ABSTRACT

The Bight Basin is a major frontier basin of Jurassic–Cretaceous age, which is currently undergoing renewed exploration interest. Although only limited data is available for understanding the petroleum systems in the basin, several observations indicate that poor fault seal integrity may represent a key exploration risk. The presence of a paleo-oil column in the Jerboa-1 well, interpreted gas chimneys, oil slicks, and asphaltite strandings indicate that seal failure caused by fault reactivation is potentially a significant issue in the Bight Basin. Thus, in this study, we investigated the likelihood that faults in the Bight Basin will undergo sufficient structural reactivation to induce fault seal failure, under the regional in-situ stress field. Fault reactivation risk was assessed for two sets of faults that represent extensional events of Late Jurassic (Sea Lion faults) and Late Cretaceous age (Tiger faults).

Analysis of in-situ stress data suggests that the region is currently under a strike-slip or normal stress regime. Interpretation of borehole breakouts from six wells indicates the average maximum horizontal stress orientation is 130°N. Although the magnitudes
of the three principal stresses could not be unequivocally constrained, plausible ranges of values were determined based on well data. Pore pressure in wells in the region is hydrostatic except in Greenly-1, where moderate overpressure occurs.

This study assesses the risk of fault reactivation using the fault analysis seal technology (FAST) technique. The FAST technique evaluates the increase in pore pressure ($\Delta P$) required to cause reactivation as a measure of fault reactivation risk. In all cases investigated, faults striking 40(±15)°N of any dip are the least likely to be reactivated. Thus, traps requiring such faults to be sealing are the least likely to be breached. Fault reactivation risk for the strike-slip and normal stress regimes have been plotted in map view on a series of fault orientations for the Sea Lion and the Tiger faults using a range of hypothetical dips. The results for these hypothetical dips clearly demonstrate the importance of knowing both the strike and dip of a particular fault when conducting a three-dimensional fault seal analysis, because the risk can range from relatively low risk at 25° dip to relatively high risk at 70° dip, with differences being more significant for certain fault orientations.

INTRODUCTION

Assessing trap integrity is of major importance in hydrocarbon exploration. Entrapment and preservation of oil and gas accumulations is dependent on the sealing potential of the rocks surrounding the reservoir, as a result of their capillary properties, geometries, and mechanical integrity. Fault-bound hydrocarbon traps rely on both the sealing potential of the cap seal and the fault seal. Cap and fault seals can be breached by several mechanisms, including membrane failure, fault juxtaposition, and dynamic reactivation (Watts, 1987; Jones et al., 2000). Although we acknowledge that it is important to have a full understanding of all the mechanisms of seal failure in a basin, in this study, we only focus on the failure of the fault seal caused by dynamic reactivation.

Fault reactivation within the in-situ stress field has been demonstrated to control leakage of hydrocarbons from the subsurface in several regions around the world. For example, trap breaching in the North Sea (Gaarenstroom et al., 1993; Wiprut and Zoback, 2000), the Gulf of Mexico (Finkbeiner et al., 2001), and the Timor Sea (Castillo et al., 1998, 2000; Hillis, 1998; de Ruig et al., 2000; Mildren et al., 2002) has been related to faulting and fracturing associated with the in-situ stress field. This study investigates the use of a regional-scale geomechanical model in assessing the risk of fault reactivation to gain some understanding on seal integrity and fault-related risks in the Bight Basin.

The Bight Basin is a largely unexplored basin located along the southern margin of Australia. Exploration costs in the basin are particularly high because of the significant water depth over much of the basin (as much as 5000 m [16,400 ft]) and the remote location. Hence, a real need exists to understand all of the risks associated with hydrocarbon exploration to minimize the overall risk prior to drilling. Fault seal failure may represent a key exploration risk in the Bight Basin as suggested by the presence of a paleo-oil column in the Jerboa-1 well, interpreted gas chimneys, oil slicks, and asphaltite strandings (Ruble et al., 2001; Struckmeyer et al., 2002). Assessment of the fault reactivation risk uses the contemporary in-situ stress field and, hence, provides an approximation for the present-day leakage of hydrocarbons.

REGIONAL GEOLOGICAL FRAMEWORK OF THE BIGHT BASIN

The Bight Basin is an important frontier petroleum exploration province, located along the southern margin of Australia in the Great Australian Bight (Figure 1). However, only 10 exploration wells have been drilled to date in a basin that spans an area of more than 800,000 km² (308,881 mi²), straddling the border of Western Australia and South Australia and extends onshore and offshore in water depths more than 5000 m (16,400 ft). Broad-scale regional geophysical surveying and limited drilling have revealed that the central eastern part of the basin contains four principal depocenters, namely, the Ceduna, Duntroon, Eyre, and Recherche subbasins. Two thin platforms, the Madura and Couedic shelves, are located along the northern and eastern margins of the basin (Totterdell et al., 2003).

The basin was formed as a result of Jurassic–Cretaceous extension and subsidence following the rifting between the Antarctic and Australian plates. According to Totterdell et al. (2003), a first episode of upper crustal extension, with a northwest–southeast to north–south extension direction occurred during the Middle–Late Jurassic to Early Cretaceous (Figure 2) and resulted in oblique to strongly oblique extension and
the formation of en echelon half graben in the Eyre, inner Recherche, eastern Ceduna, and Duntroon subbasins. The half-graben-bounding faults (Sea Lion faults) appear to strike in an east to east-northeast direction. Early Cretaceous postrift thermal subsidence was followed by a phase of accelerated subsidence, which commenced in the late Albian and continued until continental breakup in the late Santonian–early Campanian. A system of gravity-driven, detached extensional, and contractional structures developed in the Cenomanian as a result of deltaic progradation in the Ceduna subbasin, whereas a system of northwest–southeast extensional faults (Tiger faults) developed during the Turonian–Santonian extension phase. The late Santonian breakup was followed by another period of thermal subsidence and the establishment of a passive margin. The fault trends analyzed in this study are the Late Jurassic Sea Lion faults and the Turonian–Santonian Tiger faults (Figure 1), interpreted by Totterdell et al. (2003).

The platformal portion of the basin appears to have acted as a clastic bypass margin as sediment from the interior was dumped into the rapidly subsiding rift system to the south. The sedimentary section is as much as 15 km (9 mi) thick and is comprised of fluvial to paralic sediments of Late Jurassic–Early Cretaceous age disconformably overlain by nearshore marine to nonmarine Late Cretaceous sediments. A regional unconformity at the top of the Campanian–Maastrichtian Hammerhead supersequence separates the Bight Basin from the thin, transgressive sandstones and massive, open-marine carbonates of the Tertiary Eucla Basin.

The regional sequence-stratigraphic framework has allowed the identification of at least six potential petroleum systems in the Jurassic–Cretaceous sedimentary section (Totterdell et al., 2000). Only the Late Jurassic synrift, lacustrine system (Sea Lion–Minke system) was proven to be effective in the Eyre subbasin, where a paleo-oil column was inferred in the Jerboa-1 well based on the analysis of grains containing oil inclusions. Here, charge is estimated to have occurred during the late Maastrichtian to early Eocene, during a period of fault reactivation and erosion in the subbasin (Blevin et al., 2000).

The Cretaceous systems presented by Totterdell et al. (2000) are conceptual and await validation through further drilling. They include a Berriasian lacustrine system (Southern Right system), an Aptian marine system (upper Bronze Whaler system), a middle Albian marine system (Blue Whale system), a Cenomanian–Santonian marine system (White Pointer–Tiger system), and a Santonian–Campanian marine-deltaic system.
Figure 2. Bight Basin correlation chart showing the relationships between sequence stratigraphy and basin phases, modified after Totterdell et al. (2003). Distribution of source, reservoir, and seals in the petroleum systems are modified after Totterdell et al. (2000), and modeled timing of onset of expulsion (arrows) are modified after Struckmeyer et al. (2002).
(Hammerhead system). Oil and gas expulsion from the Albian to Campanian source rocks is modeled to have begun during the Cenomanian to Maastrichtian, although expulsion continued, in phases, into the Tertiary and up to the Holocene in certain parts of the basin (Struckmeyer et al., 2001).

The exploration wells drilled to date encountered only minor oil and gas shows, and the majority of intervals intersected are immature for oil generation. However, the source rock quality in the deeper parts of the basin is inferred to range from good to excellent, and modeling shows that adequate maturities were reached to generate and expel liquid and gaseous hydrocarbons (Struckmeyer et al., 2001).

**EMPIRICAL EVIDENCE FOR FAULT SEAL FAILURE IN THE BIGHT BASIN**

Identifying the principal exploration uncertainties in the Bight Basin region is difficult. Several observations indicate that poor fault seal integrity may represent a key exploration risk in the Bight Basin. Based on petrophysical analyses of fluid-inclusion samples, Ruble et al. (2001) demonstrated the presence of a 15-m (49-ft)-thick paleo-oil column in Callovian to Kimmeridgian sands in the Jerboa-1 well in the Eyre subbasin (Figure 3). The hypothesis is that Jerboa-1 was charged, probably from a Late Jurassic–Early Cretaceous petroleum system but was later breached during a period of fault reactivation during the Late Cretaceous. Vertical migration of hydrocarbons into the Tertiary sequences may also have occurred subsequent to this Late Cretaceous breaching (Ruble et al., 2001). The fault reactivation and subsequent vertical migration may have been the result of the far-field effects of the collision of the Australian and Asian plates in the late Tertiary.

Other empirical indicators of seal failure are present throughout the Bight Basin. These include the presence of numerous gas chimneys in the Duntroon and Ceduna subbasins, some of which correlate spatially with water column geochemical sniffer anomalies and observations of oil slicks across the Bight Basin using synthetic aperture radar data (Struckmeyer et al., 2002). Other indicators include the well-known presence of asphaltite strandings in the region (Sprigg and Wooley, 1963; Edwards et al., 1998) and colloquial evidence for a relationship between the timing of earthquakes and the occurrence of major strandings in the area. Overall, earthquake activity has been typically focused in the Duntroon and eastern Ceduna subbasins. Most of the earthquakes in the Bight Basin are shallow, with epicenters in the upper 10 km (6 mi) of the sedimentary section, and many are within the top 5 km (3 mi), well within the syn- or postrift sections section. Magnitudes are typically in the range 2–3.5, with some events as high as 4.6 have been recorded on the Couedic Shelf. In addition, a series of earthquakes with magnitudes ranging between 4.2 and 5.2 were recorded along the far southern edge of the Recherche subbasin. The empirical evidence for fault seal failure prompted us to analyze the stress field in the Bight Basin and investigate the likelihood that mapped fault arrays in the subbasins in the region will undergo sufficient structural reactivation to induce fault seal failure.

**METHODOLOGY FOR EVALUATING FAULT REACTIVATION IN THE BIGHT BASIN**

We have used the results of the in-situ stress field analysis in the Bight Basin (Reynolds et al., 2003) and applied the fault analysis seal technology (FAST) technique
to determine the risk of fault reactivation of the Late Jurassic Sea Lion faults and the Turonian–Santonian Tiger faults. In the FAST technique, the risk of fault reactivation is determined using the stress tensor (Mohr circle) and fault rock strength (failure envelope). Brittle failure is predicted along optimally oriented faults if the ratio of shear to effective normal stress exceeds the coefficient of frictional sliding, which can be illustrated when the Mohr circle intersects the failure envelope. All fault orientations plot within the Mohr circle, and those closest to the failure envelope are at greatest risk of reactivation. The horizontal distance between each fault plane and the failure envelope indicates the increase in pore pressure (ΔP) required to cause reactivation and is used as the measure of the likelihood of fault reactivation in the FAST technique. A small ΔP infers a high likelihood of reactivation, and a large ΔP infers a low likelihood of reactivation. The ΔP value for each plane can be plotted on a stereonet as poles to planes. The risk of reactivation of any pre-existing fault orientation is then read from the stereonet. A composite Griffith–Coulomb failure envelope has been assumed in this study. No fault rock failure envelopes are available for the area, and thus, a cohesive strength of 5 MPa and friction angle of 0.6 have been assumed. For a more detailed discussion on the FAST methodology, see Mildren et al. (2002) and Mildren et al. (2005).

The assessment of fault reactivation risk is commonly applied at prospect scale, where the in-situ stress field is better constrained than at basin scale, and depth-converted fault geometries are available from seismic interpretation. However, assessing fault reactivation at a regional, basin scale can follow similar principles, but more care should be exercised in evaluating the reactivation risk, because more uncertainty is placed on the results when basing the interpretation on just one set of parameters averaged and extrapolated over large areas. Fault reactivation predictions presented herein may not be accurate in areas where the regional stress field has been perturbed by local structures, such as faults and contrasting material properties. The inclusion of local stress perturbations is beyond the scope of this chapter and is not actually possible at the current level of knowledge of the area.

IN-SITU STRESS IN THE BIGHT BASIN

The most important step in assessing the risk of stress-induced fault reactivation that could lead to fault seal failure is to construct a well-constrained geomechanical model. The geomechanical model consists of the in-situ stress field, fault rock properties, and pore pressure. The in-situ stress field is made up of three principal stresses, which are assumed to be the vertical stress, the maximum horizontal stress, and the minimum horizontal stress. This assumption is reasonable given the generally flat-lying seabed surfaces of sedimentary basins. To define the in-situ stress field, the orientation and magnitude of the three stress components must be determined.

The in-situ stress field was determined from assessing the drilling and logging data acquired from the nine open-file exploration wells drilled in the Bight Basin (Reynolds et al., 2003). Of these nine wells, six are clustered in a tight group in the Duntroon and eastern Ceduna subbasins. To gain a better understanding of the regional stress field in the region, additional wells from the adjacent Polda Basin were included in this study (Figure 1). Stress information from the Australian stress map database was also included in the study. The reader is referred to Reynolds et al. (2003) for a more detailed description of the stress field determination in the Bight Basin.

The water depth across the Bight Basin ranges from less than 100 m (3300 ft) on the shelf to more than 5000 m (16,400 ft) in the deepest parts of the Recherche subbasin. This variation poses a significant problem when attempting to analyze the in-situ stress field for the entire basin. At any location and depth in the basin, the stress caused by the weight of the water column contributes to the magnitude of the in-situ stress field. To overcome the problem associated with water depth, effective stress (total stress minus pore pressure) has been used in this study, instead of the total stress, which is more typically used.

Stress Orientations

The maximum horizontal stress (SHmax) orientation in the Bight Basin was determined by interpreting borehole breakout directions in logs from a four-arm dipmeter (high-resolution dipmeter tool, HDT) from four wells and image log data (Formation Microscanner, FMS) from two wells. The average SHmax orientation calculated from the six wells is 130°N. The reader is referred to Reynolds et al. (2003) for a more detailed description of the stress field determination in the Bight Basin.

The SHmax orientations for the Bight Basin and surrounding regions are plotted in Figure 4. Stress orientations could only be determined for the wells that are located on the eastern side of the Bight Basin. The average SHmax orientation of 130°N for the available wells in the Bight Basin is consistent with SHmax orientations in the Otway Basin farther to the east (Figure 4). Stress trajectories, which are essentially regionally averaged stress orientations, for the Australian stress field have been calculated by Hillis and Reynolds (2000) and plotted in Figure 4 to obtain a better understanding of
the regional stress field over the entire Bight Basin. The previously calculated stress trajectories on the eastern side of the Bight Basin are consistent with the new $S_{H_{\text{max}}}$ orientation determined from the wells in the region. On the western side of the Bight Basin, the stress trajectories indicate a more east–west orientation, which is caused by the influence of the east–west $S_{H_{\text{max}}}$ Orientation in the Perth region to the west (Hillis and Reynolds, 2000; Reynolds and Hillis, 2000). Because of the lack of available data in the western Bight Basin, we are unable to verify if the $S_{H_{\text{max}}}$ Orientation rotates to an east–west orientation in the western part of the Bight Basin. As such, we have used the average $S_{H_{\text{max}}}$ orientation of 130°N for the entire Bight Basin. Additional drilling in the western Bight Basin would allow the true stress orientations in that area to be determined.

**Figure 4.** Stress map of Australia (A–D quality) including the new Bight Basin stress data. Stress trajectory map from Hillis and Reynolds (2000) has been plotted to highlight the regional trends across the Australian continent. The $S_{H_{\text{max}}}$ orientation for the Bight Basin is reasonably consistent with the stress trajectories in the region. Enlargement: Stress map of the Bight Basin showing A–D quality stress indicators. Orientation of vector represents the $S_{H_{\text{max}}}$ orientation, and length of vector represents the data quality. Wells with no data or E quality data are represented by a dot. NF = normal faulting stress regime; SS = strike-slip faulting stress regime; TF = reverse (thrust) faulting stress regime; U = unknown stress regime.
Vertical Stress Magnitude

The vertical or overburden stress ($S_v$) at a specified depth can be equated with the pressure exerted by the weight of the overlying rocks and expressed as

$$S_v = \int_0^z \rho(z)g\,dz$$

where $\rho(z)$ is the density of the overlying rock column at depth $z$, and $g$ is the acceleration caused by gravity. Vertical stress magnitudes were determined using density log data for a total of 10 wells in the Bight and Polda basins. The density logs were initially filtered for bad hole conditions using the bulk density correction density (DRHO) and the caliper data. Vertical stress calculations require that the density log be integrated from the surface (here sea level, assuming the water column has a density of 1.03 g/cm$^3$). However, the density logs are not commonly run from the surface. The average density from the surface to the top of the density log run can be estimated by converting check-shot velocity data to density using the Nafe–Drake velocity-density transform (Ludwig et al., 1970).

To account for the variation in water depth, the vertical stress profiles have been calculated as effective vertical stress ($S'_v$), assuming normally pressured sediments (Figure 5). The effective vertical stress in the Bight Basin is closely approximated by the power law function

$$S'_v = 10.46z^{1.179}$$

where effective vertical stress is in megapascals and $z$ is the depth in kilometers below seabed.

Minimum Horizontal Stress Magnitude

A total of seven leak-off tests and eight formation integrity tests were performed in four wells over the Bight region. Formation integrity tests are not reliable indicators of the minimum horizontal stress, because no fracture is created at the wellbore wall, and hence, they were not used to constrain the minimum horizontal stress magnitude. The reliable leak-off test pressures were plotted along with the formation integrity tests as effective stress magnitudes to compare wells in varying water depths. The lower bound to the effective pressures from the leak-off tests suggests that the effective minimum horizontal stress ($S'_{\min}$) gradient is approximately 6 MPa/km. Because of the lack of leak-off data, especially below 2000 m (6600 ft), the $S'_{\min}$ gradient for the Bight Basin cannot be well constrained. Nevertheless, it is clear from the results obtained that the magnitude of $S'_{\min}$ is less than that of $S'_v$ (Figure 6). Hence, the Bight Basin is either in a strike-slip faulting ($S'_{\min} < S'_v < S'_{Hmax}$) or normal faulting ($S'_{\min} < S'_{Hmax} < S'_v$) stress regime.

Maximum Horizontal Stress Magnitude

The magnitude of $S'_{Hmax}$ is the most difficult component of the stress tensor to quantify. Many of the methods commonly applied for constraining $S'_{Hmax}$ could not be applied in the Bight Basin because of a lack of relevant data. The occurrence of borehole breakouts and drilling-induced tensile fractures could not be used to constrain $S'_{Hmax}$ because drilling-induced tensile fracture was not present in the image logs, and rock strength data were not available. Hydraulic fracture test-based techniques could not be applied because no extended leak-off tests or minifracture tests have been undertaken. Nonetheless, broad limits can be placed on $S'_{Hmax}$ based on the frictional limits to stress beyond which...
faulting occurs. The magnitude of the effective maximum horizontal stress \( S_{Hmax}^{'} \) was calculated to remove the effect of the water depth. The magnitude of \( S_{Hmax}^{'} \) can be constrained by assuming that the ratio of the maximum to minimum effective stress cannot exceed that required to cause faulting on an optimally oriented, preexisting fault (Sibson, 1974; Jaeger and Cook, 1979; Zoback and Healy, 1984).

The frictional limit to stress is given by

\[
\frac{S_1^{'}}{S_3^{'}} \leq \left\{ \sqrt{\left( \frac{\mu^2 + 1}{\mu} \right)^2} \right\}
\]

where \( \mu \) is the coefficient of friction that the crust can support until an optimally oriented preexisting fault slips to regulate the stress magnitudes; \( S_1^{'} \) is the effective maximum principal stress; and \( S_3^{'} \) is the effective minimum principal stress.

For a typical value of \( \mu = 0.6 \),

\[
\frac{S_1^{'}}{S_3^{'}} \leq 3.12
\]

This relationship can be used to estimate the magnitude of \( S_{Hmax}^{'} \) in seismically active regions (Zoback and Healy, 1984) and could provide an upper bound to \( S_{Hmax}^{'} \) in the relatively seismically passive regions such as the Bight Basin.

In the Bight Basin, \( S_{hmin}^{'} \) is most likely less than the effective vertical stress, implying that \( S_{hmin}^{'} = S_3^{'} \). The frictional limits to \( S_{Hmax}^{'} \) have been determined following equation 4 and are shown in Figure 6, assuming normally pressured sediments. The maximum \( S_{Hmax}^{'} \) gradient, based on frictional limits, is 18.7 MPa/km, implying a strike-slip faulting \( (S_{hmin}^{'} < S_v^{'} < S_{Hmax}^{'} ) \) stress regime. A normal faulting \( (S_{hmin}^{'} < S_{Hmax}^{'} < S_v^{'} ) \) stress regime cannot be ruled out, however, because of the lack of data constraining the magnitude of \( S_{Hmax}^{'} \). Consequently, in our analysis of fault reactivation and seal breach risk, three cases (Table 1) have been considered: a strike-slip faulting \( (S_{hmin}^{'} < S_v^{'} < S_{Hmax}^{'} ) \) stress regime case, a normal faulting \( (S_{hmin}^{'} < S_{Hmax}^{'} < S_v^{'} ) \) stress regime case, and a case on the boundary of strike-slip-normal faulting stress regimes. The magnitude of the in-situ stress field for the three cases was determined at a depth of 1000 m (3300 ft) below seabed.

**Pore Pressure**

Pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells. Repeat formation tests (RFTs) in the two wells indicate hydrostatic pore pressure measurements were only conducted in the Jerboa-1 and Greenly-1 wells.

**Table 1.** Parameters used in the three cases to model fault reactivation and seal integrity in the Bight Basin. The cases cover a range of possible values of \( S_{Hmax}^{'} \) within the frictional limits. The magnitude values have been calculated for a depth of 1000 m (3300 ft) below seabed.

<table>
<thead>
<tr>
<th>Case</th>
<th>( S_{Hmax}^{'} ) (MPa)</th>
<th>( S_v^{'} ) (MPa)</th>
<th>( S_{hmin}^{'} ) (MPa)</th>
<th>Fault Regime</th>
<th>( S_{Hmax}^{'} ) Orientation</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>18.7</td>
<td>10.5</td>
<td>6.0</td>
<td>strike slip</td>
<td>130°N</td>
</tr>
<tr>
<td>II</td>
<td>10.5</td>
<td>10.5</td>
<td>6.0</td>
<td>strike slip-normal</td>
<td>130°N</td>
</tr>
<tr>
<td>III</td>
<td>8.5</td>
<td>10.5</td>
<td>6.0</td>
<td>normal</td>
<td>130°N</td>
</tr>
</tbody>
</table>
pressures to a depth of approximately 3600 m (11,800 ft) (10.2 MPa/km). Below 3600 m (11,800 ft), the RFT measurements in Greenly-1 indicate a moderate overpressure of 11.8 MPa/km. To obtain a better understanding of the pore-pressure distribution, the mud weights have been considered as an indicator for pore pressure (Figure 7). In general, most of the region is normally pressured, with only a small indication of overpressure below 3600 m (11,800 ft) in Greenly-1. Hydrostatic pressures are assumed in our analysis of fault reactivation risk.

**FAULT REACTIVATION AND SEAL INTEGRITY IN THE BIGHT BASIN**

In case I (strike-slip stress regime), vertical faults striking between approximately 100 and 160° are the most likely to be reactivated (Figure 8b). Hence, traps requiring such faults to be sealing are the most likely to be breached in the in-situ stress field. Vertical faults striking 130° are located between that conjugate shear pair and are also at high risk of reactivation and breach. Faults striking between 75 and 180°N show little reduction in their risk of reactivation with decreasing dip until shallow dips (<40°) are attained. Faults striking 40°N and with any dip (and horizontal planes) are the least likely to be reactivated. Hence, traps requiring such faults to be sealing are the least likely to be breached in the in-situ stress field. At 1-km (0.6-mi) depth, and assuming the failure envelope in Figure 8a, vertical and 100°N-trending faults require an increase in pore pressure of only slightly in excess of 2 MPa for reactivation and seal breach.

Both case II (strike-slip-normal stress regime) and case III (normal stress regime) show significantly less range in ΔP values than in case I (Figure 8b, c). The ΔP values in cases II and III range between 5.8 and 10 MPa. In case II, faults striking 40°N of any dip are the least likely to be reactivated. In case III, however, horizontal faults with dips as much as 30° are the least likely to be reactivated. In general, most fault orientations and dips in both cases II and III show a similar propensity to be reactivated.

In all three cases, faults striking 40(±15)°N of any dip are the least likely to be reactivated. The magnitude of ΔP required to reanimate faults of this orientation decreases from case I to case III. Thus, traps requiring such faults to be sealing are the least likely to be breached in all three of the stress scenarios investigated.

The fault reactivation risk calculated in this study has been plotted on a series of fault orientations for the Sea Lion (Late Jurassic) rift faults and the Tiger (Late Cretaceous: Turonian to Santonian) postrift faults in the Eyre and Ceduna subbasins (Figure 1). These fault polygons are based on the interpretation of Totterdell et al. (2003). The FAST results for case I (strike slip) and case III (normal) for these faults are summarized in map view in Figure 9. In the absence of a depth-converted interpretation of the fault planes, the fault polygons have been assigned a range of hypothetical dips, specifically 25, 40, 55, and 70°, so that an impression can be gained as to how these variously dipping fault arrays would behave under a range of stress conditions. Figure 9 clearly demonstrates the importance of knowing both the strike and dip of a particular fault when conducting a three-dimensional FAST analysis. The northwest-trending faults in the Ceduna subbasin range from relatively low risk at 25° dip to relatively high risk at 70° dip.

**IMPLICATIONS FOR EXPLORATION PROSPECTIVITY**

The evaluation of the stress field and the potential for fault reactivation has important implications for petroleum exploration in the Bight Basin. Although an
accurate assessment of the fault reactivation risk is not possible based on available information, some trends can be established and discussed. Several precautions are required when assessing the results from this study. First, hydrostatic pressures are assumed in our analysis of fault reactivation risk, and hence, in areas where overpressures are anticipated, these predictions would need to be modified. Second, given the complex history of changes in the stress field that controls the structural evolution of sedimentary basins, the in-situ stress field, as constrained herein, cannot be extrapolated back in time and applied to previous structural events. Knowledge of the in-situ stress field can only elucidate contemporary tectonic events.

As shown in the previous section, faults that dip at 25° (Figures 8, 9) have little risk of reactivation, irrespective of the fault orientation and the type of stress field present. However, as the dips increase to 40°, it becomes apparent that the risk of fault seal failure becomes greater in the northwest-trending fault arrays in the Ceduna subbasin. In contrast, the more east- to northeast-trending faults in the Eyre subbasin are at low risk of reactivation. At dips of 55°, the risk of fault seal failure appears to be low in the Eyre subbasin, where the faults have a generally northeast trend. However, in the more northwest-trending fault arrays, the risk of reactivation is much higher, especially in a strike-slip stress regime. An exception is the small, east–west-trending, intrabasinal Sea Lion faults that occur in the overall, northwest-trending Sea Lion faults in the Ceduna subbasin. These faults have a low risk of reactivation compared to the northwest-trending faults that dominate this part of the Bight Basin. At fault dips of 70°, a high risk of reactivation of the northwest-trending fault sets of the Ceduna subbasin is present for all stress regimes. The exception is again the small, more east–west-trending fault arrays. The Eyre subbasin appears to have a low risk of reactivation, particularly
a) Case I
(strike-slip regime)

b) Case III
(normal regime)
in the strike-slip-normal and strike slip stress regimes. It should be noted, however, that stress trajectories calculated from the Australian stress map database indicate a more east–west $S_{Hmax}$ orientation for the Eyre subbasin than the 130°N $S_{Hmax}$ orientation used for our calculations. Therefore, the results for the Eyre subbasin should be used with care.

Overall, the results suggest that in a strike-slip-normal or normal stress regime, little risk of reactivation exists for fault systems that trend east–west or northeast. For these fault trends, almost no sensitivity to fault dip is present. Clearly, the rift faults of the Eyre subbasin and the intrabasinal, east–west-trending faults of the Ceduna subbasin all have a low risk of fault reactivation. In contrast, the results suggest that the rift and postrift faults of the Ceduna subbasin and, by inference, the Duntroon subbasin have a relatively high risk of reactivation once dips exceed approximately 40° for either a strike-slip-normal or normal stress regime. Traps with the lowest risk in the Ceduna and Duntroon subbasins with respect to reactivation are those with lower ($\leq 40°$) dips on the bounding faults or those with a more east–west orientation.

If we consider earthquake data, it appears that the most common earthquakes occur in the eastern Ceduna subbasin and in the Duntroon subbasin, broadly through the area with northwest-trending fault arrays. However, the rest of the Bight appears to be largely aseismic, and this may suggest that the stress regime in the central and western Bight is less conducive to reactivation. Thus, the trends of fault reactivation risk determined herein appear broadly consistent with the earthquake data.

The distribution of oil slicks that have been mapped in the region (Struckmeyer et al., 2002) via the use of satellite-based synthetic aperture radar are generally more common in the deep-water Ceduna subbasin and eastern parts of the Bight Basin, along the northwest fault arrays. Seismic gas chimneys are very common in the eastern Ceduna and Duntroon subbasins and correlate spatially with water column sniffer anomalies. These chimneys typically relate to the northwest-trending fault arrays in the region, so this may support some loss of fault seal integrity in this area.

Interestingly, the only confirmed paleo-oil column in the region was located in the Jerboa-1 well in the Eyre subbasin. This area is predicted, under the present-day stress regime, to be of high fault seal integrity. However, this trap was actually breached in the Late Cretaceous (Ruble et al., 2001). This emphasizes the fact that the stress predictions only relate to the present day and not to paleoreactivation events, when the stresses may have been quite different. It also emphasizes the fact that the timing of hydrocarbon migration (and probably the nature of the hydrocarbon charge) is very important in relation to trap reactivation. Relatively low to moderate fault seal integrity may be beneficial in regions that are now experiencing a high gas charge because this may help to reduce the risk of gas flushing in traps in such areas, which were previously charged with oil (O’Brien and Woods, 1995).

These observations highlight the fact that the results presented here should not be used in isolation. It does appear clear that relatively steeply dipping faults with a generally northwest trend will be prone to reactivation, whereas more east–west- or northeast-trending faults are unlikely to become reactivated, irrespective of dip. To better determine how critical the present-day stress environment is to hydrocarbon prospectivity in the Bight Basin, a complete fault seal assessment that should take into consideration such observations should be integrated with other aspects of the petroleum system, such as the generation history, remote-sensing results, and direct hydrocarbon indicator mapping.

For individual traps, the assessment of fault breaching risk requires detailed prospect studies, so that a geomechanical analysis can be applied to clearly defined, depth-converted fault planes interpreted from seismic data. In addition, in-situ stress field characteristics should be based on fieldwide measurements and the failure envelope constrained by properties specific to the analyzed rocks.

**ACKNOWLEDGMENTS**

Special thanks to Jennie Totterdell and Barry Bradshaw of Geoscience Australia for permission to use their fault interpretation and for providing the digital fault files, to Peter Boulton for valuable comments and suggestions, and to Primary Industries and Resources of South Australia Publishing Services for assistance with graphic files. Fugro Multi Client Services are thanked for permission to publish the seismic image in Figure 3. We thank David Castillo, Isabelle Moretti, and Signe Ottesen for their constructive comments regarding this manuscript.

**FIGURE 9.** Fault reactivation risks calculated using FAST technique applied to Sea Lion and Tiger fault polygons shown in Figure 1, assuming constant dips of 25, 40, 55, and 70°, respectively, for (a) case I (strike-slip stress regime) and (b) case III (normal stress regime). Results should be used with care in the western part of the Bight Basin and in areas of overpressure.
REFERENCES CITED


