PSComparing Source Rock Maturity with Pore Size Distribution and Fluid Saturation in the Bakken-Three Forks Petroleum System of the Divide County, the Williston Basin, North Dakota*

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Abstract

With the continuous demand for fossil fuel and advancement in technology, the unconventional petroleum resources have come into limelight. The Devonian Three Forks formation consisting of carbonate and clastic sediments in the Williston basin is an unconventional reservoir with about 20 billion barrels of oil in place (North Dakota DMR 2010). However, understanding of rock properties and fluid saturation is still challenging within the different lithofacies.

The petroleum prospectivity was evaluated by integrating organic maturity and hydrocarbon generation with porosity distribution and fluid saturation in the Ambrose field and adjacent fields. The organic maturity was done by running a programmed pyrolysis analysis (Source Rock Analyser) at an interval of 1ft through the lower Bakken Shale that overlies the Three Forks Formation. Core samples from four (4) wells were utilized for this study. Physical core description and wireline logs were used to identify and correlate the facies within the Three Forks Formation of the study area. Five major lithofacies were identified. They are: 1) green – grey massive mudstone, 2) tan massive dolostone 3) grey – tan laminated mudstone and dolostone 4) tan - dark brown mottled dolostone and 5) Green – brown conglomerated mudstone.

Core samples from each lithofacies of interest in the wells were collected and prepared for NMR analysis by saturating with NaCl brine solution under 100 psi of compressed air for a minimum of 30 days. Porosity analysis was acquired from NMR transverse relaxation (T2) analysis with Oxford Instruments GeoSpec2 core analyzer coupled with Green Imaging Technology software. Pore size distributions were calculated using T2 cutoff values to partition total porosity measurements into micropores (less than 0.5 microns), mesopores (0.5 to 5 microns), and macropores (greater than 5 microns).

Tmax from the programmed pyrolysis showed that the organic maturity between wells varies from 427°C to 439°C. NMR relaxation time results showed saturation is proportional to distribution of pore size with mesopore and macropore contributing more to oil saturation while

micropore contributes to water saturation. The laminated lithofacies are expected to have a bimodal T2 relaxation time which is proportional to pore space divided between mud laminae and fine intercrystalline porosity while the massive mudstone lithofacies have the shortest T2 relaxation time consistent with clay bound microporosity.

References Cited

Al-Marzouqi, M.I., S. Budebes, E. Sultan, I. Bush, R. Griffiths, K.B.M. Gzara, R. Ramamoorthy, A. Husser, Z. Jeha, J Roth, B. Montaron, S.R. Narhari, S.K. Singh, X. Poirier-Coutansais, 2010, Resolving carbonate complexity, Oilfield Review, Summer 2010: v. 22/2.

Green, D.P. and D. Veselinovic, 2010, Analysis of unconventional reservoirs using new and existing NMR Methods: GeoCanada, Calgary, Canada, June 2010.

COMPARING SOURCE ROCK MATURITY WITH PORE SIZE DISTRIBUTION AND FLUID SATURATION IN THE BAKKEN-THREE FORKS PETROLEUM SYSTEM OF THE DIVIDE COUNTY, WILLISTON BASIN, NORTH DAKOTA

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ABSTRACT

With increasing demand for fossil fuels and advancement in drilling technology, unconventional reservoirs continue to be attractive. The Devonian Three Forks Formation, a mixed carbonate and clastic system is an unconventional oil accumulation containing approximately 3.73 billion barrels of technically recoverable oil (Gaswirth and Marra, 2014). Therefore, understanding rock properties for the various lithofacies of the Three Forks relative to fluid saturation is critical for increasing recovery from the unconventional reservoir.

Petroleum potential of the system was evaluated by integrating organic maturity and hydrocarbon generation with porosity distribution and fluid saturation in the Ambrose and adjacent fields. The organic maturity was conducted with a programmed pyrolysis analysis (Source Rock Analyzer) using samples taken at one ft intervals through the Lower Bakken Shale. Core samples from four (4) wells (22809, 26745, 28042 and 23828) were utilized for this study. Physical core description and wireline logs were used to identify and correlate seven (7) lithofacies within the Three Forks Formation. They are: 1) green – grey massive mudstone; 2) tan massive dolostone; 3) grey – tan laminated mudstone and dolostone; 4) tan - dark brown mottled dolostone; 5) grey and tan mottled mudstone; 6) grey and tan conglomerated mudstone; and 7) grey and tan brecciated mudstone.

Core samples from the Lower Bakken Shale and Three Forks were prepared for NMR (nuclear magnetic resonance) analysis by saturating with 300,000 ppm NaCl brine solution at 100 psi of compressed air for 40 days. Porosity analysis was conducted using a helium porosimeter and confirmed by NMR transverse relaxation (T2) analysis with Oxford Instruments GeoSpec2 core analyzer coupled with Green Imaging Technology software. Pore size distributions were calculated using T2 cutoff values to partition total porosity measurements into micropores, mesopores and macropores.

Tmax from the programmed pyrolysis indicate that organic maturity between wells varies from immature to mature (427°C to 440°C). NMR relaxation time results showed saturation is proportional to distribution of pore size with mesopore and macropore contributing more to oil saturation while, micropore contributes to water saturation. Laminated lithofacies have a bimodal T2 relaxation time which is proportional to pore space divided between micropores in mud laminae

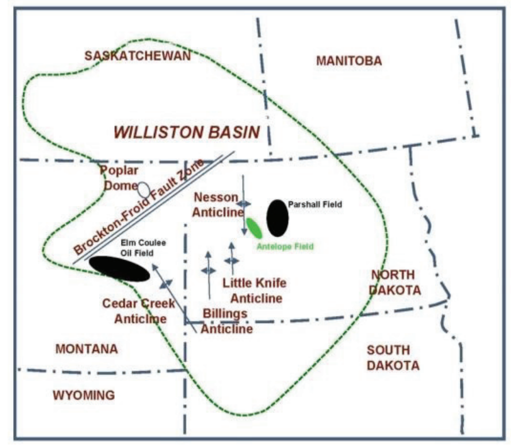
PURPOSE OF STUDY

- To determine the geochemical properties of the Lower Bakken shale through pyrolysis
- To identify and correlate the various reservoir lithofacies within the Three Forks Formation
- To estimate the porosity values and pore sizes distribution within reservoir lithofacies
- To estimate saturation and determine distribution of pore fluids within the pores spaces.

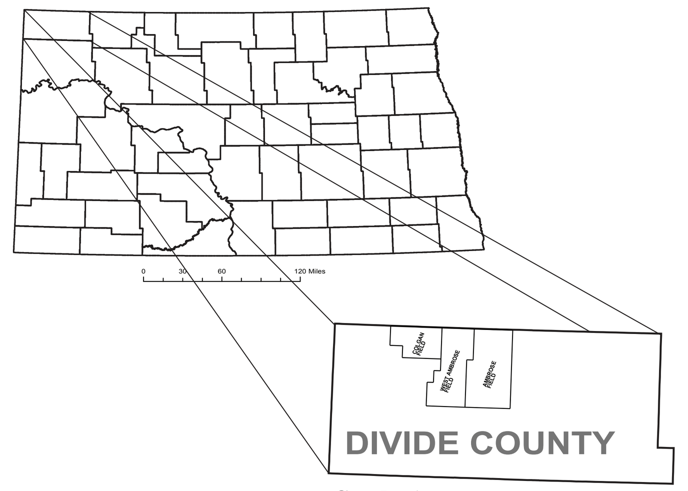
INTRODUCTION

The Williston Basin is an intracratonic sedimentary basin that extends through parts of Montana, South Dakota, North Dakota, Manitoba and Saskatchewan is known for significant petroleum resources. The thick oval shaped depression is filled with sediments that range from the Cambrian to tertiary age with the thickest part at western North Dakota. The evolution of the basin is linked to a distinct area of increased subsidence during Middle Ordovician time

The basin is a not a structurally complex basin, deepest in the center, with strata becoming both shallower and thinner towards the margins. The deepest point of the basin is near Williston, North Dakota where the Precambrian surface is more than 16,000 feet deep.



Williston Basin

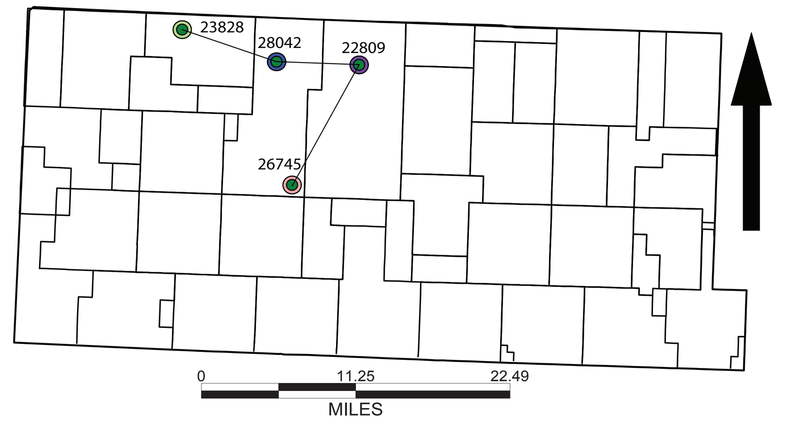


Study Area

METHODOLOGY

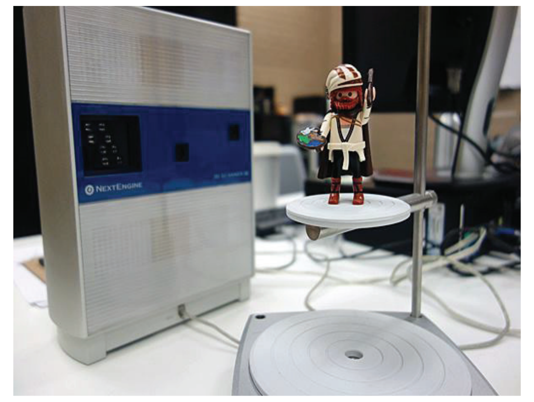
Workflow

- Facies Identification
- Well Correlation
- Rock Eval Pyrolysis
- Sample Drying
- Bulk Volume Measurement
- Helium Porosity Measurement
- Sample Saturation
- NMR T2 Analysis

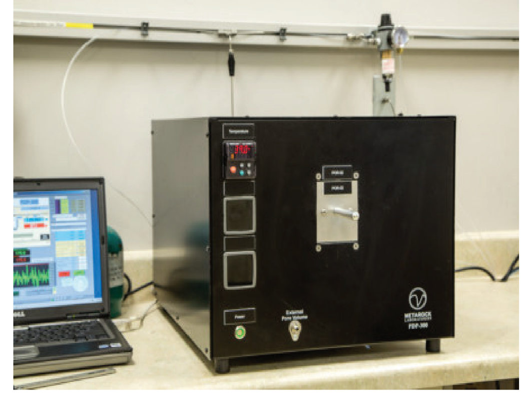


Wells distribution in the study area.

Source Rock Analyzer

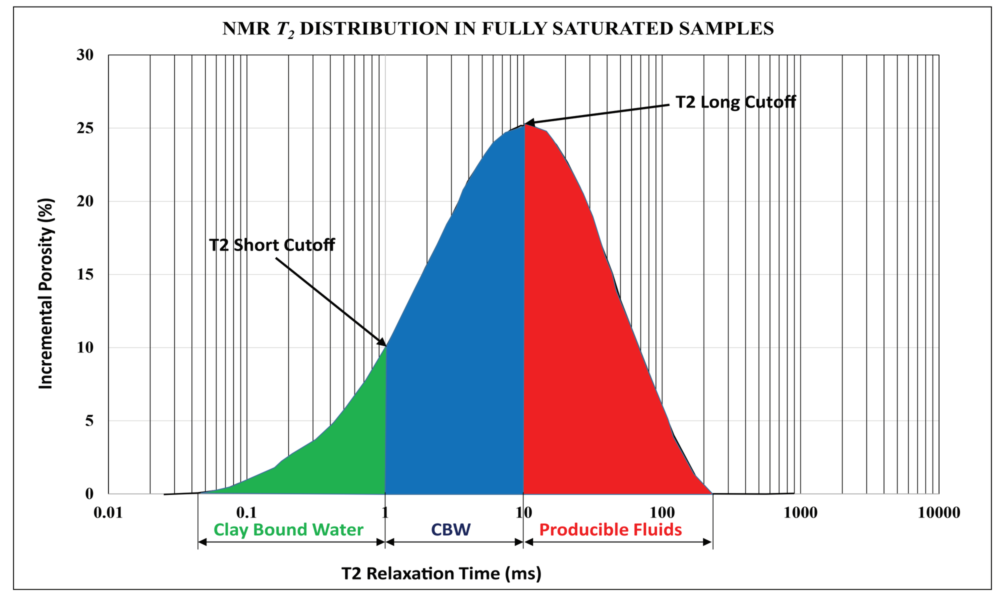


3D Laser Scanner

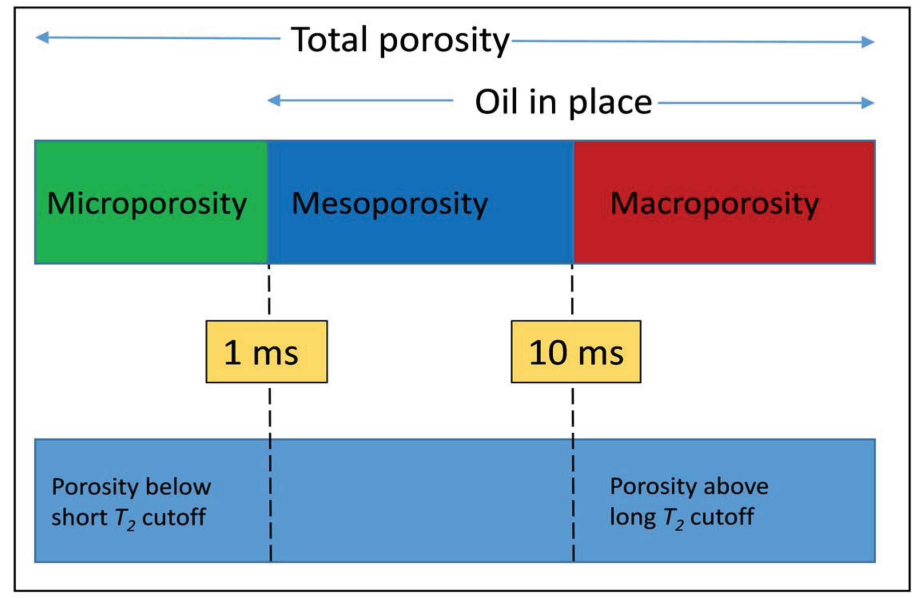


Helium Porosimer

NMR Core Analyzer



Fluid dustribution based on T2 cutoff



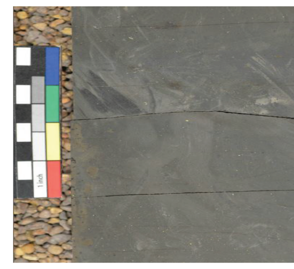
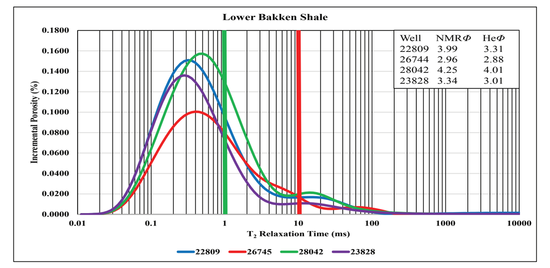
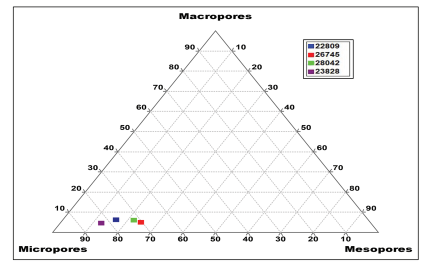
Pore sizes distribution based on T2

RESULTS

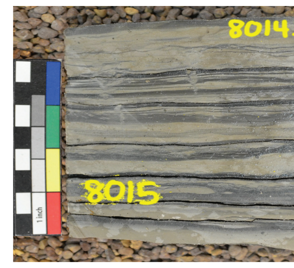
Rock Eval Pyrolysis

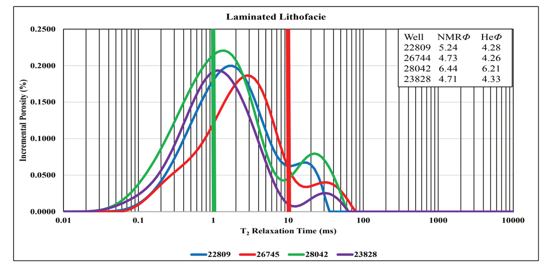
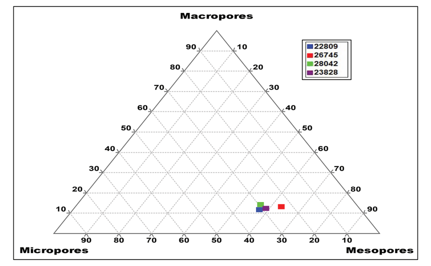
RESULTS

- **Lower Bakken Shale**
  Dark brown, massive and slightly fissile. Contains some traces of limestone with dull yellow flourescense.

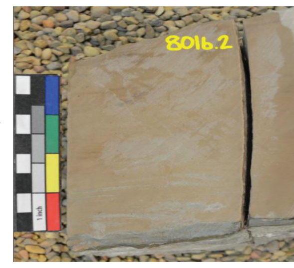
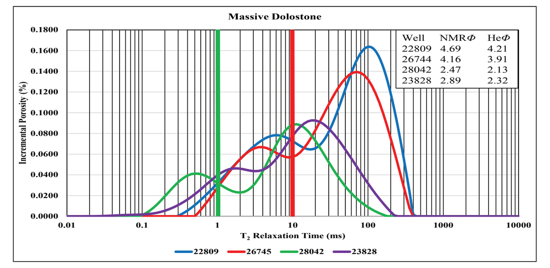
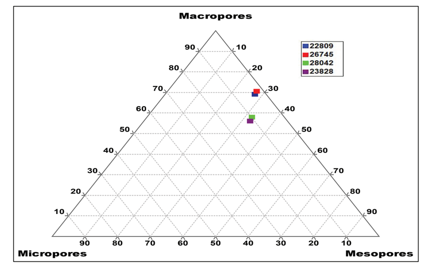




- **Laminated Lithofacie**
  Laminated green mudstone and tan dolostone. Planar to wavy lamination. The lamination of the upper Three Forks Formation are thinner with about 1 to 2cm of each facies and up to 4cm deeper in the section. Lithofacies thickness is about 2 to 5ft.

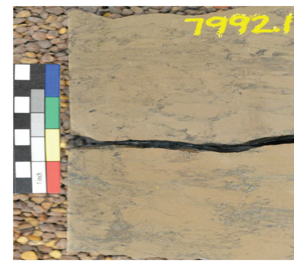
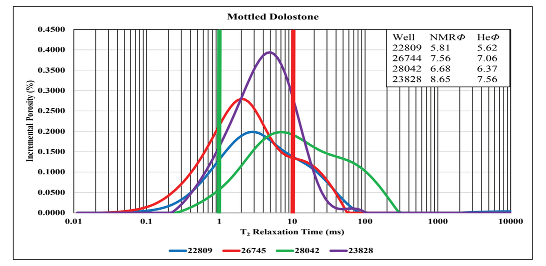
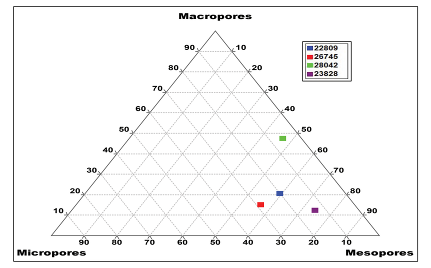


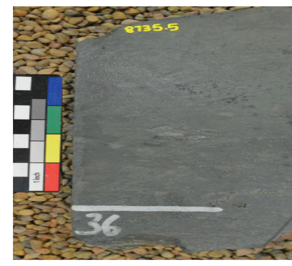
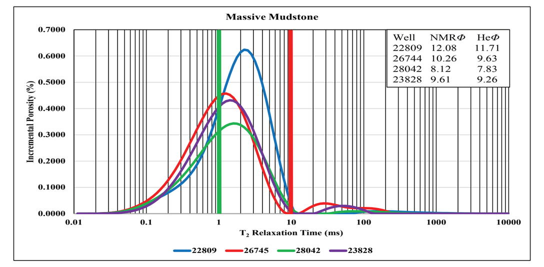
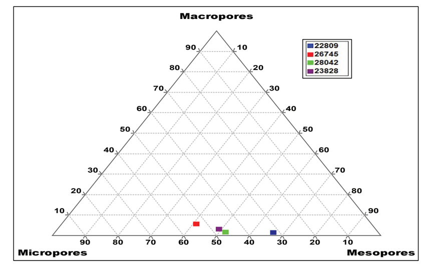
- **Massive Dolostone**
  This is a massive lithology. Tan dolostone lithofacies which is mainly composed of silt and sandsize dolomite. No sedimentary structures. Thickness varies from 1 to 3ft.

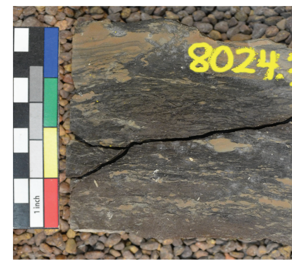
- **Mottled Dolostone**
  Predominantly tan dolostone lithofacies with green - grey patches of mudstone. The proportion of mudstone varies and could be as low as 5% to approximately 20%. Flaser bedded, slightly laminated, and random distribution of mudstone. Thickness is approximately 1 to 4ft.

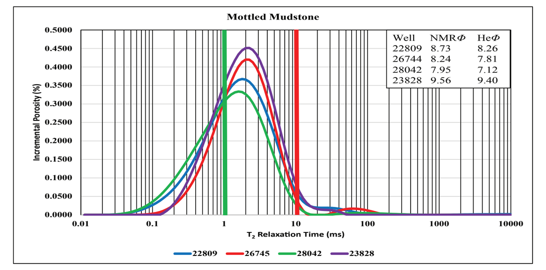
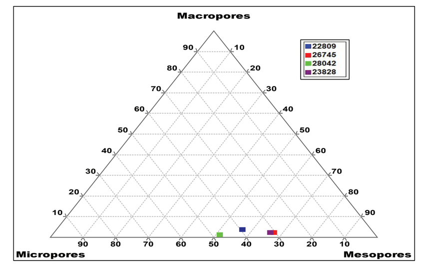




- **Massive Mudstone**
  Green to grey mudstone lithofacies. Composed mainly of fine grained clay. No sedimentary structures. Thickness range is approximately 0.5 to 3.5 ft. Present throughout the Three Forks.

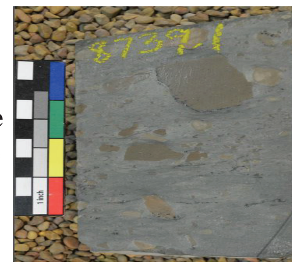
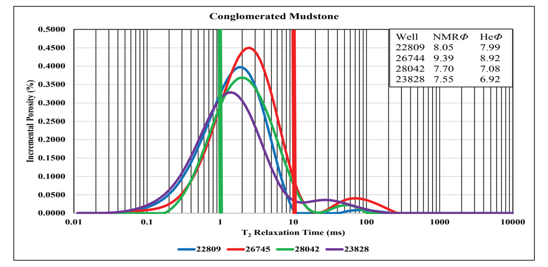
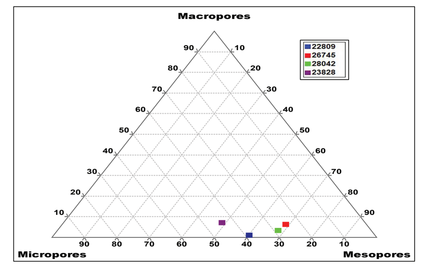




- **Mottled Mudstone**
  Green to grey mudstone with patches of dolostone occurring at various proportions. Massive, slightly laminated, flaser bedded with irregular distribution of dolostones. Thickness range from less than 1 to 5ft.

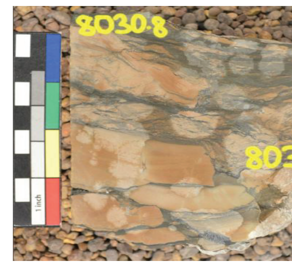
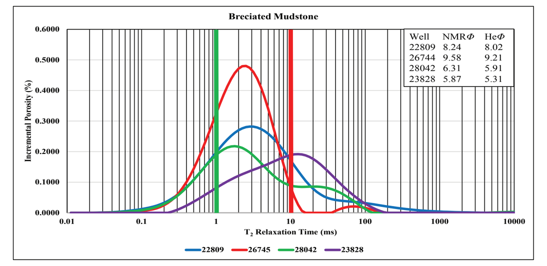
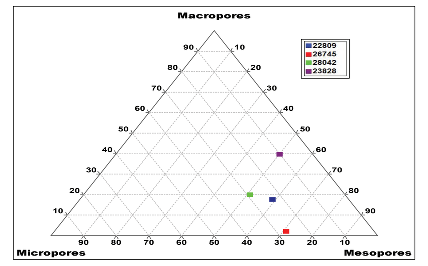


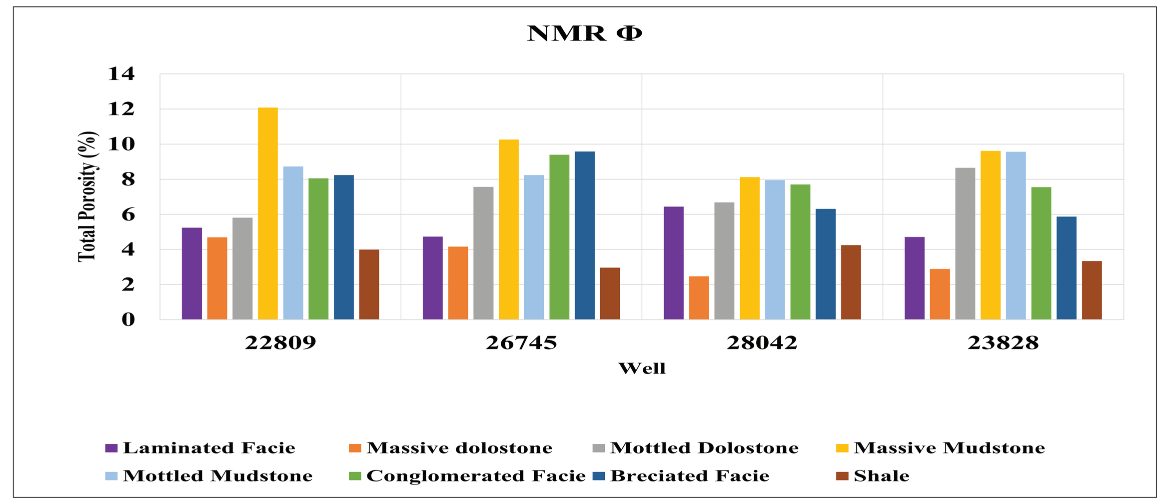
- **Conglomerated Mudstone**
  This facies consist of green-grey mudstone matrix with tan clasts of dolostone pebbles dispersed throughout the unit. The clasts range in size from 0.5 to 2cm. Moderate to well-rounded but poorly sorted. Brown in the deeper section due to oxidation.

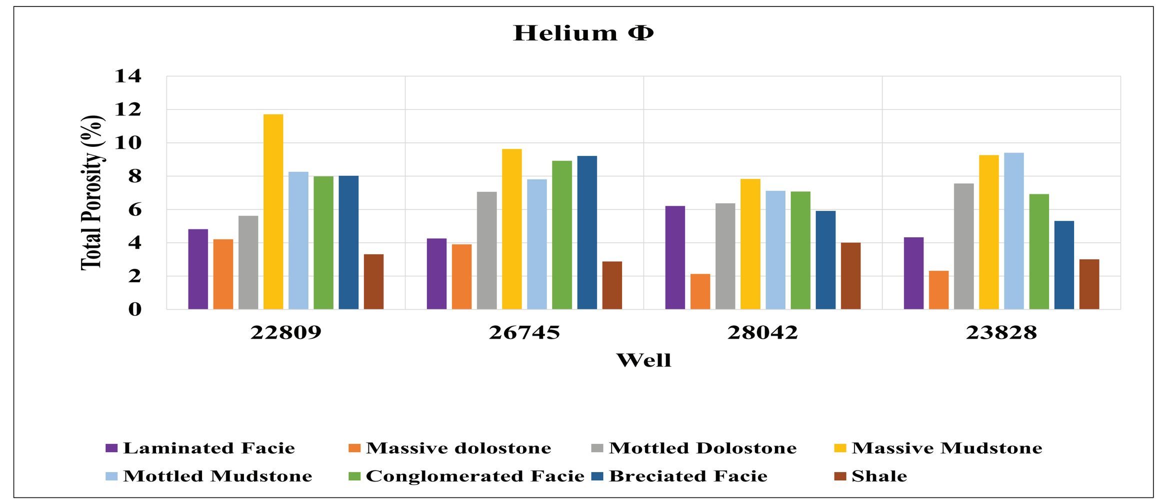




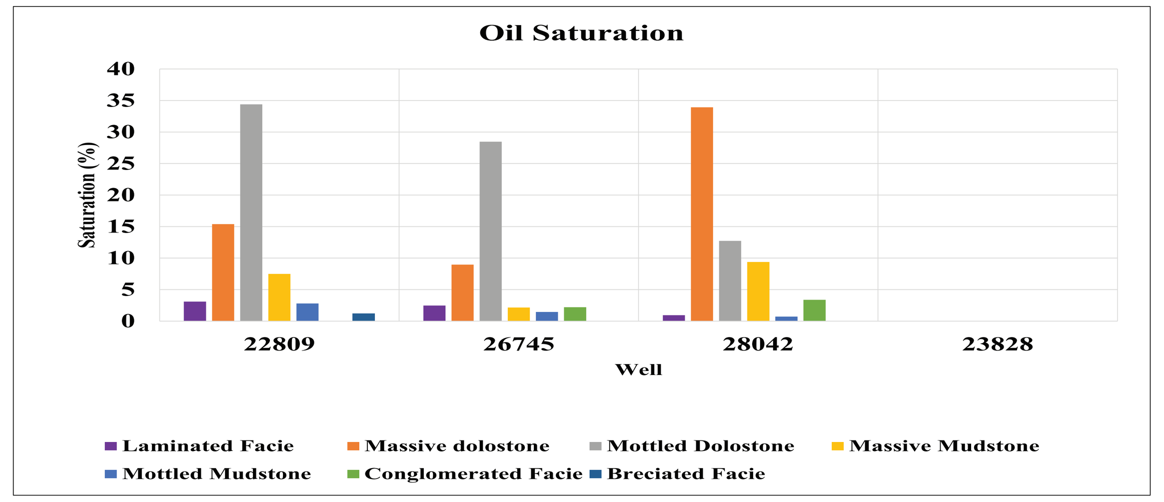
- **Brecciated Mudstone**
  The green to grey mudstone matrix contain various sizes of tan dolostone clasts ranging from less than 1 to 3.5cm. . Angular and poorly sorted.

RESULTS







CONCLUSION

- Massive mudstone lithofacie has highest porosity
- Lower Bakken Shale, massive dolostone and laminated lithofacie have relatively low porosities
- Pores in the mudstones are mainly occupied by clay-bound and capillary-bound water.
- Porosity values from NMR T2 analysis are greater than values from the helium porosimeter.
- Massive dolostone and mottled dolostone have relatively high oil saturation due to relatively abundant macropores.
- Direct relationship established between source rock maturation and fluid saturation.
- Well 22809 has relatively high Tmax values with highest oil saturation while well 23828 in the Colgan Field has a relatively low Tmax value with no oil saturation.

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