exhibits characteristics similar to the log motif C, which corresponds to the lobe margin to the lobe center of the lobe. Finally, the core's lowermost part displays characteristics similar to log motif E with a serrated log motif and low GR peaks representing thin sandstone bodies. This log motif is usually correlated with a channel levee close to the lobe axis.

Figure 2.76 Core intervals within the clinoform. Most of the cores fall within the channel levee complexes in the shelf-slope and channelized features within lobes at the base of the slope. Modified from Pyles and Slatt, 2007. AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use.
2.5 Discussion

Turbidite Reservoirs

Different lithologies affect the reservoir quality in different ways, such as cement reducing porosity and permeability, clay content increasing the inbound water, etc. In addition, lithology has been shown to vary over short distances vertically and horizontally for the cores analyzed. Thus, an intrinsic understanding of their internal characteristics to identify the variability is crucial to understand what to expect when planning new well locations in any of these intervals and be prepared for these changes when geosteering horizontal wells. This understanding can be attained by combining high-resolution analyses such as XRF, thin sections, XRD, FE-SEM, and core description.

The detrital fraction comprises silica as quartz, chert, and microcrystalline quartz. Feldspars are mostly plagioclase, and K-feldspars are found in less quantity. Rock fragments are also present as detrital carbonates and lithic volcanic fragments. In some cases, grains are altered either to chlorite, clay, or sericite, making their identification more difficult. The matrix comprises clay minerals, micas, organic matter, microcrystalline quartz, and quartz grains in matrix-supported samples, although they often are too small to be identifiable.

Physical compaction was evident in most samples, especially in the deeper ones, and can be seen by clay mineral deformation, a higher abundance of sutured contacts, and higher contact indexes. Illite/smectite swelling clays can increase water saturation and cause trouble when drilling this formation, but most samples showed low smectite content. In addition, calcite and dolomite are present as cement and detrital grains, which can decrease the permeability of the rock.

The paragenetic sequence for these intervals was identified as 1) detrital chlorite coating quartz grains, 2) compaction, 3) formation of calcite and dolomite cement, 4) illite replacement of smectite, 5) authigenic chlorite formation nucleating on detrital chlorite, 6) alteration of lithics and silica replacement of organisms, almost simultaneously the formation of microcrystalline quartz from the silica released from illite to smectite transformation and alteration of lithics, 7) formation of authigenic siderite, 8) late formation of amorphous silica nucleating on chlorite, 9) hydrocarbon migration and placement.
Porosity data showed some positive correlation with the percentage of authigenic quartz, calcite, and chlorite in the system, but permeability decreases with increasing carbonate content—both decrease in areas with higher amounts of clays. Overall, the porosity and permeabilities for these intervals are very low, with maximum values of 12% and 0.005 mD, respectively. However, FE-SEM analysis proved chlorite preserves the porosity in the sandstone facies (finely laminated silty sandstone and massive sandstone).

Correlations illustrate the heterogeneity and possible complications these turbiditic reservoirs can present, such as target thinning and an increase in clay content that could cause instability in the wellbore and a potential loss of the well or the need to drill a sidetrack. Furthermore, this was also evidenced in the thin section, XRD, and XRF analyses showing mineralogical variations down to the inch scale.

The overall composition of all the cored intervals is very consistent with high quartz content, followed by clay and carbonate contents. Illite/smectite swelling clays can increase the risk of wellbore stability and reduce porosity and permeability. Calcite and dolomite are found as grains and cement, increasing the rock's brittleness index and decreasing its porosity and permeability.

In addition, correlations illustrate the lateral variations of the cored intervals and how the sandstone packages pinch out, in some cases in less than a mile between wells and vertically within the same well. Vertical changes are usually observed at a lower scale and can occur from inches to a couple of feet.

Variation in lithology inherent to turbidite systems can make horizontal drilling quite tricky. As a result, the geosteering process is strenuous and constant supervision is needed to avoid drilling problems, well stability issues, or clay swelling.

The isopach maps reflect the change in depositional environments in the basin from North to South and the general progradation of the formation into the south part of the basin. This progradation is evidenced by displacement of the area where the flooding surfaces onlap each other. The shallower flooding surfaces tend to thin further south than the deeper ones. As evidenced by the net silt map and the correlations, the siltstone package, classified as levee-channel/overbank deposits, is more continuous in thickness and lateral distribution.
Levee-overbank deposits are also more homogeneous in composition and have high quartz, dolomite, calcite, and plagioclase, minerals usually correlated with higher Brittleness Index, making them easier to drill. However, the higher clay content decreases porosity and permeability and increases water saturation. Furthermore, low porosity and high clay content were evident when samples from this facies were analyzed using FE-SEM.

The variation from sandstones to shales and siltstones inherent to channel and levee channel deposits can make drilling a well quite tricky. The geosteering process is often strenuous, and constant supervision must be employed to remain within the sandstones. In addition, drilling into the shales can cause caving, well stability issues, or clay swelling. Finally, in some cases, channels are laterally more continuous than others. Therefore, having correlations in the area or other data that give us an idea of the type of environment these sands belong to can be very beneficial.

If well-log data, core, or thin sections are not available, XRF from cutting samples can identify the mineralogy and possible changes in the environment. For example, looking at the XRF profiles for these four cores, a shale break can be assumed or more siltstone content if we see high silica content with low clay proxies, followed by an increase in clay and anoxic/euxinic proxies. Likewise, a channel-levee system can be inferred if enough of these variations are seen. The lithological variations inherent to these environments can be expected to be high both vertically and horizontally. If a company intends to drill a sandstone horizontal target and stay within that sandstone, seeing these variations can be a problem (even more in the absence of more log data).

Well 3 has the most consistent composition of all, also seen on the core description, well-log correlations, XRD, and thin section data. Its composition, continuity, and thickness make it a good candidate for well placements within the Lewis Shale. Intervals E1, E2, and C2 look the most heterogeneous in the basin's north. All of them were classified as channelized features within lobes and channel levees based on proximity to the shelf edge at the time of deposition of the channel levee and channelized deposits.
The well with the highest production from the G interval in the Great Divide Basin has produced 183,287 bbls and 1,075,529 MCF from 2019 to 2021. For the F interval, the highest production report is 177,068 bbls and 3,109,929 from 2019 to 2021, with an API between 50-60°.

2.6 Conclusions

- The main composition of the intervals is quartz, clays, calcite and dolomite, and accessory minerals. There is low content of the smectite swelling clay which increases reservoir quality.
- Excess silica was identified using XRF elemental data and ratios with the main detrital proxies and plots. However, all the silica present is not correlated with the main detrital proxies. There is authigenic, biogenic quartz, and chert coming from Paleozoic carbonates present. It was later identified as mainly authigenic quartz using FE-SEM and EDS analysis.
- Areas of excess silica correlate with areas with higher porosity and permeability in the elemental data profiles. Presence of microcrystalline quartz seems to be preserving porosity and permeability.
- Chlorite preserves the porosity by coating the grains and inhibiting quartz overgrowths, as observed in thin sections and FE-SEM analysis.
- There is evidence of mechanical compaction seen in grain deformation, such as biotite and increased grain contact and suture contacts.
- Shallower intervals within the Dad Sandstone Member in the Great Divide Basin correlate with channel-levee complexes. These reservoirs can cause sandstone pinch outs, buffers, and baffles between the sandstone bodies, affecting the drilling and reservoir quality.

2.7 References


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CHAPTER 3

PETROPHYSICAL CHARACTERISTICS OF THE LEWIS SHALE:
CORE COMPARISON TO WELL LOG DATA.

3.1 Abstract

The Lewis Shale represents a deep-water turbidite system encompassing siltstones, organic-rich shales, and sandstones. The deposits of the Lewis Shale can reach up to 2600 ft in the Greater Green River Basin. It is subdivided into three members based on the changes in lithology: a lower member (characterized by high clay and organic matter content); a middle member or Dad Sandstone (a mixture of siltstones, shales, and sandstones); and an upper member (with decreasing amounts of sandstone and greenish-grey shales).

This work aims to develop a petrophysical model for porosity and saturations correlated with core data from four cored intervals within the Lewis Shale in the northern Greater Green River Basin, in the Sweetwater and Carbon counties. This formation is considered an unconventional reservoir due to its low porosity and permeability and the need to use hydraulic fracturing to obtain hydrocarbons at commercial rates. In addition, this area around the cores is relatively undeveloped for horizontal wells.

This model is crucial to identifying which is the most prospective sandstone interval. Data for the four cored intervals includes well logs, Routine Core Analysis (RCA), X-ray diffraction (XRD), and X-ray Fluorescence (XRF) analyses.

Tight sandstone reservoirs usually have some of the characteristics of conventional sandstone reservoirs but with lower permeabilities and lower effective porosities. The main concerns of log analyses in tight sandstone reservoirs are porosity estimation, accurate water saturation calculation, permeability determination, and understanding how clay affects log responses. In addition, petrographic thin section, routine, and special core analyses are necessary to develop a reliable petrophysical model.

As in many gas-centered basins, the Greater Green River Basin has a high amount of gas shown while drilling with low water production. Production across the area varies greatly, suggesting there might
be other factors such as rock properties, sweet spots, or different completions and production techniques affecting the production.

The Archie equation for water saturation was developed in clean-high porosity sandstones, and water saturation calculation in tight sandstones can be inaccurate. This is particularly true where the resistivity of the free water (Rw) is substantially different from the resistivity of the clay-bound water in tight sandstones. Using core saturation values to adjust the saturation values obtained from logs can be very helpful. Also, saturation and cementation exponents (m and n) can be estimated based on the core values of Sw due to the high gas content, low porosity, and permeability.

The Lewis Shale is a tight gas sandstone. As such, some petrophysical constants used to calculate water saturation using the Archie equation must be adjusted to account for gas in the formation and the “tightness” of the rock.

Several authors have mentioned some of the petrophysical properties of the Lewis Shale. However, there are no petrophysical models in the sandstone intervals tying together log and core data to the author’s knowledge.

The petrophysical characteristics of these four cores displayed the same level of heterogeneity as the facies described. Samples have high variation in water saturation values and, in general, very low porosity and permeability characteristics of these reservoirs. Samples classified as finely laminated silty sandstones displayed better reservoir properties than the other facies, even the clean, massive sandstones. This proves that the cleanest sandstones are not always the best reservoirs. Chlorite and clay content can have a significant impact on reservoir properties. For example, Well 1 and Well 2 had lower illite/smectite and higher chlorite content and showed better properties than Well 4, which had higher illite/smectite and lower chlorite content. In this case, chlorite increased the density of the matrix of the sandstones, thus, affecting the porosity calculation. Chlorite also helped preserve porosity in some of these facies.
3.2 Introduction

Well log analysis is one of the most critical tools that petroleum engineers and geologists use to correlate rocks and make maps, define reservoir characteristics, and identify the different fluids within them, ultimately leading to new drilling location identification and optimum identification of horizontal drilling targets.

The present study is in Sweetwater and Carbon Counties in Wyoming, near four Lewis shale cores around the Basin provided by MorningStar Partners/Southland Royalty (Figure 3.1).

This work aims to develop a petrophysical model for porosity and saturations correlated with core data from four cored intervals within the Lewis Shale in the northern Greater Green River Basin. This model is crucial for identifying which interval is the most prospective sandstone interval. Data for the four intervals includes well logs, Routine Core Analysis (RCA), X-ray diffraction (XRD), and X-ray Fluorescence (XRF) analyses.

The Lewis shale has been widely studied, and several authors have mentioned some of the petrophysical properties of the Lewis Shale (Almon et al., 2001, Almon et al., 2002). For example, Shanley et al. (2004) point out that the Basin is not gas-saturated everywhere or near the irreducible water saturation. Furthermore, water production is highly variable throughout the Basin.

As in many gas-centered basins, the Greater Green River Basin has a high amount of gas shown while drilling with low water production, classifying these reservoirs as continuous accumulations (Shanley et al., 2004). However, production across the area varies greatly, suggesting there might be other factors such as rock properties, sweet spots, or different completions and production techniques affecting the production.

Although traps can be structural or stratigraphic, the latter are the most common. Stratigraphic traps can occur, for example, in one of the sand pinchouts against one of the less permeable rocks in the area (Hettinger and Roberts, 2005).

Petrophysical models in the area have problems such as a concurrence between the water and gas-bearing rocks, poorly defined gas-water contacts, changes in gas-water ratios, and striking changes in...
production over short distances (Shanley et al., 2004). But there are no published porosity models and associated saturation models to the author's knowledge.

Approximately 600 billion cubic feet of gas (BCFG) have been produced from this basin from 1976 until 2005, although the exact amount produced from the Lewis Shale is not clear due to many of the wells being commingled (Hettinger and Roberts, 2005). In addition, about 8.1 million barrels of oil and condensate have been produced from the Lewis Shale, including wells where the production came solely from the Lewis Shale and wells commingled with other formations (Hettinger and Roberts, 2005).

The Lewis Shale includes continuous and conventional accumulations (Suryanto, 2003). The conventional accumulations are located in the shallower regions of the Basin where hydrocarbons from the deeper and over-pressured areas have migrated. These overpressured areas were identified by Law (1984) and Surdam et al. (1995) and affect the chances of oil generation of the rock, cracking the oil into gas in areas of overpressure where the heat flow is high.

Suryanto (2003) determined gas-in-place estimates for the Lewis Shale, with values ranging from 46.5 to 82.9 Tcf (trillion standard cubic ft) based on assumed hydrocarbon saturation of 45, 50, and 60%. This estimate was based on conventional vertical wells, and the reduced relative permeabilities in tight-gas sandstones may reduce the economic recovery of this play. However, this number can be higher (Suryanto, 2003) with horizontal development and modern stimulation.

Hettinger and Roberts (2005) compiled an oil and gas assessment of the Lewis Total Petroleum System as part of the United States Geological Survey (USGS) program to evaluate different basins and formations. Their study was centered on unconventional reservoir development in the gas-charged sandstones. They determined that the Lewis Shale's main potential is gas production with some minor potential for liquid hydrocarbons. However, the low porosities and permeabilities, gas content, and mineralogy of the Lewis Shale can make it challenging to perform a petrophysical model since these characteristics have a strong effect on log responses, and one must be very careful when performing it.

The Lewis Shale represents a deep-water turbidite system encompassing siltstones, organic-rich shales, and sandstones. The deposits of the Lewis Shale can reach up to 2600 ft in the Greater Green
River Basin. It is subdivided into three members based on the changes in lithology. A lower member (characterized by high clay and organic matter content). A middle member or Dad Sandstone Member (a mixture of siltstones, shales, and sandstones), and an upper member (with decreasing amounts of sandstone and greenish-grey shales).

Figure 3.1 Location of the study area and the cored wells in this study. The red dot is the location of the type log used by Pyles and Slatt (2007) to display the sequence stratigraphic framework of the Lewis Shale.

The Lewis Shale comprises different depositional environments within the deep-water system. The main architectural elements are turbidite channels, sheet sands, and mass transport deposits. Deeper depositional areas are located towards the south, and the transition to shallower areas is located towards the north. It is characterized by a third-order progradational highstand systems tract, comprising several fourth-order lowstand-highstand cycles and a shallowing upwards sequence. Its maximum flooding surface is located in the lower member, named the Asquith Marker. It has a maximum thickness of 50 ft within the basin, and it is believed to be a source of hydrocarbons, with TOC values ranging between 0.68% and 3.15% in core and outcrop (Mayorga-Gonzalez, 2016) and 2 and 4.8% (Pasternack, 2005). The Lewis Shale is considered a complete petroleum system with source rock (Asquith Marker), reservoir rock, seal, and different trapping mechanisms throughout the entire basin, including structural, stratigraphic, and basin centered (Zainal, 2001).
This formation is considered an unconventional reservoir due to its low porosity and permeability and the need to use hydraulic fracturing to obtain hydrocarbons at commercial rates.

This area is relatively newly developed with horizontal wells. One of the first horizontal wells in the Lewis Shale was drilled in 2012, named Spirit of Radio 7-1H by BP America, and since then, about 226 horizontal wells have been drilled in the Lewis Shale in the area (WOGCC).

The hydrocarbon production from the Lewis Shale mainly comes from the gas reservoirs within the Desert Springs, Hay Reservoir, Wamsutter, Great Divide, Strike Unite, and Siberia Ridge fields (Gonzalez, 2003).

3.2.1 Geological Setting

The Lewis Shale was deposited as a series of southward-prograding clinoforms whose sources of sediments were the different submarine deltas forming in the area (Young et al., 2003), first from the northeast and later from the south (Winn et al., 1985). The geometry of the clinoforms with the uplifting of the Lost Soldier anticline created a well-defined shelf-slope-basin floor topography with slopes between 0.6 and 1 degree (Minken, 2004).

The progradation direction suggests some structural influence during the deposition of the Dad Sandstone Member of the Lewis Shale. Several studies (Perman, 1990, MacMillen and Winn, 1991, Gonzalez, 2003, Pyles and Slatt, 2000, Pyles and Slatt, 2007) have determined that the slopes within the clinoforms are areas of constant changes in thickness.

Each of the clinoforms, intervals divided by flooding surfaces, show differences in the topography by sediment entry points and distributary channel trend (Gonzalez, 2003).

The location of the turbidites reflects a compensational character filling (new turbidites fill topographic lows between existing lobes) rather than a reflection of the paleotopography of the seafloor (Hamzah, 2001).

Slopes within the clinoforms are areas of constant changes in thickness (Perman, 1990, MacMillen and Winn, 1991, Gonzalez, 2003, Pyles and Slatt, 2000, Pyles and Slatt, 2007). The sediments show slight bioturbation to none, identifying periods of anaerobic and dysaerobic conditions with water depths
between 500-650 ft (Winn et al., 1985). The Lewis Shale in Wyoming intertongues throughout the basin with the overlying Fox Hills Formation and underlying Mesaverde Group.

Upper Cretaceous rocks were deformed in a series of intermontane basins formed during the Laramide Orogeny. During this time, the Sierra Madre uplift, Rawlins uplift, Cherokee uplift, Lost Soldier anticline, and Rock Springs uplift were uplifting and served as a source for the Lewis Shale. McMillen and Winn (1991) and McGookey et al. (1972) identified submarine fan sandstones from several directions matching the placement of the other uplifts of the time. These uplifts served as the sediment source for the Lewis Shale turbidites, and it reflects the wide variety of material present in each one.

The Lewis Shale was deposited during a subsidence period within the Greater Green River Basin from the Late Cretaceous through the earliest Tertiary (Surdam et al., 1995). The unconformities present in the Tertiary section suggest some periods of uplifting and erosion. However, there is no evidence of a significant loss of section or that the burial took place at a deeper depth than the present-day (Thyne et al., 2003). Processes of tectonism and eustacy controlled the Lewis’ Shale sedimentation. The late Absaroka thrusting, and subsidence triggered a sea-level rise (Luo and Nummedal, 2010). As a result, the basin subsided faster than sedimentation (Winn et al., 1987, Luo and Nummedal, 2010). The subsidence submerged areas of the northeastern delta. These processes created an embayment deep enough to allow the deposition of this turbidite system and sufficient restriction to preserve organic matter.

3.3 Theory and Methods

Four wells with cores totaling 816 ft were used to perform different analyses—fifty-seven X-ray diffraction analyses (XRD) and forty-two petrographic thin sections.

Figure 3.2 shows a correlation of the four cored wells. Each well is referred to as “Well 1”, “Well 2”, “Well 3”, and “Well 4”. The cored intervals are highlighted in bright pink, and the total cored footage appears next to it. The correlated surfaces are flooding surfaces that can be followed throughout the basin, subdividing the Lewis Shale into smaller intervals.
Eight facies were defined based on the core and thin section description and used to color code the data points presented in the plots and correlate results with the defined facies (Table 4.1). Thus, allowing the identification of the best ones for future development.

XRD analyses revealed that the minerals present in the cores are, on average: 50% quartz, 5% illite on the sandstone intervals and 11% on the siltstones, and 7% chlorite in both. Unfortunately, only Well 2, Well 3, and Well 4 had XRD analyses (Figure 3.3). But the petrographic thin sections and FE-SEM analyses revealed that the Well 1 interval also has very high quartz content and chlorite coating all the quartz grains (Figure 3.4).

For the petrophysical model, only the intervals with sandstones were evaluated. Therefore, well 3 was not evaluated since it mainly comprises siltstones. This interval has low porosity (from 0.4% to 3% at 1000 psi Net Confining Stress (NCS)) and permeability (between 0.001 Md and 0.938 mD at 10000 psi NCS). This core also has high levels of bioturbation. Total Organic Carbon (TOC) values range between 0.1% and 1.45%. Thus, this interval does not constitute a reservoir or a source rock.
Figure 3.2 Core wells and the cored intervals were used for this study. Cored intervals are highlighted in bright pink. Correlated lines correspond to flooding surfaces similar to those used by Pyles and Slatt (2007) that extend throughout the basin.
<table>
<thead>
<tr>
<th>Facies</th>
<th>Composition</th>
<th>Sedimentary Structures</th>
<th>Biogenic Structures</th>
<th>Diagenetic Components</th>
<th>Well where can be found</th>
<th>Core Slab Images</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bioturbated Shale.</td>
<td>Eltite-smectite, detrital mud size quartz grains. Minor amounts of other</td>
<td>Finely laminated</td>
<td>Schoubylinicchus and Physoyphon trace fossils are</td>
<td>Mechanical compaction. High Organic matter content. Matrix supported.</td>
<td>Well 1, Well 4</td>
<td><img src="image1.jpg" alt="Image" /></td>
</tr>
<tr>
<td>(Facies 1)</td>
<td>grains such as tephra, calcite, dolomite, plagioclase, chlorite, and biotite.</td>
<td></td>
<td>present. Sheel fragment.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bioturbated sandy Siltstone.</td>
<td>Same as previous.</td>
<td>Finely laminated, sand lenses.</td>
<td>Shell fragments. Physoyphon.</td>
<td>Matris supported.</td>
<td>Well 1, Well 3, Well 4</td>
<td><img src="image2.jpg" alt="Image" /></td>
</tr>
<tr>
<td>(Facies 2)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>(Facies 3)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Bioturbated Silty Sandstone.</td>
<td>Quartz, chert, minor amounts of other grains such as fisses, dolomite, calcite</td>
<td>Faint laminations</td>
<td>Schoubylinicchus and Physoyphon trace fossils are</td>
<td>Calcite cement</td>
<td>Well 1, Well 3, Well 4</td>
<td><img src="image4.jpg" alt="Image" /></td>
</tr>
<tr>
<td>(Facies 4)</td>
<td></td>
<td></td>
<td>present. Sheel fragments.</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cryptobioturbated Sandstone.</td>
<td>Eltite-smectite detrital mud size quartz grains. Minor amounts of other</td>
<td>Non observed due to bioturbation.</td>
<td></td>
<td>Calciite cement, clay coatings, chart cement and grains, quartz overgrowth</td>
<td>Well 1, Well 2, Well 4</td>
<td><img src="image5.jpg" alt="Image" /></td>
</tr>
<tr>
<td>(Facies 5)</td>
<td>grains such as tephra, calcite, dolomite, plagioclase, chlorite, and biotite.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Finely laminated Silty Sandstone.</td>
<td>Eltite-smectite biogenic and detrital mud size quartz grains. Minor amounts</td>
<td>Fine laminations, ripples, flame up structure.</td>
<td></td>
<td>Quartz overgrowth, Clay coatings, Higher Biotite content.</td>
<td>Well 1, Well 2, Well 4</td>
<td><img src="image6.jpg" alt="Image" /></td>
</tr>
<tr>
<td>(Facies 6)</td>
<td>of other grains such as tephra, calcite, dolomite, plagioclase, chlorite, and biotite.</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Contorted beds.</td>
<td>High silica, Al and K content.</td>
<td>Soft sediment deformation, rip up cists, flame up structures.</td>
<td></td>
<td>None observed.</td>
<td>Well 1, Well 2, Well 4</td>
<td><img src="image7.jpg" alt="Image" /></td>
</tr>
<tr>
<td>(Facies 7)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Figure 3.3 XRD analyses for three of the cored wells. High quartz and chlorite content are pervasive throughout the core. Well 4 only had five samples analyzed, not enough to build a mineral profile.
Figure 3.4 A, B) Photomicrographs (left PPL, right XPL) of one Well 1 sandstone interval, showing chlorite coating quartz grains. C) BSE image of a rock chip from the same well showing the quartz grains coated by chlorite. D) the same picture but under the SE; E) and F) BSE and EDS photomicrographs from Well 1 showing quartz grains coated with chlorite and calcite crystals. EDS picture shows the composition of the rock.
3.3.1 Routine Core Analyses (RCA)

A hundred and seventy-six Routine Core Analyses (RCA) plugs were taken to evaluate porosity, permeability, water, and oil saturation. Core plugs were sampled based on well-log responses and analyzed for porosity, permeability, and saturation at Corelab Laboratories and Stratum Reservoir.

Porosity and permeability analyses were performed using the application of an unsteady state, pressure-transient technique. The pressure-transient method allows Corelab Laboratories' CMS-300 instrument to generate porosity permeability at in situ stress conditions. Measurements can be made at multiple confining stresses up to 10,000 psi (Corelab: Basic rock properties). For the Lewis Shale, net confining stresses closely resembling in-situ stresses are 10,000 psi. Samples analyzed at Stratum Reservoir were not subject to the 10,000 psi in-situ stress analysis.

Pickett plots help estimate water saturation using log data. They can also help define the formation’s water resistivity, cementation factor, and matrix factors with input from sonic and density logs. They are based on observations signaling that RT (deep or true resistivity) is a function of porosity, water saturation, and the cementation exponent (Asquith and Krygowski, 2004). Buckles Plots display water saturation versus porosity to illustrate how the water saturation of the rock varies with porosity.

A flow unit is a body of rock with the same internal characteristics that are laterally continuous and affect the rock's fluid flow. Lorenz plots rank the flow capacity of different units by considering the porosity and permeability of the reservoir (Kourosh et al., 2015) and help define the flow units. The different inflection points are characteristic of storage capacity or flow capacity changes. For example, flatter areas of the plot indicate low flow units, usually in tight reservoirs, whereas steeper trends have faster flow rates (Mahjour et al., 2016). Lorenz plots from core data for the Lewis sandstone cores were generated and will be shown below.

3.3.2 Well Log Data

Well log analysis is one of the most critical tools that petroleum engineers and geologists must map and correlate rocks, define reservoirs’ characteristics, and identify the different fluids within them and
their proportions, ultimately leading to the identification of new drilling locations and horizontal drilling targets.

Mineralogy, porosity, permeability, and water saturation are some of the rock characteristics that affect logging measurements. However, the resistivity of the rock is one of the most critical characteristics measured because of its correlation with the fluid type (Asquith and Krygowski, 2004).

Porosity represents the ratio of voids to the total volume of rock and appears as a decimal fraction or percentage. There are two main definitions regarding porosity measurements. First, total porosity is the amount of internal space in a rock, translating to the amount of fluid that the rock can hold. Second, effective porosity represents the amount of interconnected space that can transmit fluids (Asquith and Krygowski, 2004).

Permeability is the ability of the rock to transmit fluids, controlled by the size (diameter) of interconnected spaces within the rock (pore throats or capillaries). Absolute permeability refers to the ability of a rock to transmit a single fluid at 100% saturation. Finally, effective permeability is the ability of a rock to transmit a fluid in the presence of another (i.e., oil and water) (Asquith and Krygowski, 2004).

Water Saturation refers to the percentage of pore volume in a rock occupied by the connate water in the formation. Irreducible water saturation or Swir refers to the amount of water adsorbed into or on the grains of rock and held by capillary pressure (Asquith and Krygowski, 2004). Resistivity refers to the ability of different materials to resist the flow of electricity. The opposite of resistivity is electrical conductivity. For example, hydrocarbons, most minerals, and freshwater from the formation have high resistivities since they are poor conductors of electricity (Asquith and Krygowski, 2004). The basic information needed in log interpretation includes the lithology of the rock; standard porosity logs require a lithology or matrix constant before the porosity of the zone can be calculated. For example, the matrix density constant for typical quartz sandstones is 2.65g/cc, and for limestones, it is 2.71 g/cc. However, the formation density varies with mineralogy—calcereous sandstones have a matrix density between 2.65 and
2.71 g/cc. In addition, formation temperature (Tfm) is an important parameter because the resistivities vary with temperature.

Although the Lewis Shale has been drilled since the 1960s, the study area has poor well control, the information is still confidential, or the suite of logs is incomplete. In addition, the first few wells drilled by MorningStar Partners/ Southland Royalty had issues while logging wells. Therefore, all the cored wells and surrounding ones were logged through-bit, limiting the number and type of logs run.

A petrophysical model for each of the cored intervals was completed using Gamma Ray (GR), total Resistivity (RT), and Bulk Density (RHOB, to calculate porosity). GR log was not used quantitatively; thus, normalization of GR was not performed.

Porosity and saturation values were compared with the core data acquired from RCA. Then, XRD and XRF analyses were used to assist mineralogy-controlled parameters such as grain density for porosity calculations.

Some of the wells did not have RT but had ATCO90 (long-spaced conductivity), from which RT was back-calculated. RHOB was not present and was back-calculated from the DPHZ using the density porosity formula. It was necessary to digitize logs to complete the necessary logs for the petrophysical analysis.

3.3.3 Petrophysical Model

Several authors have mentioned some of the petrophysical properties of the Lewis Shale (Almon et al., 2001, Almon et al., 2002, Slatt et al., 2009). However, there are no petrophysical models in the sandstone intervals tying together log and core data to the author’s knowledge.

Tight sandstone reservoirs usually have some of the characteristics of conventional sandstone reservoirs but with lower permeabilities and lower effective porosities (Ma et al., 2016). The main concerns of log analyses in tight sandstone reservoirs are porosity estimation, accurate water saturation calculation, permeability determination, and understanding how clay affects log responses (Moore et al., 2016). In addition, petrographic, routine, and special core analyses are necessary to develop a reliable petrophysical model (Moore et al., 2016).
Logs can be beneficial to determining reservoir characteristics, but in tight sandstone reservoirs, the effect of clay and light hydrocarbons are intensified by the low porosities and abnormal pressures. Porosity ranges between 2% and 12%.

Sometimes, the best reservoirs are not the cleanest ones because these usually have lower porosities and permeabilities due to quartz overgrowths or cement (Moore et al., 2016). In addition, heavy minerals such as pyrite can reduce the calculated porosity. Thus, they need to be considered. Due to these diagenetic factors, the cleanest intervals might not be the best ones.

The Archie equation for water saturation was developed in clean-high porosity sandstones, and water saturation calculation in tight sandstones can be inaccurate (Moore et al., 2016). This is particularly true where the resistivity of the free water (Rw) is substantially different from the resistivity of the clay-bound water in tight sandstones. Using core saturation values to adjust the saturation values obtained from logs can be very helpful. Also, saturation and cementation exponents (m and n) can be based on the core values of Sw due to the high gas content, low porosity, and permeability.

Core GR and GR logs for each interval were compared, and shifts were performed on the core data based on the GR to log GR shift. However, there was some uncertainty in the core to log shifts based on GR due to the serrate nature of the GR log and imprecision in core GR measurements. Therefore, the shifts were adjusted based on porosity from core measurements compared to the log-based density porosity.

Porosity calculations were made using the density porosity formula (3.1) and bulk density log.

$$\Phi_{density} = \frac{\delta_{matrix} - \delta_{bulk}}{\delta_{matrix} - \delta_{fluid}}$$ (3.1)

Where \(\delta_{matrix}\) is the grain density of the rock, it usually varies with rock type. For example, quartz sandstones have a grain density of 2.65 g/cc. In comparison, limestone’s grain density is 2.71 g/cc. This data can be obtained from RCA.

\(\delta_{bulk}\): is the bulk density log RHOB.
δfluid is the density of the fluid in the formation. Usually, freshwater is assumed, and the value equals 1 g/cc. However, if residual hydrocarbons remain in the flushed zone where density log measurements are made, this value can be below 1.

The temperature gradient was calculated using the borehole temperature and surface temperature for each cored well, using the linear equation (3.2):

\[ y = mx + c \]  

(3.2)

Where y: BHT  
\( \text{x: TD of well} \)  
\( \text{c: measured surface temperature from each log header} \)

Then the formation temperature was calculated with the temperature gradient using the same formula. Here, \( y \) is the formation temperature, and \( x \) is the depth of the formation of interest.

With this temperature, the resistivity of the formation water at depth is calculated using the following formula (3.3).

\[ R_{fm} = \frac{R_w(T_s+6.77)}{(T_{fm}+6.77)} \]  

(3.3)

Where the \( R_{fm} \) is the water's resistivity at the formation's temperature, \( R_w \) is the resistivity of the produced water at surface temperature, \( T_s \) is the surface temperature, and \( T_{fm} \) is the formation temperature. The \( R_{fm} \) (water resistivity at formation’s temperature) is then used to calculate water saturation at each interval.

Usually, density log porosity is calculated using a sandstone matrix since it is the most common type in western US basins. It automatically calculates porosity with a 2.65 matrix. Then water saturation (Sw) is computed using \( R_{fm} \) (calculated), RT log, and porosity (calculated), using the following formula, the Archie Equation (3.4)

\[ Sw = \left( \frac{\alpha R_w}{R_{RT}} \right)^{1/n} \]  

(3.4)
Where \( a \) is tortuosity factor (varies as the complexity of the path between pores varies, usually higher when it is more complex, \( n \) is the saturation exponent, \( R_w \) = formation water resistivity (ohm-m), \( R_T \) is resistivity log (ohm-m), \( \phi \) is Porosity(fraction), \( m \) is cementation exponent (varies with grain size, sorting and increases with increasing cementation) (Asquith and Krygowski, 2004).

Porosity was determined and then validated with core porosity. Then, with the computed porosity, the water saturation was calculated.

3.4 Results

3.4.1 Petrophysical Model

To calculate porosity for the intervals was used the equation (3.1)

\[
\phi_{density} = \frac{\delta_{matrix} - \delta_{bulk}}{\delta_{matrix} - \delta_{fluid}} \quad (3.1)
\]

The value of \( \delta_{matrix} \) was initially assigned based on RCA’s average grain density value, which was 2.68 g/cc. RHOB was used as \( \delta_{bulk} \). Fluid is usually assumed to be freshwater equal to 1 g/cc. When working with gas-bearing reservoirs, 0.8 g/cc is usually used to account for residual gas saturation in the flushed zone.

Some gas zones, especially tight gas zones, are not deeply invaded. Therefore, the density log can read some of that gas, and the porosity calculation might be higher than what it is in reality. Thus, using a constant fluid density of less than 1 gr/cc (i.e., 0.8 g/cc or 0.7 g/cc) reduces the effect of residual gas saturation on porosity calculations (Kukal et al., 1983).

Then, using equation (3.2), the temperature gradient was calculated. Afterward, the formation temperature curve using equation (3.2) (but replacing the values to obtain formation temperature at reservoir depth) and formation water resistivity with equation (3.3) were applied.

Table 3-2 shows the values for temperature gradient in deg F/ft calculated for each cored well.
Table 3.2 This table shows the temperature gradient (°F/ft.), surface temperature (°F), the value used for Rw (ohm-m) (from produced water) before temperature correction, and the calculated water resistivity at formation temperature (Rfm) used for water saturation calculations.

<table>
<thead>
<tr>
<th>Well</th>
<th>Temperature Gradient (°F/ft)</th>
<th>Rw from produced water at Ts (ohm-m)</th>
<th>Surface temperature Ts (°F)</th>
<th>Water Resistivity at formation T (Rfm) (ohm-m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well 1</td>
<td>0.0111</td>
<td>0.168</td>
<td>73.6</td>
<td>0.062</td>
</tr>
<tr>
<td>Well 2</td>
<td>0.0087</td>
<td>0.168</td>
<td>68.0</td>
<td>0.071</td>
</tr>
<tr>
<td>Well 4</td>
<td>0.0100</td>
<td>0.168</td>
<td>68.0</td>
<td>0.087</td>
</tr>
</tbody>
</table>

For water saturation calculation, we use equation (3.4) and the following values:

\[ S_w = \left( \frac{a \cdot R_w}{R \cdot T \cdot \phi^m} \right)^{1/n} \] (3.4)

- \( a \): tortuosity factor. Usually, a constant=1 (in consolidated sandstones)
- \( n \): saturation exponent, usually=2
- \( m \): cementation exponent, usually=2, but in tight sandstone reservoirs, 1.8 is often used.

Byrnes et al. (2008) showed that rocks with lower porosity (between 0%-6%) exhibit lower values of \( m \) (\( m \) between 1.0-1.8). Rw is the water resistivity from production data which is 0.168 ohm-m at surface temperature and then converted to water resistivity at the formation’s temperature.

As mentioned before, petrophysics in tight gas-producing rocks can be challenging. However, the availability of core data validated calculating and adjusting the porosity and water saturation values.

**Well 1 model**

Figure 3.5 shows the different porosity models for Well 1. DPHI268 was calculated using the average density from core data. Since this is a tight gas sandstone, the fluid density was replaced by 0.8 g/cc. Although the model comes close to the cored data, it seems that grain density could be higher. Grain density values range between 2.68 g/cc and 2.72 g/cc. This elevated density was attributed to the amount of the heavy mineral chlorite reported on the XRD analyses, with a density of 2.76 g/cc. This high-density value explains the higher density values found in the RCA samples. The model fits the core data better
when 2.71 g/cc density was used. Rw was used from water production in the area of 0.168 ohm-m, then converted to water resistivity at the formation’s temperature.

Water saturation was calculated once the porosity model was evaluated. The cementation exponent (m) is usually 2, but 1.8 is often used in tight sandstones. Figure 3.8 shows the different saturation models with different values.

1. Grain density equals 2.71 g/cc, fluid density of 0.8, and m=1.8.
2. Grain density equals 2.71 g/cc, the fluid density of 0.8, and m=2.
3. Grain density of 2.71 g/cc, the fluid density of 1 g/cc, and m=2
4. Grain density, 2.71 g/cc, and fluid density of 1 g/cc, and m=1.8
5. Grain density, 2.68 g/cc, the fluid density of 0.8, and m=2
6. Grain density, 2.68 g/cc, the fluid density of 0.8, and m=2.

As shown in Figure 3.6, the models using lower grain density and m=2 display higher water saturations and are further from the core data. The models using grain density of 2.71 g/cc and m=1.8 are much closer to the core measurements. In comparing the difference in the models using fluid density as 1.0 g/cc or 0.8 g/cc, the one using 0.8 g/cc fits the data better. The model presents some saturation issues at the bottom of the core with more laminations. This is because the deeper resistivity log’s resolution is insufficient, and there is a bed boundary effect. Additionally, these facies might have more clay content. Hence, water saturation calculations for the lower part are higher and unreliable (core values are very different from the calculated saturation).
Figure 3.5 Well 1 porosity models with different matrix and fluid densities. m=1.8 is used since these are tight gas sandstones. 2.68 g/cc was used for matrix density based on average grain density data from RCA. However, the high percentage of chlorite explains some of the higher values, and it explains why the model using a 2.71 g/cc matrix fits the core result better. Rw is 0.062 ohm-m.
Figure 3.6 Well 1 porosity and saturation models with different matrix and fluid densities. m=1.8 is used since these are tight gas sandstones. 2.68 g/cc was used for matrix density based on average grain density data from RCA. However, the high percentage of chlorite explains some of the higher values, and it explains why the model using a 2.71 g/cc matrix fits the core result better. Rw is 0.062 ohm-m. The star shows the preferred model used to calculate water saturation.
**Well 2 model**

Figure 3.7 shows the different porosity models for Well 2, following the same process applied to Well 1. Again, different porosity models were evaluated, and the curves were plotted against the core porosity data. The porosity model that best fits the core data is with the DPHI porosity log using limestone matrix and fluid densities of 1 g/cc and 0.8 g/cc.

Figure 3.8 shows the different saturation models using the following values, the same cases as the previous well:

1. Grain density equals 2.71 g/cc, fluid density of 0.8, and m=1.8.
2. Grain density equals 2.71 g/cc, the fluid density of 0.8, and m=2.
3. Grain density of 2.71 g/cc, the fluid density of 1 g/cc, and m=2
4. Grain density, 2.71 g/cc, and fluid density of 1 g/cc, and m=1.8
5. Grain density, 2.68 g/cc, the fluid density of 0.8, and m=2
6. Grain density, 2.68 g/cc, the fluid density of 0.8, and m=2.

The models using lower grain density and m=2 display higher water saturations further from the core data. The models using grain density of 2.71 g/cc and m=1.8 are much closer to the core measurements in comparing the difference in the models using fluid density as 1.0 g/cc or 0.8 g/cc. The model using a fluid density of 0.8 g/cc fits the data better.
Figure 3.7 Well 2 porosity models with different matrix and fluid densities. \(m=1.8\) is used since these are tight gas sandstones. 2.68 g/cc was used for matrix density based on average grain density data from RCA. However, the high percentage of chlorite explains some of the higher values, and it explains why the model using a 2.71 g/cc matrix fits the core result better. Rw is 0.071 ohm-m.
Figure 3.8 Well 2 porosity and saturation models with different matrix and fluid densities. m=1.8 is used since these are tight gas sandstones. 2.68 g/cc was used for matrix density based on average grain density data from RCA. However, the high percentage of chlorite explains some of the higher values, and it explains why the model using a 2.71 g/cc matrix fits the core result better. Rw is 0.071 ohm-m.
Well 4 model

Figure 3.9 shows the different porosity models for Well 4 following the same procedure used in the previous wells. Core porosity data was compared to the porosity models using DPHI268. Since this is a tight gas sandstone, the fluid density was replaced by 0.8 g/cc. Although the model comes close to the cored data, it seems that grain density could be higher. This elevated density was attributed to the amount of the heavy mineral chlorite reported on the XRD analyses, with a density of 2.76 g/cc. The model fits the core data better when 2.71 g/cc density was used. Rw was used from water production in the area of 0.168 ohm-m and then converted to resistivity at the formation’s temperature.

Water saturation was calculated once the porosity model was evaluated, using the same cementation exponents as the previous wells, and then compared. The columns in Figure 3.10 show the following values:

1. Grain density equals 2.71 g/cc, fluid density of 0.8, and m=1.8.
2. Grain density equals 2.71 g/cc, the fluid density of 0.8, and m=2.
3. Grain density of 2.71 g/cc, the fluid density of 1 g/cc, and m=2
4. Grain density, 2.71 g/cc, and fluid density of 1 g/cc, and m=1.8
5. Grain density, 2.68 g/cc, the fluid density of 0.8, and m=2
6. Grain density, 2.68 g/cc, the fluid density of 0.8, and m=2.

The models using lower grain density and m=2 display higher water saturations and are further from the core data. On the other hand, the models using grain density of 2.71 g/cc and m=1.8 are much closer to the core measurements. In comparing the difference in the models using fluid density as 1.0 g/cc or 0.8 g/cc, both seem to match the core data. At low porosity, residual gas saturation has a minimal effect on the Sw calculation. Water saturation calculated from logs where it is still high compared to core data could be due to variations in Rw that cannot be determined from existing water analysis data. Higher interbedding in those areas can also create a bedding boundary effect and affect the resistivity log readings. Hence the water saturation is not reliable in said areas.
Figure 3.9 Porosity models with different matrix and fluid densities for Well 4. An $m=1.8$ is used since these are tight gas sandstones. 2.68 g/cc was used for matrix density based on average grain density data from RCA. However, the high percentage of chlorite explains some of the higher values, and it explains why the model using a 2.71 g/cc matrix fits the core result better. $R_w$ is 0.087 ohm-m.
Figure 3.10 Porosity and saturation models with different matrix and fluid densities for Well 4. An $m=1.8$ is used since these are tight gas sandstones. 2.68 g/cc was used for matrix density based on average grain density data from RCA. However, the high percentage of chlorite explains some of the higher values, and it explains why the model using a 2.71 g/cc matrix fits the core result better. $R_w$ is 0.087 ohm-m.
3.4.2 Pickett and Buckles plots

Samples from the RCA were shifted using the core GR shift and plotted with the petrophysical model curves. In addition, Buckles plots for porosity vs. water saturation were plotted and color-coded based on facies for all sandstone cored wells.

Net confining stress refers to the stress applied to a rock today and reflects a series of geological events. Rocks are also not homogeneous and act differently under different confining stresses. Several factors need to be considered to define the stress over a rock, such as considering if the vertical direction is the primary stress direction and estimating the vertical stress component magnitude (Zhang, 2016).

MorningStar partners/Southland Royalty provided net confining stress values and were estimated to be around 10000 psi. Unfortunately, some of the samples had problems reporting saturation at this confining stress, in which case the next available value for saturation and porosity was used (5000 psi or 2292 psi). Byrnes (2008) showed that tight sandstones have lower cementation exponents than those found in conventional reservoirs. Hence, m=1.8 is often used in these types of sandstones instead of m=2.

Well 1

Buckles plot of porosity vs. saturation from core data shows samples with higher porosity display lower water saturation values (Figure 3.11). This core displays a wide range of facies, and the results observed in the Buckles plot (porosity vs. water saturation) show the same variety. In general, samples that are classified as silty sandstone display slightly better porosities and lower water saturation than other facies. Figure 3.12 shows the Pickett plot for Well 1 shows the Pickett plot using the Rw from produced water converted to BHT (0.062 ohm-m) and the cementation exponent, m=1.8. Most of the different siltstone facies samples fell above the 100% Sw line, probably due to the higher clay content. Thus, the values were discarded. It also confirms why the siltstone interval from Well 3 is not a reservoir.

The remaining points fall within 60% and 40% water saturation. This plot shows the same trends as the Buckles plot, where finely laminated silty sandstone samples have lower saturation values. The picket plot was modified not to have samples exceeding 100% water saturation. Samples from the lower core interval were discarded since the saturation models proved unreliable on intervals with many
intercalations. The Bioturbated silty sandstone facies also showed low saturation values. Some of the bioturbation (especially if it is vertical) can serve as migrations pathways, increasing reservoir quality. This plot can be handy to determine saturations using porosity logs instead of using core porosities. However, it is always recommended to calibrate every model with core data.

Well 2

The same procedure used on Well 1 was applied to Well 2. Figure 3.13 shows the Buckles plot for the core data on this well. Saturation values for this well are less variable in this core than in Well 1, reflecting the lower facies variability present. But, in general, they follow the same trend where samples with higher porosity display lower saturation values. Figure 3.14 shows the Picket plot for Well 2 using Rw=0.071 ohm-m and m=1.8. Most of this core is constituted by massive sandstones and silty sandstones. Samples that show higher saturation values do not show any difference on core or thin sections, besides the presence of some shale clasts that could be affecting the resistivity log readings. They only have slightly higher illite and illite/smectite values that could increase the inbound water, but more studies should be performed at these depths to determine this more accurately.

Well 4

Buckles plot show samples with lower saturations correlate with higher porosity values. This interval also shows that the bioturbated silty sandstone facies have similar properties to finely laminated silty sandstones (Figure 3.13). Mineralogically, this well has more clay content (illite and smectite, from XRD analyses) and more interbedding towards the bottom, thus increasing water saturation. For this reason, the siltstones facies were removed from the Pickett plot (Figure 3.15). The intervals from Well 1 and Well 2 have high chlorite content, which helps preserve the porosity, decrease illite/smectite content, and decrease saturation. In contrast, this interval's chlorite content is lower, affecting the porosity and decreasing the overall favorable properties of this interval. In addition, there is more interbedding in this core, which can affect the resistivity log readings, thus affecting the water saturation calculations.
Figure 3.11 Buckles plot for Well 1. It shows that samples with higher porosity display lower water saturation (Sw). Samples mainly belong to the finely laminated silty sandstone facies and Bioturbated silty sandstones.
Figure 3.12 Pickett plot for Well 1 based on log data (RT) and porosity calculated from bulk density log (RHOB). In this plot, saturation lines are based on $m=1.8$ and $R_w=0.062$. Most samples with lower water saturation belong to the finely laminated silty sandstone facies and bioturbated silty sandstones.
Figure 3.13 Buckles plot for Well 2. It shows that samples with higher porosity display lower water saturation (Sw) and some of the highest porosity samples in the cored wells.
Figure 3.14 Pickett plot for Well 2 based on log data (RT) and core data (Porosity). In this plot, m=1.8 and Rw=0.071. Samples with higher saturation values do not seem to have any lithological differences compared to the other, but more analyses need to be done to determine why they have higher saturation values.
Figure 3.15 Buckles plot for Well 4. As in the other intervals, samples with higher porosity values display lower saturation values. Siltstone intervals had higher than 100% saturation values, probably due to higher clay content. Thus, these points were discarded.
Figure 3.16 Pickett plot for Well 4 based on log data (RT) and Porosity calculated from Bulk density (RHOB) with a 2.71 g/cc matrix. In this plot, m=1.8 and Rw=0.087
3.4.3 Flow Units

Lorenz plots rank the flow capacity of different units by considering the porosity and permeability of the reservoir (Kourosh et al., 2015) and help define the flow units. The different inflection points are characteristic of storage capacity or flow capacity changes. The flatter areas of the plot indicate low flow units, usually in tight reservoirs, whereas steeper trends have faster flow rates (Mahjour et al., 2016).

Well 1

Figure 3.17 (page 199) shows the Lorenz plot for Well 1. Again, steeper areas indicate faster flow units (or better reservoir units), whereas flatter areas show slower flow units (tighter units). The flow units are shown in stratigraphic order. The Finely laminated silty sandstones facies have the same trends indicating similar rock characteristics. The inflections in the curve mark three flatter or slow flow units (2, 8 and 10).

Well 2

The Lorenz plot for this interval shows that most of the intervals have relatively steep flow units (rapid), indicating the samples have similar rock characteristics. There is only one slow unit (number 5).

The similarity in the characteristics makes sense since this is a short core with relatively homogeneous lithologies (Figure 3.18) (Page 200).

Well 4

The C2 sandstone interval from Well 4 shows poorer reservoir properties, similar to the results obtained from the Buckles and Pickett plots and the porosity and saturation models for the interbedded sections of the core. The flow units for this interval are, in general, flatter than in the Well 1 and Well 2 intervals. There is also higher variation, although it is a short core. Most of the production would be expected from intervals 5, 8, and 10 (Figure 3.19) (page 201).

Reservoir quality

The flow units in these units do not differ much from each other. Samples from the same facies have the same steep slope, showing the same rock characteristics. It also shows that the facies with the
best reservoir properties is the finely laminated silty sandstone (in most cases). These results are consistent with the Pickett plot results.

Well 4 seems to have higher clay content with increasing saturation values. Chlorite content is lower than in the other two intervals, and this could be because this is the shallowest interval, and the conversion of smectite to illite is incomplete, releasing silica for chlorite to form. Chlorite has preserved porosity in these intervals and helps with the overall reservoir properties. Thus, the lower values can be correlated with poorer reservoir properties.

3.5 Discussion

The petrophysical characteristics of these four cores displayed the same level of heterogeneity as the facies described. Samples have high variation in water saturation values and, in general, very low porosity and permeability characteristics of these reservoirs.

In all the cores, samples with higher porosity values usually correlate with lower water saturation. Samples classified as finely laminated silty sandstones and bioturbated silty sandstones displayed better reservoir properties than the other facies, even the clean, massive sandstones.

Chlorite and clay content have a significant impact on the reservoir properties. Well 1 and Well 2 had lower illite/smectite and higher chlorite content and showed better properties than Well 4, which had higher illite/smectite and lower chlorite content.

It is essential to perform additional analyses on these rock types since some minerals can affect the log responses, such as pyrite, chlorite, or carbonates. In this case, XRD and RCA proved crucial when performing a petrophysical analysis. Chlorite content was high enough to skew the rock's density closer to 2.71 g/cc even though these are sandstones, and a matrix density of 2.65 g/cc was expected. Thus, it is always recommended to calibrate every model with core data.

The presence of chlorite, seen as grain coatings in petrographic images, can preserve porosity and improve reservoir properties, thus explaining why the finely laminated silty sandstones have better properties than the clean, massive sandstones.
Vertical bioturbation observed on the cores can serve as migration pathways and increase the porosity and permeability of the rock. Hence, the bioturbated silty sandstone facies displayed optimal petrophysical properties and low saturations.

The Lewis Shale is a tight gas sandstone. As such, some petrophysical constants used to calculate water saturation using the Archie equation must be adjusted to account for gas in the formation and the “tightness” of the rock.

The next step suggested is maps of pay intervals with the calculated porosity and water saturation models. Unfortunately, publicly available well log data is scarce or incomplete in this area.

3.6 Conclusions

- The facies with better saturation, porosity, and flow properties are usually the finely laminated silty sandstone.
- Other specialized mineralogy analyses proved crucial to performing an accurate petrophysical model since the presence of some dense minerals can affect matrix density and porosity calculations, such as pyrite or chlorite.
- It appears that the presence of chlorite enhances the reservoir properties. Hence, not always the cleanest sandstone has the best properties.
- These reservoirs are tight gas sandstones. Thus, the necessary adjustment to the constants used for the Archie equation to account for this needs to be done.
- It is recommended to perform a petrophysical model in sandstone intervals with fewer intercalations to avoid bed boundary effects and unreliable water saturation values. Also, these intervals will be more continuous laterally than the highly interbedded ones.
- Some of these interbedded sandstones show good potential for development. But it is recommended to avoid the highly interbedded and more clay rich intervals.
Figure 3.17 Lorenz plot showing all the flow units present in Well 1.
Figure 3.18 Lorenz plot for Well 2. Each of the lines represents a flow unit. There is only one slow unit in this interval (number five). The other has approximately the same inclination, which indicates similar internal characteristics.
Figure 3.19 Each of the lines represents a flow unit. This well has more slow units than the other wells (numbers 1, 2, 4, 7). This could be because this well has higher clay content and lower chlorite content decreasing the reservoir quality.
3.7 References


CHAPTER 4

WELL DEVELOPMENT, PRODUCTION, AND CHALLENGES IN THE LEWIS SHALE IN THE EASTERN GREEN RIVER BASIN, WYOMING

4.1 Abstract

Wyoming is a large oil and gas producer in the United States, and it is expected to increase in the upcoming years. As a result, drilling operations in the area can significantly affect the wildlife by impacting their habitat and reproduction areas. The Wyoming Game and Fish Commission published some recommendations to lessen the impact of oil and gas development on the wildlife to mitigate these effects (WG&F, 2007). These efforts include buffers around nests, migration corridors, concentration areas, and non-surface disturbance. The present study is located in the Sweetwater and Carbon counties in Wyoming's Greater Green River Basin. Information includes production and completion data and environmental and facilities shapefiles near the four wells that were cored provided by MorningStar Partners/Southland Royalty.

Environmental stipulations, restrictions, and pipeline availability have proven to be limiting factors for developing the Lewis Shale in Wyoming. In addition, drilling operations can significantly affect the wildlife by destroying their habitat and reproduction areas. As a result, the Bureau of Land Management (BLM), Wyoming Game and Fish (WG&F), and Wyoming Oil and Gas Conservation Commission (WOGCC) have developed a set of rules that must be followed when applying for a drilling permit. These rules include areas of non-disturbance, seasonal disturbance, and buffers that indicate where and where not to drill a well or set of wells. Analyzing these limiting factors and identifying the most common well-completion techniques and how they affect well production will help reduce permitting time and create a more accurate and fast drilling program.

The resulting maps show the areas with better production, fewer environmental concerns, and more pipelines available. The areas with fewer environmental stipulations and are located closer to available pipelines are found towards the Great Divide Basin near the Lost Creek, Red Dessert, Strike, and Siberia Ridge fields. Towards the middle of the field from T19N, R93W to T19N, R103W and T17N, R91W and
R96W and on the south from T16N, R91W – T16N, R97W and T13N, R91W-T13N-R97W). These areas still have some restrictions on drilling times and some buffers present, but restrictions are fewer. These areas on the north also represent the most productive (oil) and prospective areas for well development. The production analysis did not show any correlation between production, the number of fracture stimulation stages, total fluid injected, and total proppant injected.

4.2 Introduction

Wyoming has had a long history of oil and gas development. The presence of “oil springs” was noted when Wyoming became a state. The first drilling started around 1833 at the Dallas Dome. In the 1890s, the first refinery was built thanks to some discoveries (Roberts, 2014). Natural gas was very prolific in Wyoming during the 1990s and 2000s. Coal-bed-methane is an important source of gas that helps the economy in Wyoming. Oil and associated gas production in Wyoming, specifically in the Powder River basin, has increased from 2017 through 2019. However, natural gas production has been steadily declining since 2009 with the collapse of the coalbed natural gas industry largely due to low natural gas prices. The Wyoming Game and Fish Commission published some requirements to lessen the impact of oil and gas development on wildlife. Their document, first published in 2004, has had subsequent revisions as more information became available and with input obtained from the Bureau of Land Management (BLM). This document also includes some of the standard practices the BLM and the United States Forest Service (USFS) currently use, as well as several concepts adapted from the 'Surface Operating Standards and Guidelines for Oil and Gas exploration and Development' (USDI/USDA, 2006) (Wyoming Game and Fish Department, 2007).

Environmental stipulations and regulations and pipeline availability in Wyoming are crucial to consider when filing for permits. Therefore, the Bureau of Land Management (BLM), Wyoming Game and Fish (WG&F), and Wyoming Oil and Gas Conservation Commission (WOGCC) has developed a set of rules that must be followed when applying for a drilling permit. The present study is located in the Great Divide and Wamsutter arch in the Sweetwater and Carbon counties, Wyoming. Data includes
production and completion data and environmental and facilities shapefiles near the four cores located around the basin provided by MorningStar Partners/Southland Royalty (Figure 4.1).

Besides this area's geological complexity, several environmental regulations must be considered. Unfortunately, when looking at the potential to develop a field, factors such as environmental regulations or pipeline availability are often neglected. Consequently, shapefiles and raster files from the BLM, WG&F, pipeline locations, the Sweetwater and Carbon counties, the Greater Green River Basin outline, and the wells in the area were used to build maps. The BLM also provides the dates and space buffers around each species' restrictions included in the maps. These maps allowed us to identify developable areas and identify the best months for operations in Wyoming.

Production analysis was performed around the areas where data from four wells with cores were available. Enverus provided production data for the area, and the fracture stimulation report data was obtained from the WOGCC. First, Wells were correlated using the gamma-ray (GR) signature for the Lewis Shale in the Wamsutter Field to determine the intervals produced. Since the Lewis Shale is a very thick unit, the three-member division is insufficient to correlate specific sand packages. For this reason, correlated intervals separated by different flooding surfaces that show higher GR values and can be followed throughout the basin and are named from A to H and from shallower to deeper, following a similar method to the one used by Pyles and Slatt (2000) and Pasternack (2005). Then, all the wells around the MorningStar/Southland Royalty cored areas were correlated, and wells completed in the same cored intervals were analyzed.

Data gathered consisted of total horizontal drilling length, total production, number of fracture stimulation stages, total fluid injected, and total proppant injected. Finally, the different intervals and completion procedures were compared to identify any correlation between the production and the number of fracture stimulations stages, the volume of proppant, and total fluid injected.
4.2.1 Geological Setting

The Lewis Shale is a turbidite system comprised of sandstones, siltstones, and organic-rich shales, deposited during the last Cretaceous seaway transgression. It is informally subdivided into three members: lower (characterized by high clay and organic matter content), middle member (a mixture of siltstones, shales, and sandstones), and an upper member or Dad Sandstone Member (with decreasing amounts of sandstone and greenish-grey shales) that can reach up to 2600 ft in thickness (Almon, 2002).

Each member has variable amounts of sands, siltstones, and shales, depending upon their depositional location within the platform. It includes channels, sheet sands, mass transport deposits, and flooding surfaces. The sequence stratigraphic framework was developed by Pyles and Slatt (2000) and Pyles and Slatt (2007). It is characterized by a third-order progradational highstand systems tracts, comprising several fourth-order lowstand-highstand cycles and a shallowing upwards sequence. Its maximum flooding surface is located in the lower member, named the Asquith Marker. It has a maximum thickness of 50 ft within the basin, and it is believed to be a source of hydrocarbons, with TOC values ranging between 0.68% and 3.15% in core and outcrop (Mayorga-Gonzalez, 2016). The Lewis Shale
comprises different depositional environments within the deep-water system, including turbidite channels, sheet sands, and mass transport deposits. Deeper depositional areas are located towards the south and transition to shallower areas towards the north. Upper Cretaceous rocks were deformed in a series of intermontane basins formed during the Laramide Orogeny. During this time, the Sierra Madre uplift, Rawlins uplift, Cherokee uplift, Lost Soldier anticline, and Rock Springs uplift were uplifted and served as a source of sediment for the Lewis Shale. McMillen and Winn (1991) and McGooykey et al. (1972) identified submarine fan sandstones from several directions matching the placement of the other uplifts of the time.

This formation is considered an unconventional reservoir due to its low porosity and permeability and the need to use hydraulic fracture stimulation to obtain hydrocarbons. In addition, this area is relatively newly developed with horizontal wells. One of the first horizontal wells in the Lewis Shale was drilled in 2012, named Spirit of Radio 7-1H by BP America, and since then, about 226 horizontal wells have been drilled in the Lewis Shale in the area (WOGCC). The hydrocarbon production from the Lewis Shale mainly comes from the gas reservoirs within the Desert Springs, Hay Reservoir, Wamsutter, Great Divide, Strike Unite, and Siberia Ridge fields (Gonzalez, 2003).

4.3 Theory and Methods

4.3.1 Environmental Restrictions

Maps of crucial “big game” winter ranges, Sage-Grouse habitat, priority watersheds, and other essential habitats found at the Wyoming Game and Fish (WG&F) website were used to build the different maps. The BLM also provides the dates and space buffers around each species' restrictions included on the maps.

These maps allowed us to identify developable areas and identify the best months for operations in Wyoming. As densities of wells, roads, and facilities increase, habitats within and near gas fields become progressively more stressed until most animals no longer use these areas. Wyoming has a vast amount of wildlife, including 87 species of mammals, 297 birds, and 63 species of fish, reptiles, and amphibians.
(Wyoming Game and Fish Department Vertebrate Species List, 1992). The preservation of these species is crucial for the environment; therefore, following environmental rules is essential when planning a well.

Table 1 lists the main species of consideration for this area. Some of the most important ones are sage-grouse and raptors. Sage-grouse is one of the most important species due to the decline of the general sage-grouse population. As a result, the sage-grouse Implementation Team (SGIT) was formed by the WG&F, the Oil and gas industry, and other stakeholders formed the Wyoming Core Area Strategy to ensure the long-term viability of its preservation.

This strategy prioritizes prime sage-grouse habitat populations and encourages resource development in other areas. It also defines areas where impacts from disturbance due to development are minimal and areas where impact is extreme and should be avoided.

The oil and gas industry has adhered to these regulations that include no surface operations during critical times of the year for sage-grouse reproduction and non-disturbance or drilling around set buffer areas. According to the state of Wyoming, Executive Department, Executive order (2003), the sage-grouse areas are divided into:

- Core population areas (are breeding habitats and where approximately 83% of the total sage-grouse population is located).
- Non-core population areas (habitat located outside core populations and connectivity areas).
- Connectivity areas (areas essential for maintaining the transmission of genetic material between populations)
- Winter concentration areas (places where large numbers of core population congregate and persistently occupy between December 1st and March 14th).

For the “core areas,” the following stipulations are designed to maintain the sage-grouse habitat and avoid significant impact:

- Surface Disturbance is limited to 5% of suitable habitat per average of 640 acres over the entire core area. The disturbance is considered and approved on a case-by-case basis.
• Surface Occupancy within 0.6 miles of an active lek has “no surface occupancy” (NSO).

• Seasonal Use. Activities are allowed from July 1st to March 14th outside the 0.6 miles perimeter of an occupied lek in Core Population Areas where breeding, nesting, and nearly brood-rearing habitat are present.

For non-core areas within 2 miles from an occupied lek, the following stipulations must be followed:

• Surface Disturbance has no limitation outside the 0.25 miles from an occupied lek.

• Surface occupancy within 0.25 miles of the perimeter of occupied greater sage-grouse leks is “Non-Surface Operation” (NSO), which means no permanent surface facilities, including roads, are placed within the NSO. However, other activities are authorized based on applying appropriate seasonal stipulations and avoiding any adverse effect on the resources inside the NSO area.

• Seasonal use allows activities from July 1st to March 14th outside of the 0.25 miles perimeter of an occupied lek (breeding ground) and within 2 miles from the perimeter of the occupied lek (where breeding, nesting, and early brood-rearing habitat is present).

Connectivity areas:

• Surface Disturbance. It should be limited to 5% of suitable Sage Grouse habitat.

• Surface Occupancy to protect connectivity corridors requires an NSO buffer of 0.6 miles around occupied leks or their documented perimeter.

• Seasonal Use. Within 4 miles of occupied lek (within nesting habitat), there is a March 15th to June 30th timing limitation.

Winter Concentration areas:

• Seasonal Use. New activities are allowed from March 15th to November 30th within the delineated and mapped winter concentration areas.

For oil and gas, well pads and associated infrastructure densities are not to exceed an average of one pad per square mile (1/640 acres) and suitable habitat disturbance. The geophysical exploration within the
greater sage-grouse population area may be permissible following identified seasonal use stipulations. However, staging areas should be located outside core population areas (State of Wyoming, Executive Department, Executive order, 2003).

Raptors are another one of the most important species. They are protected under the migratory Bird Treaty Act, 16 U.S.C. 703 (MBTA), which includes migratory birds, eggs, and nests from being harmed or taken. It includes hawks, eagles, and falcons. Raptors buffers vary depending upon the species, but raptor nests are often initially not identified to species (e.g., preliminary aerial surveys in winter). Therefore, BLM recommends a generic raptor nest seasonal buffer guideline of January 15th – August 15th. Similarly, for spatial nesting buffers, until the nesting species have been confirmed, they recommend applying a 1-mile spatial buffer around the nest. When the nest's species have been identified, the seasonal buffers from Table 1 must be used.

It is also essential to consider the following features:

• Migration corridors were created to protect areas used as migration corridors for different species to manage activities on a project-specific basis through avoidance and minimization. Several factors are not entirely understood in this topic, and work is still being conducted in this field. However, the oil and gas industry understands the importance of protecting and preserving the wildlife and its habitat, thus working intrinsically with the different government entities as policies are developed to ensure its protection and preservation while still developing resources.

• Crucial Range is that component that has been documented as the determining factor in a population's ability to maintain itself at a certain level (theoretically at or above the WGFD population objective) over the long term

Critical habitats are those areas designated as critical by the Secretary of the Interior or Commerce for the survival and recovery of listed Threatened and Endangered Species (50 CFR, Parts 17 and 226)

An oil and gas production analysis was performed around the four cored wells that Morningstar Partners/Southland Royalty provided in Carbon and Sweetwater counties. Well-logs obtained from the WOGCC and TGS were correlated using the gamma-ray (GR) signature for the Lewis Shale in the
Wamsutter Field to determine the intervals produced. Since the Lewis Shale is a very thick unit, the three-member division is insufficient to correlate specific sand packages. For this reason, correlated intervals separated by different flooding surfaces that show higher GR values and that can be followed throughout the basin and are named in this study from A to H and from shallower to deeper, following a similar method to the one used by Pyles and Slatt (2000) and Pasternack (2005) (Figure 4.2). These flooding surfaces are equivalent to the fourth-order flooding surfaces that Pyles and Slatt (2000) described in their work and can be seen as red lines in Figure 4.2.

4.3.2 Pipeline Distribution

There are approximately 9,000 miles of crude oil and 25,000 miles of natural gas pipelines in Wyoming, including gathering and transmission lines. There are also about 2,000 miles of pipeline used to move refined commodities such as diesel and gasoline and 1,700 miles of natural gas liquids (Figure 4.3). Figure 4.3 shows the different pipelines and pipelines owners. Pipeline availability can be a critical factor in developing a field if a contract with each owner needs to be signed. In addition, pipeline coverage for each owner needs to be considered when drilling wells.

4.4 Production Analysis

Production analysis includes analyzing decline curves. These curves have been extensively used in the past to forecast production and reserves in wells. They are used to establish remaining reserves by historical production trends and decline from historical decline. There are two main ways to do a decline curve analysis by the Arps’ method and more recent empirical methods (Cheng et al., 2008).

Decline curves were designed for vertical, single-layer wells, leading to pitfalls when applying them to unconventional wells. Unconventional wells are frequently horizontal wells that may target multiple layers to be economical, which increases uncertainty in decline curve analysis since different layers have different permeabilities and changes in transient flow versus stabilized flow related to the permeability of the reservoir. As such, production profiles in unconventional reservoirs often change several times during the life of the well.
One approach applied by the industry is using a hyperbolic curve at the beginning of the production of a well and then using exponential or harmonic to fit the rest of the life of the well, which increases the uncertainty of the results obtained (Chen et al., 2011).

Figure 4.2 Type log of the Lewis Shale with the equivalent flooding surfaces used in this study. This well is located on the Washakie basin, south of all the cores in this study AAPG©[2007], reprinted by permission of the AAPG whose permission is required for further use.
In addition to the uncertainty of these analyses, they require several years of production, reservoir pressure and temperature, bottom-hole flowing pressure data, and fluid properties (i.e., API gravity of oil, specific gravity of gas). This information is not readily available for all the wells analyzed in the area. Furthermore, most of the horizontal wells have been producing for a few years and most of them were completed almost at the same time. Hence an analysis of proppant volume, the volume of total fluid injected, and the number of fracture stimulation stages versus production was made. Wells producing for the same amount of time, length, and intervals were plotted and analyzed.

Production graphs from the WOGCC did not provide much information since the horizontal wells drilled were completed at about the same time and older vertical wells were comingled.
A spacing analysis was attempted to assess if the wells were interfering with each other, but most horizontal wells around the cored wells were completed with just a few days difference, and the vertical wells were all commingled. Therefore, the analysis was not viable.

4.5 Results

4.5.1 Environmental Restrictions Maps

Maps in ArcGIS were built based on the shapefiles and raster files from the Bureau of Land Management (BLM), (WG&F) Wyoming Game and Fish. Pipeline locations, shapefiles of the Sweetwater and Carbon counties, the Greater Green River Basin outline, and the wells in the area are also plotted. With the BLM information about buffers and when operations can occur, maps of developable areas per month were built. Production analysis and comparison from the different intervals and different completion procedures were performed. Enverus provided production data for the area, and the fracture stimulation report data was obtained from the WOGCC.

The resulting maps show that the areas have fewer environmental concerns and more pipelines available (Figure 4.4). Most of the pipelines cross through the Sweetwater and Carbon counties from north to South and East-west. Areas with fewer environmental stipulations and closer to available pipelines are located towards the Northwest of the Wamsutter field (between T23N, R92W, and T23N, R97W). Towards the middle of the field from (T19N, R93W to T19N, R103W, and T17N, R91W, and R96W). On the south, from T16N, R91W – T16N, R97W and T13N, R91W- T13N-R97W.
Table 4.1 Buffers and dates for the main species in Sweetwater and Carbon County, Wyoming.

<table>
<thead>
<tr>
<th>Species</th>
<th>Common Name</th>
<th>Buffer (Miles)</th>
<th>Dates</th>
<th>Notes</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Raptors</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Golden Eagle</td>
<td></td>
<td>0.5 from nest</td>
<td>Jan 15th-July 31st</td>
<td></td>
</tr>
<tr>
<td>Ferruginous Hawk</td>
<td></td>
<td>1 mi from the nest</td>
<td>March 15-July 31st</td>
<td></td>
</tr>
<tr>
<td>Swainson’s Hawk</td>
<td></td>
<td>0.25 mi</td>
<td>1st-August 31st</td>
<td></td>
</tr>
<tr>
<td>Bald Eagle</td>
<td></td>
<td>0.5 mi</td>
<td>January 1st – August 15th</td>
<td>Avoid disturbance within 0.5 mi of communal winter roosts from November 1st. April 1st</td>
</tr>
<tr>
<td>Prairie Falcon</td>
<td></td>
<td>0.5 mi</td>
<td>March 1st-August 15th</td>
<td></td>
</tr>
<tr>
<td>Peregrine Falcon</td>
<td></td>
<td>0.5 mi</td>
<td>March 1st-August 15th</td>
<td></td>
</tr>
<tr>
<td>Short-Eared Owl</td>
<td></td>
<td>0.25 mi</td>
<td>March 15th-August 1st</td>
<td></td>
</tr>
<tr>
<td>Burrowing owl</td>
<td></td>
<td>0.25 mi</td>
<td>April 1st-September</td>
<td></td>
</tr>
<tr>
<td>Northern Goshawk</td>
<td></td>
<td>0.5 mi</td>
<td>April 1st–August 15th</td>
<td></td>
</tr>
<tr>
<td><strong>Birds</strong></td>
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<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Greater Sage-Grouse Core area</td>
<td></td>
<td>Non-Surface occupancy within 0.6 mi of the occupied lek</td>
<td>In core areas, no more than one pad per square mile.</td>
<td></td>
</tr>
<tr>
<td>Sage Grouse non-core areas</td>
<td></td>
<td>Non-Surface Occupancy: 0.25 mi. of each lek. Mitigation 2 mi. of each lek</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sage Grouse Winter concentration areas</td>
<td></td>
<td>Avoid placing roads, wells, or other facilities within the winter concentration areas.</td>
<td>Nov 15th-March 14th</td>
<td></td>
</tr>
<tr>
<td>Yellow-billed cuckoo</td>
<td></td>
<td>Wherever found</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mountain Plover</td>
<td></td>
<td>Wherever found</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Mammals</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Elk</td>
<td></td>
<td>Wherever found</td>
<td></td>
<td>High Impact: 1-4 well pad locations or up to 60 acres of disturbance /mile². Extremes: &gt;4 pads or &gt;60 acres of disturbance per square mile</td>
</tr>
<tr>
<td>Prairie dog</td>
<td></td>
<td>Wherever found</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Black-footed ferret</td>
<td></td>
<td>Wherever found</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Plants</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>UTE Ladies Tresses</td>
<td></td>
<td>Wherever found</td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Others</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Playa around water bodies, riparian 500 feet</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Weather</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Winter months</td>
<td></td>
<td>Nov-Feb</td>
<td></td>
<td>There are no actual restrictions, but operations can take longer during these winter months and have completions problems such as waterline freezing.</td>
</tr>
</tbody>
</table>
Maps of restrictions and pipelines.

Figure 4.4 Map of the environmental restrictions and facilities in the area. Sage Grouse core area, buffers for the leks, Playa and playa buffers, and UTE ladies’ tresses are also displayed.

Figure 4.5 Environmental Stipulations map for all the species in the area except for raptors. Yellow-billed cuckoo, Mountain Plover, Elk, Prairie dog, Black-footed ferret, and UTE Ladies Tresses have extensive areas where their habitat can be found. Circles represent the buffers for the sage grouse leks.
These areas still have some restrictions on drilling times and some buffers present, but restrictions are fewer (Figure 4.4). Figure 4.5 shows the map with all the environmental restrictions in the area except for raptors since these vary seasonally. This map might seem daunting, but it allows us to identify better areas when separated by month. In addition, most of the restrictions for mammals and plants allow operations, although it limits the number of pads allowed in the area (Table 3.1).

From the data provided and the dates for seasonal buffers, the more suitable months for drilling in Wyoming are March and August to September. Although there are still some seasonal buffers during these months, these are fewer than on the remaining ones. It is not impossible to drill during other times of the year, but more buffers and migration corridors affect the well placement or its time of approval.

4.5.2 Production Analysis

Figure 4.6 and Figure 4.7 display the plots obtained for the number of fracture stimulation stages, total proppant, total fluid injected, proppant per frac, and total fluid injected per frac versus production. There seems to be no correlation between these parameters and production.

The lack of correlation could mean other parameters affect production. These factors can be geological, such as reservoir quality, thickness, oil and water saturation, overpressure effects, mechanical stratigraphy, regional stress regime, natural fractures, or migration. Other factors can depend on engineering design and completion techniques or the complete production history for these wells (Theloy and Sonnenberg, 2013).

Figures 4.8 and 4.9 are bubble maps for oil and gas production from the Lewis Shale in the area. It appears oil production from the Lewis Shale is higher towards the north of the Basin in the Great Divide Basin. Lost Creek, Red Dessert, Strike, and Siberia Ridge Fields are in this area and have fewer environmental restrictions. Oil gravity for these wells is between 50 and 60 API.
Figure 4.6 Production analysis for oil on the F interval in the Lewis Shale. There is no correlation observable between Production, Number of fracture stimulation stages (A), proppant injected and production (B), fluid injected/fracture stimulation stage (C), proppant/fracture stimulation stage and production(D), Total injected fluid, and production (E ).
Figure 4.7 Production analysis for gas for the G interval in the Lewis Shale. There is no correlation observable between Production, Number of fracture stimulation stages (A), proppant injected and production (B), fluid injected/fracture stimulation stage (C), proppant/fracture stimulation stage and production(D), Total injected fluid, and production (E).
Figure 4.8 Gas production data for the Lewis Shale in Wyoming. Data includes wells that are only produced from the Lewis Shale.
Figure 4.9 Oil production data for the Lewis Shale in Wyoming. Data includes wells that are only produced from the Lewis Shale. The areas with higher production are located towards the Great Divide Basin, close to the first three cored wells.
4.6 Discussion and Conclusions

Integration of all the restrictions and buffers can shorten the permit approval time and help develop the areas and intervals with better production. Additionally, the comparison of the most common horizontal completion procedures showed no correlation between production and fracture stimulation numbers, proppant volume of fluid volume, indicating other possible factors such as lithology or casing size affecting production. More studies and comparisons need to be completed to identify possible causes of production differences.

The areas that seem to have fewer environmental stipulations and are located closer to available pipelines are located towards the Great Divide Basin near the Lost Creek, Red Dessert, Strike, and Siberia Ridge Fields, which also have the better oil.

It is important to note that data about nests and lek locations changes periodically and needs to be updated. Therefore, constant communication and teamwork with the Bureau of Land Management and the Wyoming Game and Fish are crucial to ensure the resulting prospective areas are adequate.

4.7 References


Seasonal range definitions, Wyoming Game and Fish, Habitat information, https://wgfd.wyo.gov/WGFD/media/content/PDF/Habitat/Habitat%20Information/Seasonal-Range-Definitions.pdf (accessed July 2022)

CHAPTER 5

CONCLUSIONS

5.1 Research Contributions

This research revealed the complexity associated with deep-water turbidite systems of the Lewis Shale on a large and microscale in the Greater Green River Basin in Wyoming. Three complementary studies demonstrated the geological controls of this formation: 1) a reservoir characterization, 2) a petrophysical analysis to evaluate reservoir quality, and 3) a field development and production analysis to determine external factors affecting the economics of the wells. The findings of each study add to the current knowledge of the Lewis Shale, advancing its potential as an effective horizontal well development prospect. The critical discovery that reservoir quality is a function of depositional setting and diagenesis highlights the need to carefully evaluate each facies within this formation. This study also reveals the power of an integrated approach, combining core and log data to produce the required deep understanding necessary to identify potential reservoir intervals.

Eight facies were identified based on core petrographic description and analyses with diagnostic levels of bioturbation and mineralogic content. The core description showed the variability of lithologies and bed thicknesses on a vertical scale. Thin bedding in the Lewis Shale complicates petrophysical analysis in addition to the proportion of chlorite and other clays present. The presence of chlorite is a subtle but key differentiator between facies and resultant reservoir quality. Bed thickness, sedimentary architecture, and mineralogical variation proved to be critical parameters in the petrophysical evaluation.

Log correlations to other wells within the basin show that observed vertical variability on the core usually translates to lateral heterogeneity of the sandstone packages, emphasizing issues that may appear while drilling horizontal wells. Core data also served to calibrate the log data and adjust the values of matrix densities for porosity and saturation calculations. This analysis proves that core and log data calibration is essential to building the petrophysical models.
These results would be incomplete when assessing new potential areas without considering external factors such as pipeline availability and environmental restrictions. For example, potential reservoirs development may be located below a protected area on the surface, thus delaying or impeding the development of the said reservoir. Thus, appropriate knowledge of restrictions and pipeline availability is crucial when looking at potential areas.

Completion techniques are often one of the most expensive parts of drilling and producing a well. The internal reservoir characteristics (such as lithology or bed thickness) and the completion techniques usually impact the production and the well’s economic calculations. Therefore, the costs of proppant and completion fluid are significant in determining individual well or even field economic viability.

This study showed that internal characteristics such as chlorite content, clay, and silica content could significantly impact reservoir quality and log characteristics. Models showed that the best facies for well development are the finely laminated silty sandstones and bioturbated silty sandstones. But these facies are subject to lateral and vertical variability increases and the risk of lateral pinch-out, s while drilling horizontal wells. Some of the restrictions in the area can make the field development difficult, but it can be done with careful planning and knowledge of the different restrictions. The production analysis showed no correlation between the production and volume of proppant, fluid injected, or the number of fracture stimulation stages. Production changes are likely better correlated to internal characteristics of the rock or the position of the column height within the reservoir.

Overall, this study highlighted the importance of integrating analyses and methods to resolve these turbidite reservoirs' high complexity.
APPENDIX A

FOR CHAPTER 2 CORE DESCRIPTIONS

Well 1 core description

Figure A.1 Well 2 core description.
Figure A.1 continued

<table>
<thead>
<tr>
<th>Lithologies</th>
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<table>
<thead>
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</thead>
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<td>Sandy</td>
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<thead>
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<td>Ripple Laminated</td>
</tr>
<tr>
<td>Slumped</td>
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<thead>
<tr>
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</thead>
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<td>Straight</td>
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</table>

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<td>Fluid Escape Pipe</td>
<td>Load Structure</td>
<td>Mottled Bedding</td>
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<td>Trough Cross Lamination</td>
<td>Wispy Lamination</td>
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<td>Skolithos</td>
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<td>Terebellina</td>
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Well 2 core description

Figure A.2 Well 2 core description.
Figure A.2 continued
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<td>Coarsening Upward</td>
</tr>
<tr>
<td>FU</td>
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<tr>
<td>Fining Upward</td>
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| Bouma A (massive, graded turbidite) |
| Bouma E (massive to graded muddy turbidite) |

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<td>Levee / Overbank</td>
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<td>TRB</td>
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<td>Turbidite</td>
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Well 3 core description

Figure A.3 Well 3 core description.
Figure A.3 continued
Figure A.3 continued
Figure A.3 continued

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| ![Siltstone](image) |

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| ![Parallel Wavy bedding](image)  
| ![Wispy Lamination](image)  
| ![Planar Lamination](image) |

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| ![Terebellina](image) |

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| ![Tb](image)  
| Bouma B (parallel laminated turbidite) |

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| ![LCT](image)  
| Low Concentration Turbidite |
Figure A.4 Well 4 core description.
Figure A.4 continued
### Lithologies
- Mudstone
- Sandstone
- Siltstone

### Admixture
- Argillaceous
- Calcareous

### Structure
- Faintly Laminated
- Relict-bedded

### Contacts
- Straight

### Accessories
- Coal
- Shale Clasts

### Trace Fossils
- Bioturbation (undifferentiated)

### Facies
- **Ta**: Bouma A (massive, graded turbidite)
- **Te**: Bouma E (massive to graded muddy turbidite)
- **None**: None

### Depositional Environment
- **LVO**: Levee / Overbank
- **TRB**: Turbidite
# APPENDIX B

## COPYRIGHT PERMISSIONS

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