In situ stresses in the North Sea and their applications: petroleum geomechanics from exploration to development

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Abstract: Present-day maximum horizontal stress (σh) is oriented northwest–southeast onshore North West Europe, reflecting the first-order control on intraplate stresses exerted by plate boundary forces. Stresses associated with deglaciation appear to influence the stress regime in the Northern North Sea, with σh oriented E–W and a contemporary stress regime close to the transition between strike-slip and reverse faulting, i.e. σh > σ, ~ σv (where σ, and σv are vertical and minimum horizontal stress respectively). Maximum horizontal stress orientations are highly variable in the Central North Sea and the stress regime within the sedimentary sequence appears to be detached from that in the basement. The stress regime in the sedimentary sequence of the Central North Sea is predominantly one of normal faulting with almost isotropic horizontal stresses (σi = σh = σv).

Geomechanical risk of the likelihood of seal breach due to fracturing should incorporate the risk of reactivating sealing faults or fracturing intact cap seal rocks in shear or in tension. The risk of fracture-related seal breach is considered for stress regimes representative of the Northern and Central North Seas. Generally, reactivation of optimally oriented faults and/ or shear fracturing of intact cap rock are the most likely mechanisms of fracture-related seal breach. However, in the Central North Sea overpressured scenario, tensile failure is the most likely mechanism of fracture-related seal breach.

In situ stress data have value throughout the life cycle of a field. The implications of the stress regimes representative of the Northern and Central North Seas for naturally fractured reservoirs, wellbore stability, water flooding and fracture stimulation are analysed. These issues are stress-sensitive and the conclusions with respect to each issue differ significantly between the Northern and the Central North Sea because of their differing stress regimes.

Keywords: North Sea, stress, seals, fractures, wellbore stability, water flooding

In situ stresses have been extensively studied in the North Sea. Some, but not all, of the publicly available data are recorded on the World Stress Map (Reinecker et al. 2003). The first aim of this paper is to briefly synthesize currently available in situ stress data for the North Sea. Such a review is significant because the stress regime of the North Sea differs from that of surrounding onshore North West Europe and, furthermore, because there are differences between the in situ stress regimes of the Northern and Central North Sea areas.

Geomechanical methodologies for risking fracture-related seal breach have become widespread since Watts (1987) introduced the concept of hydraulic seals, i.e. seals where the capillary entry pressure is so high that seal breach occurs due to fracturing of the cap rock. Much of the initial work on fracture-related seal breach focused on tensile failure of cap rocks (e.g. Cailet 1993; Gaarenstroom et al. 1993). Subsequently, it has been recognized that reactivation of fault seals presents an additional risk of fracture-related seal breach that can be assessed utilizing geomechanical data (Shuster et al. 1998; Finkbeiner et al. 2001; Jones & Hillis 2003). A comprehensive analysis of the risk of fracture-related seal breach requires that consideration be given to the likelihood of tensile or shear failure of intact cap rocks and to the risk of post-charge reactivation, in tension or shear, of fault seals. Thus the second aim of this paper is to review existing geomechanical risk methodologies and present a geomechanical methodology that considers all of the above types of fracture-related seal breach. This methodology is applied to stress regimes broadly characteristic of the Northern and Central North Seas.

The combination of in situ stress, rock strength and fault property data represents the geomechanical model for a field. The geomechanical model may be applied to assess fracture-related seal breach in the exploration phase of the life cycle. With additional wells, the geomechanical model may be refined and applied to field development-related issues. The third aim of this paper is to illustrate the applications of the geomechanical model in the field development phase. In order to do this, the stress regimes broadly characteristic of the Northern and Central North Seas are briefly applied to the consideration of naturally fractured reservoir performance, wellbore stability, water flooding and fracture stimulation.

In situ stresses in the North Sea: plate boundary stresses, deglaciation and detachment

This brief review synthesizes the results of previous studies of the in situ stress field of the North Sea area. It highlights the pronounced differences between the predominant stress pattern onshore North West Europe and that of the North Sea, and indeed the very significant differences within the North Sea between the in situ stress regime of the Northern North Sea (Viking Graben and surrounding areas) and that of the Central North Sea (Central Graben and surrounding areas).

The regional northwest–southeast contemporary maximum horizontal stress orientation in North West Europe has been well documented (Klein & Barr 1986; Müller et al. 1992). It is apparent onshore northwestern Germany, the Netherlands and England on the latest release of the World Stress Map (Reinecker et al. 2003; Fig. 1), and reflects that the intraplate stress field is, to a first-order, controlled by plate boundary forces, here primarily ridge push along the mid-Atlantic ridge and collisional forces along the
Fig. 1. North Sea stress map. Maximum horizontal stress onshore England, Netherlands and Germany is typical of the NW–SE orientation that predominates in North West Europe. Maximum horizontal stress generally trends E–W in the Northern North Sea, and is variable in the Central North Sea. The long axes of the bars represent the maximum horizontal stress orientation and the length of the bars the quality ranking of that indicator. The rose diagram in the Danish Central Graben illustrates the variability of stress orientations in the Central North Sea and is based on breakouts interpreted by Ask (1997). The limit of the Z2 salt horizon is represented by the dashed red line and detachment of the stress regimes between basement and cover, in association with the salt, is interpreted to be responsible for the variable stress directions in the Central North Sea. World Stress Map data from Reinecker et al. (2003).

The recent studies of Grollimund et al. (2001) and Brudy & Kjorholt (2001) focus on in situ stress data from exploration wells in the Viking Graben area. Both studies indicate a broadly east–west maximum horizontal stress direction varying from approximately 100°N on the western flank of the Viking Graben to 080°N on the eastern flank of Viking Graben, based on the orientations of borehole breakouts and drilling-induced tensile fractures. The magnitude of the least principal stress (σ3, which in this case is the minimum horizontal stress, σh) from leak-off tests is close to the magnitude of the vertical stress (σv/σh ~ 0.9–1.0) within the Viking Graben, reducing to lower values closer to the Norwegian coastline (Grollimund et al. 2001). More detailed
analysis of stress magnitudes in the Visund and three other northern North Sea fields was presented by Wiprut & Zoback (2002). Stress orientations there are consistent with those described above, and in all cases the minimum horizontal stress magnitude is close to that of the vertical stress, with the maximum horizontal stress magnitude being significantly larger, i.e. a transitional strike-slip/reverse faulting stress regime \( \sigma_3 \gtrsim \sigma_1 \approx \sigma_2 \).

Lindholm et al. (2000) analysed the stress field in Norwegian regions based on earthquake focal mechanisms. The southwestern Norway and adjacent seas region (which includes the Viking Graben) was noted to be among the seismically most active in North West Europe with frequent magnitude 4 and stronger earthquakes (Fig. 2). Focal mechanisms indicate a NW–ESE maximum horizontal stress direction, broadly consistent with that indicated by wellbore data (Fig. 1). Reverse and strike-slip mechanisms dominate the data from this area, consistent with the wellbore-based stress magnitudes presented by Wiprut & Zoback (2002). Fejerskov & Lindholm (2000) argue that the ridge push force associated with sea-floor spreading in the North Atlantic is the primary control on the in situ stress field of Norway. Grollimund et al. (2001) argue that in the Viking Graben, stresses associated with lithospheric flexure caused by deglaciation also have an important control.

The in situ stress regime of the Central Graben varies markedly from that of the Viking Graben. Maximum horizontal stress directions are highly variable in the Central Graben (Fig. 1). Not all the available stress orientation indicators for the North Sea have been compiled within the World Stress Map database and there is abundant additional evidence that stress orientations are highly variable in the Central North Sea. Borehole breakouts analysed in 26 wells in the Danish sector of the North Sea show no preferred orientation (Ask 1997; Fig. 1). Teufel (1991) undertook anelastic strain recovery measurements on oriented cores from Ekofisk Field that indicate that the maximum horizontal stress orientation rotates around, and is controlled by the Ekofisk structure, being everywhere orthogonal to the structural contours around the dome. Yale et al. (1994) measured stress orientation in the Scott Field in Quadrant 15 of the UK North Sea using borehole breakouts and the shear acoustic anisotropy of oriented cores. The two methods were consistent, and showed that stress orientation varies between fault blocks in the field, and in most cases the maximum horizontal stress is parallel to the orientation of nearby normal and wrench faults. McLean & Addis (1990) found that there was no consistent breakout orientation in the Cyrus Field in Quadrant 16 of the UK North Sea.

Gölke & Coblenz (1996) modelled lithospheric-scale stresses in western Europe based on force conditions at the Mid-Atlantic ridge and the southern and eastern collisional plate margins. Their models predict northwest–southeast-oriented maximum horizontal stress throughout the Central North Sea and surrounding onshore areas. It is interpreted herein that the stress regime in the thick sedimentary sequence of the Central North Sea, with its variable horizontal stress orientation, is decoupled from that in the basement. Bell’s (1996) schematic illustration of in situ stress orientations in attached and detached provinces (Fig. 3) is believed to apply to the Central North Sea and surrounding onshore areas. In situ stresses onshore England, Netherlands and Germany are consistent with those predicted by lithospheric-scale modelling and these are interpreted as attached provinces that reflect stress orientations controlled by plate boundary forces. The variable stress orientations of the sedimentary sequence of the Central North Sea witness a province where the stress regime is detached from that in the basement.

Ask et al. (1996) similarly argued that variable stress orientations in the Danish Central Graben and Tornquist Fan reflect that plate-wide stresses are not transmitted to the sediments above salt detachments, resulting in a near-isotropic horizontal state of stress in those sediments. Cowgill et al. (1995) analysed breakouts throughout the North Sea, but mostly from the Outer Moray Firth and Central Graben, observing that ‘basement’ rocks show similar stress orientations to the rest of mainland Europe whereas stress orientations in the ‘basin’ rocks show much more variability that appeared to relate to intermediate-scale structures within the basin. Detached stress provinces have also been

![Fig. 2. Seismicity map of Europe (1975–1995) from the USGS National Earthquake Information Center. The colour of the ‘dots’ indicates the depth to earthquake nucleation.](image-url)
described in the Canadian Scotian Shelf, with detachment considered to occur along a halite horizon and/or overpressured shale (Yassir & Bell 1994), along halite horizons in the Aquitaine Basin of southern France (Bell & Calleit 1994) and in the Green Canyon area of the Gulf of Mexico (Yassir & Zerwer 1997). It is suggested that the interpreted detached stress province of the Central North Sea may reflect the influence of the Zechstein salt. The approximate edge of the Zechstein Z2 salt is shown on the North Sea stress map and appears to broadly coincide with the areas of variable stress orientation (Fig. 1).

Not only do the patterns of stress orientation differ between the Central and North Northern Seas, but the relative magnitudes of the principal stresses also differ between the two areas. Variable maximum horizontal stress orientations across the Central North Sea suggest that the two horizontal stresses are similar in magnitude, as McLean & Addis (1990) inferred in the Cyrus Field. Similarly, Kristiansen (1998) inferred that there was likely very little difference between the two horizontal stresses in the Valhall Field. In general, minimum horizontal stress is significantly less than the vertical stress in the Central North Sea, except where high overpressures are encountered (Gaarenstroom et al. 1993). Prior to depletion-related stress changes in the Valhall and Ekoﬁks fields, the stress regime on the crest of the structures was one of incipient normal faulting ($\sigma_2 \geq \sigma_3 \geq \sigma_1$), whereas on the flanks of those structures the state of stress was almost isotropic (Zoback & Zinke 2002). In the Nelson Field of the Central North Sea (Quadrant 22) wellbore data again indicate that the vertical stress is the maximum principal stress (Kwakwa et al. 1989). Hence the Central North Sea generally displays a normal faulting stress regime where $\sigma_3 \geq \sigma_1 > \sigma_2$, or $\sigma_2 > \sigma_1 \geq \sigma_3$. In overpressured areas of the Central North Sea, due to the coupling of pore pressure and horizontal stresses (Hillis 2001), the minimum horizontal stress, and likely the maximum horizontal stress, approach the magnitude of the vertical stress, and the state of stress tends towards isotropic.

**Geomechanical risk of seal integrity**

Faults may seal if they juxtapose reservoir rocks against sealing rocks (Allan 1989; Yielding et al. 1997) or if the faulting process has generated a membrane seal, for example by clay smearing (Bouvier et al. 1989). However, previously sealing faults may become non-sealing due to fault reactivation (Jones & Hillis 2003). There is abundant evidence that active faults and fractures provide high permeability conduits for fluid flow during deformation, or at so-called critical stresses close to those that would induce failure (e.g. Sibson 1994; Barton et al. 1995; Rogers & Evans 2002). Seal breach due to fault reactivation has been recognized as a critical risk in several Australian basins (Shuster et al. 1998; Jones et al. 2000), in the Gulf of Mexico (Finkbeiner et al. 2001) and in the northern North Sea (Wiprut & Zoback 2002; Nordgård Bolås & Hermannrud 2002).

In the North Sea, tensile fracturing of the top seal when the pore pressure reaches the minimum horizontal stress has also been widely recognized as a potential trap breaching mechanism (Caillet 1993; Gaarenstroom et al. 1993; Caillet et al. 1997). Such tensile fracture-related seal breach is the ‘hydraulic’ failure type defined in Watts’ (1987) widely used classification of seals.

Herein both fracturing of intact cap seal rocks and the reactivation of fault seals are considered a geomechanical risk to seal integrity that can be assessed utilizing data on the stress field, rock strength and (in the case of fault seals) fault orientation. The risk of tensile and shear failure of cap rocks and of reactivation of fault seals must be considered in any comprehensive geomechanical methodology for assessing fracture-related seal breach. This section briefly reviews the aspects of brittle failure theory relevant to the geomechanical risk of prospects and summarizes the geomechanical methodologies that have been applied to assess the risk of fracture-related seal breach. The subsequent section applies the preferred methodology to generalized states-of-stress characteristic of the Central and Northern North Sea areas.

The effective normal ($\sigma_n$) and shear ($\tau$) stresses leading to shear and tensile fracturing are shown on Figure 4. The Coulomb criterion for shear fracture of intact rock of cohesion ($C$) and co-efficient of internal friction ($\mu_i$) is shown (i.e. $\tau = C + \mu_i \sigma_n$). The criterion for shear reactivation of rocks with no cohesion and co-efficient of sliding friction ($\mu_s$) is also shown (i.e. $\tau = \mu_s \sigma_n$). The former may describe the behaviour of intact cap rocks and the latter the behaviour of faults. However, it cannot be assumed that fault rocks are cohesionless (Jones et al. 2002; Dewhurst & Jones 2002). The Griffith criterion is used to describe the shape of the failure envelope in tension.

Fracturing occurs where a Mohr circle touches the failure envelope. In order for pure tensile fractures to develop, Mohr circle must touch the envelope where shear stress is zero and the minimum principal stress is equal to the tensile strength of the rocks ($T$). It follows from the shape of the failure envelope, specifically the Griffith criterion, that this can only occur if the differential stress (which equals the diameter of the Mohr circle) is less than four times the tensile strength (Secor 1965).

If a Mohr circle touches the failure envelope where effective normal stresses are positive, shear fractures develop in the rock.

It can be seen from Figure 4 that, if the differential stress is large or if the rock is cohesionless (i.e. shear reactivation), shear fractures develop. Permeability enhancement associated with such shear fracturing is likely to preclude tensile effective stresses ever developing, and the limit to overpressure in such a scenario is less than that required to initiate tensile fracturing.

Sibson (1996, 1998), recognizing the role of shear reactivation, noted that tensile fractures can only form and provide conduits for fluid flow, where:

- rocks are intact and devoid of favourably oriented, cohesionless faults;
- existing faults have become severely misoriented for shear reactivation;
- existing, favourably oriented faults have regained cohesive strength due to cementation.

If none of these conditions are met, increasing pore fluid pressure leads to shear reactivation of pre-existing faults at lower pore fluid pressures than tensile fracturing.

The orientation of pre-existing planes most prone to shear reactivation is determined by the coefficient of sliding friction ($\mu_s$). Based on experimental data, Byerlee (1978) suggested $\mu_s$ lies between 0.6 and 1.0 for most rock types. For $\mu_s = 0.6$ planes optimally oriented for reactivation are inclined at 29.5° to the maximum principal stress, and for $\mu_s = 1.0$ planes optimally oriented for reactivation are inclined at 22.5° to the maximum principal stress.

The first-introduced geomechanical parameters for assessing the risk of fracture-related seal breach assumed that this was due to tensile failure of the cap rock (Watts 1987; Caillet 1993; Gaarenstroom et al. 1993) and thus the parameters were based.
on the criterion for tensile failure (i.e. $\sigma_1' = -T$, or $P_p = \sigma_3 + T$, where $T$ is tensile strength and $P_p$ is pore pressure). For example, Gaarenstroom et al. (1993) introduced the concept of retention capacity which is given by the difference between the minimum horizontal stress and pore pressure (Fig. 5a). Retention capacity is thus the effective minimum horizontal stress ($\sigma_3'$). A positive retention capacity (or $\sigma_3'$) reflects that additional pore pressure (or hydrocarbon column height) can be developed prior to tensile fractures developing. If retention capacity is zero then tensile fractures would develop if the rock had no tensile strength. Retention capacity only considers the risk of tensile (and not shear) failure of the cap rock and does not incorporate (tensile) rock strength.

In recognition of the fact that critically stressed shear fractures present conduits for fluid flow, Morris et al. (1996) introduced the concept of slip tendency which is the ratio of shear stress to effective normal stress acting on a fault and expresses the likelihood of slip on a cohesionless fault (Fig. 5b). In order to assess risk due to both shear and tensile fractures, Ferrill et al. (1999) utilized slip tendency and dilation tendency. The latter risks the likelihood of dilation (tensile reactivation) of a fault on a linear scale from zero (if $\sigma_1$ is normal to the fault) to one (if $\sigma_1$ is normal to the fault; Fig. 5c). Slip and dilation tendency can be used together to geomechanically risk the likelihood of fault seal breach due to shear and tensile fracturing. However, two separate parameters, neither of which incorporates rock strength, must be assessed.

The Coulomb failure function was utilized by Castillo et al. (2000) to risk fault seal breach due to reactivation in the Australian Timor Sea. The Coulomb failure function is the difference between the shear stress acting on a fault and that required to cause failure on a cohesionless fault (Fig. 5d). A negative Coulomb failure function thus implies a stable fault whereas a positive Coulomb failure function was associated with low fault seal integrity. Wiprut & Zoback (2002) used the critical pressure perturbation to risk fault seal breach due to reactivation in the Northern North Sea. The critical pressure perturbation is the increase in pore pressure required to reduce the effective normal stress to the value that would cause slip on a cohesionless fault (Fig. 5e). The Coulomb failure function and the critical pressure perturbation both incorporate the coefficient of sliding friction on a fault in assessing its risk of shear reactivation. However, they do not allow for any cohesive strength on pre-existing faults, nor for the development of tensile fractures, nor do they incorporate the risk of fracturing of intact cap rock.

The Fault Analysis Seal Technology (FAST) method of Mildren et al. (2002) was also applied to fault reactivation risk in the Australian Timor Sea. It allows for the input of a failure envelope with cohesion. Jones et al. (2002) and Dewhurst & Jones (2002) have demonstrated that pre-existing faults need not be cohesionless. Indeed in some cases fault rocks are stronger than the surrounding rocks. Thus knowledge of the fault rock failure envelope, including its cohesion, should be incorporated into predictions of fault reactivation and, furthermore, the risk of failure of intact cap rock must be considered as well as the risk of fault reactivation. The risk parameter in the FAST technique, $\Delta P$, is the increase in pore pressure that can be sustained by a fault of specified orientation prior to reactivating in shear or tension (Fig. 5f); failure in tension occurs where the differential stress is less than four times the tensile strength for a Griffith failure envelope and the effective minimum horizontal stress is less than the tensile rock strength). FAST provides a single parameter that assesses the risk of shear or tensile rock failure and allows for the incorporation of a failure envelope with cohesion. However, because the FAST technique incorporates the in situ stress tensor it is limited to determining present-day risk of reactivation.

In order to assess the risk of cap rock failure it is simply necessary to add an intact rock failure envelope to the analysis (Fig. 6). The risk of cap rock failure ($\Delta P_c$, as opposed to the risk of fault reactivation, $\Delta P_f$) is the increase in pore pressure that can be sustained by the point on Mohr circle closest to the failure envelope prior to failure in shear or tension (Fig. 6). In the case of cap rock analysis, as with retention capacity, a single value is provided for the (crest of the) prospect, whereas the risk of fault reactivation varies with the geometry of the fault, and this varying
Fig. 5. Geomechanical risking parameters. See text for full discussion and references. Retention capacity risks the likelihood of tensile failure of intact cap rock. Other techniques risk the reactivation of a pre-existing fault, the orientation of which is given by the dot in the 3D Mohr circles (as defined by the relative orientation of the fault and the principal stresses). All fault orientations plot within the grey-shaded area in the 3D Mohr circles.

Fig. 6. Fracture-related seal breach mechanisms. Intact cap rock is assumed to have greater cohesion (but the same co-efficient of friction) than the fault rock. For the same failure envelopes, different stress conditions and fault orientations can lead to (a) fault reactivation in shear being the critical risk (b) fault reactivation in tension being the critical risk (c) shear failure of intact cap rock being the critical risk (d) tensile failure of intact cap rock being the critical risk. $\Delta P_c$ is the increase in pore pressure required to fracture the cap rock and $\Delta P_f$ the increase required to reactivate the fault with the orientation marked by the dot.
risk can be visualized across the fault (Wiprut & Zoback 2002; Mildren et al. 2002).

Figure 6 schematically illustrates four different geomechanical risk cases. The cap rock is assumed to be stronger (higher C, same \( \mu \)) than the fault rock, although this need not necessarily be the case. In case 6a a fault that is relatively suitably oriented for reactivation in shear presents a greater geomechanical risk than shear failure of intact cap rock (or than tensile failure of the fault or cap rock). In case 6b a fault that is suitably oriented for reactivation in tension presents a greater geomechanical risk than tensile failure of intact cap rock. In this case the fault does not reactivate in shear. In case 6c, the pre-existing fault is poorly oriented for reactivation and, despite intact cap rock being stronger than the fault rock, shear failure of intact cap rock presents a greater geomechanical risk than reactivation of the fault.

Given the failure envelopes assumed in Figure 6, only faults oriented relatively close to the optimal orientation for reactivation will reactivate at a lower change in pore pressure than causes failure of intact cap rock, and thus in such instances failure of intact cap rock may often represent the key geomechanical risk. If the cap rock is stronger than fault rocks, such as the cemented cataclasites described by Dewhurst & Jones (2002), then cap rock failure is always the key risk and fault orientation with respect to the in situ stress field need not be considered. In case 6d, the pre-existing fault is again poorly oriented for reactivation and tensile failure of intact cap rock presents the key geomechanical risk. Techniques such as retention capacity (which is appropriate only for case 6d), slip tendency and Coulomb failure function (which are appropriate only for case 6a) consider special cases of the range of possible geomechanical risks to fault and cap seals, whereas the FAST technique permits a consideration of both shear and tensile failure of both cap and fault rocks incorporating realistic failure envelopes.

Geomechanical riskings of prospects in the Central and Northern North Sea areas

Geomechanical riskings of fracture-related seal breach of prospects is undertaken for states-of-stress typical of the North Sea as discussed previously. The stress tensors used herein are generalized and broadly representative and it is emphasized that prospect-specific analysis requires in situ stress data based on drilling and log data from that prospect. Nonetheless, the generalized states-of-stress allow the significant differences between the Central and Northern North Seas to be illustrated with respect to the application of geomechanical techniques in exploration and development.

In all four cases the vertical stress at 3 km is taken to be 60 MPa (Table 1), which is significantly less than the widely used value of 22.6 MPa/km (1 psi/ft), but is appropriate for the relatively low density sediment column in the North Sea (e.g. Kwakwa et al. 1989).

In the Northern North Sea hydrostatic case (Table 1):

- pore pressure is assumed to be hydrostatic;
- \( \sigma_h \) is assumed to be approximately equal to \( \sigma_r \) as indicated by Grollimund et al. (2001) in the Viking Graben;
- \( \sigma_h \) is assumed to be close to the frictional limit beyond which reverse faulting would occur on suitably oriented pre-existing cohesionless faults (see e.g. Zoback & Healy 1984), i.e. 120 MPa.

An overpressured Northern North Sea case was also considered where pore pressure at 3 km is 50 MPa. The minimum horizontal and vertical stress magnitudes in this scenario were taken to be the same as above, but the higher pore pressure (lower effective stress) results in the frictional limit to \( \sigma_h \) being much lower and approximately 80 MPa.

In the Central North Sea hydrostatic case (Table 1), \( \sigma_h \) and \( \sigma_h \) are assumed to be equal (as suggested by the very variable maximum horizontal stress directions in the area), and close to the frictional limit beyond which normal faulting would occur on suitably oriented pre-existing cohesionless faults (see e.g. Zoback & Healy 1984).

In the Central North Sea overpressured case (Table 1), \( \sigma_h \) and \( \sigma_h \) are again assumed to be equal. Pore pressure is taken to be 50 MPa. The magnitude of \( \sigma_h \) (and hence also \( \sigma_h \)) is taken to be 55 MPa. Pore pressure/stress coupling acts to keep \( \sigma_h \) in excess of pore pressure in overpressured basins (Hillis 2001).

In order to risk the likelihood of fracture-related seal breach, failure envelopes for both intact cap rocks and fault rocks must be estimated. Herein a fault rock failure envelope with a significantly lower (but non-zero) cohesive strength than that exhibited by the cataclasites and phyllosilicate fault rocks tested by Jones et al. (2002) and Dewhurst & Jones (2002) is used, specifically:

\[
\tau = C + \mu \sigma_h = 3 + 0.6\sigma_h^t. \tag{1}
\]

Intact cap rocks were assumed to have a cohesion twice that of faults rocks, i.e.

\[
\tau = C + \mu \sigma_h^t = 6 + 0.6\sigma_h^t. \tag{2}
\]

Numerous studies, and indeed geomechanical risking techniques, assume that pre-existing faults have no cohesive strength (Morris et al. 1996; Castillo et al. 2000; Wiprut & Zoback 2002). However, testing of cored intervals through faults demonstrates that this is not always the case (Jones et al. 2002; Dewhurst & Jones 2002) and that, as suggested by Sibson (1998), faults may regain cohesive strength, for example due to (hydrothermal) cementation. As shown by Dewhurst & Jones (2002), faults cannot simply be modelled as cohesionless planes using the application of Byerlee’s Law (Byerlee 1978).

The four generalized states-of-stress in the Northern and Central North Sea are represented by Mohr circles in Figure 7. The mode of failure most likely to cause seal breach is a function of the contemporary differential stress, and the fault and intact cap rock failure envelopes (Fig. 7). Reactivation of optimally oriented faults and/or the creation of shear fractures in the cap rock are the most likely mechanisms of fracture-related seal breach in the Northern North Sea hydrostatic scenario, where the differential stress is high (Fig. 7a; Table 2). It should be noted that where one assumes fractional equilibrium it is not surprising that fault reactivation presents the highest seal risk. Assuming the generalized state-of-stress and failure envelopes, an increase in pore pressure of 6.7 MPa would reactivate an optimally oriented fault in the Northern North Sea hydrostatic case (Fig. 7a; Table 2). This value and those quoted below ignore the effects of pore pressure–stress coupling (Hillis 2001). Given the effect of pore pressure–stress coupling and likely errors in both in situ stresses and failure envelopes, absolute \( \Delta P \) values for reactivation should be treated with caution and rather used to relatively risk faults of different orientation.

### Table 1. Representative states-of-stress at 3 km depth in the North Sea

<table>
<thead>
<tr>
<th></th>
<th>Pore pressure</th>
<th>( \sigma_h )</th>
<th>( \sigma_r )</th>
<th>( \sigma_h )</th>
<th>( \sigma_h ) azimuth</th>
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<tbody>
<tr>
<td>Northern North Sea (hydrostatic)</td>
<td>30</td>
<td>60</td>
<td>60</td>
<td>120</td>
<td>090</td>
</tr>
<tr>
<td>Northern North Sea (overpressured)</td>
<td>50</td>
<td>60</td>
<td>60</td>
<td>80</td>
<td>090</td>
</tr>
<tr>
<td>Central North Sea (hydrostatic)</td>
<td>30</td>
<td>40</td>
<td>60</td>
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<tr>
<td>Central North Sea (overpressured)</td>
<td>50</td>
<td>55</td>
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Fig. 7. Geomechanical risk of fracture-related seal breach for the four generalized North Sea in situ stress scenarios. The right-hand diagrams show the Mohr circle for each of the stress scenarios and the assumed fault and intact cap rock failure envelopes. The left-hand diagrams are plots of normals to fault planes which illustrate the increase in pore pressure required to reactivate pre-existing faults ($\Delta \rho$). A horizontal fault plots in the centre of the diagram, and a vertical, east–west striking plots at the 12 o’clock position. Both the scale bar and polar plots have been shaded where intact rock failure occurs at lower pore pressure than fault reactivation. Hence if faults occur in the unshaded area, fault reactivation is the key risk, and if there are no faults in those orientations failure of intact cap rock is the key risk.
Differential stress is lower in the Northern North Sea overpressured case, but still sufficiently high with respect to the cohesive (shear) strengths of the failure envelopes that reactivation of optimally oriented faults and/or the creation of shear fractures in the cap rock are again the most likely mechanisms of fracture-related seal breach. An increase in pore pressure of 5.6 MPa would reactivate an optimally oriented fault in the Northern North Sea overpressured case (Fig. 7b; Table 2). In both Northern North Sea cases such optimally oriented faults lie in a range between the optimally oriented strike-slip fault (vertical and striking 30° north or south of east–west) and the optimally oriented reverse fault (dipping 30° and striking north–south) because the stress regime is on the boundary between one of strike-slip and reverse faulting (Fig. 7a and b).

An increase in pore pressure of 11.7 MPa would lead to the formation of shear fractures in the intact cap rock in the Northern North Sea hydrostatic case. Hence in the hydrostatic case any fault oriented such that an increase in pore pressure in excess of 11.7 MPa is required to reactivate it presents less of a risk than intact cap rock. The shaded areas in Figure 7 represent fault orientations that require a higher pore pressure for reactivation than does failure of intact rock (Fig. 7a). Likewise, only fault orientations that reactivate at pore pressures less than 10.6 MPa need be considered in the Northern North Sea overpressured case (Fig. 7b). The risk colours for other fault orientations are shaded because they do not represent a risk of seal breach. Figures 7a and b show the significance of considering the risk of failure of intact cap rock, because there is a narrower range of faults that reactivate at lower pore pressure than cause failure of intact cap rock.

In the hydrostatic Central North Sea scenario, the differential stress is the same as that in the Northern North Sea overpressured scenario (i.e. 20 MPa) and thus reactivation of optimally oriented faults and/or the creation of shear fractures in the cap rock are again the most likely mechanisms of fracture-related seal breach. Here optimally oriented faults dip 60° (because the stress regime is one associated with normal faulting) but with no preferred strike because the minimum and maximum horizontal stresses were taken to be equal (Fig. 7c). All faults dipping between approximately 42°–78° reactivate at lower pore pressure than the intact rock fails. If there are no faults within this dip range then intact cap rock represents the key fracture-related risk of seal breach.

The differential stress is only 5 MPa in the overpressured Central North Sea scenario, making tensile reactivation of vertical faults or tensile failure of the intact cap rock the most likely mechanisms of fracture-related seal breach (Fig. 7d). A pore pressure increase of 6.5 MPa causes tensile failure of pre-existing faults and an increase of 8 MPa causes tensile failure of intact cap rock. Hence, provided there are pre-existing faults with dips of in excess of approximately 45°, the failure in tension of such faults represents the key risk of fracture-related seal breach.

The above, FAST methodology allows the fracture-related mechanism most likely to cause seal breach to be determined in any stress regime, provided the in situ stress tensor, rock strength and fault geometries are known (Table 2). The retention capacity, slip tendency, dilation tendency, Coulomb failure function and critical pressure perturbation methodologies consider geomechanical risks specific only to certain stress states/rock strengths.

The retention capacity concept has been applied both in the overpressured Central North Sea (Gaarenstroom et al. 1993) and the Haltenbanken area (Borgerud & Svarre 1995). In the overpressured Central North Sea very small retention capacities are observed and thus steeply dipping faults and intact cap rocks must be close to tensile failure. Leaking seals are common with retention capacities from 0–6 MPa, but at retention capacities >6 MPa traps were found not to be breached (Gaarenstroom et al. 1993). Retention capacity is a valid concept to apply in areas of low differential stress such as overpressured parts of the Central North Sea (cf. Fig. 7d).

The Haltenbanken area is subject to higher differential stress than the Central North Sea (Nordgård Bolås & Hermanrud 2002). Dry wells commonly occur where retention capacities are 10–20 MPa in the Haltenbanken area (Borgerud & Svarre 1995). Retention capacity is not an appropriate geomechanical risk parameter in this area because in this stress environment shear failure occurs at lower pore pressure than tensile failure (cf. Figs 7a and 7b). Critical pressure perturbation, which considers shear failure and a cohesionless Coulomb fault failure envelope, was used successfully in the Northern North Sea (Visund Field) to verify contemporary gas leakage along optimally oriented faults (Wiprut & Zoback 2002). As mentioned previously juxtaposition and fault gouge also influence fault seal potential and may contribute to fault leakage; however, only the geomechanical risk of seal integrity is discussed herein.

Implications for naturally fractured reservoirs

The Devonian reservoirs of the North Sea such as in the Buchan Field comprise low-permeability fluvial sandstones with production enhanced by open natural fractures. The extent to which such natural fractures are hydraulically conductive is strongly influenced by the aperture of the fracture (Cook 1992). Pre-existing faults and fractures that are critically stressed for either tensile or shear failure within the in situ stress field are considered those most likely to be open and hydraulically conductive (Ferrill et al. 1999; Finkbeiner et al. 2001; Talbot & Sirat 2001). It is acknowledged that some very weak materials such as highly porous chalks and mudstones do not dilate during shear (Yassir 2003). The methodology for targeting critically stressed fractures that are open and hydraulically conductive is very similar to that used to identify whether fault seals are likely to be reactivated.

Diagrams showing the likelihood for a fracture of any orientation to be critically stressed and thus hydraulically conductive can be constructed using the in situ stress regime and fault rock strength. The FAST parameter, $\Delta P_f$ (the increase in pore pressure required to cause failure of that fracture for a given failure envelope), indicates whether fractures are suitably oriented to be hydraulically conductive within the in situ stress field (Fig. 7). Observed fracture orientations (e.g. from image logs or oriented cores) can be plotted as planes to poles over the FAST plots of Figure 7. If they are located in low $\Delta P_f$/red areas of the FAST diagram they are likely to be hydraulically conductive within the in situ stress field. Such a plot is termed a fracture susceptibility plot (Mildren et al. 2002).

The natural fractures that are best oriented within the Northern North Sea in situ stress field scenarios to contribute to reservoir production lie in a range between the optimally oriented strike-slip fault (vertical and striking 30° north or south of east–west) and the optimally oriented reverse fault (dipping 30° and striking north–south) because the stress regime is on the boundary between one of strike-slip and reverse faulting (Figs 7a and b). In the Central North Sea scenarios, where the horizontal stresses are isotropic, fractures with dips in a range around 60°, and striking in any orientation, are likely to be hydraulically conductive within the in situ stress field (Figs 7c and 7d).

Not all fractures are stress-sensitive and fractures may be naturally propped open by mineralization, and productive, even if poorly oriented within the in situ stress field (Hillis 1998). Mineralized and non-mineralized fractures may be plotted with different symbols on the fracture susceptibility plot which is a powerful tool for the evaluation of naturally fractured reservoirs.

Implications for wellbore stability

The in situ stress field, rock strength, mud weight and wellbore trajectory control the mechanical stability of wellbores. If mud weight is too low for a given wellbore trajectory, borehole
Table 2. In situ stress scenarios, differential stress, effective horizontal stress ($\sigma_h^\prime$) and likely fracture mechanisms for the stress scenarios in the North Sea (3 km depth)

<table>
<thead>
<tr>
<th>In situ stress regime</th>
<th>Northern North Sea (hydrostatic)</th>
<th>Northern North Sea (overpressured)</th>
<th>Central North Sea (hydrostatic)</th>
<th>Central North Sea (overpressured)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Differential stress</td>
<td>$\sigma_H &gt; \sigma_h \sim \sigma_v$</td>
<td>$\sigma_H - \sigma_h = 60$ MPa</td>
<td>$\sigma_H - \sigma_h = 20$ MPa</td>
<td>$\sigma_H - \sigma_h = 5$ MPa</td>
</tr>
<tr>
<td>$\sigma_h - \sigma_h^\prime$</td>
<td>30 MPa</td>
<td>10 MPa</td>
<td>10 MPa</td>
<td>5 MPa</td>
</tr>
<tr>
<td>$\Delta P_p$ to reactivate optimally oriented fault</td>
<td>6.7 MPa</td>
<td>5.6 MPa</td>
<td>5.6 MPa</td>
<td>6.5 MPa</td>
</tr>
<tr>
<td>$\Delta P_p$ to fracture intact cap rock</td>
<td>11.7 MPa</td>
<td>10.6 MPa</td>
<td>10.6 MPa</td>
<td>8.0 MPa</td>
</tr>
<tr>
<td>Mode of failure</td>
<td>Shear</td>
<td>Shear</td>
<td>Shear</td>
<td>Tensile</td>
</tr>
</tbody>
</table>

breakout may cause the well to collapse. If mud weight is too high, fluid may be lost into drilling-induced fractures (the fracture gradient is exceeded). These stability problems can be addressed either by setting appropriate mud weights and/or by selecting a wellbore trajectory that allows specific mud weights to be used given the prevailing in situ stress field and rock strength. Assessing wellbore stability also has other applications in well planning including picking optimum casing points and in terms of optimizing drilling practices including tripping speeds.

The risk of breakout development can be assessed in terms of the rock strength (compressive strength, $C_{ij}$) required to prevent breakout formation normalized to $\sigma_v$ (Fig. 8). Blue colours indicate that only a relatively low rock strength (or low mud weight) is required to prevent breakout, i.e., the breakout propensity is low. Red colours indicate that a high rock strength (or high mud weight) is required to prevent breakout. The risk of forming drilling-induced tensile fractures (DITFs, i.e., the risk of exceeding the fracture gradient) is expressed in terms of the excess mud weight (amount of overbalance with respect to pore pressure) above which DITFs initiate (Fig. 8). Red colours indicate that DITFs initiate at mud weights that are only slightly overbalanced. Wellbore trajectories that are red on both the DITF and breakout diagrams are problematic to drill because the safe mud weight window between that required to inhibit breakouts and that which does not exceed the fracture gradient is low or even non-existent.

The risk of breakout and DITF development has been assessed for the four generalized stress tensors for the North Sea (Fig. 8). The risk of breakout and DITF formation in the Northern North Sea is greatest for a vertical well and for wells deviated in a north–south ($\sigma_r$) azimuth. The stresses acting on a horizontal well deviated in the east–west ($\sigma_{ii}$) azimuth are isotropic and hence this is a relatively stable drilling trajectory. It is perhaps counter-intuitive that, in the transitional strike-slip/reverse fault stress regime inferred for the Northern North Sea, no deviated drilling trajectory should be more problematic than the vertical well.

Stable drilling trajectories in the Central North Sea, with its inferred normal fault stress regime, are very different from those in the Northern North Sea. Vertical wells are the most stable with respect to both breakout and DITF development in the Central North Sea. Horizontal wells are the most problematic.

The highest rock strengths (or mud weights) required to inhibit breakout development occur in the Northern North Sea hydrostatic scenario, i.e., up to $C_{ii}/\sigma_v = 4.0$. Although the same drilling trajectories are also the most prone to breakout in the Northern North Sea overpressured scenario, the highest rock strength required to inhibit breakout in this scenario is $C_{ii}/\sigma_v = 1.3$. The range of rock strengths required to inhibit breakout in the Central North Sea hydrostatic scenario is the same as that in the Northern North Sea overpressured scenario because the effective stress magnitudes are the same in the two cases (Figs 7b and 7c). Other factors being equal, breakouts are more likely to develop in higher stress environments. The horizontal wells that present the trajectory most prone to breakout in the Central North Sea overpressured scenario require a rock strength to inhibit breakout ($C_{ii}/\sigma_v = 0.5$) that is only one third of that required in the trajectory least prone to breakout in the Northern North Sea hydrostatic case ($C_{ii}/\sigma_v = 1.5$).

**Implications for water flooding**

Heffer & Lean (1993) demonstrated, with reference to some 80 fields worldwide, that preferred flooding directions are in the contemporary maximum horizontal stress direction. This applies both in fields that would be characterized as naturally fractured and in non-naturally fractured fields. Recognizing such a tendency, Bell & Babcock (1986) and Yale et al. (1994) proposed that flooding arrays should avoid injection and production wells being aligned along the contemporary maximum horizontal stress direction. In general induced fractures aid water flood efficiency if they are oriented more than 50° from the line between injector and producer (they create a line injector) and are detrimental to flood efficiency if they are less than 30° from the injector–producer line (they lead to early water breakthrough and poor sweep; Yale et al. 1994). Hence in the Northern North Sea in situ stress scenarios, injector and producer wells should not be aligned in an east–west direction.

Water is usually injected from low on the structure to sweep updip to producers. In any field, the relative orientation of the structure and fault dip also affects sweep efficiency and would need to be considered (Yale et al. 1994). Fractures formed downdip and parallel to the strike of the reservoir tend to aid the updip sweep efficiency.

Water floods may aim to fracture the formation to increase the sweep area (fractured water flood), or to inject fluid into the reservoir without fracturing the formation (matrix water flood). Wells can be drilled in an orientation where the fracture initiation pressure (i.e. that which forms a DITF at the wellbore wall, Fig. 8) is lowest in order to facilitate a fractured water flood, or in the most stable orientation to facilitate a matrix water flood. The pressure required to keep a fracture open in the far-field (remote from the wellbore) is independent of wellbore trajectory and equal to $\sigma_v$. However, fracture pressure at the wellbore wall, and in the near-field (within 3–4 wellbore diameters of the well), is a function of wellbore trajectory with respect to the in situ stress field. The fracture gradient is lowest in a horizontal well drilled north–south and highest in a well drilled east–west in the Northern North Sea in situ stress scenarios (Fig. 8). Hence, wells drilled east–west should facilitate a matrix water flood whilst it should be easiest to induce fractures in a well drilled north–south. Where wells are cased and perforated the near wellbore stress environment may
Fig. 8. Wellbore stability plots for the four generalized North Sea in situ stress scenarios. The risk of forming drilling-induced tensile fractures (DITF) is expressed in terms of the excess mud weight (amount of overbalance with respect to pore pressure) above which DITFs initiate. The risk of breakout is expressed in terms of the rock strength (compressive strength, $C_r$) required to prevent breakout formation normalized to $\sigma_v$. In these plots a vertical well plots in the centre of the diagram and a horizontal well deviated north plots at the 12 o’clock position.
become more complex and the above discussion may not necessarily apply.

In the Central North Sea, all horizontal wells have a low fracture gradient which aids fracture initiation in a fractured water flood. A vertical well is most stable in the Central North Sea and would facilitate a matrix flood (Fig. 8). Whilst fractures are most easily initiated in a horizontal well in the Central North Sea, horizontal wells are also the most prone to breakout, hence the trade-off between fracture initiation pressure and wellbore instability due to breakout needs consideration (Fig. 8).

Implications for fracture stimulation

Fracture stimulation is used to enhance reservoir performance, particularly in low-permeability reservoirs. The following discussion assumes an open hole. Cased and perforated completions are more complicated and will not be considered herein. The simplest model of an induced hydraulic fracture is one which is a single, planar tensile fracture oriented normal to \( \sigma_h \). In the far-field, away from the wellbore, the induced fracture is vertical and normal to \( \sigma_h \) if \( \sigma_h \) is \( \sigma_v \), but is horizontal if \( \sigma_h \) is \( \sigma_3 \) (Hubbert & Willis 1957).

However, due to the disturbance of the stress field in the vicinity of the wellbore, fracture orientation at the wellbore wall may not be the same as that in the far field. If fracture orientation changes from the near- to the far-field, the fracture must twist and may lose hydraulic conductivity. Fracture twisting is one of the key causes of undesired fracture tortuosity (Danshy 2003). Tortuosity may also result if \( \sigma_3 \) and \( \sigma_2 \) are of similar magnitude, under which circumstance there is no single, stress-controlled preferential direction of fracture propagation in the far-field and geological discontinuities that is likely to strongly influence the direction of fracture propagation (Warpinski & Teufel 1987).

None of the generalized in situ stress scenarios described for the North Sea are considered optimal for fracture stimulation because in all cases \( \sigma_3 = \sigma_2 \) and thus, in the far-field, geological discontinuities are likely to strongly influence fracture propagation. Induced fractures strike east–west and may have any dip, or indeed be horizontal, in the Northern North Sea in situ stress scenarios. Induced fractures are vertical, but have no preferred strike direction in the Central North Sea scenarios. Although uncertain fracture orientation is not optimal, fracture stimulation may still be an effective way of increasing productivity from low-permeability reservoirs. Where induced fracture orientation is uncertain, other well completion designs such as gravel packs may be considered to optimize stimulation.

The orientation of an induced tensile fracture at the wellbore wall can be predicted, given knowledge of the in situ stress tensor and wellbore trajectory (Peskas & Zoback 1995). In the Northern North Sea stress scenarios (Fig. 9):

- induced fractures in a vertical well are vertical and strike east–west (normal to \( \sigma_h \));
- induced fractures in horizontal wells deviated north–south (or indeed most horizontal azimuths other than close to \( \sigma_h \)) are horizontal;
- the stress regime around a horizontal well deviated east–west is isotropic so induced fractures have no preferred orientation at the wellbore wall.

Fracturing from horizontal wells deviated east–west is not recommended in such a stress scenario because there is no stress-controlled preferential direction of propagation, either in the near- or the far-field, and tortuosity influenced by geological discontinuities is probable. Fractures from horizontal wells deviated north–south are horizontal at the wellbore wall and are likely to continue to propagate horizontally, especially if bedding-induced planes of weakness are horizontal. However, such fractures may be prone to twisting/tortuosity if there is a non-horizontal fabric in the reservoir. Fractures from vertical wells are likely to continue to propagate in the vertical plane normal to \( \sigma_h \) unless there is a horizontal fabric.

In the Central North Sea, where the horizontal stresses are isotropic, the stress regime around a vertical well is isotropic so induced fractures have no preferred orientation at the wellbore wall. Induced fractures are vertical and axial to the well in horizontal wells in any deviation direction. They are likely to continue to propagate in the same orientation in the far-field unless there is a steeply dipping geological fabric of differing strike.

Summary

The in situ stress regime of the Northern North Sea is generally close to the transition between strike-slip and reverse faulting (i.e. \( \sigma_h > \sigma_c = \sigma_3 \)), with maximum horizontal stress oriented east–west. Horizontal stress orientations are variable in the Central North Sea, possibly because the stress regime in the cover is detached from that in the basement. In the cover of the Central North Sea the stress regime is generally one of normal faulting with low horizontal stress anisotropy (\( \sigma_3 > \sigma_1 \)). The applications of petroleum geomechanics have been illustrated for states of in situ stress broadly characteristic of the Northern and Central North Seas.

(1) Fracture-related seal breach. Reactivation of optimally oriented faults and/or the creation of shear fractures in cap rock are the most likely mechanisms of fracture-related seal breach in the Northern North Sea hydrostatic and overpressured scenarios. For reasonably intact cap rock and fault rock failure envelopes, there is only a relatively narrow range of suitably oriented faults that reanimate at lower pore pressure than intact cap rock fails. Hence fracture of intact cap rock is a key risk that must be assessed. In the Central North Sea hydrostatic scenario, reactivation of optimally oriented faults and/or the creation of shear fractures in the cap rock are again the most likely mechanisms of fracture-related seal breach. In the Central North Sea overpressured scenario, where differential stress is lowest, tensile failure of steeply dipping faults or tensile failure of the intact cap rock are the most likely mechanisms of fracture-related seal breach. These
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observations account for the successful application of retention capacity (= $\sigma_0^t$) as a geomechanical parameter for risking fracture-related seal breach in the overpressured Central North Sea, and also for its lack of applicability elsewhere in the North Sea.

(2) Naturally fractured reservoirs. A similar methodology to that used to assess the likelihood of fault reactivation can be used to assess which fracture orientations are likely to be hydraulically conductive within the in situ stress field. In the Northern North Sea such optimally oriented fractures lie in a range between the optimally oriented strike-slip fault (vertical and striking 30° north or south of east–west) and the optimally oriented reverse fault (dipping 30° and striking north–south). In the Central North Sea, fractures dipping 60° are the most likely to be hydraulically conductive within the in situ stress field.

(3) Wellbore stability. The in situ stress field, rock strength, mud weight and wellbore trajectory control the mechanical stability of wellbores. The risk of breakout and DITF formation in the Northern North Sea is greatest for a vertical well and for wells deviated in a north–south ($\sigma_0^t$) azimuth. The stresses acting on a horizontal well deviated in the east–west ($\sigma_0^t$) azimuth are isotropic and hence this is a relatively stable drilling trajectory. Vertical wells are the most stable with respect to both breakout and DITF development in the Central North Sea. Horizontal wells are the most problematic.

(4) Water flooding. Induced fractures aid water flood efficiency if they are oriented at a high angle to the line between injector and producer and are detrimental to flood efficiency if they are parallel to the injector–producer line. Hence in the Northern North Sea, injector and producer wells should not be aligned in an east–west direction. The fracture gradient is lowest in a horizontal well drilled north–south and highest in a well drilled east–west in the Northern North Sea. Hence, wells drilled east–west should facilitate a matrix water flood whilst those drilled north–south should facilitate a fractured flood. In the Central North Sea horizontal wells facilitate a fractured water flood, and vertical wells a matrix flood.

(5) Fracture stimulation. Fracture stimulation should be carefully planned with respect to the in situ stress field in order to minimize fracture tortuosity. For example, in the Northern North Sea fracture stimulation from a horizontal well deviated east–west is not recommended because there is no strong stress-controlled preferred direction of propagation, either in the immediate vicinity of the wellbore or in the far-field, and geological discontinuities are likely to strongly influence the direction of fracture propagation.

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