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Olusoga Martins Akintunde (olusogamartins@gmail.com)
University of South Carolina College of Arts and Sciences https://orcid.org/0000-0001-6711-2988
Camelia C. Knapp
Oklahoma State University Stillwater
James H. Knapp
Oklahoma State University Stillwater

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Olusoga M. Akintunde*, Camelia C. Knapp**, and James H. Knapp**
*Formerly University of South Carolina, Columbia, South Carolina
**Boone Pickens School of Geology, Oklahoma State University

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Abstract

The lack of the permeability log data necessary to assess reservoir injectivity as well as aid in the correlation and interpretation of existing porosity and resistivity logs for reservoir quality characterization for potential CO_2 storage in the heterogenous and complex South Georgia Rift

(SGR) basin provides the motivation for this study. The focus was on the Triassic-Jurassic red beds buried, entrenched beneath the Cretaceous-Cenozoic Coastal Plain sediments. Moreover, the significant cost typically between $10 M to $100M associated with drilling and logging for in situ permeability coupled with the limited resolution of existing core data further makes this work necessary. The purpose is to relate, use the interpretation of the predicted permeability distribution to assess feasibility for safe and long-term CO_2 sequestration. This study also intends to establish the impacts of active and passive tectonism that has shaped and/or re-shaped the evolution of the basin on the present-day permeability. A methodology was applied that utilizes the pore space and geohydraulic properties of the reservoir from existing laboratory and well data to produce a newly derived permeability log. It shows a non-uniform distribution with depths possibly due to geologic changes in the confined and heterogeneous red beds. The derived log displays characteristics consistent with observations from the porosity and resistivity logs. The interpretation of these logs provides evidence for the presence of low permeable, tightly cemented and compacted red beds. We conclude that the low permeability aided by the low resistivity depicted in the red beds suggests increased confining stress and reduced injectivity, and that the uncharacteristically low permeability reflects a deformed basin shaped with episodes of uplift and erosion.

Introduction

Permeability is an important reservoir property that measures the ability of a rock to allow fluid to pass through. It is a function of the pore space and pore connectivity within a rock (Mavko et al., 2003). Its pore space property enables it to have a direct, linear relationship with porosity. A rock with high porosity would typically exhibit high permeability so long as it is characterized by large and uniformly rounded grains. However, poor sorting and presence of fine grain

materials can reduce permeability even if the porosity is high. Porosity is heavily influenced by the rock's pore space and grain size distribution, while permeability is controlled by a combination of these factors as well as by other subsurface or near surface fluid flow properties such as tortuosity, pore shape and pore throats.

Permeability as a rock property complements porosity for the purpose of assessing reservoir quality either for fluid injection involving CO_2 storage or for oil and gas exploration and development. Its importance to the evaluation of the suitability of the confined and porous red beds formations of the SGR basin for safe and permanent geologic CO_2 sequestration makes it of great interest to this study.

The SGR basin was formed about 215 – 175 Ma through the breakup of Pangaea and opening of the Atlantic. It is believed to be the largest and probably the most geologically complex Mesozoic graben of the Eastern North American Passive Margin (McBride et al., 1989; and Chowns and Williams, 1983). As shown in Figure 1, it covers an area of about 100,000 km^2 encompassing South Carolina, Georgia, Alabama, and parts of Florida (Chowns and Williams, 1983). The basin fills consist of basalts, diabase sills and red beds. Extrusion of the basalt and intrusion of the diabase sills followed the post rifting events that occurred during the Jurassic (Chowns and Williams, 1983; Ghon, 1983; Ghon et al., 1983; and Olsen et al., 1991). The red beds were formed through sediment deposition that accompanied the formation of the basin in late Triassic. Studies by Heffner et al. (2012), Akintunde et al. (2013a), and McBride et al. (1989) show the SGR basin fills to be overlain by the Cretaceous-Cenozoic sediments.

This study focuses on the red beds found in the Norris Lightsey #1 well, in Northwest Colleton County, South Carolina (Figure 1). The Norris Lightsey #1 was a wild cat well drilled in the

early 1980s to explore for hydrocarbons. It is also one of the very few wells in Southern South Carolina with significant penetration of the Triassic red beds, covering a depth of about 4,000 m and penetrating over 3,100 m of Triassic red beds. The lithology of the Norris Lightsey red beds consists of fine grained sandstones that are mixed with siltstone, conglomerate and mudstone (Figure 2). Geological characterization of these red beds for optimum reservoir quality assessment for safe and permanent CO_2 storage will require the interpretation and correlation of a combination of relevant well logs. Core scale laboratory data are of limited resolution and are characterized by coarse sampling at depth. On the other hand, well logs offer fine spatial sampling and continuity that are absolutely essential for comprehensive and uncompromising assessment of the state and suitability of a target reservoir for CO_2 storage. Unlike core scaled data, knowledge of reservoir permeability at in situ conditions is important to dynamic reservoir modeling for better understanding and accurate prediction of the distribution of fluid flow for injection optimization and management. Unfortunately for the study location, there is no log of permeability changes at depth to either assess the suitability of the porous red beds for injectivity or correlate with available porosity and resistivity logs to aid site characterization. This lack of a permeability log, especially at reservoir depths not sampled by the available core laboratory data (Table 1), provides the motivation for this study.

Objectives

In evaluating subsurface suitability for CO_2 storage in a heterogeneous reservoir such as the confined red beds formations encountered in this study area, three questions are important to the interpretation of permeability. How does the permeability change with depth? What do the observed changes reveal about the state of the reservoir for potential CO_2 storage? Do the depth-varying permeability changes exhibit the same behavior as porosities at same depth intervals? A

permeability log because of its continuity within the subsurface meets the optimum resolution required to better quantify, understand and interpret depth dependent permeability changes as these relate to the above questions. Moreover, laboratory derived core scale porosity and permeability measurements (Table 1) are limited in resolution, while porosity and permeability information from wells logs provide continuous coverage for reservoir quality assessment. Core based laboratory data provides subsurface measurements on the order of inch/cm (core scale) whereas well logs measure up to m/km (reservoir scale) with better resolution for subsurface characterization. The primary goal of this study is to predict and provide permeability changes at the well log scale for the purpose of optimum reservoir quality assessment for CO_2 storage.

The local and regional implications of the depth-dependent permeability changes for safe CO_2 storage, as this concerns the potential for pore pressure build up, fault reactivation, and induced seismicity, is the second issue of interest. Given the relative proximity of the Norris Lightsey well to the Summerville seismogenic zone of South Carolina, the decision to drill and store CO_2 will also need to address questions about environmental safety as follows. Could CO_2 storage in the confined red beds lead to reservoir overpressure capable of causing leakage or threatening the integrity of the storage reservoirs and overlying seals? How can site-specific permeability conditions curtail or expose the risk of fault reactivation and induced seismicity with injection and storage?

Methodology

The approach utilized involves applications of the modified Kozeny-Carman relation (Gomez, et al., 2010, and Mavko et al., 2003) and the Flow Zone Indicator (FZI) technique developed by Amaefule et al. (1993). The modified Kozeny-Carman relation described below in equation 1

118 computes permeability k from porosity ϕ for a rock with predetermined pore space and
119 geometrical properties.

120 $$k = \left(\frac{d_{Mean}^2}{72\tau^2}\right)\frac{\left(\phi - \phi_p\right)^3}{\left[1 - \left(\phi - \phi_p\right)\right]^2} \quad (1)$$

121 where d_{Mean} is the mean grain size; τ is tortuosity, ϕ is the total porosity and ϕ_p is the percolation
122 porosity. These properties can be obtained from laboratory measurements on rock samples.
123 Percolation porosity is the porosity when the pore is disconnected and does not contribute to
124 flow. It is generally between 1 to 3% (Gomez, et al., 2010, and Mavko et al., 2003). Further
125 discussion on the Kozeny-Carman relation including its derivation can be found in Mavko et al
126 (2003), and Schon, (2011).

127 The FZI as used in this study and previous research by Alam et al. (2011), and Prasad (2003)
128 adapts and extends the Kozeny-Carman relation to enable better characterization of the spatial
129 distribution of permeability in a reservoir characterized by presence of heterogeneities. It allows
130 for an assessment of the petrophysical response and sensitivity to dynamic and depth dependent
131 reservoir changes in a way similar to the applications of geophysical well logs for reservoir
132 characterization. Its relationship to porosity ϕ and permeability k, which represents the
133 application to this study, can be seen in the below equation 2.

134 $$FZI = \frac{0.0314}{\epsilon}\sqrt{\frac{k}{\phi}} \quad (2)$$

135 In the above equation, 0.0314 is a constant that accounts for the pore size, tortuosity, pore shape,
136 and the pore throat to pore-body ratio (Prasad, 2003). ϵ (equation 3) is the ratio of the pore
137 volume to grain volume.

138 $$\epsilon = \frac{\phi}{1 - \phi} \quad (3)$$

139 Further discussion and derivation of this equation can be found in Schon (2011), Prasad (2003)
140 and Amaefule et al. (1993). The application to a porous reservoir is based on the premise that
141 reservoir units with FZI values within a narrow range belong to one hydraulic unit. The
142 implication of this is that these have similar pore throats and therefore constitute a flow unit. The
143 step-by-step procedure for the implementation of the Kozeny Carman and the FZI technique to
144 predict and provide depth-varying permeability changes in the heterogeneous red beds reservoir
145 are discussed as follows.

146 1. Development of a porosity-permeability transform for the study area based on the
147 Kozeny-Carman approach.
148 2. Development of FZI from the core derived laboratory measurements in Table 1 to allow
149 for red beds with similar pore throats to be grouped as a single flow unit.
150 3. The use of the porosity-permeability relationship in step 1 to convert the porosity from
151 the Norris Lightsey #1 well to reservoir scale permeability at target depths for potential
152 CO_2 injection.
153 4. Incorporation of the results from step 3 into equation 2 using the computed FZI values
154 from step 2 to produce the permeability log.

155 In both the Kozeny-Carman and FZI applications for this study, we utilized the existing well
156 data, and the core laboratory measurements for the Norris Lightsey #1 well and other locations
157 with penetrations of the South Georgia Rift red beds (Table 1). The Norris Lightsey #1 well has
158 the deepest penetration of the red beds, covering a depth greater than 800 m below the surface to
159 maintain supercritical CO_2 injection (Akintunde et al., 2013a). The variations in the porosity and
160 permeability data from these locations are due to the influence of depositional environments
161 (Akintunde et al., 2013b). In addition, these study locations share similar lithologic composition,

age, geologic history and tectonic setting with red beds recovered from several wells within the basin (Heffner et al., 2012; Chowns and Williams, 1983; Gohn, 1983; and Marine and Siple, 1974).

Results

The permeability-porosity relationships based on linear correlation and the Kozeny-Carman relation are shown in Figure 3. A grain size of 250 μm was used based on relevant information from literature review (Mavko et al., 2003, and Gomez et al., 2010), and the subsequent testing and comparison with the direct correlation approach (Figure 3). The Kozeny-Carman porosity-permeability relationship yields a more accurate prediction of permeability from porosity than the linear correlation approach (Figure 3).The Kozeny-Carman relationship takes into account the grain size and tortuosity of the rock, whereas the direct correlation does not account. The FZI adapts and extends the predicted permeability from Kozeny Carman to provide estimates of permeability within definable flow units within the reservoir.

The FZI allows for a division of the core-derived porosity and permeability data into flow zone units (Figure 4). It performs this by treating the assigned porosity and permeability contributing to the same flow unit as one FZI value. The consequence of this is that reservoir units with FZI values within a narrow range have similar pore throats and therefore constitute a single hydraulic or flow unit. The distribution of the FZI shows that a large concentration of the data falls within FZI of 0.35. Plugging this value into equation 2 and substituting the well log derived porosity values into the derived porosity-permeability transform (in Figure 3) allow for the production of the permeability log in Figure 5. The permeability log signatures are consistent with the trends exhibited by the porosity log as should be expected given the contribution from porosity. This

184 provides a measure of the reliability of the Kozeny-Carman prediction and the computed FZI
185 values that contributed to the production of the permeability log. It also shows that rock's
186 volumetric properties, such as pore space and grain size distribution that are primarily
187 responsible for porosity, do exert control on permeability. It is remarkable to note that while the
188 porosities are high, the permeability values are low. This is significant as it shows that factors
189 responsible for porosity such as pore size and grain size distribution are not the sole and most
190 dominant controls on permeability. Permeability also depend on the rock's geometrical and fluid
191 flow properties, such as tortuosity, pore shape and pore throats, that are of critical importance to
192 reservoir injectivity.

193 **Discussion**

194 The derived permeability log (Figure 5) manifests the following characteristics: (1) uniform and
195 non-uniform distribution with depths (2) noticeable spikes or increases at depth intervals 1395 to
196 1440 m, 1438 to 1445 m, and 1458 to 1465 m, (3) generally low permeability values that are less
197 than 2 mD , and (4) vertical distribution which is consistent with the trends of the porosity log .
198 The correlation of the permeability log with the porosity and resistivity logs allows for easy
199 recognition of the highly resistive and non-porous diabase sills at 1410 to 1424 m. Within the
200 confined and heterogeneous red beds that are both above and below the impermeable diabase
201 sills (Figures 2 and 5), non-uniform permeability distribution are observed. We interpret the
202 permeability variations with depth to be due to geologic changes and the presence of fluids in the
203 red beds. These geologic changes involve key controls on permeability such as sorting, pore
204 shape, pore throats and tortuosity. Analysis of photomicrographs (Figures 6 to 9) of thin sections
205 on red bed cores recovered from the Rizer #1 Test Borehole in Collenton County, South
206 Carolina, provides evidence for these geologic changes. The Rizer #1 borehole, drilled in spring

2012, is within 5 km to the Norris Lightsey well (Figure 1). The similarities in depositional environment and lithologic composition of the Rizer #1 well red beds with the Norris Lightsey lacustrine red beds provide the basis for the use of these thin sections. Analysis reveals cemented and lithified red beds with abundant quartz overgrowths and calcite cement (Figures 6 to 9). The exposure to increased compaction and possibly periods of sustained subsidence during sediments deposition has significantly altered reservoir properties responsible for permeability judging by the presence of clasts and small pore sizes and pore throats seen in the thin sections. These photomicrographs also show irregular pore shapes and sizes in the tectonically deformed red beds which may be responsible for the non-uniform distribution of permeability with depths (Figure 5).

The low resistivity in the red bed units is indicative of water or brine saturated red beds. This is because the observed log resistivity values ranging from as low as 0.05 to less than 100 ohm m fall within the range of known resistivity values for water and saltwater reported in Telford et al., 2001. Chemical analysis conducted by Marine and Siple (1974) on pore water from a Dunbarton well with penetration of the red beds found dissolved solid content of approximately 11,000 mg/L that supports the interpretation of brine-saturated red beds. Their study also revealed much higher chloride in the red beds (6720 mg/L) in comparison with water from the Cretaceous-Cenozoic coastal plain sediments (1.5 mg/L) and the crystalline metamorphic rock (1260–1400mg/L). Also, there is no gas in the red beds as this would have caused an increase in resistivity. On the other hand, the overlying and non-porous diabase sills are completely dry. This explains the virtually non-existent permeability and the unusually high resistivity of the sills. The interpretation of a brine saturated reservoir is consistent with the plan for a deep saline CO_2 storage system for the South Georgia Rift basin.

230 The consistency in the observed trends of the porosity and permeability logs provides validation
231 for the reliability of the derived permeability log. Their disproportionate values relative to each
232 other however show that the key controls responsible for both are not mutually identical.
233 Porosity is primarily a function of the pore space in a rock. On the other hand, permeability is a
234 function of the pore space and fluid flow properties of the rock such as tortuosity, pore shape and
235 pore throat that control injectivity. This strengthens the need for a permeability log to
236 supplement and complement the porosity log for comprehensive assessment of the suitability of
237 the SGR red beds for CO_2 storage. The correlation with the resistivity log which allows and
238 supports the delineation of the diabase sills and the fully water saturated red beds from the
239 interpretation of the observed permeability distribution also provides an additional, independent
240 verification of the genuineness of the permeability log.

241 The ensuing question from the signatures of the resistivity and permeability logs is what does
242 this mean about the state of the reservoir? The resistivity of a formation based on Archie (1942)
243 varies with porosity depending on the nature and degree of fluid saturation as well as on the
244 rock's cementation and tortuosity. For a fully brine saturated reservoir exhibiting the kind of
245 depth varying porosities shown in Figure 5, the consistently low resistivity also suggests a tightly
246 cemented, compacted rock. This is because the presence of brine (as indicated by the low
247 resistivity) exposes the red beds to chemical dissolution and geochemical reactions that
248 contribute to their cementation and compaction. And with increasing confining stress from burial
249 depths, compaction is further aided. The thin sections (Figures 6 to 9) support the inference for a
250 tightly cemented, compacted rock.

251 The process of compaction or lithification in a reservoir closes pores and/or restricts the
252 interconnectivity between pores that are responsible for permeability (Figures 6 to 9). This

process is further enhanced by exposure to increased confining stress with depths. The effect of increasing confining stress is to reduce or weaken the pore pressure by closing openings in a rock responsible for fluid movement (permeability). The thin sections (Figures 6 to 9) support this view as they show severe degradation in grain size distribution, pore sizes and shapes with increasing depths and net confining stress. Apart from geologic changes in the reservoir, the reservoir response to the permeability log signatures may be stress induced. Burial depth, age, geologic history, and composition are additional factors that influence low permeability. The regional implication of the low permeability is that the South Georgia Rift red beds and possibly the ones encountered in other buried Triassic-Jurassic basins in the Southeastern United States are most likely to be low permeable rocks in view of the similarities in age, geologic history and composition (Akintunde et al., 2013b, Marine, 1974, Marine and Siple, 1974).

Applications to CO_2 Storage and Regional Tectonics

In assessing the implications for CO_2 storage, we ask these questions. What does the low permeability mean for reservoir quality determination? How would this affect subsurface suitability for CO_2 storage? How would this impact CO_2 migration and containment in the red beds? Hydrogeologically, the injection, movement and storage of fluids are most effective in underground formations with high porosity and permeability. The direct consequence for low permeability is a reduction in fluid flow and movement even if the porosity or pore space distribution favors substantial fluid storage. Low permeability would impact the degree and effectiveness of injectivity for CO_2 sequestration in the porous formation. Whether or not a reservoir would be viable for long term CO_2 storage depends not only on the storage capacity but also on the quality of reservoir injectivity. A preliminary petrophysical investigation by Akintunde et al., 2013 b demonstrates that the confined South Georgia Rift red beds in the Norris

Lightsey do exhibit porous intervals with the potential for substantial CO_2 storage capacity that far exceeds the 30 million tons set by the Department of Energy. Also, a preliminary reservoir modeling of CO_2 injection in the Norris Lightsey red beds by Brantley et al., 2015 basins demonstrates feasibility for injection of at least 30 million tons of CO_2 at a rate of 1 million tons per year for 30 yr. The overarching issue for the kind of subsurface distribution depicted by the permeability log in figure 5 is the impact on the degree of reservoir injectivity. The desirability for an effective CO_2 storage is to have sufficient injectivity to allow seamless fluid flow, movement, and containment without any fear of reservoir failure should the pore pressure exceeds the reservoir capacity. Conceptually, low permeability suggests reduced injectivity which in turn would impact the effectiveness of fluid flow and movement in the heterogeneous, porous red beds. Ideally, an increase if fluid flow and concentration will increase the pore pressure. The implication of increasing pore pressure with fluid injection is to counteract the effect of increased confining stress thereby opening pores and interconnectivity that could enhance permeability or fluid movement. Unless the pre-injection permeability can be physically or geo-mechanically enhanced, the predictably low injectivity will not be promising for effective fluid flow and storage.

Low permeability may help with safety and security of storage since the chances of sudden and unsafe pore pressure build up capable of either triggering induced seismicity or threatening the caprock integrity are unlikely with low injectivity. We understand from Zoback and Gorelick (2012) that increasing pore pressure with CO_2 especially in the vicinity of preexisting potentially active faults and considering the critically stressed nature of the crust were likely to increase the potentials for earthquake triggering. It is also inferred from Brantley et al., 2016 that the presence of an active fault with a permeability as low as 1 mD can cause significant CO_2 leakage. With a

properly planned injection that incorporates and implements the applicable geological framework as well as robust monitoring and management techniques, the risks of faulting and induced seismicity can be mitigated. A study by Talwani et al. (2007) showing related seimogenic permeability values that are unlikely to cause induced seismicity with fluid injection also lends credence to the potential for safe storage in the low permeable SGR red beds. Ideally, CO_2 injection will increase the pore pressure leading to opening of closed pores. So long as this effectively balances the effect of increasing confining stress with depths and does not alter the differential stress equilibrium, the chances of unsafe seismicity within and around the injection reservoir are very unlikely. Moreover, the confining nature of the red beds together with the presence of the impermeable diabase caprocks would ensure containment of the injected CO_2.

With adequate pore pressure monitoring before, during, and after injection, the risks to safe CO_2 storage may be quickly detected and averted. 4D seismic monitoring can help with understanding and quantifying dynamic reservoir changes to assess storage efficiency as well as the integrity of the overlying cap rocks. The current permeability log would provide the baseline information necessary for the next steps involving reservoir modeling and simulations, seismic modeling, and imaging, as well as field testing to assess the impacts of enhanced permeability on long term storage, the integrity of the overlying diabase sills, and monitor the efficiency and safety of injection and storage.

In terms of the application to regional tectonics, the predicted low permeability at depth reflects a compacted, deformed basin with a history of uplift and erosion. The thin sections' analysis on recovered red beds from the Rizer #1 Test Borehole in Collenton County, South Carolina (figures 6 to 9) supports this observation. The interpretation of these photomicrographs reveals the presence of red beds whose physical properties including key controls on permeability such

as sorting, pore shape, pore throats and tortuosity have been altered, impacted by tectonically induced post depositional processes (such as compaction and uplift) that have re-shaped the tectonic evolution of the SGR basin following the major phase of rifting. Whether or not the permeability can be recovered and/or enhanced by a physical or geo-mechanical means is beyond the scope of this current research.

Conclusions

The decision to drill and store CO_2 will depend on the quality of the reservoir and the safety of injection and containment. Of importance to reservoir quality are the in-situ porosity and permeability that determine the storage capacity and injectivity. Knowledge of the permeability regime is an extremely valuable rock property that dictates and determines the progress and efficiency of injection and storage. Its correlation and interpretation with porosity and resistivity logs to better understand and characterize the state of the red beds reservoir for CO_2 storage provides the motivation for this study. Permeability is most relevant for correlation with these logs, because of its strong connection to fluid saturation, grain size, pore shapes, cementation and tortuosity that are key controls on porosity and resistivity. Core based laboratory data do not have the resolution, scale, and continuity required for correlation and interpretation with well logs. Consequently, a significant, new contribution from this work is the development of a permeability log for the study area based on a robust methodology involving applications of the Kozeny-Carman relation and the Flow Zone Indicator technique. The rationale for the use of these two approaches was to ensure reliable permeability prediction and distribution that considers the pore space and geometrical properties of the target red beds. The development of this permeability log offers an alternative way to save time and significant cost associated with expensive well drilling and logging for in situ permeability measurements for reservoir

characterization. It would also aid dynamic reservoir modeling of the distribution of fluid flow to better characterize the CO_2 injection distribution and efficiency for the purpose of storage optimization and management.

The interpretation of the permeability log supported by the correlation with the porosity and resistivity logs shows non-uniform distribution with depths possibly caused by geological and stress induced changes in the heterogeneous red beds. Moreover, the petrophysical responses in both the resistivity and permeability logs are generally low. We interpret this in conjunction with the porosity distribution to suggest: (1) the South Georgia Rift is a tightly cemented and compacted reservoir, and (2) a reservoir exposed to increased confining stress. Increasing confining stress closes and/or restricts reservoir openings responsible for porosity and permeability. On the other hand, increasing pore pressure with CO_2 injection has the potential to counteract the effects of increased confining stress by opening closed pores or enhancing weak pores for efficient fluid movement and storage over time. However, low permeability will reduce injectivity that is a key requirement for the efficiency of CO_2 injection and storage. We also conclude that the predicted low permeability distribution with depth is a function of the active and passive post-tectonic depositional processes that have impacted the physical properties of the Triassic red beds.

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Figures

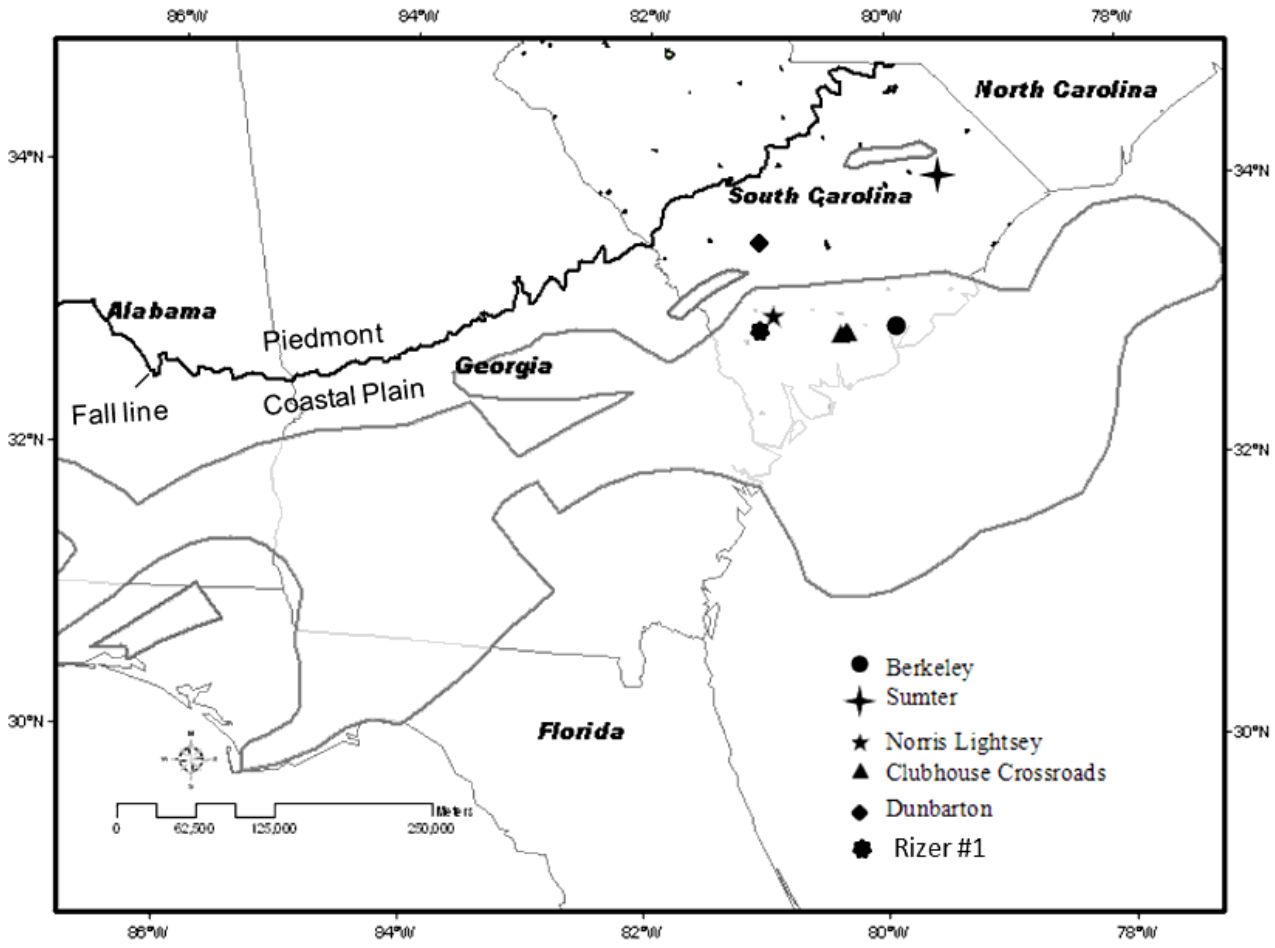

Figure 1

Areal extent of the South Georgia Rift basin (modified from Chowns and Williams, 1983) showing the Norris Lightsey #1 well study location. Other wells used in this study such as Sumter, Berkeley, Clubhouse Crossroad, Dunbarton and newly drilled Rizer #1 are shown. Gray shaded area represents the areal extent of the basin

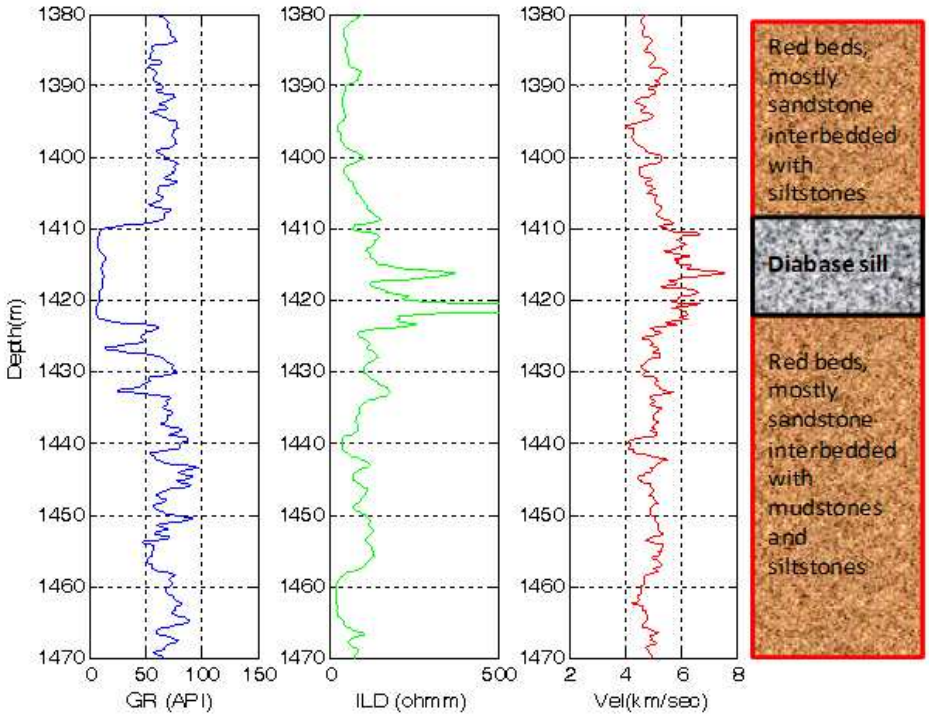

Figure 2

Target reservoir depths from the Norris Lightsey #1 well for potential CO2 storage. The diabase sill stands out from the red beds by its low Gamma Ray (GR in API), high resistivity (deep induction resistivity log, ILD, in ohm-meter), and high velocity (km/s)

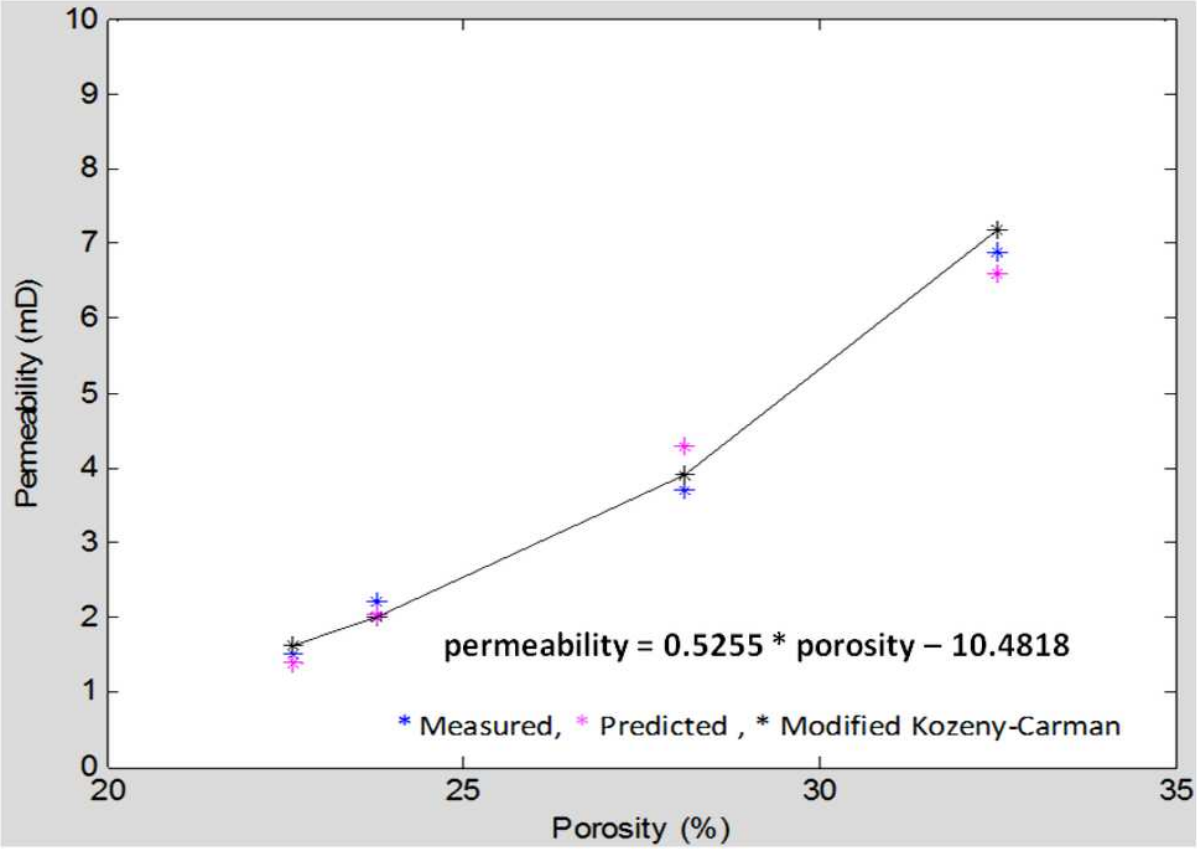

Figure 3

Permeability versus Porosity for the Norris Lightsey #1 well data shown in Table 1. Prediction by Kozeny-Carman relation provided the most reliable fit for the plotted data points.

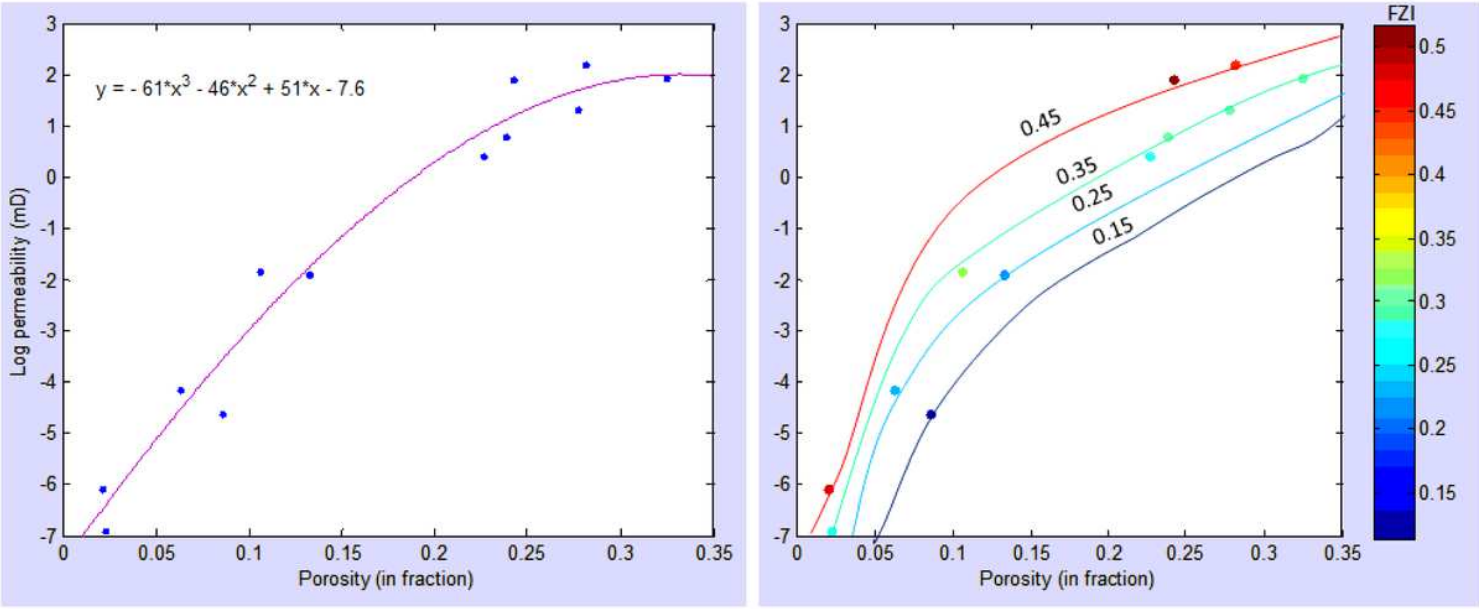

Figure 4

Permeability based on the concept of Flow Zone Units (FZI). The permeabilityporosity distribution for well locations shown in Table 1 is plotted on the left. The computed flow zone indicators are shown on the right. The flow zone intervals are shown by different colors in the color bar.

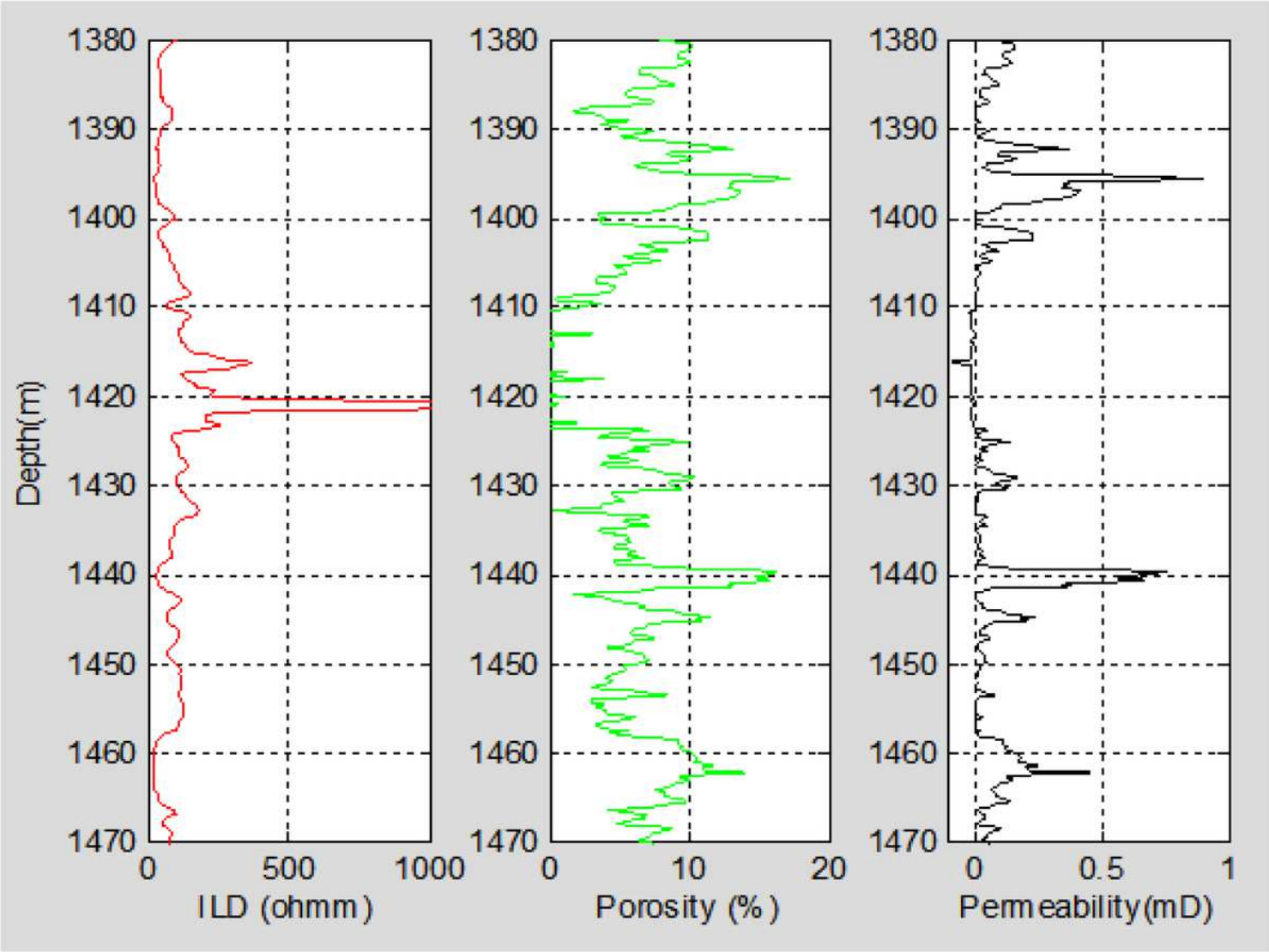

Figure 5

Predicted permeability changes at the reservoir scale using flow zone interval 0.35. The derived permeability follows same trend as the porosity log that is characterized by significant changes in the red beds at 1400, 1440 and 1465 m. Plotted alongside is the deep lateral induction (ILD) resistivity log. The high ILD reading is due to presence of diabase sills.

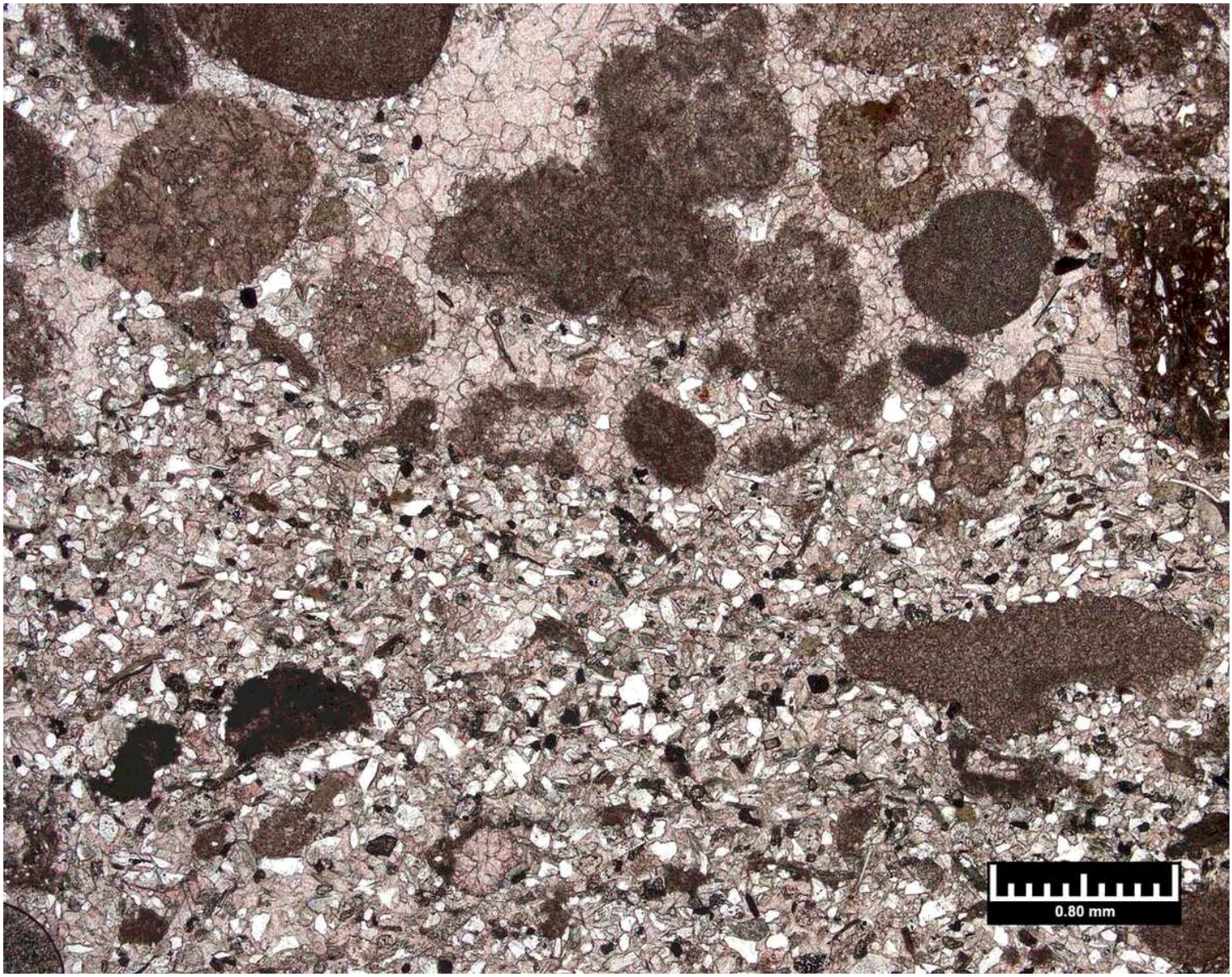

Figure 6

Photomicrograph of a thin section of a red bed at the Rizer #1 Test Borehole at 1172.11 m and net confining stress 11.03 MPa (Megapascal). It consists of very fine-grained sandstone and coarse-grained calcitic and mudstone clasts. Though well sorted, the presence of clasts and compaction are factors that reduce the permeability. The various colors are due to variations in mineralogical composition consisting of quartz and calcite, biotite, feldspar, and chlorite (after Weatherford Laboratories Report, 2014).

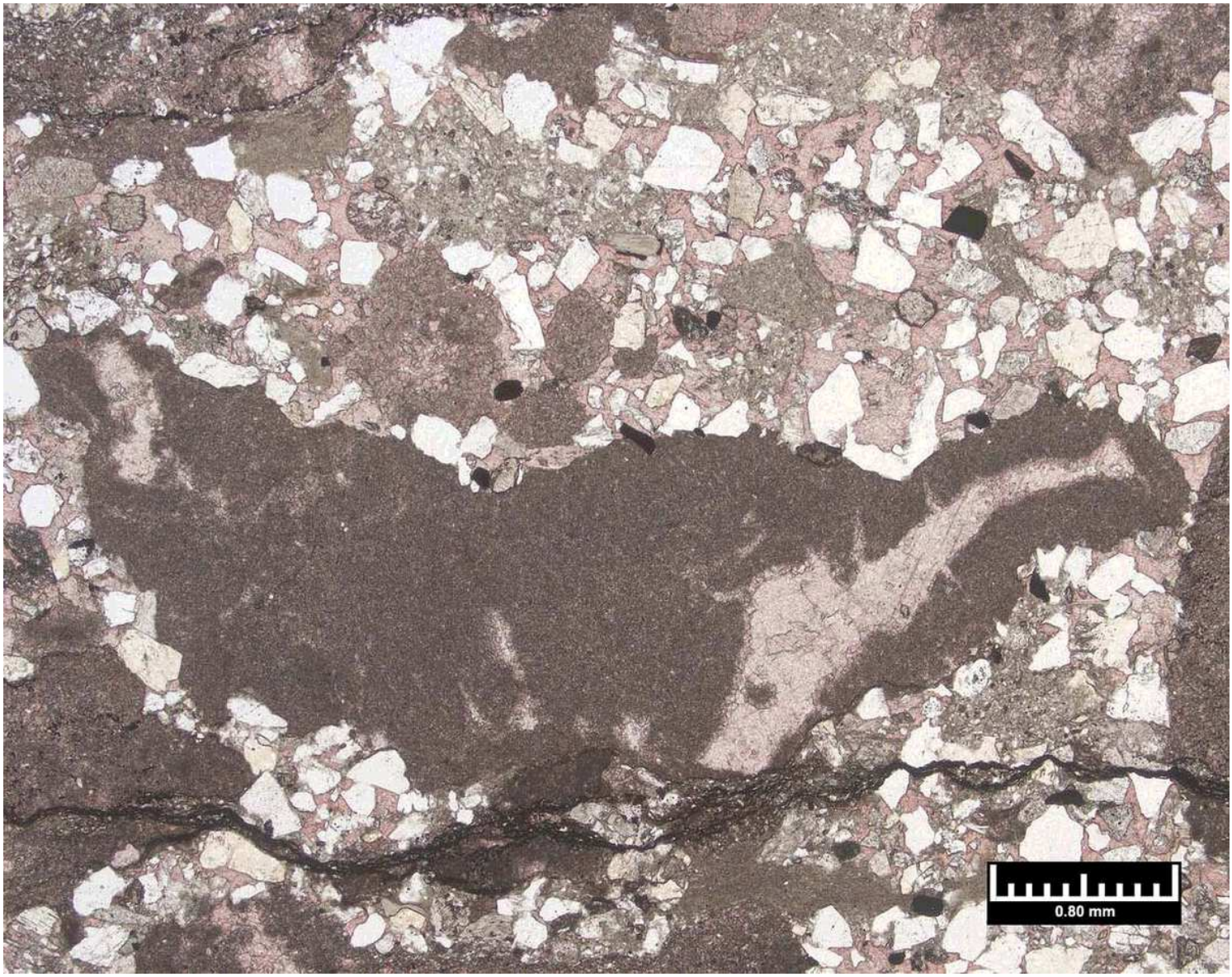

Figure 7

Photomicrograph of a thin section of a medium grained red bed at the Rizer #1 Test Borehole at 1602.64 m and net confining stress 11.38 MPa. It is a poorly sorted, sandy clast conglomerate mixed with silt and clay. The dark color is due presence of claystone and silty claystone casts. The light red color is due to presence of calcite. Quart grains are common with minor amounts of potassium feldspar (after Weatherford Laboratories Report, 2014).

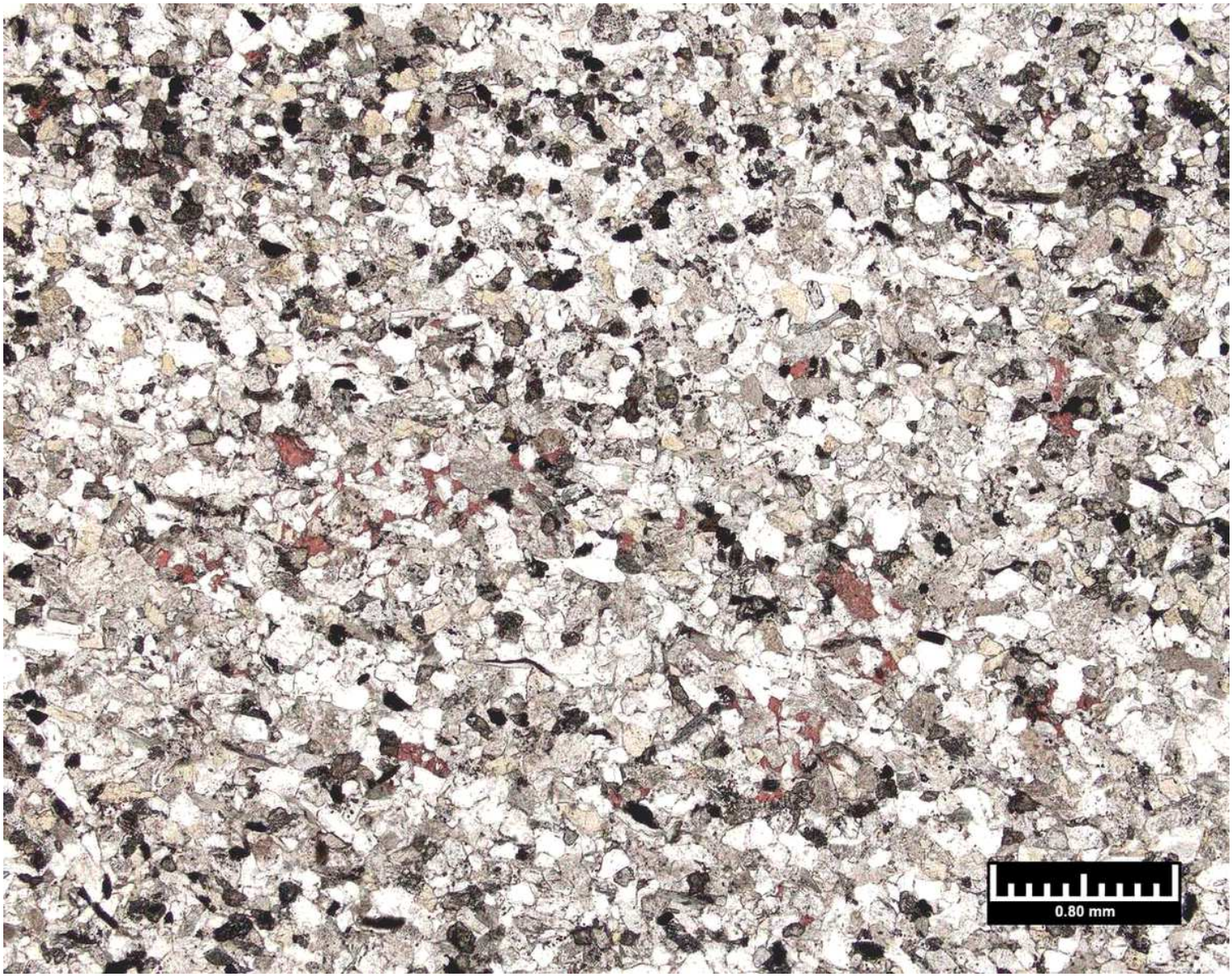

Figure 8

Photomicrograph of a thin section of a fined grained red bed at the Rizer #1 Test Borehole at 1773.48 m, and net confining stress 12.76 MPa. Though well sorted, it is highly compacted and cemented effectively reducing the pore size and pore connectivity responsible for permeability. Quartz and calcite (light red) are common (after Weatherford Laboratories Report, 2014).

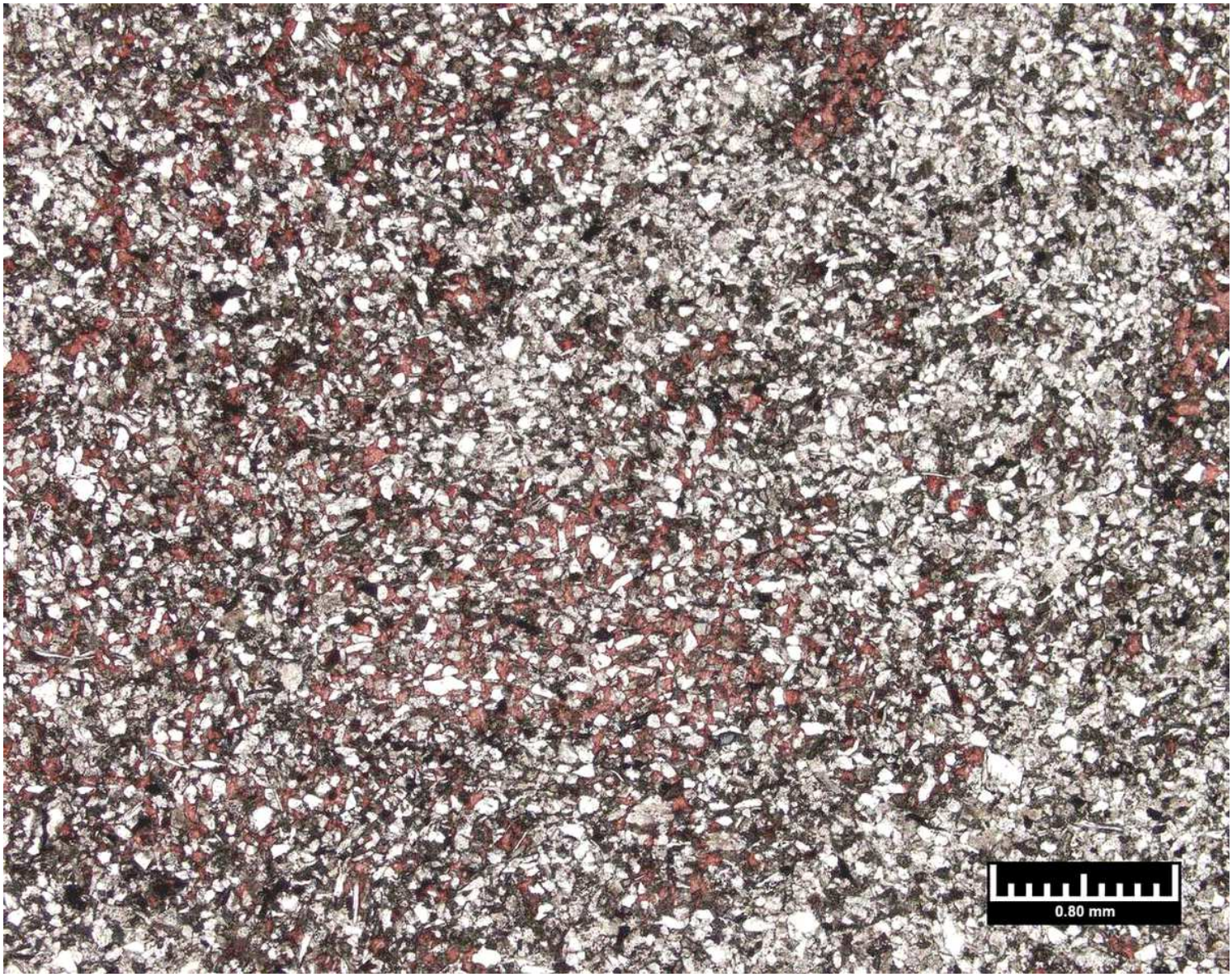

Figure 9

Photomicrograph of a thin section of a very fined grained red bed at the Rizer #1 Test Borehole at 1862.33 m, and net confining stress 13.10 MPa. It is well sorted but its lithified and compacted nature is not helpful to permeability. Changes in color are due to variations in mineralogy (after Weatherford Laboratories Report, 2014).

Supplementary Files

This is a list of supplementary files associated with this preprint. Click to download.

- Table.pdf