# Petrographic Examination of Three Forks Formation Reservoir Lithofacies: Implications for Porosity Development

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## Abstract

Petrographic examination of Three Forks Formation Lithofacies with implications on porosity and pore space distribution in the Bakken-Three Forks Petroleum System.The Devonian Three Forks Formation is a mixed carbonate and clastic tight reservoir within the unconventional Bakken-Three Forks petroleum system. The accumulation in the Three Forks Formation is estimated to contain approximately 3.73 billion barrels technically recoverable oil. Physical core examination, wireline logs and published work were used to identify lithofacies within the Three Forks formation interval. Lithofacies identified include 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 Analysis including thin section petrography, X-ray diffraction (XRD), scanning electron microscopy (SEM) imaging, helium porosimetry and nuclear magnetic resonance (NMR) T2 analysis were utilized to characterize the Three Forks Formation lithofacies. XRD analysis showed a very diverse range of mineralogy with varying percentages. Minerals analyzed include dolomite, calcite, quartz, felspar, pyrite, anhydrites, illites, muscovites and other clay minerals. Pores from SEM imaging includes clay matrix, microfractures, intercrystaline and moldic pores, the dominant pore types vary for different lithofacies. Mudstone dominated lithofacies have higher total porosities from both helium porosimetry and NMR method. Conversely, dolostone-rich lithofacies have relatively lower total porosity. This worked established a

relationship between clay mineral abundance from XRD analysis and total porosity from both helium porosimetry and NMR analysis. NMR porosities values are greater that the corresponding helium porosimetry method for same facies, the difference in porosity also increases with increasing clay mineral proportions. Pore fluid distribution were estimated using published T2 cutoff values for the Bakken-Three Forks petroleum system. Massive dolostones having relatively very low porosities with the highest proportions of movable fluids due to the presence of large macropores. Massive mudstone lithofacies with highest total porosities have lowest oil saturation due to the presence of abundant micropores and clay bound water.