Fault seal modelling – the influence of fluid properties on fault sealing capacity in hydrocarbon and CO_2 systems

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Abstract

Fault seal analysis is a key part of understanding the hydrocarbon trapping mechanisms in the petroleum industry. Fault seal research has also been expanded to CO_2-brine systems for the application to Carbon Capture and Storage (CCS). The wetting properties of rock-forming minerals in the presence of hydrocarbons or CO_2 are a source of uncertainty in the calculations of capillary threshold pressure, which defines the fault sealing capacity. Here we explore this uncertainty in a comparison study between two fault-sealed fields located in the Otway Basin, south-east Australia. The Katnook field in the Penola Trough is a methane field, while Boggy Creek in Port Campbell contains a high-CO_2/methane mixture. Two industry standard fault seal modelling methods (Yielding et al., 2010; Sperrevik et al., 2002) are used to discuss their relative strengths and applicability to the CO_2 storage context. We identify a range of interfacial tensions and contact angle values in the hydrocarbon-water system under the conditions assumed by the Yielding et al. (2010) method. Based on this, the uncertainty related to the spread in fluid properties was determined to be 24% of the calculated threshold capillary pressure value. We propose a methodology of threshold capillary pressure conversion from hydrocarbon-brine to the CO_2-brine system, using an input of appropriate interfacial tension and contact angle under reservoir conditions. The method can be used for any fluid system where fluid properties are defined by these two parameters.

1 Introduction

Faults can be either pathways for, or barriers to fluid migration in the subsurface and to the surface. Fault seal analytical techniques have been developed to improve the prediction of hydrocarbon traps suitable for exploration. More recently, fault seal research has expanded to applications to Carbon Capture and Storage (CCS), where faults can act to: decrease the maximum storage capacity of the reservoir; become unwanted barriers to fluid migration along the planned injection pathway, causing pressure increase and limiting the maximum rate of injection; or, provide a conduit for leakage of CO_2.

Two distinct methodologies of predictive modelling of the threshold capillary pressure, which is a proxy for fault sealing capacity to hydrocarbons, have been developed in the last two decades: one based on a calibration of a global dataset of known sealing faults (Bretan et al., 2003; Yielding et al., 2010), and another, based on laboratory measurements of fault samples (Sperrevik et al., 2002). Both of these techniques have been widely applied to hydrocarbon systems. Fault capacity to seal for CO_2 has been explored in theoretical studies (Iglauer, 2018; Miocic et al., 2019; Naylor et al., 2010), yet there have been few attempts to test the methodology with real geological examples (Bretan, 2016; Bretan et al., 2011; Yielding et al., 2011).

In terms of practically applying model results to either exploration of hydrocarbons or CO_2 sequestration, the subject of interest is not the exact threshold capillary pressure of a certain fault but rather the implications of that value to the desired industrial activity. In exploration, this is applied to estimate maximum column height and determine the economic viability of production. It is therefore important to estimate how the uncertainty associated with the predictive method impacts the prospect. In the context of CO_2 storage, threshold capillary pressure is used to define the reservoir storage capacity. In this case the aim is not to overpressure the fault and thus cause leakage. The practical use of fault seal modelling therefore requires a good understanding of the uncertainty associated with the two different approaches.

The interfacial tension (IFT) and the contact angle (CA) are the main fluid-specific properties controlling the capillary seal and the key parameters used in both hydrocarbon and CO_2 studies. The wetting properties of various rock-forming minerals are different for CO_2 and hydrocarbons, which has caused a concern that the seal rocks proven to retain hydrocarbon columns might be less sealing to CO_2 (Chiquet et al., 2007b; Daniel and Kaldi, 2009; Guariguata-Rojas and Underhill, 2017; Tenthorey et al., 2014). A recent study by Miocic et al. (2019) explored the interplay between uncertainties in CA, IFT and fault rock composition in the CO_2-brine system. The results highlighted that higher phyllosilicate content in the fault rock reduces the threshold capillary pressure in the CO_2-brine system due to the wettability of the clay minerals in the presence of CO_2, especially at depths > 1 km.

Our understanding of CA and IFT primarily relies on empirical measurements, meaning that significant uncertainty exists in both hydrocarbon and CO_2-brine systems. While the above concerns are valid for the CO_2 storage, the existing uncertainties associated with CA and IFT also exist in the hydrocarbons. This is because of the wide range of chemical compositions of crude oil and the difficulty of sampling undegassed reservoir fluids.

In this contribution we investigate the uncertainty associated with the fluid properties (CA, IFT) as well as geological assumptions required for the model (depth at the time of faulting and maximum burial depth) in two field examples. One, methane gas field in South Australia (Katnook), and another, a high CO_2/methane mixture in Port Campbell, Victoria (Boggy Creek). In both cases, a gas column is supported by the fault rock and the column height is known. The fields are located in the Otway Basin, which is very well characterised in respect to hydrocarbon exploration as well as CO_2 storage. These case studies therefore provide a realistic example of the level of uncertainties that can be expected in future potential CO_2 storage sites.

This approach allows us to verify if the model predictions are valid and systematically compare the uncertainties in the CO_2 and methane system. Fault seal analysis is performed using the Sperrevik et al. (2002) and Yielding et al. (2010) fault seal modelling methods, discussing the differences in the modelling approaches, their associated uncertainties and suitability for the CO_2-brine system. The former method inherently allows the conversion from mercury-air system to CO_2-brine, while the latter method is calibrated to a hydrocarbon system. We summarise the current understanding of the IFT and CA ranges in hydrocarbons that the Yielding et al. (2010) method is based on to define the expected IFT and CA distribution and their mean values. Based on this, we propose a new calibration of the Yielding et al. (2010) algorithm to the CO_2-brine system.

2 Fault rock seal dependencies

Fault rock seals occur when movement along a fault plane creates a low-permeability fault rock, and depend on the fault rock composition as well as the properties of the fluids in the system. In siliciclastic sand-shale sequences, the sealing fault rocks are characterised by continuous clay-rich smears (Lindsay et al., 1993). Their thickness is favoured by greater thickness of shale beds in host rocks, weight of the overburden, and burial depth (Lehner and Pilaar, 1997). Quartz cementation at temperatures above 90 °C or ~>3 km further decreases fault rock porosity and increases the sealing potential (Fisher and Knipe, 1998; Rimstidt and Barnes, 1980). The resulting fault rock may act as baffle to fluid migration through a process of capillary sealing, which is created by the opposing forces between the two phases at their interface – the wetting phase (water or brine) and the non-wetting phase (hydrocarbons or CO_2, in this context) (Fisher and Knipe, 1998; Watts, 1987; Yielding et al., 1997). Capillary seals fail when the fluid buoyancy pressure exceeds the threshold capillary pressure. Capillary threshold pressure (P_c) is therefore a key fault rock attribute used in the hydrocarbon exploration industry to determine the sealing potential of the fault and calculate maximum column heights (h_{max}), using the relationship between the height of the fluid column and the buoyancy pressure it exerts on the sealing rocks (Schowalter, 1974):

$$P_c = \frac{2IFT \times cos\theta}{r} \quad (1)$$

$$h_{max} = \frac{P_c}{(\rho_h - \rho_w)g} \quad (2)$$

Where IFT is the interfacial tension between the fluids, θ is the contact angle, r is the effective pore throat radius, ρ is density, g is acceleration due to gravity, h and w denote hydrocarbons and water.

The interfacial tension and contact angle (or wettability) are the key properties controlling capillary seal and depend on many factors including pressure, temperature, fluid type, fluid density and rock mineralogy (e.g. Iglauer et al., 2015; Nordgard Bolas et al., 2005; Øren and Bakke, 2003; Radke et al., 1992; Schowalter, 1974). The influence of these factors is a key concern in describing fault zone behaviour. The advantage, however, is that the characteristics of fluids and their affinity to reservoir rock can be approximated by these two input parameters, and therefore applied in the same manner to systems involving hydrocarbons, CO_2 or any other fluid type of interest.

The buoyancy pressure exerted on the fault rock by the column of fluid is greater with increasing density contrast between the wetting and the non-wetting phases. Under typical reservoir conditions, density of methane ranges between 100 – 300 kg/m^3, CO_2 is approximately 400 – 600 kg/m^3 and oil density varies between 700 – 1000 kg/m^3 (Danesh, 1998). Brine density depends on salinity and has a value of 1000-1150 kg/m^3. It is therefore apparent, that a fault rock with a certain capillary threshold pressure would retain a smaller column of methane than of CO_2 or oil, if the other parameters were the same. However, the differences in interfacial tension and CA between CO_2 and hydrocarbons also impact the threshold capillary pressure of the fault rock in a CO_2-brine system (Chiquet et al., 2007b). The interplay between IFT, CA and fluid density therefore is key to consider in applying fault seal modelling techniques to CO_2 sequestration.

The effective pore throat radius of a fault zone is impossible to directly determine, and by standard practice is approximated using a predictive algorithm based on the clay content of the faulted rocks, such as SGR (Yielding et al., 1997). Two different approaches have been developed to link SGR to capillary threshold pressure. One approach is based on laboratory experiments of mercury-air injection tests in micro-fault samples and subsequent correlation of measured capillary pressures to sample clay content (Sperrevik et al., 2002), based on earlier studies by Knipe (1997), Gibson (1998). The second approach uses data from known hydrocarbon traps sealed by faults to empirically correlate the maximum observed buoyancy pressures (assumed equivalent to threshold pressure) to SGR values (Bretan et al., 2003; Yielding, 2002; Yielding et al., 2010). The two approaches have been termed 'deterministic' and 'empirical' respectively (Yielding et al., 2010), and will be referred to as such in the forthcoming text. The two methods are often used in conjunction and have been shown to produce similar results in certain but not all SGR/burial depth configurations (Yielding et al., 2010). To date, the application of these methods to the CO_2-brine systems has been limited (Bretan et al., 2011).

The deterministic approach is based on laboratory measurements of fault rock permeability from a variety of fault structures within reservoir core samples and requires a conversion from the mercury-air system to hydrocarbon-water or CO_2-brine system by using appropriate values for IFT and contact angle between the fluid and the wetting phase (Sperrevik et al., 2002). In contrast, the empirical approach (Bretan et al., 2003; Yielding, 2002) is based on a calibration of SGR values and across-fault buoyancy pressure differences of known sealing faults. Importantly, the calibration includes only hydrocarbons at depths greater than 1.5 km. This means that theoretically, the method can only be applied to fluid systems which fall within the range of IFT and contact angle parameters as the hydrocarbon field used in the calibration. Further constraining this range is discussed below before we propose a methodology to convert fault seal modelling results from hydrocarbons to CO_2-brine system.

3 Geological background

In this study we describe two gas fields in the Otway Basin, Victoria, Australia: The Katnook field in the Penola Trough and the Boggy Creek field in the Port Campbell embayment. Below we outline the geology of the fields in terms of stratigraphy, trap geometries and gas charge.

3.1 Basin stratigraphy

The present day geometry of the Otway Basin was developed during the Cretaceous to Miocene rifting with a period of inversion in the mid-Cretaceous, when the rift axis moved south (Teasdale et al., 2003). A series of graben and half-graben structures consist of compartmentalised fault-bound reservoirs, with numerous hydrocarbon and CO_2 accumulations (Fig. 1). Two case studies discussed here present examples of gas column retention by a fault rock in a situation of reservoir-reservoir juxtaposition. Katnook in the Penola Trough is a methane field, while the Boggy Creek field in Port Campbell contains a high-CO_2/methane mixture.

The two fields are within different reservoir formations at different stratigraphic intervals (Fig. 1). The Katnook field is stratigraphically lower, located in Pretty Hill Formation of 2 - 4.5 km thickness, within the Pretty Hill Sandstone. The main target reservoir is the Pretty Hill Sandstone member at the top of the sequence (Lyon et al., 2005). The formation consists of massive, slumped and cross-bedded sand packages, classified as lith-arenites to feldspathic lith-arenites (Little and Phillips, 1995). The Laira Formation forms a regional seal, comprised of siltstones and shales interbedded with sandstones. The Katnook sandstone at the top of the Crayfish Group (consisting of both the reservoir and the seal lithologies) is also gas-bearing, but is not a subject to this discussion. Katnook-1 and 2 are production wells targeting Katnook sandstone within the Crayfish Group, while Katnook-3 produces from the deeper Pretty Hill Formation. Shale units within the lower parts of the Pretty Hill Formation and the underlying Casterton Formation are the oil and gas source rocks in the Penola Trough and the SW part of the basin (Boreham et al., 2004).

The Boggy Creek CO_2 field is stratigraphically higher, within the Waarre Sandstone, comprised of interbedded siltstones and shales, segregated into four units defined by depositional environments. Unit C, the main reservoir interval, is poorly sorted, medium to coarse-grained quartz arenite (Watson et al., 2004). The underlying Eumeralla Formation consist of inter-bedded lithic sandstones, siltstones, coals and claystones (Cockshell et al., 1995). The deeper coal-rich units of Eumeralla Formation are the source rocks in the SE part of the basin. The Belfast Mudstone overlies the reservoir and forms a regional seal (Boreham et al., 2004).

The Waarre sandstone is approx. 90 m thick and the main producing interval within it (Unit C) is 25 -40 m thick (Dance, 2013). The underlying Eumeralla Formation is up to 3 km thick (Cockshell et al., 1995). Significant oil shows have been observed within the Eumeralla Formation in other parts of the basin (Lisk, 2004) and therefore good connectivity between the Waare and Eumeralla units is expected despite the silt and clay inter-beds.

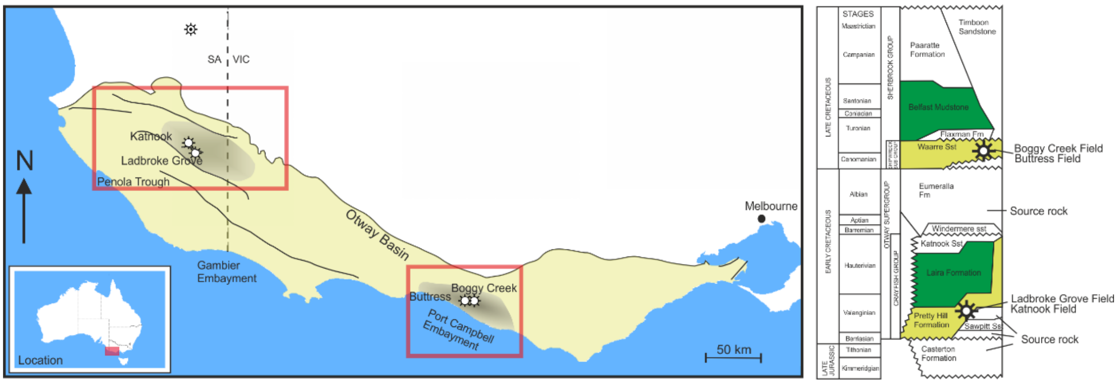


Figure 1. Location map of Penola Trough (Katnook/Ladbroke Grove fields) and Port Campbell (Buttress/Boggy Creek fields). Both localities are within the Otway Basin. Inset on the right shows the location of both reservoirs within the stratigraphic column (adapted from Lyon et al., 2004).

3.2 Trap geometry

The Katnook field is bound by the Katnook fault to the north and Ladbroke Grove fault to the south (Fig. 2a). The northern side of the field is juxtaposition-sealed against Crayfish Group shales, while the southern side reaches the Ladbroke Grove Fault, where the reservoir is self-juxtaposed (Fig. 2c). The Boggy Creek field is bound by the Boggy Creek Fault to the south and the Buttress Fault to the north

(Fig. 2b). Similarly to the Katnook field, the main seal to the reservoir is provided by juxtaposition seal to the south, but fault rock seal exists to the north (Fig. 2d).

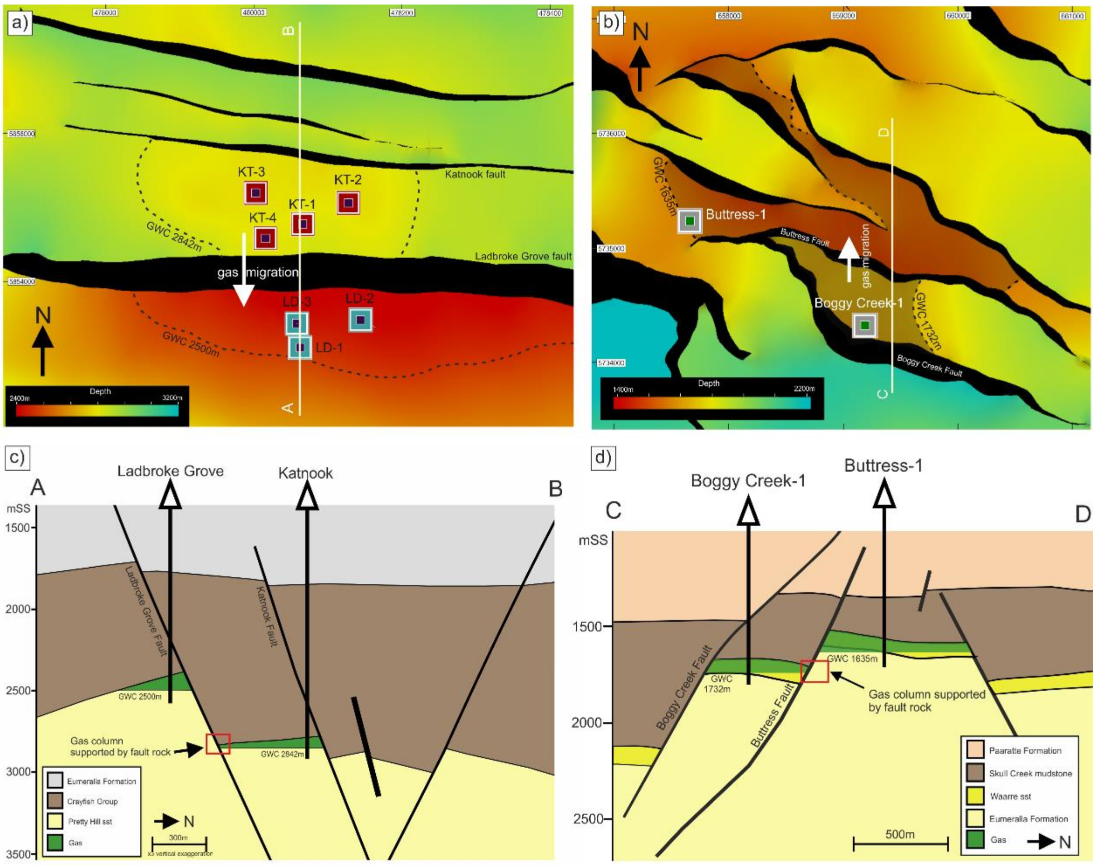


Figure 2. Map and cross-sectional views of Penola Trough (a, c) and Port Campbell (c, d) gas field locations. a) Map view of the top of the Pretty Hill reservoir horizon, coloured by depth. b) Map view of the top of the Waarre sandstone reservoir horizon, coloured by depth. c) Cross-section view of line A-B from figure (a). Ladbroke Grove and Katnook fields in Penola Trough. Cross-section drawn from seismic data using 3x vertical exaggeration. Katnook field is supported by Katnook fault to the north (juxtaposition seal) and Ladbroke Grove fault to the south (fault rock seal). d) C-D cross-section view (from figure b) of the Boggy Creek and Buttress fields in Port Campbell. Cross-section drawn from seismic data without vertical exaggeration. Boggy Creek gas field is retained by juxtaposition seal to the south and fault rock seal to the north. The adjacent Buttress field is structurally higher.

3.3 The sequence of gas charge events

The two main phases of hydrocarbon generation in the Otway Basin are estimated at mid-Cretaceous (Boult et al., 2004) and mid-Paleogene (Duddy, 1997), based on thermal maturation modelling and the relationship between GWC positions above spill points and known gas diffusion rates (Lyon et al., 2005). Early oil/wet gas charge was flushed or diluted by later dry gas charge (Boreham et al., 2004).

Methane charge was followed by a later stage magmatic CO_2 injection (Chivas et al., 1987; Lyon et al., 2005; Watson et al., 2003). Due to the sealing or partially sealing nature of bounding faults, the CO_2/methane ratio significantly varies across geographically closely located fields.

The Ladbroke Grove field contains CO_2, with higher concentrations at the base (49%) and lower at the top of the reservoir interval (27%). The Katnook field contains primarily methane with only trace amounts of CO_2 (0.2%). $^{3}He/^{4}He$, $CO_2/^{3}He$ and neon isotopic ratios indicate that CO_2 in Ladbroke Grove is of mantle origin ($^{3}He/^{4}He$ = 1.46 R/R_A) (Karolytė, 2018). $^{3}He/^{4}He$ ratios in the Katnook field are slightly elevated above the crustal values (0.06 R/R_A), but any mantle-sourced noble gases are decoupled from the migrating CO_2 (Karolytė, 2018). These geochemistry results suggest that methane has likely migrated through the fault rock from Katnook to the Ladbroke Grove field, while the later CO_2 charge was restricted to Ladbroke Grove only.

The Boggy Creek and Buttress fields both contain mixtures of mantle CO_2 and methane. CO_2 concentrations within the traps increase with depth because of its higher density, and Boggy Creek (87% CO_2) is more CO_2-rich than Buttress (77% CO_2) (Karolytė et al., 2019). While independent charge to both fields cannot be completely excluded, the observed concentration gradient suggests that CO_2 was first charged to the Boggy Creek field, and later migrated to Buttress. The trap is not filled up to the spill point, suggesting this migration occurred through the fault rock which supports the column.

4 Methods

4.1 Geological 3D models

This work has been undertaken using a compilation of existing industry and academic datasets. 3D model development, structural and fault seal analysis was undertaken using TrapTester™ software. The Penola Trough 3D model was developed by Paul Lyon and published in Lyon et al. (2005b, 2007, 2004). It was constructed by interpretation of the 3D Balnaves-Haselgrove seismic survey in time and pseudo-depth (Lyon et al., 2004). The 3D model used for Port Campbell area was developed by Ziesch et al. (2017) using a combination of OGF93A, ONH01 and Curdie Vale 3D seismic surveys. Seismic data reinterpretation in this study has led to addition of some new faults and modification of fault and horizon geometries in the original models.

4.1.1 V-shale

The V-shale curves for the studied wells were created from GR wireline logs. ‘Clean sand’ and ‘pure shale’ (0 and 100% V-shale) values were determined by correlating GR measurements to core descriptions and, where possible, core permeability tests from the well completion reports. The Waarre sandstone is feldspathic (Watson et al., 2003), which is reflected in the relatively high chosen API (American Petroleum Institute unit) values of clean sands. The strength of the GR signal is often not uniform between different wells, in which case different clean sand and pure shale values have to be chosen to produce internally consistent V-shale logs. The V-shale values were calculated using the linear response equation (Asquith et al., 2004):

$$V_{Shale} = I_{GR} = \frac{GR_{log} - GR_{sand}}{GR_{shale} - GR_{sand}} \quad (3)$$

4.1.2 **Fault seal modelling**

The intersection lines between the top of the reservoir formation on the footwall and the hanging wall side of the fault were created on the fault planes (e.g. Yielding & Freeman, 2016). Manual quality check techniques such as projecting seismic slices on the fault plane were used to accurately map out the geometry of the intersections. Allan diagrams (Allan, 1989) were created to identify the areas of interest where reservoir formation is juxtaposed against another permeable rock on the other side of the fault.

Buoyancy pressure is calculated on the 3D surface of the fault based on the input of gas and water pressure gradient and the gas water contact (GWC). This data was obtained from repeat formation tester (RFT) plots in well completion reports (WCRs) from Buttress and Ladbroke Grove fields. Pressure profile data did not exist for Katnook and Boggy Creek fields, so gas pressure gradients were calculated from gas densities. Gas densities at reservoir conditions were calculated using the Peng-Robinson equation of state (Peng and Robinson, 1976). A summary of input parameters relevant to buoyancy pressure calculation is given in Table 1.

Table 1. Summary of parameters used in the buoyancy pressure calculations. Temperature and pressure relevant where density was calculated using equation of state rather than obtained from RFT measurements. Major gas compositions are from Karolytė (2018) and Karolytė et al. (2019).

Field	Temperature °C	Pressure MPa	GWC mSS	ρ_w kg/m³	ρ_g kg/m³	Major gas composition		
						C_1+	N_2	CO_2
Penola Trough								
Ladbroke Grove	104	23	2500	927	244	45	7.2	49
Katnook	118	28	2842	1035	125	97	3.2	0.2
Port Campbell								
Buttress	62	16	1635	1035	382	22	1.9	77
Boggy Creek	59	17	1732	1035	456	10	2.0	87

SGR was calculated on the 3D plane of the fault using the input of V-shale curves. The threshold capillary pressures were calculated using two different SGR calibration techniques: empirical and deterministic. Both of these methods require an input of the maximum burial depth. The empirical method uses the burial depth to categorize faults for three different seal envelopes (< 3 km, 3 - 3.5 km, 3.5 – 5 km), while the deterministic method directly incorporates the value. The deterministic method additionally requires an estimate of the depth at the time of faulting and a conversion factor from mercury-air to gas-brine system, which is dependent on the interfacial tension between the wetting and non-wetting phases and the wettability of the system. A minimum and maximum estimate of each of the parameters were determined based on known reservoir conditions and a literature review, resulting in two and eight possible scenarios for the empirical and deterministic methods, respectively (Fig. 3). Both of these methods ascribe threshold capillary pressures to every point of the 3D fault surface. These can then be compared to the known buoyancy pressure exerted by the gas column trapped in the reservoir.

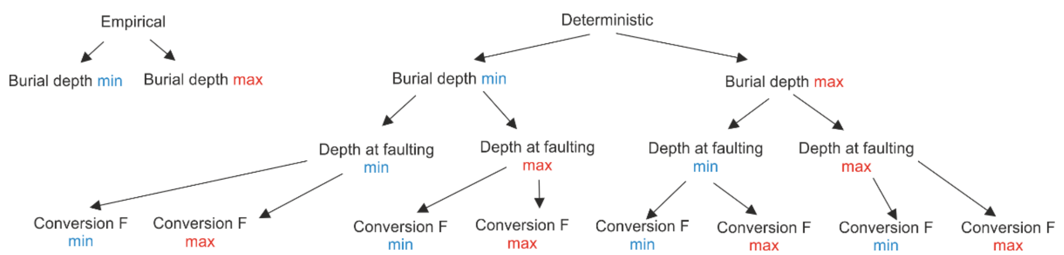


Figure 3. Schematic diagram of different scenarios including minimum and maximum estimates of parameters required by the empirical and deterministic methods.

4.1.3 **Input parameters**

The input parameters used in the fault seal modelling are summarised in Table 2, and the reasoning is explained below.

Table 2. Summary of parameters used in fault seal modelling

Field	Burial depth (m) (for deterministic)		Burial depth (m) (for empirical)		Depth at the time of faulting (m)		Conversion factor	
	min	max	min	max	min	max	min	max
Boggy Creek	1623	1783	<3000	-	450	1200	0.054	0.087
Katnook	2787	2987	<3000	3000-3500	800	1200	0.111	0.133

4.1.3.1 Maximum burial depth

The Otway Basin has undergone two significant phases of uplift and denudation, but the effects are less significant at the margins of the basin where the two case studies are situated. A comprehensive basin-wide sonic transit time study by (Tassone et al., 2014) suggests that Port Campbell is close to its maximum burial depth, with a net exhumation range obtained from Boggy Creek-1 indicating 0 – 160 m net exhumation. The same is true for Penola Trough, where conservative estimate of net exhumation is in the range of 0 - 200 m. This is confirmed by vitrinite reflectance and apatite fission track data (Boult and Hibburt, 2002; Duddy, 1997). The upper end of this range gives a maximum burial depth of 2987 m, which is very close to the cut-off value of 3 km between different seal envelopes in Yielding et al. (2010) method. We therefore consider two scenarios of < 3 km and 3 - 3.5 km maximum burial depth for the Penola Trough.

4.1.3.2 Depth at the time of faulting

4.1.3.2.1 Penola Trough

The main faulting event was contemporaneous with the Early Cretaceous rifting which coincided with the deposition of the regional seal formation. The sediments of the Crayfish Group commonly drape over major structural highs, indicating that faulting had ceased by the end of its deposition (Briguglio et al., 2015) and was inactive during the deposition of the overlying Eumeralla Formation (Boult et al., 2008), which is also evident from the seismic data. The depth of Ladbroke Grove fault at the time of displacement is therefore constrained by the total thickness of the Crayfish Group. The current thickness of the Crayfish Group in the Katnook well is 800 m, which is also the thickest in the Penola Graben. Structural cross-section balance and restoration indicates that 400 m of Crayfish sediments were removed in the Penola Graben (Briguglio et al., 2015). Depth at the time of faulting is therefore constrained to 800 - 1200 m.

4.1.3.2.2 Port Campbell

The seal formation, consisting of a succession of mudstones overlain by Skull Creek mudstone, varies in thickness across the faults, indicating syn-sedimentary faulting (Ziesch et al., 2015). The faulting ceased during the deposition of the unconformably overlain Wangerrip Group in Paleocene. Depth at the time of faulting is therefore represented by the thickness of this group, which ranges from 450 to 1200 m.

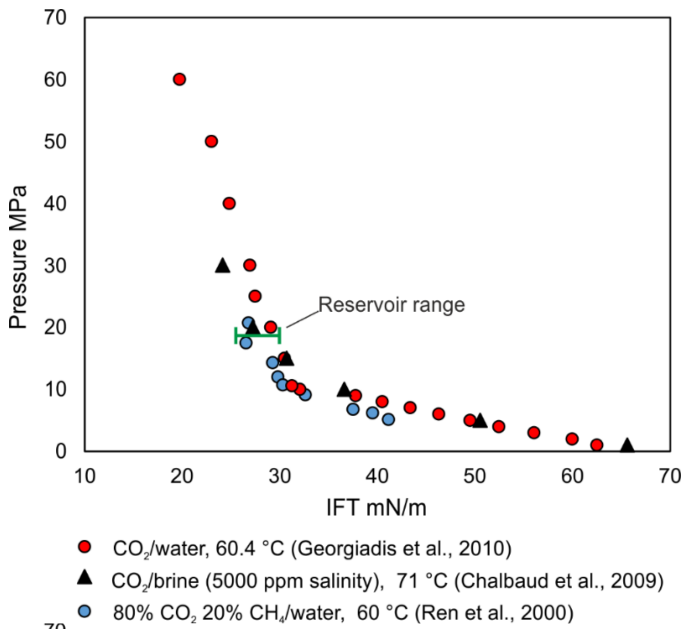
4.1.4 Conversion factor

The conversion factor from mercury-air to the chosen wetting and non-wetting phase requires an input of IFT and contact angle:

$$P_{wn} = P_{ma} \times \frac{IFT_{wn} \times cos\theta_{wn}}{IFT_{ma} \times cos\theta_{ma}} \qquad (4)$$

where P is threshold capillary pressure, θ is the contact angle, w*n* and *ma* denote wetting/non-wetting phase of choice and mercury/air, respectively.

IFT has a strong dependency on pressure and temperature for both CO_2 and methane, so assessment for local reservoir conditions is imperative. Figure 4 shows a compilation of results selected from laboratory studies under conditions similar to those in Boggy Creek and Katnook reservoirs. Presented data include CH_4-water, CO_2-water, CO_2-brine and CO_2-CH_4 mixtures in water (Chalbaud et al., 2009; Georgiadis et al., 2010; Hough et al., 1951; Kashefi, 2012; Ren et al., 2000; Wiegand and Franck, 1994; Yi-Ling et al., 1997). The range constrained for the Boggy Creek field is 26 - 32 mN/m (Fig. 4). Admixture of CH_4 to pure CO_2 generally increases the IFT, but as shown in Figure 4a, the measurements in mixtures containing < 20% methane are not significantly different from CO_2-water system (Ren et al., 2000). The IFT range expected in Katnook methane field is 47-49 mN/m (Fig. 4b).



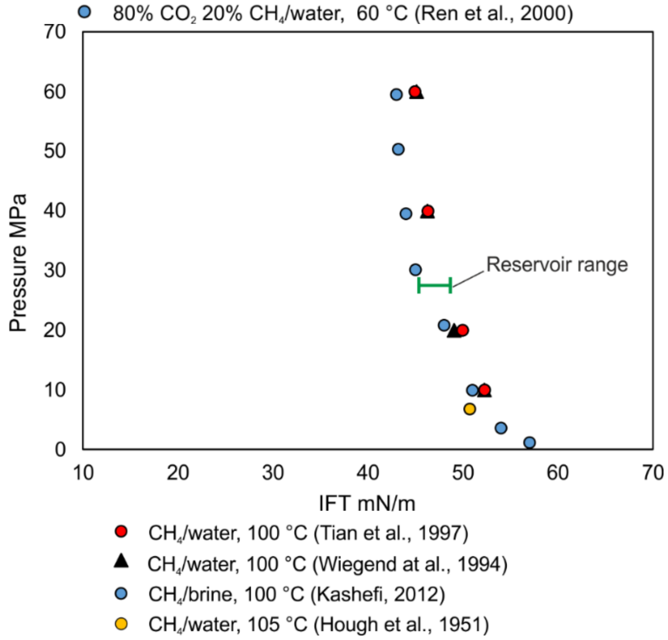


Fig. 4. IFT vs pressure for a) Boggy Creek reservoir conditions b) Katnook reservoir conditions. Green line shows the expected range for reservoir pressure.

Typical reservoir rocks are often considered to be water-wet in the presence of hydrocarbons (e.g. Schowalter, 1974; Vavra et al., 1992), with some exceptions, including grain coating with high polarity of crude oil components (Singh et al., 2016). The Penola Trough traps show evidence for early charge of oil which was later displaced by gas (Higgs et al., 2015; Lovibond et al., 1995), therefore a range of 0-

30° contact angles is taken to reflect the potential effect of acid adsorption on grain surfaces.

The wettability of CO_2-brine-mineral system has been investigated by a growing number of studies (Bikkina, 2011; Farokhpoor et al., 2013; Jung and Wan, 2012), most commonly directly on single mineral surfaces, where minerals are required to be ultraclean and smooth on an atomic level for reproducible results. The results are highly variable (0 - 90°), but much of the variation is attributed to the surface roughness and sample preparation practices (Iglauer et al., 2015). However, the most consistent findings include a contact angle increase by up to 30° at CO_2 transition from the gaseous to the supercritical phase (Jung and Wan, 2012; Sutjiadi-Sia et al., 2008). In the absence of minerals known to be particularly hydrophobic in the presence of CO_2 in the reservoir, the expected contact angle range for Boggy Creek is taken to be 10 - 40°, as expected for common silicate and carbonate reservoir minerals (Espinoza and Santamarina, 2010).

Given the defined range of IFT and contact angles for both reservoirs, minimum and maximum conversion factors calculated for Boggy Creek Field (CO_2-dominated) and Katnook Field (methane-dominated) were 0.054 - 0.087 and 0.111 - 0.133, respectively.

5 Results

5.1 Juxtaposition

The Allan diagrams in Figure 5 show the juxtaposition of lithologies along the strike of the fault planes for Katnook (a) and Boggy Creek (b) reservoirs. The Katnook reservoir is primarily sealed by sand on shale juxtaposition by the Katnook fault to the north, but the field extends to the hanging wall of the Ladbroke Grove fault which is supporting the column to the south (Fig. 7.5a). The entire extent of the reservoir is juxtaposed against reservoir on the other side of the fault. Similarly, the Boggy Creek field is supported by sand on shale juxtaposition in the footwall of the Boggy Creek fault to the south. The field extends to the hanging wall of the Buttress fault (Fig. 5b), where the reservoir is self-juxtaposed for the entire extent of the gas field. Calculated V-shale values for areas of reservoir self-juxtaposition range between 20 and 50% on the Ladbroke Grove Fault and 10% to 80% on the Buttress fault. SGR values above 20% are considered to be sealing (Yielding et al., 2010), so in both cases the model indicates that the faults are acting as barriers to gas migration.

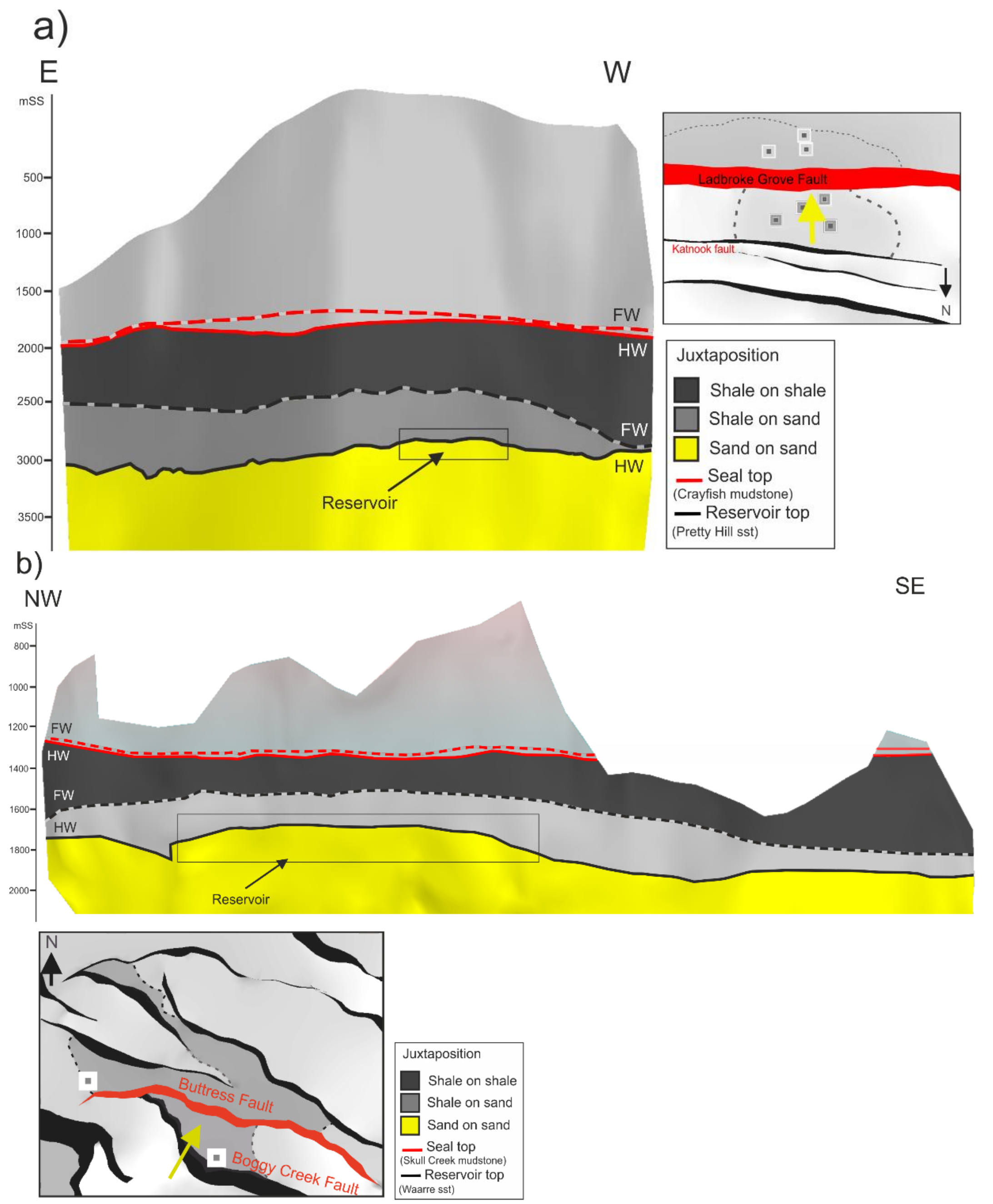


Figure 5. Allan diagrams showing juxtaposition along the strike-view of the faults, viewed from the hanging wall side. Insets show the location of the faults (marked in red), the yellow arrows show the direction of view. a) Ladbroke Grove fault, supporting the southern side of the Katnook gas field (3x vertical exaggeration). b) Buttress fault, supporting the northern side of the Boggy Creek gas field (no vertical exaggeration). Black rectangles show the extent of the gas-bearing reservoir. Horizon intersections on the fault plane are displayed as dashed lines for the footwall side and solid lines for the hanging wall side.

5.2 Threshold capillary pressure

Across fault leakage through capillary seal breach commonly occurs near the top of the trap structure, where buoyancy pressure is the highest. The critical (and therefore most likely to leak) points occur where the lowest SGR values coincide with the highest buoyancy pressure on a given fault plane. The buoyancy pressure values identified at these points are 0.28 MPa for the Katnook field and 0.29 MPa for the Boggy Creek.

The calculated threshold capillary and buoyancy pressures can then be compared at the critical points, where the difference between them represents the amount of extra pressure (or extra gas column) the fault can retain before seal breach. Figure 6 shows the results of the deterministic (a, c) and empirical (b, d) calibrations for Katnook and Boggy Creek fields.

The results from both calibrations for the Katnook methane gas field indicate that the current live gas column of 31 metres (equivalent to 0.28 MPa buoyancy pressure) is stable but the fault is close to being critically pressured. The threshold capillary pressures range from 0.32 to 0.55 MPa, equivalent to a total column of gas between 35 to 57 m according to the deterministic calibration. Empirical calibration suggests the fault seal will be breached at pressures between 0.3 and 0.57 MPa, equivalent to a total gas column of 33 to 63 m. The results from both calibrations are remarkably similar, with the average threshold capillary pressure of 0.42 and 0.43 MPa using the deterministic and empirical methods respectively.

The deterministic and empirical methods provide different results for the Boggy Creek CO_2 field. The fault is currently supporting a 51 m column of gas, equivalent to a buoyancy pressure of 0.29 MPa. This is close to the upper range values predicted by the deterministic method. The threshold capillary pressure ranges from 0.15 to 0.31 MPa (26 – 55 m of total column height). The predicted average column height is 39 m, slightly under-predicting the sealing potential of the fault. In contrast, the empirical calibration indicates a threshold pressure of 0.65 MPa and a maximum column height of 115 m, which is more than double the current amount.

The empirical method requires only one parameter of the maximum burial depth. The deterministic method requires three parameters. In the case of the Katnook methane field, the uncertainty in maximum burial depth has the biggest impact on the results and the conversion factor is the second largest uncertainty (see y axis annotation on Fig. 6). In contrast, the uncertainty in the conversion factor has a greater impact on the Boggy Creek CO_2 field results than the maximum burial depth.

The structural spill point at the Katnook field is identified at 2891 m, which effectively allows a maximum gas column height of 81 m. In Boggy Creek, the structural spill point occurs at 1956 m, allowing a maximum column height of 272 m. The maximum column heights identified from the structural perspective of the traps are all higher than those modelled by fault seal analysis. This means that filling the traps to the maximum fault-rock threshold pressures derived from all models would not result in fill-to-spill and therefore both methods indicate that migration to the adjacent fault trap occurred through the fault rather than through over-spilling.

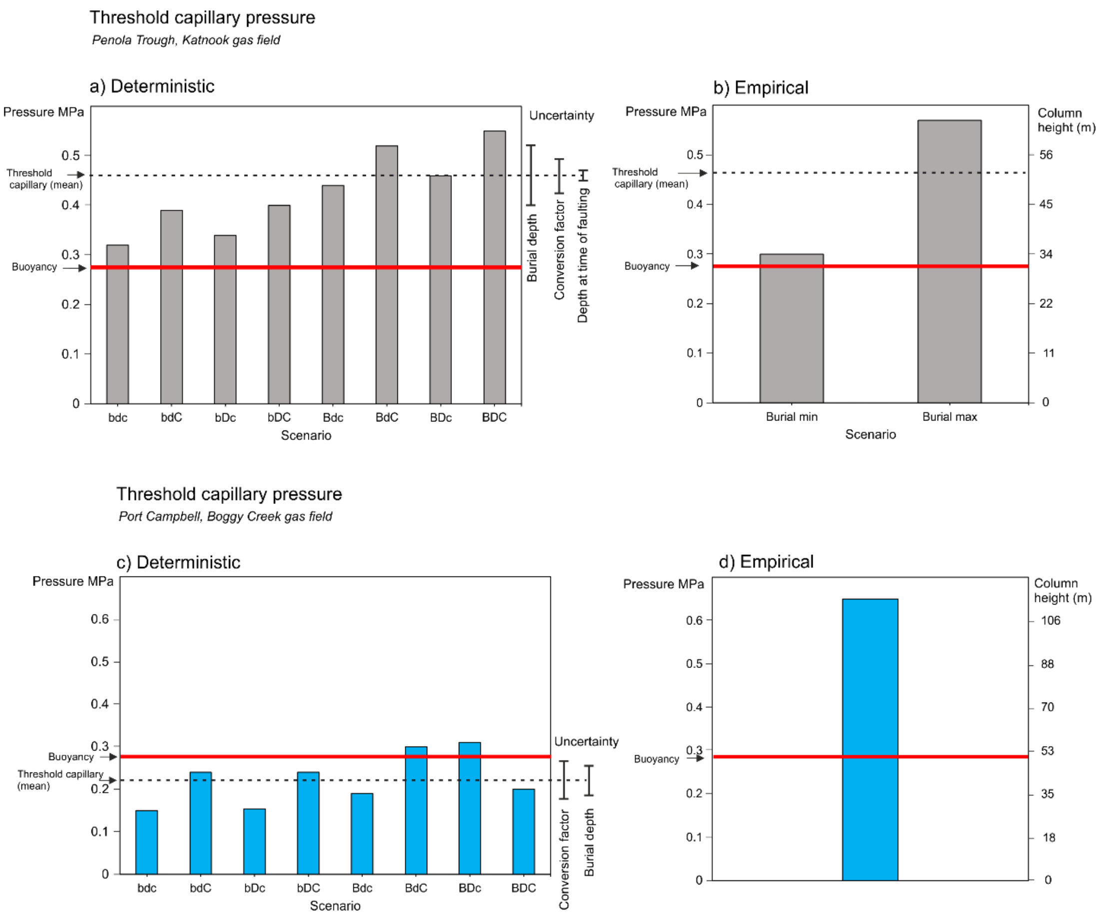


Figure 6. Bar chart showing threshold capillary pressure results for the Katnook methane field (a, b) and the Boggy Creek CO_2 field (c, d) using deterministic (a, c) and empirical (b, d) SGR calibration algorithms. Conversion to column height displayed on the secondary y axis (same values applicable to both deterministic and empirical method graphs. Red line shows current column height/buoyancy pressure. The Katnook gas column is predicted to be stable by both methods with maximum threshold capillary pressure ranging from 0.32 to 0.55 MPa (deterministic) and 0.3 to 0.57 MPa (empirical). The Boggy Creek field is predicted to be within the upper end of the critical pressure zone by the deterministic method (0.15-0.31 MPa) and stable by the empirical method. Labels in deterministic scenarios: B- maximum burial depth, D – depth at the time of faulting, C – conversion factor. Upper and lower case letter indicate maximum and minimum values respectively.

6 Discussion

6.1 Addressing the uncertainty in fault seal modelling

The deterministic and empirical methods present a key difference in their definition of the threshold capillary pressure. The deterministic method defines a best fit line through the data points of measured capillary entry pressures during injection experiments to fault rock samples. Therefore, by definition, the method predicts the average threshold pressure for the modelled conditions. In contrast, the fault seal envelopes defining the threshold capillary pressure in the empirical method represent the upper limit of data for buoyancy pressures retained by fault rocks with a given SGR. The threshold pressure returned by the empirical equation is therefore a maximum estimate. In other words, even though the same term of threshold capillary pressure is used by the two methods, the derived value represents somewhat different concepts and presents a different level of uncertainty.

Some uncertainties are inherent to the modelling method and cannot be easily accounted for. The deterministic method is based on threshold capillary pressure measurements of micro-fault samples on the scale of millimetres to centimetres (Sperrevik et al., 2002). The measured clay content of the fault structures is assumed to be represented by SGR when upscaled to use in a predictive way. The method is therefore applied on the assumption that kilometre scale faults behave in the same way as micro structures. In reality this is not strictly the case, with seismic-scale fault zones comprising clay smears, cataclastic zones and multiple planes of deformation (Bense et al., 2016; Faulkner et al., 2010; Fisher and Knipe, 1998; Pei et al., 2015; Shipton and Cowie, 2001), which all add to the total sealing capacity of the fault zone. Detailed fault zone analyses show that the permeability over individual fault zone components can vary considerably (e.g. over 3 orders of magnitude) (Shipton et al., 2002) and therefore upscaling one of those components to be representative of the entire fault zone involves a significant simplification.

The advantage of the empirical method in this respect is that SGR is assumed to be a proxy for the fault sealing properties, which include shale content but also various heterogeneous components of the fault zone. SGR calculated on the 3D surface of the fault planes is the direct input in the calibration as well as in the predictive workflow, which eliminates the uncertainty associated with equating SGR to specific rock properties such as the true volume of shale. The compilation dataset includes data from 7 different basins, covering a wider range of diagenetic conditions relative to the deterministic method which is based on samples from the North Sea (Yielding, 2002).

Some of the uncertainties associated with the local geological conditions and fluid properties are parameterised in the deterministic method and therefore can be accounted for. The error bars in Figure 6 a) and c) show the relative uncertainties associated with the different model input parameters. For the two case studies presented here, fluid properties (governing the conversion factor) present a higher uncertainty for CO_2 rather than methane. This is primarily due to the larger IFT range selected for CO_2, but does not suggest that the interfacial tension of CO_2 is less characterised than that of methane. The larger range is due to a relatively higher number of currently available studies, including measurements using different salinity, salt types and gas mixtures, while methane laboratory studies are largely constrained to pure methane and deionized water. In cases where fluid properties are well defined, maximum burial depth is the most significant source of uncertainty, while depth at the time of faulting is the least significant input parameter.

6.2 Uncertainty related to fluid properties

An important difference between the two methods is the approach to accounting for the fluid properties. The interfacial tension and wettability are parameterised in the deterministic method, making it more versatile, arguably adaptive to CO_2-brine system and more precise in cases where fluid properties are well characterised. The empirical method does not explicitly address the fluid properties, but operates under the assumption that the range of IFT and contact angle configurations in hydrocarbons is small, and that the possible variability of fluid properties is represented in the global dataset compilation. The two important issues with the empirical approach are:

a) the uncertainty related to fluid properties is undefined when applied to hydrocarbons.

b) the application to CO_2 can only be considered valid in cases where CO_2 exhibits properties within the range of those observed in hydrocarbons.

These are explained in detail below.

6.3 a) Uncertainty related to fluid properties of hydrocarbons in the empirical model

To further assess the empirical method application to CO_2, the uncertainty related to the fluid properties of hydrocarbons has to be defined. The percentage error of the capillary threshold pressure (δP_c) from the uncertainty in fluid properties (as standard deviation) can therefore be expressed as, using Equation 1:

$$\delta P_c = \frac{\sigma(P_c)}{\partial(P_c)} \times 100\% = \frac{\sigma(2IFT \times cos\theta)}{\partial(2IFT \times cos\theta)} \times 100\% \quad (5)$$

The empirical method uses a data compilation including both oil and methane in reservoirs > 1.5 km depth (Yielding, 2002), and can be assumed to reflect the general IFT and contact angle variability of all hydrocarbons at that depth. The percentage error can therefore be calculated using a random sampling modelling approach with inputs of the probability distribution of IFT and contact angle values in hydrocarbons-brine system. Interfacial tension and contact angle are assumed to be independent variables; even though some co-variation may exist, currently it is not well understood and there are far more factors affecting the contact angle not directly related to the fluid type.

6.3.1 **Defining IFT and wettability range for hydrocarbons**

The IFT between hydrocarbons and water (or brine) is primarily controlled by the chemical composition of the hydrocarbons, the density contrast between the two phases and temperature (Flock et al., 1986; Hassan et al., 1953; Rajayi and Kantzas, 2011). Pressure mainly affects gas solubility in oil and therefore has a bigger effect on oils with high dissolved gas content (Ghorbani and Mohammadi, 2017). Generally, the IFT in hydrocarbons is not well characterised and usually an average IFT of 30-35 mN/m is used for capillary seal modelling purposes (Berg, 1975; Robert M. Sneider and Neasham, 1997). Considerable effort has been made to characterise IFT of individual hydrocarbon compounds and derive predictive equations to determine the IFT based on the input of reservoir temperature (Kalantari Meybodi et al., 2016), density difference (Danesh, 1998; Sutton, 2006) and critical fluid temperature (Najafi-Marghmaleki et al., 2016). However, these methods are developed for data compilations of pure aromatics and alkanes, and do not reflect the fluid properties of crude oil at reservoir conditions, which include high percentage of other compounds such as napthenes and asphaltics (Buckley et al., 1997).

There have been relatively few studies presenting IFT measurements in crude oil-water systems, but these can be considered the most reservoir-representative. Figure 8 shows a compilation of laboratory measurements within the envelope of pressures and temperatures valid for geothermal gradients between 25 and 35 °C/km and hydrostatic pressure gradient of 10 MPa/km. The compilation includes samples of crude oil above bubble point representing non-degassed oils, below-bubble point oils and methane. The IFT values of crude oil range 26-42 mN/m and are more strongly controlled by chemical differences rather than depth. IFT of methane decreases with depth and ranges from 40 to 53 mN/m. Based on this example dataset, it is assumed that the IFT values of hydrocarbons used in the empirical calibration method are expected to be within a uniform probability distribution with a mean value of 39 ± 8 mN/m (Fig. 9a).

In the context of capillary seal modelling, reservoir formations are generally considered to be water-wet in the presence of hydrocarbons (contact angle = 0°) (e.g. Schowalter, 1974; Vavra et al., 1992). This is not strictly true, with mixed-wet and oil-wet states often observed in hydrocarbon reservoirs (Treiber and Owens, 1972), often due to mineral surface coating with high polarity crude oil components such as asphaltenes which have high affinity to the reservoir minerals (Alipour Tabrizy et al., 2011; Singh et al., 2016). The degree of oil-wetting is expected to be higher in reservoirs containing high maturity oil and in the presence of carbonate cements, smectite, chlorite, kaolinite and iron-oxides (Barclay and Worden, 2009; Worden and Morad, 2000). Because the contact angle directly affects the calculated column heights and associated threshold capillary pressures, the practice of assuming 0° contact angle in hydrocarbon reservoirs always provides a maximum rather than conservative estimate. In the absence of strong statistical data, we assume that reservoir rocks are more commonly water-wet than oil-wet in the presence of hydrocarbons. This spread of data is best described by an exponential probability distribution ($\beta = 15$), with a mean value of 15 ± 15° (Fig 9b) The lowest values in the range are the most probable. Based on Equation 3, retention of a gas column is only possible when the contact angle is ≤ 90° ($\cos\theta > 0$). Because the data set by definition only includes reservoirs with observed columns, contact angles must range between 0 and 90°.

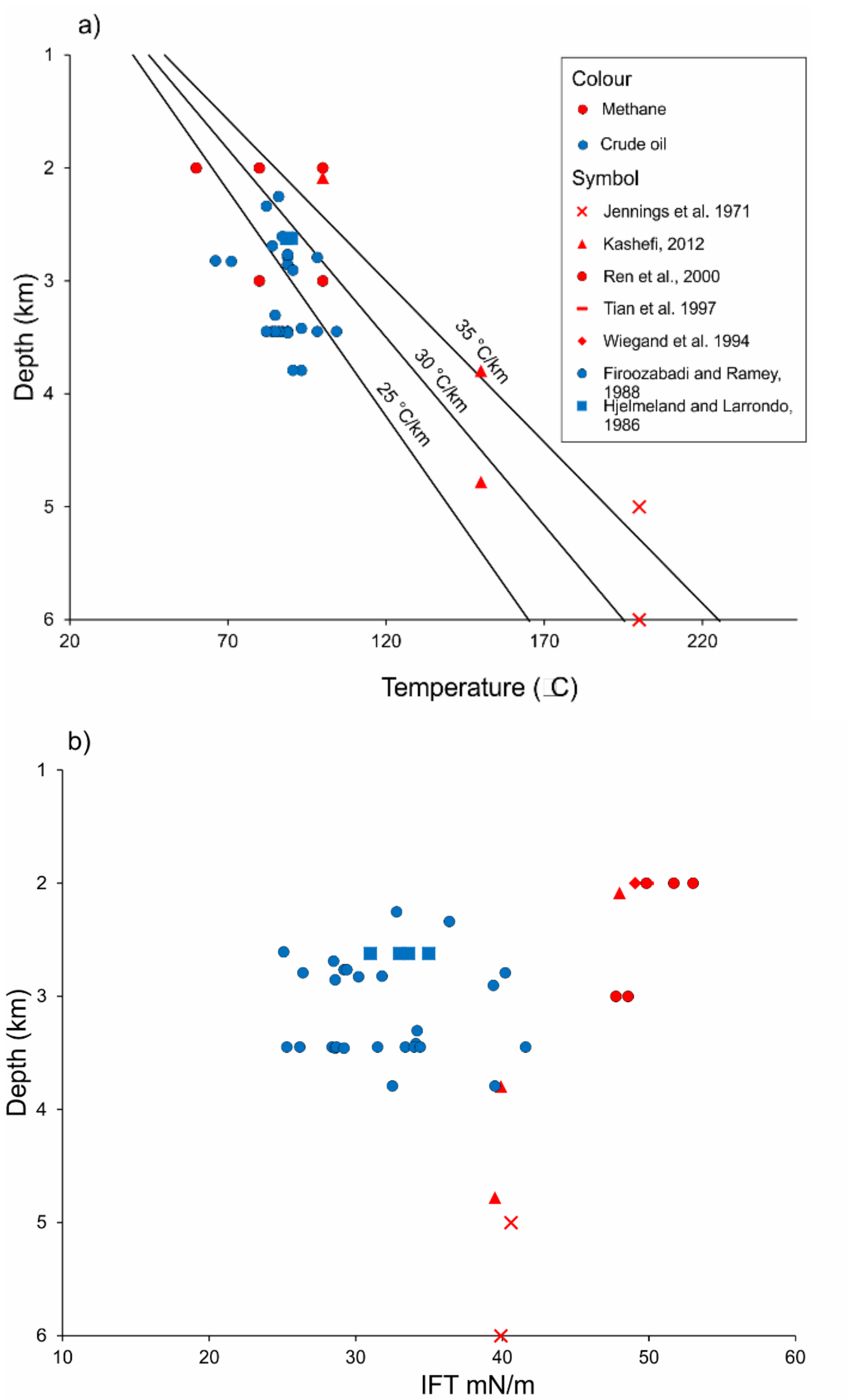


Figure 8. IFT of crude oil and methane data compilation from the literature, filtered to conditions applicable to geological pressure and temperature conditions (25 - 35 °C/km geothermal gradient). a) shows the distribution depth vs temperature conditions, b) shows the IFT values of the same data points. Crude oil IFT values range between 26 - 42 mN/m

and are uniformly distributed. Methane values range 40 - 53 mN/m and decrease with depth. Combined together, this data represents a uniform distribution.

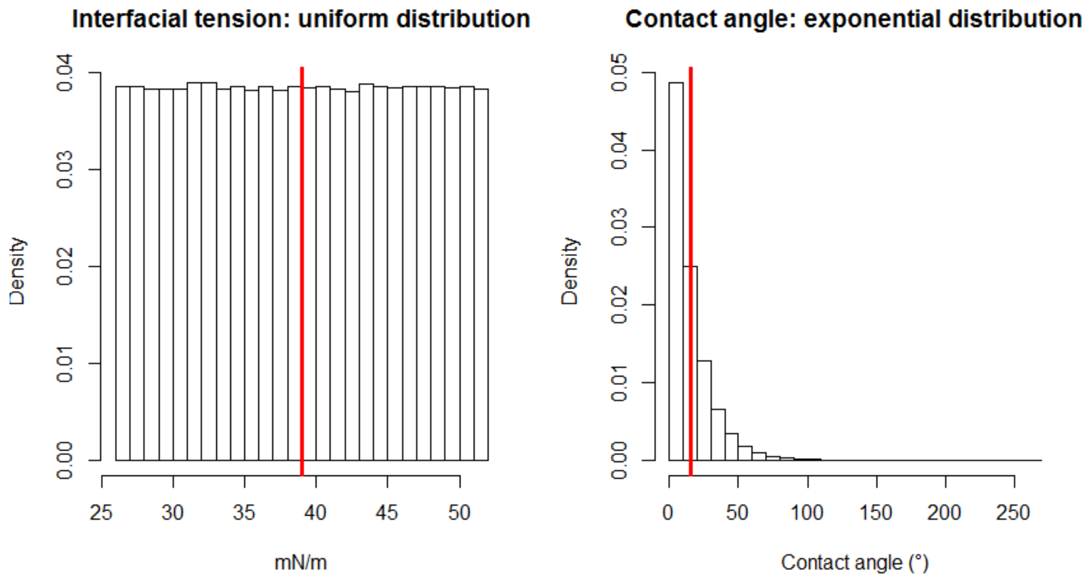


Figure 9. Probability distribution of IFT (a) and contact angle (b) in hydrocarbons at reservoir conditions below 2 km depth, defined based on a literature review of laboratory studies (discussed in text). Red vertical line shows mean. IFT is expected to be uniformly distributed with a mean value of 39 ± 8 mN/m. Exponential distribution (β =15) best describes the expected contact angle.

Based on the probability distributions of IFT and contact angle determined above, the percentage error of threshold capillary pressure (δP_c) determined from Equation 5 using Monte Carlo random sampling analysis (n = 10^6) is 24%. Figure 10 shows the seal failure envelopes of the empirical model (Yielding et al., 2010) with the calculated error added. The seal envelopes define the upper boundary of all buoyancy pressures observed to be sealed by fault rocks and therefore statistically represent the higher values within the data distribution or maximum threshold capillary pressure. We can therefore use the calculated uncertainty to estimate the average threshold capillary pressure $(P_c - \sigma)$ and minimum threshold capillary pressure $(P_c - 2\sigma)$. The uncertainty increases with increasing P_c.

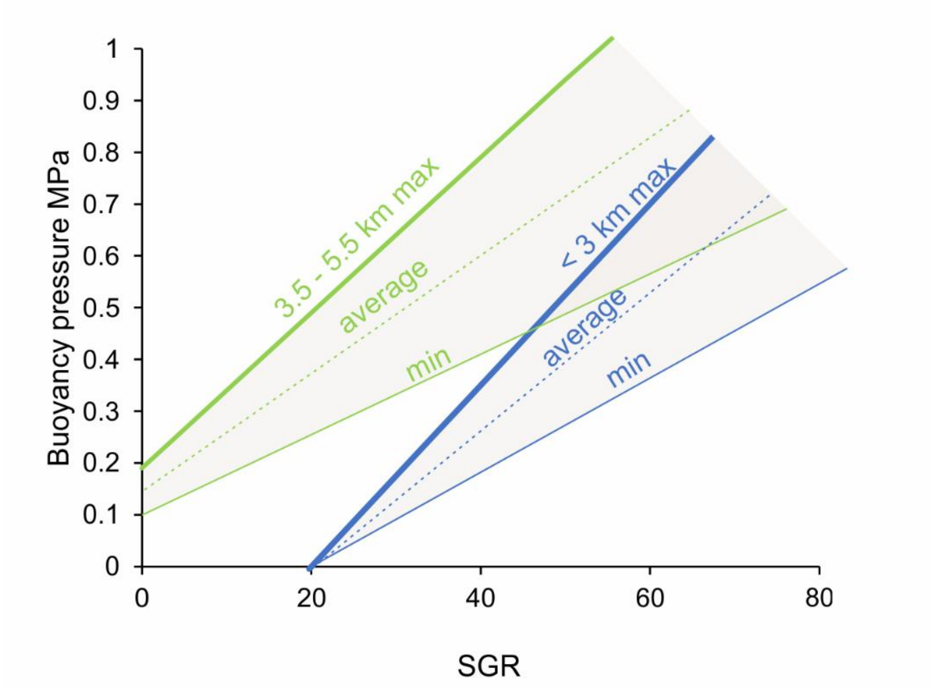


Figure 10. SGR vs Buoyancy pressure with < 3 km and 3.5 - 5.5 km threshold capillary pressure envelopes from Yielding et al. (2010). The thick solid line shows the original maximum threshold capillary pressure. Dashed lines show calculated average and minimum pressures for given burial depth brackets.

6.3.1.1 Implications for use in hydrocarbons

The calculated uncertainty envelopes do not change the interpretation of the empirical calibration method, but rather provide additional constraints that can be applied in variety of contexts. In cases where capillary pressure modelling is used to assess the economic viability of the reservoir, the uncertainty can be a useful input into the risking process. The average threshold capillary pressure value is better used in the calculation of likely hydrocarbon column heights, bearing in mind that the true column height can be controlled by many factors independent to fault seal such as structural spill points and charge. In cases where sufficient geological evidence exists to indicate that the trap has been filled, the calculated uncertainty envelope provides means to determine the minimum expected column. The average threshold capillary pressure value using the empirical method is also more comparable to the average results of the deterministic method (rather than using the current empirical max value) when the two are used in conjunction.

6.4 b) Empirical method applied to the fluid properties of CO_2

In the last decade significant effort has gone into characterising IFT of CO_2 at a range of conditions, with existing data covering CO_2/water (Chiquet et al., 2007a; Georgiadis et al., 2010) and CO_2/brine with variable salinity and salt types (Bachu and Bennion, 2009; Chalbaud et al., 2009). IFT has been characterised for mixtures of CO_2 and methane in water (Ren et al., 2000) and brine (Liu et al., 2016). Increasing brine salinity has been shown to increase the IFT in CO_2/brine system with significant deviations in saline and hypersaline conditions (Bachu and Bennion, 2009; Chalbaud et al., 2009; Liu et al., 2016). Figure 11 shows results from published laboratory studies filtered to those representative of pressure and temperature conditions in the subsurface (geothermal gradients 25 – 35 °C/km, hydrostatic pressure gradient 10 MPa/km). The data includes pressures above 15 MPa (~1.5 km depth), which is in line with depths recommended for safe geological CO_2 sequestration (> 1.2 km) (Miocic et al., 2016). It is apparent that in the supercritical fluid state, depth does not significantly influence the IFT. The most important controlling factor is brine salinity which increases the IFT due to increasing density contrast between CO_2 and the brine. The maximum IFT values of 44.7 and 41.1 mN/m at 1.7 km and 2.7 km depth respectively from the study of Bachu and Bennion (2009) are measured in brines of 334 g/L salinity, which is close to the maximum possible salt saturation in water. In comparison, the salinity of UK oil and gas fields ranges from 30 to 227 g/L with an average value of 130 g/L (Gluyas and Hichens, 2003). The IFT range presented here covers the minimum (CO_2-pure water) to maximum (CO_2-hypersaline brine) geologically possible conditions relevant to CO_2 sequestration context (> 1.5 km depth), and also falls within the range observed in liquid hydrocarbons. The IFT values range between 26 to 45 mN/m, which is remarkably similar to IFT range in crude oil (26 – 42 mN/m, Fig. 8).

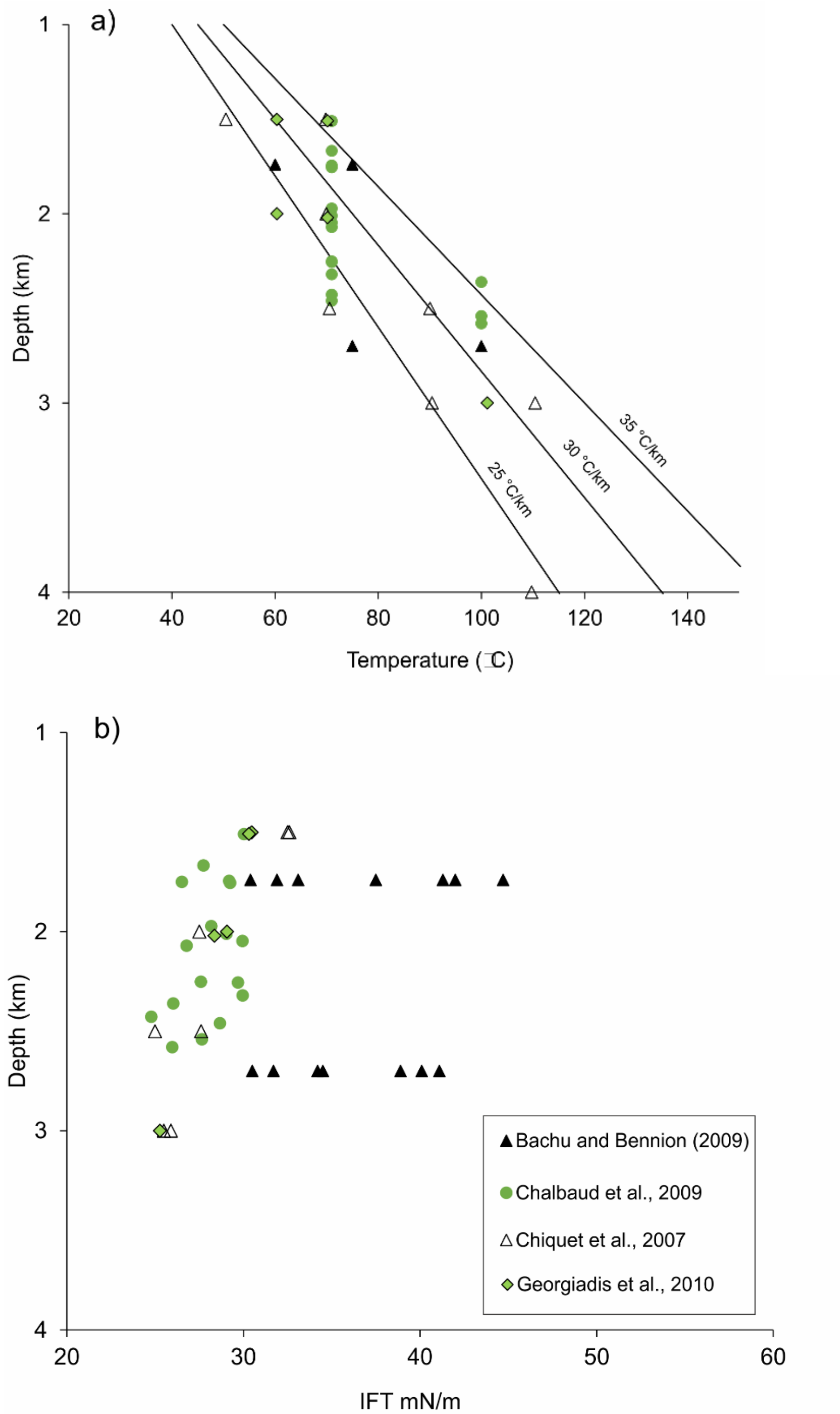


Figure 11. IFT of CO_2 in water and brine of different salinities, filtered to only display pressure and temperature conditions applicable to geological setting (25-35 °C/km geothermal gradient). a) shows the distribution depth vs temperature conditions, b) shows the IFT values of the same data points. IFT ranges 26-45 mN/m. Datapoints from Bachu and Bennion (2009) show the effects of increasing salinity, with a maximum of 334 g/L resulting in the highest IFT values.

The wettability in CO_2-brine system is a complex issue and cannot be easily defined as a bracket range for all reservoir conditions. The conditions of many experimental set ups are very different to reservoir conditions, as discussed in section 4.1.4, therefore the upscaling of single mineral experimental results to reservoir is problematic Irrespective of this variation, the most significant observation emerging from CO_2-brine lab studies is the change in wettability caused by pressure. This is observed when CO_2 changes from gaseous to supercritical fluid phase at around 8 MPa. It is presently not understood if the change in wettability is related to the process of phase change or to the physical properties of supercritical CO_2.

In summary, the IFT values for CO_2 are similar to those of oil, while methane IFT values are higher on average. The contact angles in CO_2-brine system present a higher level of uncertainty and are hard to evaluate as a generic range. IFT and contact angles can however be defined with higher confidence for specific reservoir conditions, as exemplified by this study.

6.4.1 Conversion factor from hydrocarbons to CO_2

This work has defined an average value (μ) of the probability distributions of IFT (39 mN/m) and CA (15°) for hydrocarbons under pressure and temperature conditions included in the calibration dataset by Yielding et al. (2010). This means that the calculated threshold capillary pressure of hydrocarbons can be converted to CO_2-brine system for chosen IFT and CA values of CO_2:

$$P_c(CO_2) = P_c \times \frac{IFT_{CO2} \times cos\theta_{CO2}}{\mu IFT_h \times \mu cos\theta_h} \qquad (6)$$

This can also be applicable to hydrocarbons in instances where IFT and CA are well defined and significantly different to the average values.

Figure 12 shows calculated column heights calculated using the standard empirical and deterministic methods, compared to the empirical model after conversion to CO_2 using Equation 6 (maximum value) and calculated average and minimum values. For the Katnook methane system, the correction factor increases the column heights for methane due to higher IFT, but the overall change is not significantly different from the original empirical model. The current column is predicted to be stable regardless of the correction.

The maximum column height for the Boggy Creek CO_2 field is reduced by the correction, with the average empirical value slightly higher than the column height value known to be held by the fault. This prediction is in closer agreement to the deterministic model, and is more likely to be correct based on the geochemistry of the fields, indicating higher mantle CO_2 contents at Boggy Creek than in the adjacent Buttress field and suggesting initial charge to Boggy Creek lead to subsequent migration into Buttress. The current column in Boggy Creek is not near the structural spill point, suggesting the CO_2 transfer between the fields occurred through the fault rock, and the current column is therefore expected to be near the threshold value.

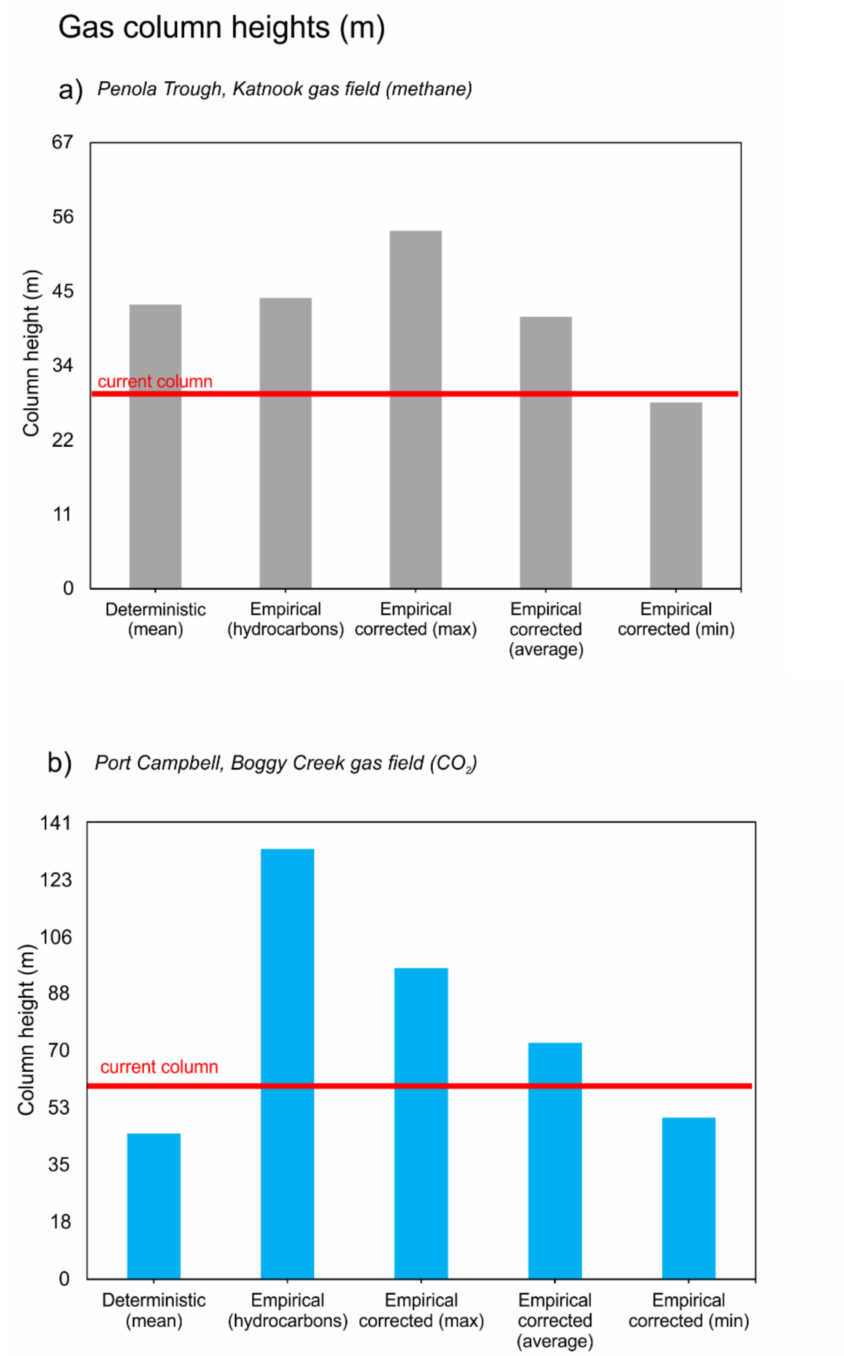


Figure 12. Gas column heights a) Penola Trough, Katnook field b) Port Campbell, Boggy Creek field. Current live columns marked in red. Models shown: deterministic (Sperrevik et al., 2002), empirical (Yielding et al., 2010), empirical corrected max, average and min values (this work).

7 Conclusions

Two gas fields sealed by fault rocks were examined to compare the standard fault seal analysis techniques applied to methane-brine and CO_2-brine systems. In both cases, the column heights supported by the fault rocks were known, and geochemical gas analysis provided evidence for across-fault connectivity. This allowed us to assess and compare the strengths and weaknesses of two fault seal calibration methods (Sperrevik et al., 2002; Yielding et al., 2010).

The deterministic method predicted critical buoyancy pressure in Katnook (methane) and Boggy Creek (CO_2) fields. The empirical method predicted critical buoyancy pressure in Katnook field and well below threshold pressure in the Boggy Creek field. However, after accounting for uncertainty and applying the newly proposed correction for CO_2, the method also predicted criticality. Thus, the geochemistry and fault seal analysis results corroborate each other.

CO_2 fluid properties and their differences from hydrocarbons have been previously identified as the biggest uncertainty associated with fault seal application to CO_2 systems. However, an extensive literature review showed that a similar spread in IFT values exists within the hydrocarbons, due to the wide range of possible chemical compositions of crude oil. This means that IFT in CO_2-brine system is easier to identify for particular pressure and temperature conditions than in liquid hydrocarbons. Wettability of hydrocarbons is not very well characterised either, and the recent academic focus to CO_2 sequestration applications means that currently far more laboratory experimental data exists for CO_2-brine systems. Perhaps surprisingly, the main challenge in adapting fault seal modelling techniques from hydrocarbons to CO_2 is the uncertainty associated to the hydrocarbon properties.

The two fault seal prediction methods discussed here come with different inherent uncertainties and are best used in conjunction, bearing in mind the differences in the approach. The deterministic method (Sperrevik et al., 2002) can be applied to different fluids via the input of IFT and CA. This work has presented a similar conversion factor system applied to the empirical method (Bretan et al., 2003; Yielding et al., 2010). To do this, an average range of IFT and CA in hydrocarbons under reservoir conditions was determined from literature review. The uncertainty related to the spread in fluid properties was calculated to be 24% of the calculated threshold capillary pressure value. This finding does not change the application of the empirical method, which by definition provides a maximum estimate for capillary threshold pressures. However, it allows to constrain an average and minimum capillary pressure values, which can be used to ascertain 'most likely' and minimum column heights in hydrocarbon exploration. The newly defined average capillary threshold pressure value also allows for better comparison with the deterministic method, which by definition models average rather than maximum pressures.

The definition of average IFT and CA of the dataset in the empirical method also allows the conversion of the threshold capillary pressures to other fluid systems, which is desirable for the application to CO_2 sequestration. In application to CO_2 storage, where a full column is fully or partially sealed by a fault, the buoyancy pressure must not exceed the minimum threshold capillary pressure value. However, the minimum values discussed here do not equate to safe or recommended buoyancy pressures for CCS contexts. Future studies should define the recommended limit in relation to the minimum threshold capillary pressure values defined here, based on risk analysis and regulatory guidelines.

8 Acknowledgments

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