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SPRING 2021 SPONSOR MEETING

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Kathy L. Emme, CSM – Research Associate

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The Diagenesis and Petroleum Potential of the Mowry Shale in the Powder River Basin, WY

Brian Hankins, M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

The Mowry Formation has long been considered an important source rock in the Rocky Mountain Region, and particularly in Wyoming's Laramide Basins. However, it has barely been targeted as a self-sourcing reservoir since the development of modern drilling and completion technologies. Up until 2018, production results had been mixed, but recent interest has resulted in a 50% increase in the number of Mowry targeted wells. This study's aim is to characterize the role diagenesis has played on the reservoir quality, and to evaluate the petroleum potential of the Mowry.

The Mowry is an organic-rich siliceous mudstone with numerous interbedded altered volcanic ash layers. On the eastern side of the Western Interior Basin, the Mowry was deposited as a distal marine accumulation and is predominantly mudstones characterized by reworked storm and current deposits, hemipelagic settling, and high productivity.

The Mowry has experienced extensive diagenesis, particularly early diagenesis, which has had a significant influence on the reservoir quality. Key diagenetic processes include biogenic silica dissolution and precipitation, mineralization, compaction, illitization of smectite, organic matter maturation, and secondary porosity development. The relatively early stabilization and lithification of the matrix resulting from the transition of opal-A to opal-CT to microcrystalline quartz is a key diagenetic process that contributed significantly to the preservation of pore space. These preserved pore spaces accommodated the pre-oil bitumen, which likely formed a connected bitumen network. With increasing depth, mineral matrix porosity declined as a result of mechanical and chemical compaction while organic matter hosted pores developed and became the chief pore type deep in the basin.

Overall, the Mowry Formation in eight study wells has an average TOC of 2.71 wt.% which meets the minimum TOC threshold requirement of 2 wt.% for effective petroleum source rocks. The middle Mowry is more organically rich than the upper and lower Mowry and has an average TOC of 3.03 wt.%. Pyrolysis S1 is 33% higher and pyrolysis S2 is 42% higher in the middle Mowry relative to the upper and lower Mowry. Along the basin axis, the Mowry has reached the late oil maturity window with Tmax values measuring 458°C. There are three hotspots in the Powder River Basin that have resulted in higher measured maturity values.

Into the Void: Compositional and Thermal Controls on Pore-Scale Reservoir Quality in the Mowry Shale, Powder River Basin, Wyoming

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Abstract

The Mowry Shale is a laterally-extensive mudrock in several Laramide basins across the Rockies region deposited during an overall transgression of the ancient Western Interior Seaway during the mid-Cretaceous. The Mowry is a prolific source rock, expelling hydrocarbons into over- and under-lying sandy formations and acting as a self-sourced unconventional reservoir. Advances in drilling and hydraulic fracturing techniques in recent years renewed interest this unit as an unconventional target, particularly within the Powder River Basin (PRB).

Intrabasinal, highly recrystallized biogenic silica pervades the Mowry, overprinted with varying amounts of extrabasinal silt and sand. End-member facies in the PRB range from micro-crystalline quartz-rich mudstone to bioturbated and ripple cross-laminated muddy siltstone. Core data show a strong correlation between crushed rock permeability and thermal maturity, particularly in the early- to late-oil window. This trend suggests that diagenetic and/or thermal changes play an important role in the development of a connected pore network but does not elucidate which rock components are most influential, nor does it provide insight into the actual pore size distributions and types present.

Our work utilizes a combination of low-pressure gas adsorption (LPGA) and scanning electron microscopy (SEM) on a suite of samples from the PRB Mowry Shale to investigate compositional and thermal controls on pore types, development, and size distribution. The sample suite spans a wide thermal maturity range (Ro%=0.5-1.3) and includes all the major mudrock facies characteristic of the distal Mowry. Pore size distributions show a diffuse peak in the 20-60nm range which becomes more pronounced in higher maturity samples along with an increase in pore volume from meso- and macropores (2-50nm and >50nm pore widths, respectively). SEM analysis reveals 200-400nm macropores associated with clays in the rock matrix and a range of pore sizes <150nm associated with organics, particularly in higher thermal maturity samples. Mean pore size from image analysis of ion-milled SEM samples is 40-50nm, corroborating the pore size distributions interpreted from LPGA.

Understanding the influence of compositional and thermal controls on Mowry Shale samples is a necessary step toward developing more sophisticated and accurate petrophysical and fluid flow models, leading toward improved reservoir predictability across the basin. Pore-scale studies utilizing LPGA help to characterize optimum reservoir rock types and maturities which are in turn mappable at the basin scale with the use of wireline logs. Upscaling the pore-scale results to the basin-scale, integrating with additional core data, and improving upon existing sequence stratigraphic models can aid in identifying ideal areas and horizontal targets for future Mowry Shale unconventional development.

Reservoir Characterization of the Shannon Sandstone near Pine Tree Field, SW Powder River Basin, Wyoming

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Abstract

The Shannon Sandstone is an early Campanian aged unconventional stratigraphic play in the southwestern part of the Powder River Basin in Wyoming. There are varying interpretations of the depositional environment for the Shannon, including a shelf sand-ridge complex, prograding shoreface, or incised valley fill. The Shannon Sandstone near Pine Tree Field has not been studied as extensively as the nearby Hartzog Draw and Jepson Holler Draw fields. This study will include detailed analysis of up to nine cores in Johnson and Campbell Counties, field outcrop work in Natrona County, and data analyses across the area, including seismic interpretation.

The Shannon Sandstone has a long history of petroleum production, as well as varied geological interpretation. Detailed geologic reservoir characterization of the Shannon Sandstone will improve understanding of a long-debated formation and allow for more efficient and successful exploration in the area. Based on facies determinations and mineralogical, stratigraphic, and petrographic character analyses, this study will be able to evaluate the previous depositional interpretations. Doing so will yield a much clearer picture of what the Powder River Basin looked like during the Late Cretaceous, as the methods of sedimentation were changing in the Western Interior Seaway. A core to outcrop to seismic scale study allows for increased understanding of lateral changes within the Shannon. The goal of this thesis is to better understand the stratigraphy and reservoir characteristics of the Shannon, to evaluate previous depositional interpretations and maximize efficient development. This increased understanding of the depositional environment has implications for the geologic evolution of the basin.

Reservoir Characteristics and Production Analyses for the Niobrara A Interval at Redtail Field, Weld County, Colorado

Scott Manwaring, M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

The Cretaceous Niobrara Formation of the Denver Basin in northeast Colorado and southeast Wyoming received renewed interest since the success of EOG Resources' horizontal Niobrara 02-1H Jake well in Hereford Field, Weld County, Colorado, in 2009. The coupling of horizontal drilling with multi-stage hydraulic fracturing have caused the Niobrara Formation in the Denver Basin to become a heavily drilled target with nearly 5,000 horizontal wells drilled during the period from 2009 to end of year 2019. These wells targeted the Niobrara (A, B, C, and Fort Hays) Formation and the Codell member of the Carlile Formation. Production during this time is approximately 540 million barrels of oil and 2.7 trillion cubic feet of gas. The majority of development has occurred in Wattenberg Field, Weld County, Colorado, and lesser development in: Silo Field, Laramie County, Wyoming; Fairway Field, Laramie County, Wyoming; Hereford Field, Weld County, Colorado; and Redtail/East Pony Fields, Weld County, Colorado.

The Niobrara Formation consists of two members, from oldest to youngest: the Fort Hays Limestone, and the Smoky Hill member. Within the Smoky Hill member, the Niobrara is divided into four benches, from oldest to youngest: the Niobrara D, C, B, and A. These benches are demarcated by series of alternating chalks and marls. Additionally, each bench differs in fossil assemblages, porosity, permeability, total organic carbon, thermal maturity, and log signatures. The majority of production has come from wells that target the Niobrara B interval, rather than the underlying Niobrara C and D intervals, or the overlying and sometimes missing Niobrara A interval. However, in the vicinity of Redtail Field, sufficient thickness of the Niobrara A interval allows the development of this bench. This development marks the only widespread drilling and production of Niobrara A wells in the Denver Basin.

A recent study in Wattenberg Field discovered the A Chalk to possess the highest porosity and permeability of the Smoky Hill benches, as described in the Aristocrat Angus PC H11-07 core. Additionally, another study performed an extensive peloid characterization study of the A Chalk in the Denver Basin from a transect of seven cored wells and identified diagenetic processes that effected the reservoir interval of the Niobrara A. This study at Redtail Field discusses why a hydrocarbon accumulation is present in the Niobrara A interval and how the techniques used to identify and exploit the accumulation may be used in other areas prospective to the same interval.

Reservoir Characterization of the Niobrara B Interval at Redtail Field: Weld County, Denver Basin, Northeast Colorado

Adam Simonsen: M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

The Late Cretaceous Niobrara Formation is a prominent source and reservoir rock in the Denver Basin. It was deposited during a marine transgressive cycle known as the Niobrara cyclothem. In the Late Cretaceous, the Western Interior Seaway covered the DJ Basin depositing chalks and marls. The Niobrara Formation is an unconventional play that consists of alternating chalk and marl beds. Due to low porosity and low permeability, the reservoirs require fracture stimulation to produce hydrocarbons. Marls in the Niobrara Formation have a higher total organic carbon (TOC) and act as the seal and source rock, while the chalks are more brittle and act as the reservoir. The Niobrara is subdivided from oldest to youngest: Fort Hays Limestone, D Interval, C Interval, B2 Interval, B1 Interval, and A Interval. Within the, Niobrara the B1 and B2 chalks are one of the main producers and are often targeted for completions. The Niobrara is a key play in the DJ Basin. A better understanding of the reservoir characteristics in this field will help in future development and production of hydrocarbons.

Five cores total are used in this study, which were provided by Whiting Petroleum Company. Three of these cores contain the entire B interval, while two of the cores include partial sections of the B interval.

XRF scanning and analysis was conducted through the B1 and B2 interval for the Razor 25-2514H well. This is the type well for Redtail Field with cored intervals of the entire Niobrara Formation and Codell Sandstone. Cross plots indicate that the Si, Al, and K are detrital sourced elements. The cross plot of Ca vs. Al suggests an authigenic or biogenic origin for Ca. Sr vs. Ca cross plot indicates that there is no aragonite enrichment present. The identification of trace redox elements was used to interpret the paleo-oxygen content during the time of deposition to be anoxic to euxinic. The presence of Mo indicates authigenic enrichment in euxinic waters. The weak positive covariance between S vs. Mo shows the relationship to pyrite through Mo-Fe-S compounds during authigenic enrichment. Mo vs. V have a moderate covariance indicating similar authigenic enrichment pathways and further supports deposition in anoxic waters. Source rock analysis data from Razor 25-2514H indicate a type II-III kerogen and is mature.

Future analysis and interpretation of the cores accompanied by well logs will aid in building a reservoir model for the Niobrara B interval. Understanding the correlation between well logs and core analysis will help with future explorations in chalk and marl reservoirs.

CCUS Potential for the Niobrara A and B Intervals at Redtail Field, Weld County, Colorado

Chris Beliveau, M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

Carbon capture, utilization, and storage (CCUS) is the process to capture CO_2 from the atmosphere, utilize that carbon dioxide to facilitate oil and gas production, and find a safe, permanent storage option. It's becoming increasingly common in the oil and gas industry as both a means to enhance production, as well as decrease "negative externalities" associated with production. While carbon capture and storage (CCS) has sometimes garnered more attention, carbon capture, utilization and storage is more attractive as it offers additional economic incentives. Primary and secondary means of oil and gas recovery can still leave up to ~80% of oil in the reservoir and in some cases CCUS can be a more effective means of production than primary and secondary recovery. CCUS is continuing to expand and has the potential to capture ~6GtCO_2 per year by 2050.

The Niobrara System was deposited in the Western Interior Seaway (WIS) during a series of transgressions and regressions. The geologic environment of cooler, oxygen rich water from the north, mixing with warmer, oxygen poor water from the south facilitated carbonate development. In the Denver Basin, the Niobrara has been explored and produced from extensively with recent production focused on the Niobrara A and B as the Niobrara A and B exhibit favorable petrophysical properties with increased resistivity and porosity.

Studying the Razor 25-2514H core from the Redtail Field offers an opportunity to explore CCUS technology running lab tests over the Niobrara A and B. I'll examine and analyze porosity and permeability at different confining stresses with Core Measurement System (CMS 300), CO_2 miscibility with oil saturated core plugs using the Beckman high-speed centrifuge (ACES200), and production flow and injection treatments with CO_2 and methane acting on a core plugs using Formation Response Tester 6100 (FRT-6100). The objective of this study is to discern favorable characteristics and properties for CCUS from core as well as petrophysical data.

Reservoir Characterization of the Codell Sandstone at Redtail Field, Weld County, Colorado

Nick Damon, M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

The Late Turonian Codell Sandstone of the Carlile Formation is one of the primary reservoirs targeted for hydrocarbon development within the Denver Basin. Although recent improvements in multi-stage hydraulic fracture stimulation and advanced recovery techniques have increased production, the Codell Sandstone remains a difficult exploration target due to its low porosity, permeability, and heterogeneities in these reservoir properties around the basin. The goal of this study is to use a multiscale approach to examine the mineralogical, geomechanical, and depositional properties of the Codell Sandstone and determine their impacts on reservoir quality in the Redtail Field area.

Redtail Field was drilled extensively for oil and gas by Whiting Petroleum. The Razor 25-2514H well is considered the type well for the field. In this well, the Codell Sandstone displays above average porosity (10-25%) when compared to other parts of the Denver Basin. Analytical methods such as petrographic analysis, core description, spot permeametry, and scanning electron microscopy are being employed to uncover what exactly makes the Codell Sandstone at Redtail Field display superior reservoir quality than its counterparts in the region.

The Codell Sandstone is comprised of very fine-to fine-grained sandstone and was deposited during a major regressive period at the end of the Greenhorn cycle in the Western Cretaceous Interior Seaway (WKIS). The Codell Sandstone is interpreted to be a shallow marine sediment between the Greenhorn and Niobrara Formations. The Codell Sandstone is bounded unconformably above and below by the Fort Hays Limestone and Carlile Shale, respectively. In Redtail Field, we have delineated the Codell Sandstone into four distinct facies: the lower bioturbated facies, the heterolithic facies, the middle low-angle cross stratified (interpreted as hummocks) facies, and upper bioturbated facies. The low porosity, permeability in the Codell Sandstone and its characteristic low resistivity in geophysical well logs are caused by high clay content observed within the reservoir. Reservoirs that are analogs to the Codell are targeted worldwide and knowledge gained from this study could potentially be used as a framework for evaluating reservoir quality in these unconventional, shallow marine sandstones.

Reservoir Characterization and Assessment of the Controls on Reservoir Performance for Unconventional Niobrara and Codell Reservoir Targets within the Hereford Field Area, Weld County, Colorado

Chad Taylor, M.S. Student, Department of Geology and Geological Engineering, CSM
Alicia Downard, M.S. Student, Department of Geophysics, CSM

Abstract

With the completion of the Jake 2-01H well in 2009 for an impressive 90-day IP of 555 BOPD, EOG Resources proved the viability of the Niobrara Formation's B Chalk reservoir as a significant unconventional resource play in the Hereford Field, Colorado, with cumulative field production exceeding 13.3 MMBO, 18.6 BCF, and 12.7 MMBW. The Hereford Field is located in the north-central portion of the Denver Basin, roughly 60 miles north of the prolific Wattenberg Field. Drilling and completion methodologies employed in Hereford Field have quickly evolved since the completion of the Jake well in 2009; modern redevelopment operations incorporate cemented pad-drilled laterals (XRL and SRL) and high-volume plug and perf completions that mirror designs employed in modern unconventional Niobrara and Codell wells completed in the Wattenberg Field.

Several of the newer horizontal wells in the area have shown increases in production associated with modern completion design deployment. Understanding the geological controls driving well performance from the Niobrara B Chalk and Codell Sandstone reservoirs has led HighPoint Resources to design and acquire high-resolution geochemistry, petrophysical, and geophysical data covering two extended reach drilling and spacing units, called the Chalk Bluff Project. Chalk Bluff project data is supplemented by a large proprietary regional 3D seismic volume calibrated by extensive legacy well and production data from the surrounding multi-township area. Chalk Bluff DSU's

Reservoir quality within the Hereford Field appears to be influenced by the abundant fracturing associated with the E / NE trending paleo structure, the Morrill County High, directly south of the Chalk Bluff project DSU's. Fracture development and reservoir fluid dynamics were impacted by episodic structural wrenching and the development of extensive networks of layer-bound normal fault systems throughout the deposition of the younger Pierre Shale. Furthermore, reactivation of basement structures coupled with the complicated deposition and compactional history and observed irregularities in the reservoir fluids system have all added to the complexity and heterogeneity exhibited in many wells throughout the Hereford field.

This study integrates the structural learnings from the high-quality 3D seismic with petrophysical data, fluid and sample geochemistry, laterally-acquired formation image logs, produced fluids analysis, and legacy well data located throughout the greater Hereford Field area to identify the underlying controls on the heterogeneity of the petroleum system. In doing so,

understanding of the relationship between structure, stratigraphy, and the petroleum system and how these components combine to impact well performance across the region has been gained; this understanding will ultimately allow for the optimization of further development of the region. Overall, taking an integrated approach to the analysis of geophysical, geological, and reservoir fluid data has provided a much deeper understanding of the fractured reservoir systems in the Hereford Field; the methods and analyses produced from this work can ultimately serve as a framework to better understand this system across the wider DJ Basin, and provide insight on future subsurface evaluation and optimal well planning in other basins that exhibit similar controls on reservoir deliverability.

Insights into Mudstone Sedimentology, Organic Richness and Anoxia at the Opening of the Cretaceous Interior Seaway: Colorado's Skull Creek Formation

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Abstract

The Skull Creek Formation is a suite of shallow marine mudstones and fine sandstones within the Lower Cretaceous Dakota Group. The formation signals the onset of marine deposition in the Western Interior Seaway (WIS) and is a potential source rock to the Dakota-Mowry petroleum system in the Denver Basin of northeastern Colorado, yet its depositional environments, stratigraphic correlations, and source rock contributions remain poorly understood. This study aims to remove those uncertainties and presents new sedimentological and geochemical data from four cores and 38 well logs in the subsurface of the central Denver Basin, integrating it into previous outcrop-based analyses of the Skull Creek Formation.

Four major flooding surfaces divide the Skull Creek Formation into geochemically distinct informal lower, middle, and upper units. The Lower Skull Creek contains a silica-rich basinal to lower slope facies succession and displays poor TOC (avg. 0.9 wt. %). The Middle Skull Creek documents a transition from silica-rich to calcareous basin to slope facies and displays good TOC (avg. 2.3 wt. %). This notable unit represents the maximum flooding surface and documents the earliest connection between the Arctic and Tethyan lobes of the WIS. The Upper Skull Creek displays good TOC values (avg. 2.3 wt. %) which decrease upward. There is a strong correlation between TOC and anoxic proxies - high Molybdenum (ppm) and low bioturbation intensity. Considering the thickness and TOC trends in the Wattenberg, the Skull Creek Formation is a promising, historically underestimated source rock to the Dakota-Mowry petroleum system.

Characterization of the Graneros Shale: A Key Source Rock of the Denver Basin

Adrienne Bryant, M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

The Graneros Shale formation of the Denver Basin in Colorado, Nebraska, Kansas, and Wyoming serves as an important source bed for the basin. Despite its importance, little work has been done in recent years on the formation. The primary goal of this study is to characterize the source potential of the Graneros Shale in the Denver Basin.

The Graneros Shale is a black shale that was deposited in the Late Cretaceous about 93.9 to 100.5 million years ago. During this time, the Western Interior Seaway covered the study area and the Graneros was deposited in an offshore marine environment. Three members compose the formation: 1) the Lower Shale Member, 2) the Thatcher Limestone, and 3) the Upper Shale Member. Learning more about the geological characteristics of the Graneros Shale is key to obtain an improved understanding of the Denver Basin petroleum system. In order to conduct an appropriate evaluation of the Graneros Shale, core analysis, thin section petrography, XRF, XRD, and FE-SEM will be used. At the conclusion of the study, the source rock quality of the Graneros Shale will be quantifiable, and its kerogen signature will be identifiable for future work.

Evaluating Production Performance of Permian Basin Wells to Improve Hydrocarbon Recovery

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Abstract

The Permian Basin is one of the most prolific oil and gas producing geologic basins in the United States. Permian Basin spans West Texas and Southeastern New Mexico. It has supplied more than 33.4 billion barrels of oil and 118 Tcf of natural gas during a 100-year period (EIA 2018). The ever-increasing water production and usage in the Permian Basin requires produced water management by the operators. Classical waterflooding in unconventional reservoirs is not plausible because of the small pore size and low permeability of shale matrix. Therefore, creative approaches are needed to increase the oil production without relying on large quantities of water injection to displace oil favorably. The practical alternative is cyclic or continuous gas injection which is one objective of my research to increase oil production.

As a preliminary study, I reviewed and organized the production data for the wells that had been drilled in Wolfcamp Formation of the Delaware Basin from 2012 to 2020. I prepared bubble maps to highlight the changes in cumulative production of oil, gas, and water. The maps reveal the maturity of the basin in the sense that gas-prone wells are in the north and north-western part or the basin while south is more oil-prone. Furthermore, gas production is highest in Culberson, North Reeves and Loving counties while the wells drilled in Lea, Loving, and East-Reeves counties yielded the most amount of oil production in the first year of production. In addition, water production is large throughout the region regardless of the type of fluid produced.

As part of the preliminary analysis, I conducted Production Decline Analysis (PDA) on several Delaware Basin wells to forecast the ultimate primary oil recovery and I performed Rate Transient Analysis (RTA) to calculate the stimulated formation permeability for assessing stimulation effectiveness and the flow regimes of the individual wells in the region. The main observation is that the wells' production behavior are diverse.

In the area of rock physics, the unconventional reservoirs are heterogeneous and show strong velocity anisotropy (Vernik and Milovac, 2011). Quantifying velocity anisotropy and geomechanical properties are important for reservoir characterization. Thus, I conducted experiments on selected cores from two wells in Delaware basin to determine permeability, porosity, and pore compressibility for the cores. I discovered that the siliceous mudstone samples have higher permeability values compared to calcareous silty mudstone facies. The mineralogical content was correlated to the experimental pore compressibility which indicated a decrease in pore compressibility with increasing quartz content.

Furthermore, using the data from four different wells, static and dynamic elastic properties, Young's Modulus (E), Bulk Modulus (K), and Poisson's Ratio (v), were compared. The core data

and log data were used to obtain a static/dynamic relationship between static and dynamic stiffness coefficients. Rocks showing a vertical transverse isotropy (VTI) behavior have larger stiffness parallel to the plane of isotropy than the one in transverse plane. The data showed that the wells in Delaware Basin there exist significant VTI. These results will be used as the foundation for the future geomechanics-based reservoir modeling effort.

As for the future, I will conduct reservoir engineering assessment and core flooding experiments to arrive at a method to improve oil production. The experiments will include injecting low-sanity brine at reservoir conditions with and without a non-ionic surfactant. Other experiments will include the use of a Beckman high-speed centrifuge (ACES200) with a 3-rotor system to determine capillary pressure magnitudes for different displacement methods, and saturation endpoints for oil, gas, and free gas for each displacement method. I will also conduct core flooding experiments using Formation Response Tester 6100 (FRT-6100) at reservoir pressure, temperature and confining stress. In addition, I will use the PE department's Rising Bubble Apparatus (RBA) to determine the Minimum Miscibility Pressure (MMP) for carbon dioxide-oil in the Permian.

In conjunction with the experiments, I built a conceptual compositional dual-porosity reservoir model using CMG-GEM commercial reservoir modeling software. To simulate the actual hydraulic fracture propagation, I built hydraulic fracturing model using GOHFER commercial software. The well completions and stimulation reports were used to build this model. This model provides conductivity and hydraulic fracture properties for each stage which is used in further reservoir simulation model. The PVT reports were used to build the fluid model using CMG-Winprop module. I used the production data from a well to characterize the reservoir behavior of Permian Basin production. From here on, I will perform sensitivity analysis to identify the parameters which most impact the reservoir performance. The ultimate goal is to combine geology, fluid flow theory, experimental observations, and reservoir simulation to evaluate production performance and to improve hydrocarbon recovery in Permian.

In the upcoming summer and fall, I will evaluate the current machine learning models using data from hydraulic fracture treatments and the associated production data to arrive at an optimal hydraulic fracture design. To accomplish this, I will be collaborating with the GOHFER commercial software team. We will build a workflow to be used in GOHFER to arrive at more accurate model interpretations using statistically quantified inputs from many treatments. The first step in this effort involves petrophysical analysis to create synthetic logs for the wells when they are not available. The created synthetic logs will be verified using known geologic model data. This involves two cycles consisting of training and verification. With each cycle, the accuracy of the model will improve. Initially, I will use 1667 digital log files from Ward County wells, TX.

Core- to Log-Scale Analysis of the Wolfcamp Formation in the Thunder C20-13 #2H Core, Delaware Basin, Reeves County, Texas

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Abstract

The Pennsylvanian-Permian Wolfcamp Formation of the Permian Basin in West Texas and New Mexico is currently one of the most important and pursued unconventional plays in the world. In most areas, the Wolfcamp is over 2,000 ft thick and contains multiple stacked pay intervals. A 2018 United States Geological Survey (USGS) assessment evaluated the potential of technically recoverable and undiscovered resources of the Wolfcamp Formation in the Delaware Basin to contain 29,476 MMbbl of oil, 220,824 Bscf of gas, and 14,907 MMbbl of natural gas liquids (NGLs). The vast opportunities available have sparked interest in understanding the complexity and heterogeneity of the Wolfcamp strata to their implications on reservoir performance.

The Wolfcamp Formation records deepwater deposition of organic-rich mudstones interbedded with calcareous mudstones, calcareous siltstones, and carbonates deposited within mixed siliciclastic-carbonate fan systems. These fan systems reside in a semi-restricted basin with sediment originating from multiple sources. The Wolfcamp Formation is informally subdivided into four benches, from youngest to oldest, as Wolfcamp A, B, C, and D. Understanding the geological processes and characteristics that comprise each member is critical for exploration and in selecting the best landing zones. Wolfcamp strata are comprised of mass movement and sediment gravity flow deposits separated by background hemipelagic settling. While the Wolfcamp has been widely correlated using only wireline logs, Wolfcamp event beds and the facies that make up these event beds are below log resolution.

The objective of this study involves using core, core associated data and logs sourced from the Wolfcamp play to investigate the vertical variability seen in the Wolfcamp benches. The key dataset used in this study is the Cimarex Energy Thunder C20-13 #2H well located in Reeves County, Texas. This study is a 739.5 ft core, including portions of the four Wolfcamp benches. Integration of detailed core description, X-ray Diffraction (XRD), X-ray Fluorescence (XRF), Routine Core Analysis (RCA), Source Rock Analysis (SRA), Field Emission Scanning Electron Microscopy (FE-SEM) imaging, geomechanical analysis, and petrophysical well logs were utilized in this study to identify facies, facies characteristics, and associated reservoir properties.

Nine lithofacies were identified with considerations including mineral composition, grain size, grain shape, sorting, color fabric, and sedimentary features. Within these facies, porosity ranges from 4.5 to 12.1% and permeability from 0.1 to 340.0 nD. TOC was observed highest in siliceous mudstones, with TOC up to 6.3 wt.%. Unconfined compressive strength (UCS), the most

practical and economical way to access rock strength, was acquired by taking measurements using an Equotip Bambino micro-rebound hammer. Carbonate-rich lithofacies were found to have higher rock strength compared to clay-rich facies. The skeletal packstone has the highest average rock strength at 65 MPa. The lowest rock strength observed in the argillaceous mudstone lithofacies has an average UCS of 45 MPa. The distribution of Wolfcamp lithofacies is highly stratified. However, cyclicity is observed in both carbonate and siliciclastic event beds, ranging from less than an inch to tens of feet in total thickness. Source rock analysis was used to examine the quantity of organic matter, thermal maturity, kerogen type, and hydrocarbon generative potential. The reservoir properties of each lithofacies were evaluated to identify one primary reservoir facies, three secondary reservoir facies, and five nonreservoir facies. Facies distribution and stacking patterns were analyzed to gain insights into changes in depositional settings and climatic fluctuations at the time of deposition.

Midland Basin's Wolfcamp A and B – Carbonate Gravity Flows and Rock Characterization through Machine Learning

Selena Neale: M.S. Student, Department of Geology and Geological Engineering, CSM

Abstract

During Pennsylvanian-Permian time, the Permian Basin formed along the southern end of the North American Craton. Initially, sedimentation in the Permian Basin was dominated by carbonate ramp environments. But glacial eustasy combined with several tectonic events uplifted the Central Basin Platform, thereby dividing the Permian Basin into the westerly Delaware and easterly Midland Basins. The Permian then developed into a more complex basin where platform depositional sequences laid down alternating siliciclastic and carbonate layers in the separated Delaware and Midland Basins. These carbonate layers are primarily carbonate-sediment gravity flows, which spread from shelf edges to deep within the basins, where they interlayer with the siliciclastic strata and can be up to 10 meters thick.

The siliciclastic/carbonate facies of Midland Basin's Wolfcamp A and B formations are recognized as a world-class unconventional hydrocarbon play. The carbonate gravity flows pose numerous opportunities for operators if they could better plan to avoid or tap into these potential reservoir rocks. By using machine learning algorithms to characterize well logs through Midland Basin's Wolfcamp A and B into siliciclastic mudrocks or carbonates, it is possible to map and model these sediment gravity flows. This would allow for the better planning of target facies, well paths, and completion strategies. The first step in this process is selecting well logs from wells near each other and separating the logs into mudrock or carbonate, using machine learning algorithms in the Python language. Future steps will be working with more complex machine learning algorithms to characterize the well logs, extracting sections of carbonate, and using them to model possible gravity flow geometries which could connect these wells.

Geochemistry of Ocean Anoxic Event III (OAE III) in the Niobrara Formation

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Abstract

Upper Coniacian – Lower Santonian Ocean Anoxic Event III (OAE III) has been identified and investigated by several researchers to understand its nature, paleogeographic extent, and causal mechanisms. Global scale correlations of OAE III are obtained using stable carbon isotope trends. Although, OAEs are defined by an increase in carbon preservation potential throughout their extents, understanding the mechanisms that promoted anoxia within such marine environments stays ambiguous.

OAE III event in the Western Interior Seaway (WIS) is found within the Niobrara Formation. Niobrara Formation was deposited in open marine conditions reflecting interbedding of chalk- and marl-rich units. Variations in mineralogy is a function of sediment supply, proximity to clastic sources, and presence of suitable ocean chemistry for carbonate deposition and preservation. Niobrara Formation is one of the major unconventional plays in the Rocky Mountain Region and is also a prolific source rock for the Frontier, Turner, Codell, Sussex, Shannon, Terry, Hygiene, and Parkman sandstones.

In this study, OAE III is investigated using stable carbon and oxygen isotopes, trends in total organic carbon (TOC), and elemental trends from X-ray fluorescence (XRF). In the Niobrara Formation, OAE III is accentuated by a positive excursion in stable carbon isotope trends, as well as an increase in the concentrations of redox sensitive elements. In this study, cored intervals from Denver Basin are used to provide a detailed understanding on OAE III. The study area also involves one well covering the Niobrara Interval from the Canadian portion of the WIS as well as, a section from Dallas, TX covering the Austin Chalk interval. Based on WIS-wide correlation of stable carbon isotope trends, OAE III is found to be a region-wide event displaying variations in its thickness and stable carbon isotope values. Therefore, the duration of this event and the level of carbon preservation might have been variable in different parts of the basin. However, further studies on compaction and sedimentation rates are required to better understand the timing and duration of such events. OAE III in the study area displays better organic carbon preservation. Total organic carbon profiles from wells used in the study display positive trends within the anoxic event. Redox sensitive elements, including, Mo, V, and U also display increasing values, indicating an oxygen depleted water column.

Increasing Mg/Ca elemental ratios display a steadily increasing trend prior to the deposition of the Niobrara Formation, indicating a decrease spreading rates. A sharp decrease in the Mg/Ca ratio at the beginning of the Niobrara Formation deposition indicates faster spreading events that are typically associated with intensified structural deformation causing an increase in the rates of greenhouse gas emissions followed by changes in climatic conditions. The increase

in the intensity of structural deformation at the beginning of the Niobrara Formation is also supported by the high and sharp Mn excursion seen in the Fort Hays Member. Stable oxygen isotope trends from wells used display a drastic shift towards cooler climates with the onset of Niobrara Formation deposition. The cooling is associated with increasing greenhouse gas concentrations leading to higher weathering rates followed by an increase in the amount of stream discharge bringing nutrients. An increase in the amount of nutrition followed by algae blooms in the photic zone might be one of the causal mechanisms promoting anoxia in the water column. Moreover, presence of framboidal pyrite and trends in Mo, V, Fe, and S, indicate euxinic conditions were established at times.

Overall, OAE III within the Niobrara Formation display a positive excursion in stable carbon isotopes and higher TOC content with trends in redox sensitive elements pointing out to an increase in carbon preservation potential under reducing conditions. Stable oxygen isotope trends indicate cooling during the Niobrara Formation. A combined use of geochemical signatures indicate cooler climates promoted anoxia due to higher productivity followed by ocean column anoxia in the area. Therefore, OAE III might have occurred as a result of higher organic productivity resulting in anoxic conditions permitting more efficient organic carbon preservation.

Silica Diagenesis and its Pore-Scale Influence on the Characteristics of the Upper and Lower Bakken Shales, Williston Basin, North Dakota and Montana

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Abstract

The Bakken Formation has been a major producer of oil and gas in North Dakota and Montana since the advent of horizontal drilling, reaching peak production of over 1.2 million barrels of oil per day. It is Upper Devonian and Lower Mississippian in age and consists primarily of a dolomitic reservoir stratigraphically bounded by two organic-rich mudrock members. These interbedded shales have been interpreted as depositional sequences of transgression and regression related to eustatic sea level variations and serve as important source rocks in the Williston Basin. The lower and upper Bakken shale members were deposited in euxinic bottom-water conditions linked to transgressive systems and contain a significant portion of biogenic silica. Biogenic silica dissolution and re-precipitation is known to contribute to the development and/or preservation of pore space, ultimately affecting source rock quality and reservoir recoverability. Diagenesis occurs in multiple stages, beginning with amorphous silica (opal-A) and followed by a sequence of metastable intermediates known as opal-CT, then chalcedony, and finally microcrystalline quartz. The transition from amorphous silica to progressively more orderly crystallographic stages in this sequence is largely controlled by an increase in temperature and a decrease in silica saturation. Recent studies of mudrocks in other high-profile unconventional plays have highlighted the importance of silica diagenesis in the post-depositional development and preservation of porosity, but this sequence remains understudied in the setting of the Bakken Formation's radiolarian-rich lower and upper shale members. This study describes and characterizes silica in the lower and upper Bakken shales to estimate the extent to which its diagenesis has altered pore networks within the shales.

This study incorporates data from three core samples drilled in northwestern North Dakota and one core sample drilled in northeastern Montana. Data was collected via X-ray fluorescence (XRF), X-ray diffraction (XRD), field emission scanning electron microscopy (FE-SEM), and N2 physisorption. XRF analysis provided a compositional framework to assist in selecting ten sample locations within the cores. FE-SEM and XRD analysis paired with quartz crystallinity index calculations assisted in determining the nature and extent of silica diagenesis in each sample. Finally, the N2 physisorption technique was used to measure differences in pore volume and surface area between samples. Results suggest that the intervals of each core with the highest concentration of silica contain primarily amorphous, biogenic silica that is in the form of recrystallized radiolarian tests. N2 physisorption results indicate that intervals in the shales that contain the highest concentration of silica and radiolarian tests have a slightly larger surface area and pore volume than samples with low silica concentration and no radiolarians. These results tentatively suggest that radiolarians contribute a minor amount of surface area and pore space to the lower and upper Bakken shales through the dissolution and reprecipitation of silica

in the most heavily siliceous intervals of the shales. Similar future analysis at a regional scale would assist in determining the extent or existence of this trend throughout the Williston Basin.

Reservoir character of the Three Forks Formation in the Williston Basin: Evaluations of Hydrocarbon Charge, Petrophysical response, Depositional environment, and Production Sweetspots

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Abstract

The Three Forks Formation of the Williston Basin in western North Dakota and eastern Montana is a significant reservoir contributor to the overall Bakken petroleum system. At present, the formation has produced 1.172 billion barrels of oil and 1.962 trillion cubic feet of gas. With over 5,300 horizontal wells drilled and completed to date within the overall formation, roughly 250 of those have targeted the middle Three Forks (2nd bench), and only 43 horizontal wells have targeted the lower Three Forks (3rd bench). The remaining wells in that well-total (approximately 5,000 wells) have all targeted the upper Three Forks (1st bench). Thus, horizontal drilling activity in the Three Forks has mainly focused on the upper-most member.

This trend in Three Forks activity has been driven, generally, by the recognized patterns of hydrocarbon charge within the three members. The upper Three Forks typically has greater oil saturation relative to the middle and lower members. This oil saturation in the upper member is also more laterally continuous than the others across the play area. These charge variances between the members are currently attributed to their proximity to the hydrocarbon-generation source beds in the overlying Lower Bakken Shale. The apparent charging trend has indicated the upper Three Forks as the lower-risk drilling target, and operators have acted accordingly with their development decisions.

However, despite industry's focus on the upper Three Forks, commercially viable wells (>700,000 cumulative bbls of oil in 700 producing-days) have been drilled in the middle and lower members. These results indicate that both units exhibit demonstrated potential for future development although the strong production results from these members are localized. Given this potential combined with the upper Three Forks, further analyses on drivers of hydrocarbon charge distribution throughout each member could significantly impact and improve the future development efforts of the hydrocarbon resources within the Three Forks overall and are worthy of further attention.

In light of the above, the primary goal in revisiting the Three Forks in the MUDTOC consortium is to update and improve the understanding of the formation's reservoir characteristics, and how hydrocarbon charge variations are controlled downward through each of the members. To accomplish these tasks, focused evaluations of the following are proposed: 1) a review of facies and depositional models and their implied spatial reservoir bed geometries, 2) detailed assessment of petrophysical response and viable reservoir identification, and 3) reservoir sweet spot distribution regionally. Developed research questions, detailed

methodology, and incremental findings from these evaluations will be presented with future progress.

High Resolution Reservoir Characterization of the Lewis Shale, Greater Green River Basin, Wyoming

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Abstract

The Lewis Shale is a turbidite system that encompasses 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 (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.

Each member has variable amounts of sands, siltstones, and shales depending upon its depositional location within the platform. The sequence stratigraphic framework was developed by Pyles (2001) and Pyles and Slatt (2000) and is characterized by third-order progradational high stand systems tracts with several fourth-order lowstand-highstand cycles and a shallowing upwards sequence. The maximum flooding surface is within the lower member, named the Asquith Marker. It has a maximum thickness of 50 ft within the basin and is considered a source of hydrocarbons with TOC values ranging between 0.68% and 3.15% in core and outcrop.

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 that formed during the Laramide orogeny. During this time, the Sierra Madre uplift, Rawlins uplift, Cherokee uplift, Lost Soldier anticline, and Rock Springs uplift were rising and served as sediment sources 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.

The Lewis Shale is considered an unconventional reservoir due to its low porosity and permeability and the need to use hydraulic fracturing to obtain hydrocarbons. Unconventional reservoirs hold high percentages of hydrocarbons, but are highly complex and still not completely understood. The increasing importance of these reservoirs creates a need to understand several aspects such as their internal characteristics to correlate them regionally and locally, assess gas migration pathways, and determine well placements.

The present study is located in Sweetwater and Carbon counties in Wyoming. Data includes four cores located around the basin provided by MorningStar Partners/Southland Royalty. Cores have various lithologies, including shales, siltstones, and sandstones, representing the Lewis Shale's lithologic heterogeneity and complexity. High-resolution reservoir characterization is a crucial tool for understanding this reservoir and decreasing uncertainty

when planning new well placements. It is unclear whether or not the Asquith Marker is the source rock for all hydrocarbons within the Lewis Shale, but it is undoubtedly a contributing source bed. Migration pathways and optimal reservoir quality are essential to make this play economical. Thus, high-resolution reservoir characterization from cores and logs will help understand this highly heterogeneous system and even aid during the geosteering process. The high-resolution reservoir characterization includes but is not limited to XRD, XRF, thin section petrography, porosity/permeability analyses on the cores, and maps of the relevant correlative intervals that will aid in determining the depositional environment and ultimately will control the reservoir quality.

Stratigraphic Study of the Turonian Semilla Sandstone Member of the Mancos Shale, San Juan Basin, New Mexico

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Abstract

The Turonian Semilla Sandstone Member of the Mancos Shale crops out on the eastern flank of the San Juan Basin along the Jemez Mountains of New Mexico. This tight sandstone was formed during the last regression of the Western Interior Seaway during the Greenhorn Cyclothem. This change in accommodation space in the seaway saw the deposition of the Codell Sandstone of the Denver Basin and the Turner Sandstone of the Powder River Basin. Out of all of these time equivalent sands, the Semilla shows the greatest similarity to the type I sand of the Codell, present in the southern end of the Denver Basin. Although their offshore bar origin is agreed upon, the mechanism, being either tidal or storm dominated, is debated. Petrographic thin sections from this part of the Codell have been taken from Forest Oil's #1-3 Mackenzie well, which was drilled near Florence, Colorado. These will be compared to petrographic thin sections taken from Semilla outcrops.

The total outcrop length of the Semilla is about 35 miles long, forming two discrete sets of bars with a maximum thickness of about 70 feet. The main focus of the outcrop portion of the study will be the Holy Ghost Bar, which is the type section for the member. In his 1981 paper, Neal La Fon described these bar outcrops consist of two facies: a silty sandstone facies and a cross-bedded sandstone facies. Being the dominant lithology in the member, the silty sandstone facies is a fine to very fine sandstone with about 20% silt and clay. Extensive bioturbation creates a lack of sedimentary structures. The cross-bedded sandstone facies is located predominantly at the top of the bars, with a gradational contact from the silty sandstone facies below and a sharp contact with the overlying Mancos Shale. Burrowing significantly decreases in this facies with trough cross-bedding being the dominant sedimentary structure. Between the lenticular sand bodies lies a transitional, horizontally laminated silty shale that ranges from 3-6 feet thick. Although this shale is a member of the Mancos, it was deposited contemporaneously to the bar sands. Comparing the orientation of sedimentary structures to bar geometries will better define these types of lenticular sand bodies in the subsurface.