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DOI: https://doi.org/10.1144/petgeo2021-101

To access the most recent version of this article, please click the DOI URL in the line above. When citing this article please include the above DOI.

Received 3 December 2021
Revised 10 May 2022
Accepted 21 May 2022

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Comparison of shale depth functions in contrasting offshore basins and sealing behaviour for CH$_4$ and CO$_2$ containment systems

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Abstract

Mudrock compaction trends from the Rovuma basin offshore Mozambique are compared with those of the Norwegian North Sea, the Gulf of Mexico and the Kutai basin offshore Indonesia. The comparison reveals that burial rates and timing of rifting are the dominant causes for the differences observed. The compaction trend for the Rovuma basin is broadly similar to the trends for the Kutai basin and the Gulf of Mexico, but very different from those for the Norwegian North Sea data, which show higher porosity and shallower onset of overpressure than those from the other three basins. The relationships for seismic velocities as a function of depth show strong similarities between the Rovuma and Gulf of Mexico basins.

We then use these comparisons to make a general assessment of the capillary sealing potential of Cretaceous mudrocks in the Rovuma basin, using a mudstone permeability prediction function and a method for mapping permeability to threshold pressure, allowing estimation of maximum column heights for CO$_2$ and CH$_4$ with uncertainty ranges. Predicted CO$_2$ column heights are slightly less than the equivalent CH$_4$ column heights. The observed CH$_4$ column height at one of the wells is significantly lower than that predicted from mudstone permeability, which is probably due to other factors such as fracturing or gas migration out of the structure. The comparison indicates generally good capillary sealing potential for the Rovuma basin Cretaceous shales and offers a general approach for assessing CO$_2$ storage potential from hydrocarbon sealing datasets from multiple offshore basins.

Introduction

Analysis of the properties of sedimentary rocks as a function of depth is important for pore pressure prediction and assessment of fluid containment (Bjørlykke & Hoeg 1997; Ramdhan & Goulty 2017). Typically, porosity-prediction models, compaction-trend functions and elastic properties are estimated for representative rock types using empirical models. Sediment properties during burial are strongly
controlled by the effective stress, but lithology, burial rate, depositional history and temperature gradient also play an important role, which makes general prediction of properties difficult.

It is now well established that the effective stress is the dominant controlling factor in the early stages of burial when mechanical compaction processes dominate. However, the pore pressure itself is controlled by the gradually reducing permeability such that non-linear trends in porosity and permeability are often observed at greater depths. Chemical compaction (diagenesis) plays an increasing role at depths where higher temperatures are encountered and adds to the complexity of property prediction at greater depths (e.g. Bolås et al. 2004). Zones of anomalous overpressure are typically encountered at depths where permeability reduction prevents fluid escape and therefore slows the mechanical compaction, in a process known as disequilibrium compaction (Swarbrick & Osborne 1998).

Since mudrocks generally have the lowest permeability in a sedimentary sequence (typically with permeability in the nano- to micro-darcy range), their presence is usually the most important factor in preventing fluids from being expelled; although salt formations, cemented layers and faults can also play a role. Mudrock permeability prediction from laboratory experiments can be challenging due to rock damage when samples are retrieved from depth (Van Oort et al. 1996); however, low permeability values are routinely observed (e.g. Chuhan et al. 2002; Mondol et al., 2007) and provide an important calibration to prediction models. The permeability trends in mudrocks are highly dependent on the compaction regime, with mechanical compaction effects dominating at shallow depths and becoming gradually less important as the temperature increases, especially beyond about 70 °C where chemical compaction processes start to dominate. At depths of around 3 km to 4 km, highly variable rock properties are encountered, and rock units become increasingly impermeable, with very few gas reservoirs found in the 5-8 km depth range (Takach et al. 1987), although there is a lack of data on mudrock permeability in these deeper units.

There are many factors affecting mudrock compaction under the two main processes of mechanical and chemical compaction, discussed further below. The rate of burial for low-permeability sediments also plays a significant role, since under-compaction at shallow depths may be caused by excess pore pressure developed during rapid burial (Swarbrick 2002; Zhang 2011). Effects of varying geothermal gradients have also been observed, as compaction of rocks at low temperature is a function of the physical strength of the grains which is temperature dependent (Bjørlykke & Høeg 1997; Mondol et al. 2007). Compaction of mudrocks occurs faster than for sandstones and carbonates due to their lower strength, smaller grain size and more elongated grain shape. The temperature range for pure mechanical compaction (before the onset of chemical compaction) is generally reported to be less than around 60-70 °C, and this implies depths down to around 2-3 km (depending on local geothermal gradient). However, the onset of chemical compaction also depends on the burial history, fluid flow and mineralogical composition (e.g. Bjørlykke 1998; Goulty et al. 2012; Storvoll & Brevik 2008). So, although the onset of mudrock diagenesis typically occurs at temperatures of around 60-70 °C it also depends on other factors such as deposition rate, clay mineral composition, fluid salinity, and availability of a source of potassium. Generally, significant chemical compaction will occur at temperatures of greater than 100 °C (Bjørlykke 1998; Storvoll & Brevik 2008; Ramdhan & Goulty 2017).
Compaction regimes and burial history also have significant effects on the dynamic elastic properties of mudrocks, as the former control the mineral transformations and especially the onset of cementation at higher temperatures which can lead to significant increases in velocities. Generally, for a given lithology, compressional and shear velocities ($v_p$ and $v_s$) increase with depth; however, in overpressured depth intervals they may decrease or remain almost unchanged.

In this study, we compare depth trends from example mudrock formations (including mudstone, shale, claystone and siltstone) in four offshore sedimentary basins and contrast their properties and capillary sealing capabilities (Fig. 1). We also investigate if general functions for capillary sealing behaviour can be established by comparing these basins, especially because much previous work has been done on the North Sea and Gulf of Mexico basins and it is unclear how much these findings apply to other basins. We then compare the containment potential for different buoyant fluids by contrasting the properties of CH$_4$ and CO$_2$ as a basis for assessing the general storage potential. These basin compaction trends can then be used to assess potential future CO$_2$ storage capacity as compared with the known methane retention capacity during the basin history.

Despite the many challenges, siliciclastic sediments have a generally predictable trend for reduction in porosity and permeability as a function of depth, especially at shallower depths where the effective stress is the main control. Various relationships between the effective stress, depth and porosity have been proposed for mudrocks in different basins (e.g. Ramm 1992; Lander & Walderhaug 1999). In a previous study of the Rovuma basin offshore Mozambique (Nhabanga & Ringrose 2019), we used an effective stress approach for analysis of example well-log data by applying Eaton’s method (Eaton 1975) for pore-pressure prediction to estimate a compaction trendline for the basin. We successfully predicted the pore-pressure and compaction trendlines in three exploration wells in the Rovuma Basin. In the present study and for the multi-basin comparison, we use a representative compaction trendline from these Rovuma basin (RB) wells and compare them with published trendlines from three other important basins on offshore continental margins: the Kutai basin (KB) in Indonesia; the Norwegian North Sea (NNS), and the Gulf of Mexico (GoM). Using this comparison, we then estimate the sealing capacity of the Rovuma basin shales for both CH$_4$ and CO$_2$ containment systems. Additionally, we compare compressional and shear velocities ($v_p$ and $v_s$) with ‘the mudrock line’ initially published by Castagna et al. (1985) for use in the GoM, allowing us to contrast mudrock $v_p/v_s$ ratios in RB against the Gulf Coast dataset.

Estimation of capillary sealing potential

The trapping of buoyant non-wetting fluids, such as hydrocarbons or CO$_2$, beneath lower-permeability units (especially shales) is mainly determined by the capillary threshold pressure, which is a function of the pore-throat diameter, the fluid interfacial tension and the fluid contact angle. This concept is also known as membrane sealing. A general expression for the column height of a buoyant fluid, $Z_g$, retained by a capillary seal is given by (after Schowalter 1974 and Berg 1975):

$$Z_g = \frac{2y\cos \theta (1/r_{cap}-1/r_{res})}{g(\rho_w-\rho_g)}$$

(1)
where \( \gamma \) is the interfacial tension (also known as IFT), \( \theta \) is the fluid contact angle, \( r_{\text{cap}} \) and \( r_{\text{res}} \) are the mean pore throat radii in the cap rock and reservoir, and \( \rho_w \) and \( \rho_g \) are the fluid densities of the water and gas phases. Note that Berg (1975) used Imperial Units for \( \gamma \) and \( \rho \), with \( r \) in microns, while we use SI units unless otherwise stated (i.e., permeability is in millidarcy). If the capillary threshold pressure can be measured or estimated for a specific fluid system within known values of \( \gamma \) and \( \theta \), then \( Z_g \) can be simplified to:

\[
Z_g = \frac{P_c}{g(\rho_w - \rho_g)}
\]  

(2)

where \( P_c \) is the capillary pressure of the caprock for a given fluid system. Because the pore-throat radii also fundamentally control the permeability (by application of the Navier-Stokes equations for flow in porous media; Zhou & Sheng 1989), the permeability and capillary threshold pressure are closely correlated. A general scaling relationship between permeability and capillary pressure, as proposed by Ringrose et al. (1993), modified from Leverett (1941), is given by:

\[
P_c = C S_e^{-2/3} \left( \frac{\phi}{k} \right)^{1/2}
\]  

(3)

where \( S_e \) is the effective wetting phase saturation and \( C \) is a constant combining the interfacial tension (in \( \text{mN/m} \)) and a unit conversion factor to give \( P_c \) in kilopascals. To determine the threshold pressure condition, \( P_{th} \), we assume \( S_e=1 \) (i.e., a water-saturated caprock). Then, by assuming an empirical relationship between porosity and permeability given by \( \phi = 0.05k^{0.25} \) fitted to a wide range of data reported by Manzocchi et al. (2002) we obtain a general scaling law for capillary threshold pressure in sedimentary rocks:

\[
P_{th} = 3\gamma k^{-0.375}
\]  

(4)

Where the scaling constant \( 3\gamma \) renders the result in kilopascals assuming permeability is given in millidarcies. Manzocchi et al. (2002) showed how this function fits a wide range of rock measurements, but argued that fault rocks follow a slightly different trend, on account of their typically different pore size distributions. Figure 2 shows an example function for \( P_{th} \) versus permeability using Eqn 4 and assuming an interfacial tension (IFT) of 30 mN/m, appropriate for a typical \( \text{CO}_2 \) storage trap. The trend function is compared to a range of measured mercury-air capillary threshold data from Schloemer & Krooss (1997), alongside some unpublished data, and scaled using a fluid conversion factor, \( f \), given by Eqn 5:

\[
f = \text{IFT (CO}_2\text{-water)} \times \text{Cos } \theta^\circ / \text{IFT(Hg-air)} \times \text{Cos } 40^\circ
\]  

(5)

This assumes a fluid contact angle of \( 40^\circ \) for mercury-air systems. Also shown on Figure 2 are data points for \( \text{CO}_2\)-brine experiments published by Hillenbrand et al. (2004), where they measured upstream breakthrough pressures (P1) as an approximation to capillary threshold pressure. Hillenbrand et al. (2004) performed a more complex analysis of breakthrough phenomena for different gases in pelitic mudrocks and focused on measuring the 'minimum capillary displacement pressures' (Pd) for two-phase
flow (after gas breakthrough) as well as the initial capillary breakthrough pressures. Their work further develops and explores the complexity of capillary-sealing processes in low-permeability sedimentary rocks; however, their measurements are consistent with our proposed model for capillary threshold pressure (Fig. 2). More recently, Busch & Amann-Hildenbrand (2013) reviewed a range of published capillary pressure measurements in mudrocks, demonstrating a strong correlation between capillary snap-off pressure and permeability.

It is therefore possible to estimate hydrocarbon or CO$_2$ trapping potential beneath low-permeability mudrock units based on well data and compaction trends, by correlating porosity, permeability and capillary pressure. Although there are some uncertainties in each of these correlations, there is extensive empirical data support for Equation 4 (Manzocchi et al. 2002), such that the main uncertainty is in determining the mudrock permeability, as discussed and developed below. We also compared our approach with a similar study by Karolyte et al. (2020) comparing the hydrocarbon and CO$_2$ sealing capacity of fault-sealed traps located in the Otway Basin in Australia. Indeed, this study was partly inspired by the work reported by Karolyte et al. (2020).

**Rationale for the inter-basin comparison**

Here, we first evaluate the observed compaction trends in four different basins to determine whether a general first-order sealing potential can be established. We contrast more mature datasets from two well-studied basins (the Gulf of Mexico and the Norwegian North Sea) with two less mature but important emerging gas-resource basins: the Indonesian Kutai offshore Basin and the Mozambican offshore Rovuma basin. In particular, we are interested in establishing how the example wells from Rovuma basin compare with other basins.

The tectonic settings of these continental basin margins are significantly different. The Rovuma basin has been developed as a result of plate tectonic processes along the East Africa margin, following the break-up of Gondwana, with the formation of the East Africa rift system in the early Triassic. In the next phase, a major rifting episode in the Middle to Late Jurassic occurred with a development of a major north-south-trending transform fault during the Late Jurassic (Francis et al. 2017; Macgregor et al. 2018). Thus, although this basin is characterized as a passive continental margin, it has a complex tectonic history with significant strike-slip tectonics as well as extension. In terms of the hydrocarbon system, Jurassic shales are the main source rock for the major gas reserves in the basin with important reservoirs found in the Late Cretaceous to the Late Miocene formations (MacGregor et al. 2018; Davison & Steel 2017).

In comparison, the Kutai basin (KB) in Indonesia developed more recently, during Mid to Late Eocene times, driven by tectonic extension in South East Asia (Chambers et al. 2004). Deposition of deep-marine muds occurred from the Late Eocene to the Late Oligocene with development of deltaic sediments from the Late Oligocene to the early Miocene. The main source rocks are mudstones and coal beds suspected to be of Jurassic and Cretaceous age (Ramdhah & Goulty 2017).

The Norwegian North Sea (NNS) basin is part of a passive continental margin formed in response to early Cenozoic continental breakup and subsequent opening of the Norwegian-Greenland Sea (Fossen et al.
A complex series of post-Caledonian rift episodes occurred, which were active until the Paleogene, when complete continental separation took place (Fossen et al. 2017; Lundin et al. 2018). The source rocks are mainly of Jurassic age, and important reservoir rocks range from the Jurassic to the Cretaceous and into the Paleocene (Sclater & Christie 1980; Glennie 2009).

The Gulf of Mexico (GoM) basin formed as a result of rifting in the Triassic-Jurassic times (driven by the continental breakup of Pangea). It contains multiple source rocks, mainly of late Jurassic, early Cretaceous, and Tertiary ages. The most prolific hydrocarbon host rocks are of Tertiary age, with important reservoirs of Jurassic and Cretaceous ages (Snedden & Galloway 2019). Significant episodes of salt tectonics have also influenced this basin (Xie et al. 2019).

Thus, although the four basins have significantly different tectonic histories, it is notable that the GoM and RB basins have an earlier transition from rifting to post-rift phases related to the break-up of Pangea (Frizon de Lamotte et al. 2015). In contrast, the NNS and KB basins continued rifting up to the Paleogene, related to continued extension of the North Atlantic during the final breakup of Pangea (for the NNS) and eventual break-up of eastern Gondwana in the Asia-Australasia region (KB). One might therefore expect the RB mudrocks to be most similar to those found in the GoM datasets. In Figure 3, we summarize the main characteristics of these four basins, in term of the main episodes of rifting and post-rift subsidence as well as the ages of the main source and reservoir rocks. Of course, each basin has been influenced by a complex series of tectonic events, so this simplified overview is intended only as a framework for the analyses of petrophysical trends developed in this paper.

In a recent review of the global potential for CO$_2$ storage in the world’s offshore basins, Ringrose and Meckel (2019) argued that broad similarities in the stratigraphic and tectonic histories of passive continental margins are evident, despite the many important local and regional differences in their tectonic histories. Some basins have significant salt tectonic components (e.g. the Gulf of Mexico), others are seismically active (e.g. Southeast Asia), and others have significant geologically recent vertical tectonic (epeirogenic) movements (e.g. the North Sea). The provenance and deposition rate of clastic sediments supplying the offshore basins can also create important compositional differences that could have a significant influence on the cementation processes during diagenesis. Despite these differences, Ringrose and Meckel (2019) showed that depth functions for overburden stress, fracture pressure and fluid pressure show many similarities when comparing published datasets from the Norwegian North Sea (NNS) and the Gulf of Mexico (GoM). Here we extend and further assess these comparisons by contrasting published porosity-depth trends for mudrocks in the GoM, NNS, KB and RB basins (Figure 1). We also contrast fluid-pressure trends in all four basins and compare the velocity data ($v_p$, $v_s$, and $v_p/v_s$ ratio) for the RB wells with Gulf Coast velocity depth trends (the mudrock line). Finally, we estimate porosity-permeability depth trends for the RB wells and, using published trendlines for mudrocks from various basins, use them to estimate the capillary sealing potential of the Cretaceous mudrocks in the RB.

**Summary of mechanical and chemical controls on compaction**
Compaction of rocks is a function of the physical strength of the grains, the nature of their packing arrangement and their interaction with the fluid phase (Ramn 1992, Bjørlykke & Hoeg 1997; Mondol et al. 2007). Due to their weaker strength, smaller grain size and generally elongate grain shape, compaction of mudstones occurs more intensely and quickly than that of other clastic rock types such as sandstones and limestones. In a comprehensive evaluation of compaction curves for mudrock sediments selected from different parts of the world, Mondol et al. (2007) showed significant variations in properties as a function of depth. These variations are believed to be due to many factors including grain size, shape and sorting, deposition time, temperature gradient, and burial rates.

Laboratory studies indicate that under mechanical compaction, grain size and sorting play an important role for mudrocks. Well-sorted finer-grained sediments generally have higher porosity at deposition than coarser-grained sediments, which are usually more poorly sorted. During compaction it has also been observed that well-sorted fine-grained sediments are much less compressible than coarse-grained sediments. The grain packing in well-sorted fine-grained sediments allows the distribution of the total stress over a very large number of grains so that the stress per grain contact is lower than that in coarser-grained sediments (Mondol et al. 2007).

Generally, rock compaction in sedimentary basins is affected by both mechanical compaction (controlled by effective stress) and chemical compaction (part of the process of diagenesis). These two compaction regimes may develop differently in each basin, which will affect the rate of rock compaction as a function of depth and also influence the pore pressure evolution. At shallower depths (typically less than 2 km), mechanical compaction usually dominates, while at greater depths chemical compaction starts to prevail due to the higher temperatures.

For the case of the Rovuma basin, Nhabanga & Ringrose (2019) showed that the pore pressures in the shale sections were mainly controlled by effects of mechanical compaction, while at greater depths (generally >2 km) the onset of chemical compaction was observed. The predicted pore-pressure results were validated using the well-test data from adjacent permeable zones. The well intersecting the Paleogene mudrock interval showed no evidence of overpressure, while the wells intersecting the Cretaceous mudstone interval showed some development of overpressure. Chemical compaction, which was observed to decrease the porosity to around 6%, was associated with higher temperatures (>70 °C) and caused an increase in the bulk density and sonic velocity. In the present study, we further develop these assessments of RB depths trends, by comparison with data from other basins.

**Approach used in this study**

Our aim is to contrast the general relationships for porosity change as a function of depth for the four offshore basins studied, and to assess the compaction and pressure trends. The underlying question is to assess similarities and differences in the compaction trends, and potential causes related to the basin history. Regarding the dynamic elastic rock properties, we also studied the relationship between compressional and shear wave velocities for mudrocks in the Rovuma basin and contrasted these with a reference mudrock line for the Gulf of Mexico.
In order to estimate the sealing potential of these low-permeability rock units from well data, we need to establish transform functions from porosity to permeability to capillary pressure. Without access to core permeability measurements for the RB mudrocks, we had to estimate permeability from the RB well logs using trendlines from published datasets. After reviewing trends in mudrock permeability from many datasets as reported by Casey et al. (2013) we decided to use the empirical function proposed by Yang & Aplin (2010) and fitted to a large dataset of mudstone permeability-porosity data. Their approach assumes that the scaling of permeability ($k$) as a function of void ratio ($e$) in mudstones has the form:

$$k = A + Be + Ce^{0.5}$$  \hspace{2cm} (6)

where the constants $A$, $B$ and $C$ are controlled by the clay fraction (CF). Fitting Equation 6 to a large set of mudstone data, they obtained the following general mudstone permeability predictor:

$$\ln (k) = -69.59 - 26.79 \times CF + 44.07 \times \sqrt{CF}$$

$$+\left(-53.61 - 80.03 + 132.78 \times \sqrt{CF}\right) \times e$$

$$+\left(86.61 + 81.91 \times CF - 163.61 \times \sqrt{CF}\right) \times \sqrt{e}$$  \hspace{2cm} (7)

where, $CF$ = clay fraction and $e$ is the void ratio.

Although CF is difficult to predict accurately from well log data, a first approximation can be made by assuming CF is equal to the shale index derived from gamma ray log data, using established log analysis methods, as originally proposed by Poupon et al. 1970.

**Results**

To evaluate the effect of the differences in tectonic evolution of the four basins on mudrock compaction trends, we contrasted porosity-depth relationships from published studies for mudrocks in these basins, alongside porosity functions for mudrocks with rapid and slow burial rates as proposed by Worden & Burley (2003) as shown in Figure 4. Note that these burial-rate mudrock trends represent only the effects of mechanical compaction and they are only intended as a general indicator. Other effects which may affect the compaction trendline are not taken into account, including diagenesis, grain sorting and clay mineral compositions. We observe that the GoM mudrock compaction trend lies close to the slow burial rate reference function while the NNS trend is quite close to the rapid burial rate reference function. The KB and RB trends lie in between, although at shallow depths the RB trend is close to the rapid burial rate reference function.

We then compared the reservoir pressure trends versus depth for the four continental margins, as shown in Figure 5. Here, we observe that the KB pressures are close to hydrostatic pressure down to 3 km, while overpressure begins to develop at around 2.5 km in both the RB and GoM basins. Fluid pressures in the NNS are more variable, with overpressure developing at various levels below about 2 km, depending on the formation and structural setting (Gaarenstroom et al. 1993; Bolás and Hermanrud 2003; Bolás et al. 2004). For our study, these comparisons are important to determine at what depth overpressures may be influencing mudrock properties.
Turning to the sonic velocity data, Figure 6 shows a comparison of the $v_p$-$v_s$ crossplots for the Cretaceous mudrocks from two wells (Buzio and Cachalote) in the RB compared with the mudrock line based on data from the GoM proposed by Castagna et al. (1985). In Figure 7, we also compare the $v_p/v_s$ ratio versus depth for the same wells compared to the corresponding mudrock trend from the GoM (Castagna et al. 1985). These comparisons suggest the RB wells have mudrock velocity trends fairly similar to the Gulf of Mexico basin trend, with some differences discussed further below.

**Discussion of inter-basin basin comparisons**

The comparison of compaction trendlines from the four continental-margin basins with trendlines for mudrocks deposited at slow and rapid rates (Figure 4) is only intended as a general indicator of likely effects. Large variations in mudrock properties, including elastic and rock physical properties, are expected in all these basins. These variations are in part due to differences in mudrock composition. We also note that the initial depositional porosity in these trend functions is different (around 65% for GoM and KB, and 80% for RB and NNS); however, we consider this to be a model assumption without a very significant impact on the deeper depth trends, where diagenesis is expected to dominate and the residual porosity of these basins becomes similar. It is the comparison of the rate of porosity reduction versus depth that is more relevant. Here we observe that the average residual porosity at 3000 m depth is much lower for GoM, KB, and RB (between 8% and 12%) than for the NNS (at around 18%), suggesting that the NNS is significantly different in terms of mudstone compaction trend. It also seems that the rapid decrease in porosity for mudrocks at depths >1 km in the GoM, RB and KB are all consistent with the slow burial rate curve (as proposed by Worden & Burley 2003). The less-compacted NNS mudrock trendline is consistent with a rapid burial rate, especially at depths >1.5 km. In the very shallow intervals (<1 km) the trends are less consistent, suggesting that local effects (both lithology and tectonic history) are important in the early stages of burial. The observation that the NNS basin follows a rapid mudrock burial trend is consistent with the basin history reconstructions, which indicate rapid burial during the Quaternary which is also likely to have contributed to higher pore pressures at shallower depths in the Central and Viking Graben areas of the NNS (Baig et al. 2019).

In Figure 5, we compare reservoir pressure change through depth in the four basins. The analyzed data were obtained from the following sources: for the Rovuma Basin the data are from well reports from selected wells (Nhabanga & Ringrose 2019), for the Kutai Basin from the trend line reported by Ramdhan & Goulty (2017), for the Gulf of Mexico from data reported by Ringrose & Meckel (2019), and for the Norwegian North Sea from data reported by Bolås et al. (2004). These datasets are not comprehensive but are considered representative of typical pressure trends in these basins. These reservoir pressure variations (Fig. 5) show general similarities between the four basins, but also important differences especially with regard to the depth of overpressure. In particular, the NNS basin shows a shallower onset of overpressure than the other three basins. The RB basin starts to reveal some overpressure at 2.5 km, as does the GoM basin. However, the KB pressure lies close to hydrostatic down to 3 km. Therefore, on the basis of pressure trends, comparisons between mudrocks of the RB, KB and GoM basins are likely to be valid at least down to 2.5 km depth, but comparison with the NNS mudrocks may be significantly influenced by higher overpressures.
Inter-basin sonic velocity data relationship

We were not able to compare sonic properties in all four basins due to lack of published data on trends in other basins, but the comparison of the RB compressional and shear wave velocities with the mudrock line originally established by Castagna et al. (1985) for GoM data (Fig. 6) is informative. In the case of the Buzio well data (Fig. 6A), the majority of data points lie close to the mudrock line, with some scatter around the trend. However, for the Cachalote well (Fig. 6B), the velocity data appear to fall above and below the mudrock line. In other work (Nhabanga et al. 2021), we show that this range in compressional and shear wave velocity data in the Cachalote well is due to the effects of diagenesis in the deeper, hotter sections of the Cretaceous mudstone.

In comparing the $v_p/v_s$ ratio against depth plot (Fig. 7) with the Gulf coast mudrock analysis of Castagna et al. (1985), we also see broad similarity between the two Rovuma basin wells with the mudrock line from the GoM. The Cretaceous mudrock from the Buzio well (at greater depths of 2705-3250 m) shows higher $v_p/v_s$ ratios, with the majority of data points falling above the mudrock line from the Gulf Coast. The Cachalote well data (at shallow depths of 1455-2031 m) are more consistent with the Gulf Coast trend, but they tend to have higher $v_p/v_s$ ratio at increased depth. We suspect that these departures from the GoM trendline are due to cementation effects (Nhabanga et al. 2021). However, in general we can conclude that the Cretaceous mudrocks from both wells in the RB are consistent with the mudrock line from the Gulf Coast.

Porosity-permeability relationship

Finally, we proceeded to predict the mudrock permeability for the Cretaceous mudstone intervals in the RB wells from the porosity and gamma log data. We used the mudstone permeability function from Yang & Aplin (2010) (Eqn 7) as it takes into account the correlation to porosity (void ratio) as well as the effects of clay fraction (CF). In our analysis of the Cretaceous mudrocks in two example wells from the RB we found the CF to be 0.44 on average, with 0.30 as the lower quartile value and 0.58 as the upper quartile value. We then used Eqn 7 to estimate the permeability from well logs using the observed CF and void ratio, estimated from the gamma and porosity log (red points on Figure 8). We also used the interquartile range in CF to determine an uncertainty range in permeability (shown as trend lines in Figure 8). It should be pointed out that these permeability predictions are based on a mechanical compaction assumption and on an estimated clay content. They do not take into account the effects of cementation and diagenesis, which we have already noted begins to have an effect in the deeper intervals of the Cretaceous mudstone in the RB.

Capillary pressure and column height
Based on this analysis of permeability, we are now able to estimate the capillary threshold pressure, using Eqn 4, for the mudrocks in the studied wells for the Rovuma Basin. Table 1 gives the best estimates for fluid density and IFT for the in situ pressure and temperature at the two wells in the RB. We used the estimated geothermal gradients of 5.5 °C/100 m at the Buzio well and 4.92 °C/100 m at the Cachalote wells (Nhabanga & Ringrose 2019) to estimate the base Cretaceous temperature at around 180 °C at the Buzio well (3250 m depth) and 105 °C for the Cachalote well (2031 m depth). Pressures are assumed to be close to hydrostatic for the purposes of IFT estimation.

Then, using Eqn 7, we estimated the low, medium and high permeability values for these two wells at the base of the Cretaceous mudrock intervals, in order to estimate the likely range in capillary threshold pressure and fluid column heights. The results are shown in Table 2 and Figure 9. As expected, the CO₂ column height is slightly lower than the CH₄ column height for a given permeability. This is because the lower IFT for the CO₂-brine system (Table 1) is nearly compensated by the lower buoyancy pressure for the CO₂ column, as previously observed by Naylor et al. (2011). For the case of the Buzio well we can compare our predicted median CH₄ column height of 1053 m with the reported gas column of 115 m, which is clearly much lower. Unfortunately, no structural or seismic data were available for our study of mudrock properties in this basin; however, from other studies (e.g. Mahanjane 2014; Davison & Steel 2017) we know that faulting and structural history have played important roles in the hydrocarbon prospectivity. It is therefore likely that the observed column heights are controlled by structural and tectonic factors (i.e. leakage or migration out of the structure). Due to lack of data in this basin (RB), our estimates for column height are related only to the mudrock sealing potential. Furthermore, in this inter-basin comparison we have not explored the potential effects of CO₂ wetting behaviour in mudrocks (reviewed by Iglauer et al. 2015), and site-specific assessments of capillary traps would need to assess the influence of mudrock wetting to CO₂.

Summary of findings

This comparison of mudrock compaction trends between four offshore basins has been very informative. The higher porosity ranges for the NNS mudrocks are thought to be mainly due to overpressure caused by rapid burial of sediments; while the closer similarity between the RB, KB and GoM mudrocks may be an indication of a broadly similar compaction history. The closer similarity between these three basins may also be due to the depositional setting (e.g. similarities in grain size, shape and mudstone mineralogy); however further studies would be needed to understand these factors. The fluid pressure differences between the basins (Fig. 5) are also thought to be due mainly to differences in the compaction history. The GoM, RB and KB pressure trends are also generally similar and remain close to hydrostatic pressure down to around 3 km depth, while NNS shows onset of overpressure at shallower depths of around 2.5 km.

For the comparison of RB velocity data with the GoM datasets (Fig. 5), most of the RB data lie close to the GoM mudrock line, with some departures from the trend: points lying above the mudrock line are suspected to be due to effects of chemical compaction, while those lying below it, due to overpressure. For the \( v_p/v_s \) ratio plot (Fig. 6), the RB data lie close to the GoM trendline, but depart from the mudrock line with increasing depth. Again, it is likely that at these depths chemical compaction (diagenesis) is the main cause for points which lie significantly above the mudrock line and that overpressure is the cause for points below the mudrock line.
Using estimates of permeability from wireline log data, we predicted permeability ranges using a mudstone clay-fraction model (Fig. 8). These estimates were then used to estimate values for the capillary threshold pressures for both wells and for CH₄ and CO₂ fluid systems (Table 2). Good sealing potential was predicted with large maximum column heights of several hundred metres. Although the observed live gas column height at the Buzio well is lower than this range, this is thought to be due to unknown (or unpublished) effects of faulting or hydrocarbon migration.

**Discussion and Conclusions**

This analysis of depth trends for mudrocks from four continental margins is valuable in establishing generalized trends for the basins, especially where well log or core data are scarce. In general, we find that the RB, GoM and KB datasets show fairly similar compaction trends which are close to the slow burial rate reference curve. The NNS shows quite a different compaction trend, which is closer to the fast burial rate reference curve. This suggests that GoM mudrock-trend data are more appropriate for the RB and KB basins than the NNS datasets. It is interesting to compare these inter-basin comparisons of mudrock properties with the overall plate tectonic settings. Figure 10 shows the basin study locations compared with a long-range model of Earth’s geoid, derived from GRACE intersatellite observations and from the GFZ GRACE gravity field model EIGEN-GRACE02S (gfz-potsdam.de). The GoM and RB locations are found in similar negative geoid regions, related to the fact that these are relatively ancient basins with early rifting phases which ended in the Jurassic Period. In contrast, the NNS and KB basins are both in positive geoid regions, related to their more recent phases of rifting which continued into the mid Tertiary Period (cf. Fig. 3). This comparison supports our conclusion that the RB data are most similar to the GoM data. Local factors, such as mudrock lithology and details of the burial history, likely play an important role as well. We also note that chemical compaction effects at deeper intervals limit these inter-basin comparisons. We argue that increased values of $v_p$, $v_s$ and $v_p/v_s$ ratio through depth in the RB are likely due to chemical compaction and that anomalously low velocity values at depth are believed to be due to overpressure.

We have further shown how application of mudrock porosity-permeability relationships to the RB well wireline log data gives a reasonable basis for estimating capillary sealing potential, using well established scaling laws between permeability and capillary threshold pressure. Our estimates show that the Cretaceous mudrocks in the Rovuma Basis are expected to offer a very good seal for hydrocarbons or CO₂. The ability to assess CO₂ trapping potential beneath seals with known hydrocarbon traps will be important for the emerging efforts in CO₂ storage as part of the energy transition. Importantly, the inter-basin comparison reduces the uncertainties in estimating the sealing potential of mudrocks in emerging offshore basins, such as the RB, by revealing which mature basin datasets are most relevant for deriving prediction functions. We find that the GoM datasets are a better basis for prediction in the RB than the NNS datasets.

**Acknowledgements**
We thank the Mozambique Petroleum Institute (INP) for providing the example well data used for this research. Rune M. Holt (NTNU) is thanked for valuable advice on the analysis of the velocity data.

**Funding**

This work was funded by the Norwegian Programme for Capacity Development in Higher Education and Research for Development within the Fields of Energy and Petroleum (EnPe). PR is funded by the Centre for Geophysical Forecasting (CGF), a 'Research-based Innovation' (SFI) Centre funded by the Norwegian Research Council (NRC), as well as several industrial partners and NTNU.

**Data availability**

Most data used in this study are from published sources. Well data used for the Rovuma Basin analysis are available on request from the Mozambique Petroleum Institute (INP).

**References**


doi:https://doi.org/10.1190/1.2944160


### Tables

#### Table 1. Fluid property estimates for in situ conditions (see text for values) at the two Rovuma basin wells

<table>
<thead>
<tr>
<th>Well</th>
<th>Fluid type</th>
<th>Density (kg/m$^3$) Based on standard properties (NIST)</th>
<th>Interfacial tension (mN/m) Based on Naylor et al (2011)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buzio</td>
<td>CH$_4$</td>
<td>130</td>
<td>50</td>
</tr>
<tr>
<td></td>
<td>CO$_2$</td>
<td>461</td>
<td>30</td>
</tr>
<tr>
<td>Cachalote</td>
<td>CH$_4$</td>
<td>110</td>
<td>54</td>
</tr>
<tr>
<td></td>
<td>CO$_2$</td>
<td>480</td>
<td>32</td>
</tr>
</tbody>
</table>

#### Table 2. Estimated permeabilities, capillary threshold pressures and column heights for CO$_2$ and CH$_4$ for trapping by the Cretaceous mudstones in the Buzio and Cachalote wells, assuming fluid properties given in Table 1. The reference depth is the base of the Cretaceous mudstone in each well (see text for values).

<table>
<thead>
<tr>
<th>Well</th>
<th>Depth (m)</th>
<th>$\phi$</th>
<th>Permeability (nD)</th>
<th>Pth-CO$_2$ (kPa)</th>
<th>CO2 column (m)</th>
<th>Pth-CH$_4$ (kPa)</th>
<th>CH4 column (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Buzio</td>
<td>3250</td>
<td>0.12</td>
<td>low 1.6, med 4.7, high 8.7</td>
<td>8543.1, 5703.3, 4527.3</td>
<td>1479, 987, 784</td>
<td>14238.6, 9505.5, 7545.6</td>
<td>1578, 1053</td>
</tr>
<tr>
<td>Cachalote</td>
<td>2031</td>
<td>0.255</td>
<td>low 15.0, med 65.0, high 300.0</td>
<td>3936.9, 2271.7, 1280.2</td>
<td>704, 406, 229</td>
<td>6643.6, 3833.5, 2160.3</td>
<td>720, 416</td>
</tr>
</tbody>
</table>
Figure captions

Figure 1. Map of global distribution and thickness of sediment accumulations on continental margins (based on data from Divins 2003; Whittaker et al. 2013) with the basins evaluated in this study (blue boxes). Dots represent the largest offshore and onshore hydrocarbon fields and blue lines are the largest continental river systems. Modified from Ringrose & Meckel (2019).

Figure 2. Scaling relationship for capillary threshold pressure ($P_{th}$) versus permeability for an IFT of 35 mN/m using Eqn 4 (red curve). Data points are measured mercury-air $P_{th}$ values from Schloemer & Krooss (1997) (orange squares) and other unpublished data from North Sea mudrocks (X) scaled to the same IFT system. Data trend function is shown for comparison. Also shown are measurements of upstream breakthrough pressures (diamond symbols) for CO$_2$-brine experiments published by Hildenbrand et al. (2004).

Figure 3. Comparison of rifting and post-rifting tectonic phases, and ages of main source and reservoir rock intervals in the four basins studied (based on published data: Snedden & Galloway 2019; Glennie 2009; Xie et al. 2019; Ramdhan & Goulty 2017; Francis et al. 2017; Macgregor et al. 2018).

Figure 4. Porosity-depth curve for the Cretaceous shale in the Rovuma Basin compared with published porosity-depth trends for mudrocks from three different basins, with rapid and slow burial rate functions proposed by Worden & Burley (2003). Basin function sources given in legend.

Figure 5. Comparison of published pore pressure vs depth data from four different continental margins (data sources given in the legend).

Figure 6. Relationship between compressional and shear wave velocities for Cretaceous mudrocks in the Buzio well (A) and the Cachalote well (B) in the Rovuma basin.

Figure 7. Comparison of $v_p/v_s$ ratio versus depth for Cretaceous mudrocks in the two Rovuma Basin wells against the trend for Gulf Coast mudrocks from Castagna et al. (1985).

Figure 8. Porosity-permeability function estimated for the Rovuma Basin well data, compared with uncertainty ranges assuming the Yang & Aplin (2010) equation for mudstone permeability as a function of clay fraction (CF) and void ratio. The mean CF of 44% and the upper and lower quartiles (+14%) were estimated from gamma log data and $V_{shale}$ functions.

Figure 9. Column heights for CH$_4$ and CO$_2$ predicted using the shale permeability predictor converted to capillary threshold pressures. The mean, and upper and lower quartile ranges shown are based on the assumption that permeability is the dominant uncertainty (other parameters are assumed fixed). The reported CH$_4$ column height at the Buzio well (115 m) is much lower than predicted from the mudstone properties analysis, which could be due to several reasons such as faulting or fill-to-spill trap geometry.

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