Carbon dioxide storage in the Captain Sandstone aquifer: determination of in situ stresses and fault-stability analysis

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Abstract: The Lower Cretaceous Captain Sandstone Member of the Inner Moray Firth has significant potential for the injection and storage of anthropogenic CO₂ in saline aquifer parts of the formation. Pre-existing faults constitute a potential risk to storage security owing to the elevated pore pressures likely to result from large-scale fluid injection. Determination of the regional in situ stresses permits mapping of the stress tensor affecting these faults. Either normal or strike-slip faulting conditions are suggested to be prevalent, with the maximum horizontal stress orientated 33°–213°. Slip-tendency analysis indicates that some fault segments are close to being critically stressed under strike-slip stress conditions, with small pore-pressure perturbations of approximately 1.5 MPa potentially causing reactivation of those faults. Greater pore-pressure increases of approximately 5 MPa would be required to reactivate optimally orientated faults under normal faulting or transitional normal/strike-slip faulting conditions at average reservoir depths. The results provide a useful indication of the fault geometries most susceptible to reactivation under current stress conditions. To account for uncertainty in principal stress magnitudes, high differential stresses have been assumed, providing conservative fault-stability estimates. Detailed geological models and data pertaining to pore pressure, rock mechanics and stress will be required to more accurately investigate fault stability.

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Large-scale deployment of CO₂ storage as a strategy for reducing greenhouse gas emissions will rely on the integrity of sealing strata overlying the storage reservoirs to ensure that the captured CO₂ is permanently isolated from the atmosphere (IPCC 2005; Chadwick et al. 2009a; Holloway 2009). The existence of pre-existing fault systems of varying dimensions is a common feature throughout the subsurface, and the efficacy of seals may potentially be compromised by any enhanced transmissibility associated with fault zones. Within the Moray Firth, the Lower Cretaceous Captain Sandstone Member of the Wick Sandstone Formation has been proposed as a suitable storage reservoir candidate (SCCS 2011; Shell 2011a; Akhurst et al. 2015). Storage potential exists within depleting hydrocarbon fields (Marshall et al. 2016), while significant additional capacity is available in the surrounding saline aquifer volume. Regional top seals include the Cretaceous Rodby, Carrack and Valhall formations. Simulation studies of CO₂ injection identified the storage capacity of the Captain Sandstone to be between 358 and 2495 Mt (Jin et al. 2012). As the injection of CO₂ is reliant on the displacement of existing pore fluids, large-scale injection results in increased pore-fluid pressure, the effects of which will be felt across large areas in well-connected aquifer systems (Chadwick et al. 2009b; Jin et al. 2012; Noy et al. 2012).

It is well documented that some faults are transmissible to fluid flow, while others act as effective capillary seals (Caine et al. 1996; Aydin 2000; Faulkner et al. 2010). Whether cross-fault flow occurs depends on the juxtaposition of lithologies in the footwall and hanging-wall blocks, as well as the composition of the fault zone and any differential pressure across the fault. In addition, reactivation of previously stable faults caused by increasing pressure, and therefore a reduction in the effective stress, could allow faults to become transmissive to buoyant fluids, such as supercritical CO₂, due to the opening of flow pathways during failure (Streit & Hillis 2004). It is this aspect of fault stability that forms the focus of this study, with respect to the Captain Sandstone of the Inner Moray Firth, and utilizing an adaptation of the geological model presented by Jin et al. (2012).

Analysis of the geomechanical stability of faults offsetting the Captain Sandstone requires the contemporary stress field affecting the basin to be characterized, in order to resolve the shear and normal stresses acting on mapped faults and to determine which faults, or segments of faults, are most susceptible to becoming reactivated if pore-fluid pressures in the basin are increased as a result of CO₂ injection. In order to do so, detailed knowledge of the pore-pressure conditions at depth, the magnitude and orientations of the principal stresses, and the properties of the faults is required.

Geological setting

The Captain Sandstone is located within the eastern part of the Inner Moray Firth (IMF), and the western part of the Outer Moray Firth (OMF) basins (Fig. 1). In general, the present-day geological structure of the Moray Firth region is characterized by ENE–WSW-trending fault-defined horsts, basins and sub-basins formed from a series of Mesozoic displacements. The IMF has a dominantly NE structural trend, while the OMF has a predominantly NW structural trend. Subsequent reactivation of some of the faults during the Cenozoic resulted in some fault displacements propagating to the seabed. The ENE-trending Wick Fault Zone marks the northern boundary of the present study area. The Smith Bank (ENE-trending), West Halibut (east–west– to NW–SE-trending) and the Little Halibut (NW-trending) faults mark the boundaries of the Halibut Horst, a major Jurassic structural high that lies beneath the southern part of the study area. The Halibut Horst was present throughout the Lower Cretaceous where it influenced sedimentation patterns of the deep submarine fans that include the Captain sandstone; the horst was eventually submerged during the Late Cretaceous (Ahmadi et al. 2003). A major rifting event, spanning Late Jurassic–Early Cretaceous times, comprising faulting episodes interspersed by periods of
relative tectonic quiescence, resulted in the development of numerous half-graben and associated synrift deposits over the area (Hillis et al. 1994; Zanella & Coward 2003). The regional extension direction during this time was NE–SW, resulting in the formation of new NW-trending normal faults or reactivation of existing faults with normal or strike-slip components depending on their orientation: for instance, existing ENE-trending faults might have been reactivated with a strike-slip component (Zanella & Coward 2003). The progressive onlap shown by Lower Cretaceous shales and sands onto basin margins and of the Upper Cretaceous Chalk onto basin highs is interpreted as evidence of a post-rift thermal phase of subsidence, with the sedimentary environment in this area set against a background of rising sea level (Hillis et al. 1994). However, during the Lower Cretaceous, this general increase in sea level was punctuated by sea-level falls during the Hauterivian–Valanginian and later during the Aptian times, related to far-field tectonic events (Oakman 2005). These periods of lowered sea level exposed shelf areas and caused sand, originally sourced from north and west of the Wick Fault Zone, to be deposited in deeper water by gravity-flow processes feeding submarine fans that led to the accumulation of the Wick Sandstone Formation (Fig. 2) (Johnson & Lott 1993). The half-graben topography played an important role in the distribution of Lower Cretaceous sandstones in these basins (Rose et al. 2000). Deposition of the Late Cretaceous
Chalk Group reflects the widespread flooding of the basin/high topography during a time of relative tectonic quiescence but punctuated by pulses of compression related to the Alpine Orogeny, although in the study area the effects are thought to be quite weak (Zanella & Coward 2003). Regional uplift of the Scottish Highlands and East Shetland Platform at the beginning of the Paleocene led to the deposition of large volumes of siliciclastic sediments (Ahmadi et al. 2003). In the study area, a shelf-environment setting prevailed with deposition characterized by transgression and restricted deposition along basin margins or regression leading to more widespread gravity-flow deposition into the basin itself (Garrett et al. 2000; Ahmadi et al. 2003). It is generally accepted that the subcrop of Mesozoic and Cenozoic rocks at the seabed in the Inner Moray Firth is the result of Cenozoic uplift (Argent et al. 2002), and Hills et al. (1994) suggested significant uplift and erosion during the Danian. Cenozoic uplift led to the reactivation of earlier faults, some of which have propagated to the seabed. However, Richardson et al. (2005) noted that the main bounding fault of the Beatrice Field had not propagated to the seabed and remained as a seal for the trapped hydrocarbons.

Over the study area, the post-Jurassic succession comprises Paleocene, Upper Cretaceous Chalk and Lower Cretaceous Cromer Knoll groups that shallow and progressively subcrop the seabed towards the coast (Fig. 1). The Lower Cretaceous Cromer Knoll Group generally rests conformably on Upper Jurassic sediments over much of the area (Thomson & Underhill 1993) and reaches thicknesses of more than 1000 m to the NW, adjacent to the Wick Fault Zone (Copestake et al. 2003), but thins and onlaps the Captain Ridge and Halibut Horst (Rose 1999). In some areas, the Lower Cretaceous and underlying Jurassic are absent, and Upper Cretaceous Chalk rests unconformably on Devonian Old Red Sandstone. The Upper Cretaceous Chalk varies in thickness from 250 to 500 m, and reaches over 750 m south of the Wick Fault Zone. It is absent along the western margin of the model due to erosion (Surlýk et al. 2003) and here the underlying Lower Cretaceous stratigraphy subcrops at the seabed (Fig. 1). The Paleocene is also absent along the western margin of the model, but thickens rapidly to more than 900 m on the southern side of the Halibut Horst, and varies between 200 and 750 m over much of the study area (Ahmadi et al. 2003).

The Lower Cretaceous Cromer Knoll Group (Fig. 2) (Johnson & Lott 1993) comprises the Rodby, Carrack, Valhall and Wick formations. The Lower Cretaceous Wick Sandstone Formation comprises laterally extensive units of occasionally thick sandstone interbedded with siltstone and mudstone that are interpreted as having been deposited by a range of mass-flow processes (Fig. 2) (Johnson & Lott 1993). The Wick Sandstone Formation has been divided into three members: the Captain Sandstone (Early Aptian–earliest Albian) is the youngest of three members, the others being the Coracle (latest Early Hauterivian–earliest Barremian) and the Punt (intra-Late Ryazanian–earliest Hauterivian). Because there are fewer well penetrations at depth, the older members are poorly resolved on seismic data, and the extent and disposition of the Coracle and Punt sandstones is not well known. The Wick Sandstone Formation passes laterally into the dominantly mud-prone successions of the Valhall Formation, which comprises interbedded calcareous mudstone and thin limestone, and the Carrack Formation that comprises non-calcareous, carbonaceous, pyritic, micaceous mudstone and siltstone: both of these formations may also locally contain mass-flow sandstone and occasional conglomerate (Johnson & Lott 1993). The overlying Rodby Formation comprises calcareous mudstone with occasional thin beds of argillaceous limestone.

** Geological model location and context**

Hydrocarbons are produced from the Captain Sandstone in several fields, notably the Captain and Blake oil fields, the Cromarty Gas Field, and the Atlantic and Goldeneye gas condensate fields. The Wick Fault Zone forms the northern boundary to the Captain Sandstone, while faulting and stratigraphic closure form the southern boundary. With the exception of the Captain Oil Field, which is situated on the Captain Ridge to the west of the Halibut Horst, the other fields are located along a thin sand-rich pan-handle termed the Kopervik Fairway (Law et al. 2000) that extends eastwards along strike of the South Halibut Trough. The depleted Goldeneye Field has been proposed as a site for the storage of CO₂ (Shell 2011a; Marshall et al. 2016): however, the present study focuses on the main depocentre to the West of the Halibut Horst, corresponding roughly to the Wick Sub-basin, the Smith Bank High and the Smith Bank Graben, where a pre-existing 3D geological model is available. The model does not extend eastwards beyond the Atlantic Field in the vicinity of the Grampian Arch, and so does not include the full length of the Kopervik Fairway (Fig. 1). The model comprises the Captain Sandstone aquifer and its under- and overburden, and has been adapted from interpretations used to generate the reservoir simulation model of Jin et al. (2012), based on interpretation of 2D seismic reflection and well data. The data and methodology that contributed towards the geometry and structure of the original model is described in a research report (Quinn et al. 2010), and is not described in detail here.

Unlike the proposed Goldeneye storage site, in this area there are no specific structural traps that have been specifically identified for CO₂ storage, so any prospective projects would need to take measures to avoid the updip migration of CO₂ towards shallower depths and, ultimately, towards the seabed. Jin et al. (2012) conducted multiphase fluid-flow simulations which demonstrated that storage capacities in excess of 1 Gt could be achieved without CO₂ reaching a depth significantly shallow so as not to exist in a supercritical state, limiting the risk of westwards migration towards the seabed. Water depth across the study area is in the range of 30–120 m, with an average of 90 m.

In the adapted model used here, faulting has been restricted to those faults that affect the Captain Sandstone reservoir and its overburden only, as these are the faults most likely to experience increased pressure during injection and to pose a risk to storage integrity. Deeper faults that do not cut the Captain Sandstone or its overburden would not be expected to experience significant increased pore-pressure perturbations as a result of injection, so reactivation of these faults, although possible, is not considered a risk to storage integrity despite the potential for induced seismicity. The number of faults within the model was therefore reduced from 43 to 15. It is noted that unmapped or non-seismically resolvable faults are also likely to be present across the study region given that no 3D seismic reflection data were available to the mapping exercise. The potential presence of such faults should also be considered in studies of regional geomechanical stability.

**Fig. 3. Pressure measurements and hydrostatic gradient to surface across the Captain Sandstone. Location of the wells shown in Figure 1.**
As shown by Figure 1, the area is relatively aseismic, with the exception of a series of seismic events clustered around the Beatrice Oil Field. Although the co-location of the seismicity in relation to the field boundaries suggest that they may be related to petroleum production, Wilson et al. (2015) curiously observed little correlation in relation to the production and injection history of the field. The vertical stress ($S_z$) significantly affect the results of the fault-stability analysis. For example, the pore-fluid pressure is unlikely in the area west of the Kopervik Fairway due to pressure maintenance in the Captain and Blake oil fields (Du et al. 2000; Pinnock & Clitheroe 2003). Owing to the good fit of the assumed gradient to the observed data, the variation in the pore-pressure gradient is expected to be small and should not significantly affect the results of the fault-stability analysis.

**Pore-fluid pressure**

Direct measurements of pore-fluid pressure over the Lower Cretaceous are available from several hydrocarbon wells across the study region. Repeat Formation Tester (RFT), Modular Formation Dynamics Tester (MDT) and Formation Multi Tester (FMT) data provide pressure measurements over the Captain, Coracle and Ettrick sandstones, and record a pore-fluid pressure gradient of approximately 0.01 MPa m$^{-1}$ (Fig. 3). A similar pore-pressure gradient is seen in the Jurassic Claymore and Ross Sandstone members in well 13/26a-4. The pore-pressure measurements are slightly above an assumed hydrostatic gradient of 10 MPa km$^{-1}$ from the surface level, but as the Lower Cretaceous penetrated by these wells contains hydrocarbons, and given the lack of information regarding brine salinity variations with depth, a pore-pressure gradient of 10 MPa km$^{-1}$ to the surface is assumed over the wider area. Despite the history of oil and gas production from the Captain Sandstone, widespread pressure depletion of the reservoir periphery is unlikely in the area west of the Kopervik Fairway due to pressure maintenance in the Captain and Blake oil fields (Du et al. 2000; Pinnock & Clitheroe 2003).

**Stress orientations**

The vertical stress ($S_z$) is generally considered to be one of the principal stresses in the subsurface, while the other two principal stresses are horizontal and orthogonal to each other. Borehole breakout and drilling-induced tensile fractures are modes of borehole failure resulting from stress concentration in the rock around a wellbore once the material supporting that rock is removed (Zoback et al. 1985; Bell 1990). Breakouts are enlargements of the borehole wall formed by the development of conjugate shear fractures, while drilling-induced tensile fractures develop as narrow features sub-parallel to the borehole axis in vertical wells and are not associated with significant borehole enlargement. In approximately vertical boreholes, such as those studied here, breakouts occur in the direction of the minimum horizontal stress ($S_{hmin}$) and therefore the borehole is enlarged in a direction perpendicular to the maximum horizontal stress ($S_{Hmax}$). The measurements have been subjected to the quality ranking scheme utilized by the World Stress Map (WSM) project (Sperner et al. 2003; Heidbach et al. 2010). They are considered to represent good

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**Table 1. Summary of wellbore breakouts interpreted from image logs. The mean and standard deviation have been calculated using the directional statistics of Mardia (1972). Image logs for well 13/24a-6 were not reinterpreted as part of this study.**

<table>
<thead>
<tr>
<th>Well name</th>
<th>Image type</th>
<th>Start depth (m)</th>
<th>Number of breakouts</th>
<th>Total length (m)</th>
<th>$S_{Hmax}$ azimuth</th>
<th>Standard deviation</th>
<th>WSM rank</th>
</tr>
</thead>
<tbody>
<tr>
<td>13/21a–4</td>
<td>FMI</td>
<td>937</td>
<td>1</td>
<td>0.73</td>
<td>30</td>
<td>–</td>
<td>D</td>
</tr>
<tr>
<td>13/24b–3</td>
<td>UBI</td>
<td>1590</td>
<td>4</td>
<td>2.9</td>
<td>42</td>
<td>12</td>
<td>D</td>
</tr>
<tr>
<td>13/26a–4</td>
<td>FMI</td>
<td>1021</td>
<td>10</td>
<td>8.15</td>
<td>29</td>
<td>6</td>
<td>D</td>
</tr>
<tr>
<td>13/24a–6</td>
<td>STAR</td>
<td>–</td>
<td>27</td>
<td>–</td>
<td>33</td>
<td>–</td>
<td>–</td>
</tr>
<tr>
<td>Combined</td>
<td>–</td>
<td>937–1590 (range)</td>
<td>15</td>
<td>11.78</td>
<td>33</td>
<td>9</td>
<td>D</td>
</tr>
</tbody>
</table>

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**Fig. 4.** Example of breakouts from UBI logs in well 13/24b-3. Breakouts are identified by darker zones of increased borehole radius. Note also the borehole enlargement indicated by the caliper log.
measurements of the horizontal stress directions due to the clarity of the processed images: however, these would be classified only as category D measurements according to the WSM ranking scheme. This is due to the limited number of observed breakouts in these wells and to the short combined length (height) of the observed breakouts. As the breakout orientations appear to be consistent across the region, they are considered to be representative of the far-field orientation of $S_{\text{Hmax}}$, so the mean orientation of 33°–213° derived from all breakout orientations using the directional statistics of Mardia (1972) is used in this analysis. The orientations of $S_{\text{Hmax}}$ are shown in Figure 6. These observations are consistent with those of 27 breakouts that indicate $S_{\text{Hmax}}$ striking in a mean orientation of 33°–213° reported from the Valhall Formation in well 13/24a-6, interpreted from the analysis of Simultaneous Acoustic and Resistivity (STAR) image logs reported by Hilton (1999). Although the STAR image logs have not been reinterpreted for this study, the reported orientation of $S_{\text{Hmax}}$ from the well is also shown in Figure 6. Although it is noted that only a limited dataset is available, the mean $S_{\text{Hmax}}$ orientation is considered to be reasonably well constrained due to the similarity of orientations at different depths and in each of the studied wells, and due to the low standard deviation of all the breakouts (9.4°). It is not expected that a variation of this amount will be sufficient to significantly affect the fault-stability analysis.

The far-field stresses affecting NW Europe result from the configuration of tectonic plate boundaries and associated ridge-push forces (Grilke & Koblenz 1996); however, the orientations of $S_{\text{Hmax}}$ observed from the IMF suggest a departure from the NW–SE orientation expected, which is observed onshore UK (Kingdon et al. 2016). This suggests that the structural lineaments bounding the IMF Basin have altered the orientation of the tectonic stresses, a feature of the North Sea stress field previously suggested by Cowgill et al. (1993). Perman evaporite sequences are relatively thin and do not impose a control on the Mesozoic–Recent stress regime as they have been proposed to do in the Central and Southern North Sea regions (Hillis & Nelson 2005; Williams et al. 2015).

**Stress magnitudes**

The magnitude of the vertical stress ($S_v$) was obtained by integrating rock densities from downhole bulk density logs in three wells using equation (1), after Zoback et al. (2003):

$$S_v = \rho_w g z_w + \int_{z_w}^{z} \rho(z) g \, dz = \rho_w g z_w + \rho g (z - z_w)$$  

where $\rho(z)$ is density as a function of depth, $g$ is the acceleration due to gravity, $\rho$ is the mean overburden density, $\rho_w$ is the density of water (taken as 1 g cm$^{-3}$) and $z_w$ is water depth. As the strata in the shallower section were not logged by the density tool (Fig. 7a), an average rock density of 2.5 g cm$^{-3}$ was inferred for the unlogged section up to the seabed. An average overburden stress profile was calculated from the three wells and is shown in Figure 7b. The overburden stress gradient to the seabed can be conveniently expressed as a $S_v$ gradient of 25 MPa km$^{-1}$. The lack of density logs in the shallower section (Fig. 7a) gives rise to some uncertainty regarding the magnitude of $S_v$. Bulk density of the relatively less-consolidated Palaeogene in the shallower subsurface is likely to be less than that assumed, and so the calculated overburden stress profile could give rise to slightly elevated $S_v$ magnitudes at depth. This would result in greater differential stress between $S_v$ and the minimum principal stress, resulting in a higher susceptibility of faults to fail. The fault-stability analysis is therefore regarded as conservative.

The magnitude of the least principal stress ($S_{\text{hmin}}$) is commonly estimated from leak-off tests (LOTs), during which short open-hole well sections beneath cemented casing shoes primarily to assess suitable drilling mud densities, but can also be used to determine the magnitude of the least principal stress. Available LOT data for four wells in the area are shown in Table 2. Extended leak-off tests (XLOT) provide an improved estimate of the $S_{\text{hmin}}$ magnitude: however, no such data are available in the study area. In the absence of XLOT measurements, the lower bound of LOT data provides an estimate of $S_{\text{hmin}}$, although it is noted that XLOTs should be acquired where detailed stress data are required (Addis et al. 1998; White et al. 2002).

A single LOT value is reported for the 13/24b–3 well, recorded in the Tor Formation in the uppermost part of the Chalk Group. The value reported is close to the calculated $S_v$ of approximately 23.14 MPa at that depth. As the test was taken in strata described as firm–hard limestone at relatively shallow depth (998 m below sea level, as shown in Fig. 8), it is uncertain how the least principal stress magnitude would be determined for well 13/22a-21.
stress magnitude relates to the unconsolidated sandstones of the Captain Sandstone Member or to the mudstones of the overlying Rodyb Formation caprock. The other three reported LOT values were all taken from the Aptian–Barremian-aged Valhall or Wick Sandstone formations, and the values are therefore more likely to represent those applicable to the Captain Sandstone and its clay-rich overburden. A $S_{\text{min}}$ gradient of 18 MPa km$^{-1}$ relative to the seabed appears to represent a suitable lower bound to the LOT data, and is taken here to represent $S_{\text{min}}$ in the fault-stability analysis (Fig. 8), although the Tor Formation measurement indicates that the magnitude of $S_{\text{min}}$ is not a simple linear gradient through the overburden. This gradient is similar to the assumed 18.09 MPa km$^{-1}$ fracture pressure gradient noted by Jin et al. (2012). Because leak-off pressure does not provide a direct measurement of $S_{\text{min}}$, depending as it does on other factors such as lithology, drilling fluids and wellbore stability, there is inherent uncertainty in the $S_{\text{min}}$ gradient determined, particularly given the limited number of test data available. The sand-rich nature of the lithologies tested by the lowermost LOT measurements are expected to possess lower fracture pressures than the overburden lithologies, to some extent justifying the use of the lower bound to the LOT data to represent the lower bound of $S_{\text{min}}$ in the absence of more reliable XLOT data. Using the lower bound as an estimate of $S_{\text{min}}$ provides larger differential stresses, ensuring that the fault-stability analysis is conservative. Greater differential stresses would result in faults being closer to failure in the current stress regime, while smaller differential stresses will tend to increase the mechanical stability of faults.

According to critically stressed faulting theory, it is possible to determine the upper and lower bound magnitudes of $S_{\text{min}}$ and $S_{\text{Hmax}}$ for any particular depth given knowledge of the pore pressure, $S_s$, and the coefficient of friction. A stress polygon (Moos & Zoback 1990; Zoback et al. 2003) can be constructed to illustrate the allowable stress states constrained by the strength of faults optimally oriented for failure in the current stress regime using equation (2), after Jaeger et al. (2007):

$$\frac{\sigma_1}{\sigma_3} = \frac{S_1 - P_p}{S_3 - P_p} \leq (\mu^2 + 1)^{1/2} + \mu^2$$

where $P_p$ is pore pressure, $S_1$ and $S_3$ are respectively the maximum and minimum principal stresses, and $\mu$ is the coefficient of friction. Byerlee (1978) shows that, commonly, $0.6 \leq \mu \leq 1$, so a value of 0.6 is taken here as a reasonable assumption for $\mu$, given that the Captain Sandstone is poorly cemented and consolidated. The occurrence or non-occurrence of borehole breakouts and drilling-induced tensile fractures may be used to estimate the magnitude of $S_{\text{Hmax}}$ using equation (3) for drilling-induced tensile fractures and equation (4) for borehole breakouts (see Barton & Zoback 1988; Moos & Zoback 1990; Zoback et al. 2003 for derivation of the equations):

$$S_{\text{Hmax}} = 3S_{\text{min}} - 2P_p - \Delta P - T_0 - \sigma^N_T$$

(3)

where $\Delta P$ is the difference in pressure between the pore-fluid pressure and the pressure exerted by the column of mud in the wellbore, $T_0$ is the tensile strength of the rock, and $\sigma^N_T$ is the stress induced by the temperature differential between the formation and drilling fluids: and for breakouts:

$$S_{\text{Hmax}} = \frac{(C_0 + 2P_p + \Delta P + \sigma^N_T) - S_{\text{min}}(1 + 2 \cos 2\theta_b)}{1 - 2 \cos 2\theta_b}$$

(4)

where $2\theta_b = \pi - \omega_{bo}$.

In equation (4), $C_0$ is the rock strength and $W_{bo}$ represents the width of the observed breakout in units of degrees. Equations (3) and (4) have been used to estimate the magnitude of $S_{\text{Hmax}}$ in wells 13/21a–4, 13/24b–3 and 13/26a–4. Figure 9a shows the constraints on the magnitudes of the horizontal stresses at a depth of 1564 m TVDSS (True Vertical Depth Subsea) where breakouts are observed in well 13/24b–3. The lack of tensile fractures over the logged interval suggests that, for a given value of $S_{\text{min}}$, the magnitude of $S_{\text{Hmax}}$ should fall below the appropriate tensile failure contour denoted by the black dotted line in Figure 9a. The tensile strength of the Captain Sandstone is generally less than 70 kPa (Skopec 2001) and, as such, is considered here to be essentially zero. As shown by Figure 9a, greater tensile strength would reduce the magnitude of $S_{\text{Hmax}}$ required to form a drilling-induced tensile fracture for any given value of $S_{\text{min}}$. As no information is available regarding the temperature-induced stress perturbation at the depth of interest, this parameter is also assumed to be zero. As shown by Zoback et al. (2003), the result of moderate cooling has a limited impact on the tensile fracture contours, whereas modest increases in mud weight

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**Table 2. Formation leak-off test data from wells in the study area. The leak-off pressure can be taken as the fracture pressure for the rocks at the depths tested. The lithological descriptions are taken from the company logs**

<table>
<thead>
<tr>
<th>Well</th>
<th>Depth subsea (m)</th>
<th>Pressure (MPa)</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>13/24b-3</td>
<td>988</td>
<td>23</td>
<td>Tor Formation – firm to hard limestone</td>
</tr>
<tr>
<td>13/22b-4</td>
<td>1563</td>
<td>29</td>
<td>Valhall Formation, Aptian ‘Sandy’</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Unit – soft to firm claystone grading</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>to siltstone in parts</td>
</tr>
<tr>
<td>13/22b-19</td>
<td>1611</td>
<td>31</td>
<td>Valhall Formation, Early Aptian – loose</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>sand and soft to firm claystone</td>
</tr>
<tr>
<td>13/22b-20</td>
<td>1584</td>
<td>30</td>
<td>Early Barremian Wick Sandstone</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Formation – loose fine- to medium-</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>grained sandstone and calcareous claystone</td>
</tr>
</tbody>
</table>

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**Fig. 7. (a) Example of a bulk density log from well 13/26a-4. (b) Vertical stress profiles calculated from integration of**

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**Fig. 8.** Example of a bulk density log from well 13/26a-4. (b) Vertical stress profiles calculated from integration of density logs and the average gradient of $S_s$ used in this study.
are far more influential to the formation of drilling-induced tensile fracture. In the event that significant borehole cooling had occurred, the magnitude of $S_{H_{\text{max}}}$ required to cause the formation of drilling-induced tensile fractures would be reduced for any given magnitude of $S_{h_{\text{min}}}$, and so the assumption of zero $\sigma_{\Delta T}$ gives an upper bound to the tensile fracture contour, providing the upper possible frictional limit of $S_{H_{\text{max}}}$. In the absence of equivalent circulating density data, static mud weight is used to calculate $\Delta P$. Despite the observation of borehole breakouts, the borehole breakout contours cannot be used to accurately constrain the magnitude of $S_{H_{\text{max}}}$ as a function of $S_{h_{\text{min}}}$ because the strength of the rock is unknown. However, contours are plotted for different rock strength values using equation (4) and the average breakout width in well 13/24b-3 of 41.6° (Fig. 9a). These contours may be used to provide constraints on the strength of the rock given the end-member magnitude of $S_{H_{\text{max}}}$ allowable. As breakouts have been observed, the magnitude of $S_{H_{\text{max}}}$ should lie above the appropriate rock strength contour. Breakout width can be difficult to measure accurately from image logs, and so this is considered an uncertain parameter and the breakout contours are not used here to predict the magnitude of $S_{H_{\text{max}}}$. Figure 9b shows the maximum allowable values of $S_{H_{\text{max}}}$ obtained from the analyses described above for each depth where borehole breakout has been observed. Albeit highly uncertain due to the uncertainty of the input parameters, a linear $S_{H_{\text{max}}}$ gradient of 31.95 MPa to the seabed has been derived from the outer envelope of the measurements in the three wells. This provides the end-member conservative case for the fault-stability study where differential stresses are at a maximum. As $S_{H_{\text{max}}} > S_{v} > S_{h_{\text{min}}}$, this would imply a strike-slip faulting stress state after Anderson (1951). As the true magnitude of $S_{H_{\text{max}}}$ is unknown and might, in fact, be significantly lower, a further two stress magnitude cases are considered for the fault-stability study corresponding to the normal/strike-slip and normal faulting stress states (Table 3).

Fault-stability analysis

The stress orientations derived from borehole breakouts, and the stress magnitude gradients shown in Table 3, have been used to resolve the shear and normal stresses onto the faults using the 3D geological model. As the magnitude of $S_{H_{\text{max}}}$ is uncertain, all three cases have been considered. Slip tendency ($T_s$), the ratio of shear to normal stress (Morris et al. 1996; Ferrill et al. 1999), has subsequently been calculated for each node on the fault planes.

<table>
<thead>
<tr>
<th>Stress magnitude gradients (MPa km$^{-1}$ relative to seabed)</th>
<th>Strike-slip</th>
<th>Normal/strike-slip</th>
<th>Normal</th>
</tr>
</thead>
<tbody>
<tr>
<td>$S_v$</td>
<td>25</td>
<td>25</td>
<td>25</td>
</tr>
<tr>
<td>$S_{H_{\text{max}}}$</td>
<td>31.95</td>
<td>25</td>
<td>18</td>
</tr>
<tr>
<td>$S_{h_{\text{min}}}$</td>
<td>18</td>
<td>18</td>
<td>18</td>
</tr>
</tbody>
</table>

Faults and CO$_2$ storage in the Captain Sandstone
The slip tendency calculated for the strike-slip case is highly susceptible to reactivation. Faults orientated perpendicular to the direction of $S_{\text{hmax}}$ exhibit lower slip tendencies as a result of higher normal stresses. The normal/strike-slip case exhibits much lower slip tendencies, with no fault segments possessing a slip tendency greater than 0.3. Faults striking sub-parallel to $S_{\text{hmax}}$ again possess the higher values of slip tendency. The normal faulting case possesses the least variation in slip tendency, with values of approximately 0.3 over most of the fault nodes, with the clear exception of the eastern part of the South Halibut Fault, which dips at a steeper angle of about 80° and is therefore less susceptible to failure in a normal faulting stress state. In this case, despite many of the faults dipping at optimal angles close to 60° (30° from $S_{\text{s}}$), none of the fault segments have particularly high slip tendencies because the gradient of $S_{\text{min}}$ implies values higher than the frictional minimum illustrated by the stress polygon in Figure 9a. It is worth noting that, although the faults shown by Figure 10 extend from the Captain Sandstone and through the overburden to the seabed, the majority of the pressure increase resulting from the injection of CO$_2$ will be confined to the reservoir interval into which CO$_2$ is injected. Segments of faults with high slip tendencies in the shallower section are therefore less likely to experience a significant increase in pore-fluid pressure unless the fault zones become a conduit for fluid flow (either CO$_2$ or displaced formation fluids) from greater depths.

The slip-tendency results presented are dependent on the reliability of the 3D fault model and the validity of the input stress field (Worum et al. 2004). As the fault model presented is based on regional mapping using 2D seismic reflection profiles, with regional depth conversion applied, the model will inevitably contain some geometrical inaccuracies that will affect the calculated values. In particular, the depth conversion can affect the dip of the faults, which is critical as it affects the angle of the fault plane relative to the stress tensor. Despite this, the main structural trends are captured by the geological model, and the results are useful in assessing fault risk at the basin scale.

The susceptibility to failure of faults at a given depth can also be expressed in terms of the pore-pressure perturbation required in order to cause the reactivation of faults, known as the fracture stability. Fracture stability for the stress regimes shown in Table 3 are illustrated by Figure 11 for a depth of 1200 m. This is the average depth of the Captain Sandstone below 800 m, where it is most prospective for CO$_2$ storage and injected CO$_2$ would be expected to remain in its dense phase (Chadwick et al. 2008). Because not all faults and fractures will be accurately mapped using seismic reflection data, stereographic projections are useful as they can be used to calculate the change in pore pressure required to reactivate faults of any orientation at a given depth.

Poroelastic effects on fault stability are illustrated in Figure 12. Owing to coupling between pore pressure and stress (Hillis 2000), horizontal stress magnitudes are likely to decrease during depletion (Streit & Hillis 2004), and to increase during injection. Equation (5), after Brown et al. (1994), can be used to estimate the poroelastic effect in reservoirs with a high lateral extent compared to thickness:

$$\Delta S_{\text{hlor}} = \frac{1}{1 - 2\nu} \frac{\alpha}{C_0} \Delta P_f$$

where $S_{\text{hlor}}$ is both $S_{\text{hmax}}$ and $S_{\text{hmin}}$, $\alpha$ is Biot’s coefficient and $\nu$ is Poisson’s ratio. For reasonable values for $\alpha=1$ and $\nu=0.25$ (Chiaramonte et al. 2008; McDermott et al. 2016), the horizontal stresses will increase by 2 MPa as a result of a 3 MPa pore-pressure increase, a reasonable far-field pore-pressure perturbation (Jin et al. 2012). It is noted that equation (5) should not be used for predicting actual stress values at depth as it has been derived for a homogeneous, isotropic and linear poroelastic reservoir. Nevertheless, it provides a useful guide as to the likely poroelastic effects that might result from CO$_2$ injection and the subsequent
pressure increases. This effect would be largely constrained to the reservoir interval where the majority of the pressure perturbation will occur during injection.

The results shown in Figures 11 and 12 show that the change in pore pressure ($\Delta P$) required to cause fault reactivation varies considerably across the different stress states. In the strike-slip stress state, optimally orientated faults at virgin reservoir pressures are approximately 1.5 MPa from failure, moving to approximately 0.5 MPa after a perturbation of 3 MPa (Fig. 12a). The poroelastic effect counteracts the effect of the reducing effective stresses, increasing the stability of the faults somewhat and allowing the faults to sustain more pressure than if the poroelastic effect is discounted. Chiaramonte et al. (2008) similarly found that the poroelastic effect increased the pressure required to cause failure of a fault bounding a prospective CO$_2$ storage site in the USA. In the normal/strike-slip stress state, optimally orientated faults that strike parallel to $S_{H\text{max}}$ and dip at angles of 60° will fail at increased fluid pressures of approximately 5 MPa. Once poroelastic effects are accounted for, the stress state transitions to a strike-slip faulting regime as $S_{H\text{max}}$ exceeds the magnitude of $S_v$ (Fig. 12b). Optimally orientated faults are then vertical faults striking at angles of 30° from $S_{H\text{max}}$ and will fail at slightly lower pressures. In the normal stress state, where $S_{H\text{max}} = S_{h\text{min}}$, faults dipping at 30° and striking in any orientation are those that are most susceptible to failure, with a required pore-pressure increase of approximately 5 MPa. Little change in the fault stability is seen once the poroelastic effect is considered, as the difference between the horizontal stress and $S_v$ magnitude is reduced, resulting in a smaller Mohr circle (Fig. 12c).

Fig. 11. Fault stability represented as equal-angle, lower-hemisphere stereographic poles to planes for (a) strike-slip, (b) normal/strike-slip and (c) normal faulting stress states at a depth of 1200 m below sea level. The numerical values refer to the increase in fluid pressure ($\Delta P$) required to cause fault reactivation, assuming a Griffith–Coulomb failure envelope for cohesionless faults with a value of $\mu$ of 0.6.

Fig. 12. Mohr–Coulomb diagrams showing stress states in relation to a cohesionless fault-failure envelope at a depth of 1200 m below sea level for (a) strike-slip, (b) normal/strike-slip and (c) normal faulting stress states. Poro-elastic stress change is shown for a pressure increase of 3 MPa. The pre-injection cases are shown as solid circles and the post-injection cases shown as dotted circles.
bridging and redistribution between layers with different mechanical properties can, in some cases, lead to enhanced geomechanical stability in the caprock (McDermott et al. 2016).

The presented fault-stability analysis considers only the effect of increasing the pore-fluid pressures as a result of CO₂ injection. Production-induced stress perturbations have not been considered here, but are noteworthy given the history of hydrocarbon production from the Captain Sandstone reservoir in the Moray Firth and the current interest in storage of CO₂ in depleted fields. Such effects should be studied on a site-specific scale, where knowledge of the full production history (including water injection, if applicable) is available. Such an in-depth study has been conducted for the proposed storage project at the Goldeneye Field (Shell 2011b), which found that geomechanical effects are not prohibitive to the proposed storage plans.

Discussion

Both migration and pressure limitations act to constrain the volumes of CO₂ that can be stored in subsurface reservoirs (Williams et al. 2013). In relation to the geomechanical stability of faults, it is therefore important to consider both the pressure propagation and the expected distribution of the CO₂ during the injection period and subsequently until the plume has stabilized. It is feasible that a far-field fault might be reactivated during CO₂ injection, but that the CO₂ would be confined to some area remote from the reactivated fault segment. In such a case, the reactivated fault would not compromise storage integrity. It would be possible, therefore, to optimize CO₂ storage activities by avoiding injection into areas from which CO₂ would be likely to migrate towards critically stressed faults, as identified by Figure 10. Jin et al. (2012) considered simulations of CO₂ injection into the Captain Sandstone in which faults were considered to be non-transmissible to fluid flow and where hydraulic communication was permitted across them. Potential migration pathways between fault blocks can be identified using fault-plane Allan diagrams (Allan 1989), where stratigraphic intersections with the fault are mapped onto the fault plane. In the case of the Little Halibut Fault, a significant potentially compartmentalizing fault (Fig. 1), the Captain Sandstone in the footwall block is not juxtaposed against permeable formations above the primary and secondary top seals (Fig. 13). Considering the aquifer integrity due to an increase in along-fault permeability during slip, it has been shown that shear-stress hysteresis during uplift and exhumation can also affect the ability of faults to conduct fluids, even if they are not critically stressed in the present stress state (Sathar et al. 2012). Experiments on synthetic fault gouge composed of pure kaolinite found that, although fault orientation does have an effect on gas entry pressure, non-optimally orientated faults can also experience flow (Cuss et al. 2015). In addition, reactivation of a fault will not necessarily increase the permeability of the fault plane because in some materials, such as weakly cemented sand, initial dilation and continued shearing will result in the formation of low-porosity/low-permeability material ( Bjørlykke et al. 2005). Processes such as clay smear can also act to reduce fault-zone permeability, and so the assumption that a reactivated fault will permit vertical flow of CO₂ is conservative.

Conclusions

The in situ stress field affecting the Captain Sandstone in the Inner Moray Firth area, a potential target for CO₂ storage, has been evaluated. The available data suggest that either normal, strike-slip or normal/strike-slip transitional faulting stress regimes might prevail at reservoir depth in the region, while the observation of borehole breakouts indicate a relatively uniform direction of S_{Hmax}, oriented NNE–SSW. The magnitudes of the principal stresses have been determined for each of the possible stress regimes using integrated density logs, LOTs, borehole image logs and frictional faulting limits. Where stress-magnitude parameters are regarded to be uncertain, the analysis has assumed large differential stresses, meaning that a conservative approach has been taken to the fault-stability analysis. Given the paucity and quality of available stress-field indicators and measurements, such an approach is useful in determining the low end-member constraints on the pore-pressure window with which to operate without reactivating existing faults.

The stress tensor has been resolved onto 3D fault planes, derived from an existing geological model of the Captain Sandstone and its overburden, to evaluate the susceptibility of the larger faults to reactivation, the risk of which might be increased if pore-fluid pressure increases as a result of large-scale CO₂ injection. The results suggest that some segments of the regional faults are likely to be near-critically stressed under some of the possible stress conditions, and therefore would not require a considerable pore-pressure increase in order to become reactivated. It is likely, however, that smaller local faults will become reactivated first. If this occurs in the area outside of the CO₂ plume footprint, formation
brine rather than CO₂ would leak-off from the reservoir, potentially relieving some reservoir pressure (Hannis et al. 2013). As slip on existing faults could facilitate a risk to CO₂ storage integrity, it is suggested that aspects surrounding the in situ stress conditions (both regional and local) are critically assessed during site appraisal. In addition, thermal stresses, which affect an area relatively local to the injection well, have not been considered here, but can significantly alter the stress state locally as a result of the injection of cold fluid, and should be examined by coupled flow–geomechanical models (McDemott et al. 2016).

The results presented provide a useful indication of the fault geometries most susceptible to reactivation in the current in situ stress conditions across the IMF, at depths where CO₂ might be injected. To account for uncertainty in principal stress magnitudes, addition, thermal stresses, which affect an area relatively local to the injection well, have not been considered here, but can significantly alter the stress state locally as a result of the injection of cold fluid, and should be examined by coupled flow–geomechanical models (McDemott et al. 2016).

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