Permeability Prediction in the South Georgia Rift Basin – Applications to CO\textsubscript{2} Storage and Regional Tectonics

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\textsubscript{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 CO₂ 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 CO₂ 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 CO₂ 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 km²
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 CO₂ 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 CO₂ 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 CO₂ 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 CO₂ 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
computes permeability $k$ from porosity $\phi$ for a rock with predetermined pore space and geometrical properties.

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

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

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

$$\text{FZI} = \frac{0.0314}{\epsilon} \sqrt{\frac{k}{\phi}}$$  \hspace{1cm} (2)

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

$$\epsilon = \frac{\phi}{1 - \phi}$$  \hspace{1cm} (3)
Further discussion and derivation of this equation can be found in Schon (2011), Prasad (2003) and Amaefule et al. (1993). The application to a porous reservoir is based on the premise that reservoir units with FZI values within a narrow range belong to one hydraulic unit. The implication of this is that these have similar pore throats and therefore constitute a flow unit. The step-by-step procedure for the implementation of the Kozeny Carman and the FZI technique to predict and provide depth-varying permeability changes in the heterogeneous red beds reservoir are discussed as follows.

1. Development of a porosity-permeability transform for the study area based on the Kozeny-Carman approach.
2. Development of FZI from the core derived laboratory measurements in Table 1 to allow for red beds with similar pore throats to be grouped as a single flow unit.
3. The use of the porosity-permeability relationship in step 1 to convert the porosity from the Norris Lightsey #1 well to reservoir scale permeability at target depths for potential CO$_2$ injection.
4. Incorporation of the results from step 3 into equation 2 using the computed FZI values from step 2 to produce the permeability log.

In both the Kozeny-Carman and FZI applications for this study, we utilized the existing well data, and the core laboratory measurements for the Norris Lightsey #1 well and other locations with penetrations of the South Georgia Rift red beds (Table 1). The Norris Lightsey #1 well has the deepest penetration of the red beds, covering a depth greater than 800 m below the surface to maintain supercritical CO$_2$ injection (Akintunde et al., 2013a). The variations in the porosity and permeability data from these locations are due to the influence of depositional environments (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
provides a measure of the reliability of the Kozeny-Carman prediction and the computed FZI values that contributed to the production of the permeability log. It also shows that rock’s volumetric properties, such as pore space and grain size distribution that are primarily responsible for porosity, do exert control on permeability. It is remarkable to note that while the porosities are high, the permeability values are low. This is significant as it shows that factors responsible for porosity such as pore size and grain size distribution are not the sole and most dominant controls on permeability. Permeability also depend on the rock’s geometrical and fluid flow properties, such as tortuosity, pore shape and pore throats, that are of critical importance to reservoir injectivity.

Discussion

The derived permeability log (Figure 5) manifests the following characteristics: (1) uniform and non-uniform distribution with depths (2) noticeable spikes or increases at depth intervals 1395 to 1440 m, 1438 to 1445 m, and 1458 to 1465 m, (3) generally low permeability values that are less than 2 mD, and (4) vertical distribution which is consistent with the trends of the porosity log. The correlation of the permeability log with the porosity and resistivity logs allows for easy recognition of the highly resistive and non-porous diabase sills at 1410 to 1424 m. Within the confined and heterogeneous red beds that are both above and below the impermeable diabase sills (Figures 2 and 5), non-uniform permeability distribution are observed. We interpret the permeability variations with depth to be due to geologic changes and the presence of fluids in the red beds. These geologic changes involve key controls on permeability such as sorting, pore shape, pore throats and tortuosity. Analysis of photomicrographs (Figures 6 to 9) of thin sections on red bed cores recovered from the Rizer #1 Test Borehole in Collenton County, South Carolina, provides evidence for these geologic changes. The Rizer #1 borehole, drilled in spring
207 2012, is within 5 km to the Norris Lightsey well (Figure 1). The similarities in depositional
208 environment and lithologic composition of the Rizer #1 well red beds with the Norris Lightsey
209 lacustrine red beds provide the basis for the use of these thin sections. Analysis reveals cemented
210 and lithified red beds with abundant quartz overgrowths and calcite cement (Figures 6 to 9). The
211 exposure to increased compaction and possibly periods of sustained subsidence during sediments
212 deposition has significantly altered reservoir properties responsible for permeability judging by
213 the presence of clasts and small pore sizes and pore throats seen in the thin sections. These
214 photomicrographs also show irregular pore shapes and sizes in the tectonically deformed red
215 beds which may be responsible for the non-uniform distribution of permeability with depths
216 (Figure 5).

217 The low resistivity in the red bed units is indicative of water or brine saturated red beds. This is
218 because the observed log resistivity values ranging from as low as 0.05 to less than 100 ohm m
219 fall within the range of known resistivity values for water and saltwater reported in Telford et al.,
220 2001. Chemical analysis conducted by Marine and Siple (1974) on pore water from a Dunbarton
221 well with penetration of the red beds found dissolved solid content of approximately 11,000
222 mg/L that supports the interpretation of brine-saturated red beds. Their study also revealed much
223 higher chloride in the red beds (6720 mg/L) in comparison with water from the Cretaceous-
224 Cenozoic coastal plain sediments (1.5 mg/L) and the crystalline metamorphic rock (1260–
225 1400mg/L). Also, there is no gas in the red beds as this would have caused an increase in
226 resistivity. On the other hand, the overlying and non-porous diabase sills are completely dry.
227 This explains the virtually non-existent permeability and the unusually high resistivity of the
228 sills. The interpretation of a brine saturated reservoir is consistent with the plan for a deep saline
229 CO₂ storage system for the South Georgia Rift basin.
The consistency in the observed trends of the porosity and permeability logs provides validation for the reliability of the derived permeability log. Their disproportionate values relative to each other however show that the key controls responsible for both are not mutually identical.

Porosity is primarily a function of the pore space in a rock. On the other hand, permeability is a function of the pore space and fluid flow properties of the rock such as tortuosity, pore shape and pore throat that control injectivity. This strengthens the need for a permeability log to supplement and complement the porosity log for comprehensive assessment of the suitability of the SGR red beds for CO₂ storage. The correlation with the resistivity log which allows and supports the delineation of the diabase sills and the fully water saturated red beds from the interpretation of the observed permeability distribution also provides an additional, independent verification of the genuineness of the permeability log.

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

The process of compaction or lithification in a reservoir closes pores and/or restricts the 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 CO₂ Storage and Regional Tectonics

In assessing the implications for CO₂ storage, we ask these questions. What does the low permeability mean for reservoir quality determination? How would this affect subsurface suitability for CO₂ storage? How would this impact CO₂ 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 CO₂ sequestration in the porous formation. Whether or not a reservoir would be viable for long term CO₂ storage depends not only on the storage capacity but also on the quality of reservoir injectivity. A preliminary petrophysical investigation by Akintunde et al., 2013b demonstrates that the confined South Georgia Rift red beds in the Norris
Lightsey do exhibit porous intervals with the potential for substantial CO\textsubscript{2} storage capacity that far exceeds the 30 million tons set by the Department of Energy. Also, a preliminary reservoir modeling of CO\textsubscript{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\textsubscript{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\textsubscript{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\textsubscript{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\textsubscript{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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