Characterising the present-day stress regime of the Georgina Basin

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ABSTRACT
The onshore Georgina Basin in northern Australia is prospective for unconventional hydrocarbons; however, like many frontier basins, it is underexplored. A well-connected hydraulic fracture network has been shown to be essential for the extraction of resources from the tight reservoirs that categorise unconventional plays, as they allow for economic flows of fluid from the reservoir to the well. One of the fundamental scientific questions regarding hydraulic stimulation within the subsurface of sedimentary basins is the degree to which local and regional tectonic stresses act as a primary control on fracture propagation. As such, an understanding of present-day stresses has become increasingly important to modern petroleum exploration and production, particularly when considering unconventional hydrocarbon reservoirs. This study characterises the regional stress regime in the Georgina Basin using existing well data. Wellbore geophysical logs, including electrical resistivity image logs, and well tests from 31 petroleum and stratigraphic wells have been used to derive stress magnitudes and constrain horizontal stress orientations. Borehole failure features interpreted from wellbore image and caliper logs yield a maximum horizontal stress orientation of 044°N. Integration of density log data results in a vertical stress gradient of 24.6 MPa km⁻¹. Leak-off and mini-fracture tests suggest that this is the minimum principal stress, as leak-off values are generally shown to be at or above the magnitude of vertical stress. The maximum horizontal stress gradient is calculated to be in the range of 31.3–53.9 MPa km⁻¹. As such, a compressional stress regime favouring reverse/reverse–strike-slip faulting is interpreted for the Georgina Basin.

Introduction
The Australian continent hosts a highly variable stress field (Hillis & Reynolds, 2003; Rajabi, Tingay, King, & Heidbach, 2016a; Rajabi, Tingay, & Heidbach, 2016b) where stress patterns are not oriented sub-parallel to absolute plate motion as they are in many other continents (Rajabi et al., 2016b). Knowledge of contemporary stresses can provide important information for understanding large-scale processes, such as intraplate deformation, geodynamic and neotectonic processes, through to localised processes, with implications for the mining, petroleum, and geothermal industries (Bell, 1996; Hillis & Reynolds, 2003; Rajabi et al., 2016b). Patterns of stress orientations in the Australian continent have been analysed in the Australian Stress Map project (Hillis & Reynolds, 2000, 2003; Reynolds, Coblentz, & Hillis, 2002) and in subsequent studies (e.g. Bailey, King, Holford, & Hand, 2016; King, Hillis, & Reynolds, 2008; Rajabi et al., 2016a) (Figure 1). However, data from some locations, including the Georgina Basin in northern Australia, have not yet been analysed and/or incorporated into the most recent version of the Australian Stress Map (Hillis & Reynolds, 2003; Rajabi et al., 2016a) (Figure 1).

The Georgina Basin is an onshore Australian basin considered to be prospective for conventional and unconventional oil and gas (Ambrose, Kruse, & Putnam, 2001; Munson, 2014). The Georgina Basin is a frontier basin, and with limited seismic data coverage and only ~60 wells targeting prospective formations drilled to date, it is underexplored (Bennett, Philipchuk, & Freeman, 2010; Munson, 2014; PetroFrontier, 2012, 2014; Smith et al., 2013). Conventional hydrocarbon exploration and stratigraphic drilling in the basin commenced in the 1960s; however, commercial flows of oil and gas are yet to be achieved. Recent exploration has primarily targeted source rocks in the Arthur Creek Formation and Thorntonia Limestone in the southern Georgina Basin for unconventional oil and gas.

The extraction of oil and gas from tight reservoirs such as shale requires hydraulic stimulation to create fracture pathways to enable adequate flows of fluid from the reservoir to the well (Bell, 1990; Bell & Babcock, 1986). Local and regional tectonic stresses act as primary controls over the generation and propagation of hydraulic fractures; thus, an understanding of present-day stresses has become increasingly important to modern petroleum exploration and production (Bell, 1996; Hillis & Reynolds, 2003; Zoback, 2007) (Figure 1). While critical for predicting hydraulic fracture patterns associated with reservoir stimulation, the orientations and magnitudes of present-day stresses also have implications for borehole...
stability, water-flood design, and fault reactivation (Addis, Last, Boulter, Roca-Ramisa, & Plumb, 1993; Caillet, 1993; Hillis & Reynolds, 2003; Hillis & Williams, 1993a, 1993b; Horn, 1991; Mildren, Hillis, Fett, & Robinson, 1994). Lithospheric stresses can be defined in terms of the orientation and magnitude of three orthogonal principal stresses, namely a maximum ($\sigma_1$), minimum ($\sigma_3$), and intermediate ($\sigma_2$). One stress is generally vertical owing to the mass of overburden and is referred to as $\sigma_V$ (Anderson, 1951; Sibson, 1974). The two remaining principal stresses are generally confined to the horizontal plane and are referred to as the maximum ($\sigma_H$) and minimum ($\sigma_h$) horizontal stresses. The relative magnitudes of these three principal stresses define a tectonic regime in which a type of faulting will dominate (Zoback et al., 1989), although pre-existing structures can exhibit hybrid failure modes under any given regime (Anderson, 1951; Heidbach & Hohne, 2008; Sibson, 1977). With one stress assumed to be vertical, knowledge of one of the horizontal stress orientations ($\sigma_H$ or $\sigma_h$) enables the orientations of all three stresses to be determined (Bell, 1996; Tingay, Hillis, Morley, Swarbrick, & Okpere, 2003).

The aim of this study was to characterise the regional stress regime within the Georgina Basin and the variation in stress orientations within the region (Figures 1, 2). Owing to limited public availability of appropriate, detailed geophysical log data, lithological controls on stress regime within the basin are not evaluated in this study, and we focus on the regional stress regime. Data from 31 petroleum and stratigraphic wells were used to derive stress parameters from which a whole-of-basin representation of the present-day stress regime was constructed. Stress magnitudes were constrained using wellbore geophysical logs and tests. Vertical stress ($\sigma_V$) magnitudes were derived from checkshot-calibrated density logs, minimum horizontal stress ($\sigma_h$) magnitudes were constrained using data from leak-off tests (LOTs) and formation integrity tests (FITs). Maximum horizontal stress ($\sigma_H$) magnitudes were constrained using frictional limits calculations (Jaeger & Cook, 1979) and estimates assuming shear failure of pre-existing fractures during LOTs (Couzens-Schulz & Chan, 2010). Electrical resistivity-based image logs from six wells were used in conjunction with four-arm caliper (4AC) logs to assess $\sigma_H$ orientations within the Georgina Basin. Common wellbore-failure features, such as borehole breakouts (BOs) and drilling-induced tensile fractures (DITFs), have been shown to be reliable indicators of stress orientations within sedimentary basins and can be identified on both electrical resistivity-based image and caliper logs (Brudy & Zoback, 1999; Dart & Zoback, 1989; Hillis & Reynolds, 2000).
Geological setting

The Georgina Basin is a polyphase Neoproterozoic to Paleozoic intracratonic basin and is the largest remnant of the Neoproterozoic to early Paleozoic Centralian Superbasin (Ambrose et al., 2001; Greene, 2010; Munson, 2014; Walter, Veevers, Calver, & Grey, 1995). The basin covers an area of approximately 333,000 km² throughout the central-eastern Northern Territory and western Queensland (Figure 2). The basin is bounded by the Tennant Region to the west, the McArthur Basin, South Nicholson Basin and Lawn Hill Platform to the northeast, and the Mount Isa Province to the east. The basin was once contiguous with the Amadeus Basin to the south; however, uplift of the Arunta Block led to their separation (Ambrose et al., 2001; Munson, 2014). Unconformably overlying the Proterozoic crystalline basement, the Georgina Basin hosts up to 5 km of Cryogenian to Devonian-aged sedimentary rocks that have experienced several major deformation events, most notably the Paleozoic Alice Springs Orogeny and the Neoproterozoic Petermann Orogeny (Ambrose et al., 2001; Greene, 2010; Munson, 2014). The basin is commonly separated into two distinct domains: (1) a southern depocentre south of latitude 21°S and a central-northern quiescent platform (Munson, 2014). The dominant petroleum prospectivity is associated with the southern Georgina Basin, and in particular in the Dulcie and Toko synclines (Figure 2).

The main interval of interest for petroleum exploration in the Georgina Basin has historically been the middle Cambrian succession, which contains high-quality marine source rocks (Ambrose et al., 2001, Boreham & Ambrose, 2005, 2007; Dunster, Kruse, Duffett, & Ambrose, 2007; Munson, 2014; Tiem, Horsfield, & di Primo, 2011). Of these, within the Arthur Creek Formation (Figure 3) oil shows increase in abundance with

Figure 2. Regional map of the Georgina Basin. Interpreted maximum horizontal stress orientations from wells featuring four-arm caliper or electrical resistivity image logs are displayed as scaled arrows based on the world stress map quality ranking (Heidbach et al., 2010) assigned to that data point (Table 1). Two distinct domains of the basin are generally recognised: a southern depocentre south of latitude 21°S and a central-northern quiescent platform (Munson, 2014).
Figure 3. Stratigraphy of the Georgina Basin. Recent exploration has focused on the potential unconventional resources of the middle Cambrian Arthur Creek Formation and Thorntonia Limestone.
depth (Ambrose et al., 2001). The basal hot shale facies of the lower Arthur Creek Formation is thought to have the greatest potential as both a traditional source rock and an unconventional target (Ambrose & Putnam, 2007; Boreham & Ambrose, 2005; Munson, 2014). The Thorntonia Limestone, a transgressive dolostone that underlies the Arthur Creek Formation and features interbeds of carbonaceous mudstone, is also considered to host high-quality source rocks with unconventional prospectivity (Ambrose et al., 2001; Boreham & Ambrose, 2005; Dunster et al., 2007; Munson, 2014).

Method and results

Data sources and data evaluation

Data were sourced from open-file well-completion reports [FITs, LOTs, drill stem tests (DSTs), mini-fracture tests] and associated well-log data (density, velocity and resistivity image logs). In addition, image-log and other digital data were obtained for two recently drilled wells in the basin (Owen 3 and Baldwin 2).

Data were evaluated for quality and reliability, processed to remove erroneous values and compiled. Of the 60 wells identified within the study area, 31 wells were found to contain relevant parameters for the analysis and met the criteria for reliability. These wells are detailed in the Supplementary Papers (Table A1). Several wells from the McArthur Basin, which underlies the Georgina Basin in the north, and from the northern Pedirka Basin, which lies to the south of the Georgina Basin, were used to validate and extend the interpretation of regional \( \sigma_{HV} \) azimuths (Figure 2).

Vertical stress magnitude

The magnitude of vertical stress \( (\sigma_v) \) is defined as the stress applied by the mass of overburden above a specific depth and is calculated through an integration of measured formation bulk density to the depth of interest (Bell, 1996; Brown & Hoek, 1978; Engelder, 1993; Tingay et al., 2003). Where no overlying water column is present, the following equation applies:

\[
\sigma_v = \int_0^Z \rho(z)g \, dz
\]

where \( \rho(z) \) is overburden density at depth \( z \) and \( g \) is gravitational acceleration (Bell, 1996; Engelder, 1993; King, Neubauer, Hillis, & Reynolds, 2010; Tingay et al., 2003). Density logs were used to calculate \( \sigma_v \) (Bell, 1996; King et al., 2010; Tingay et al., 2003). In wells that are not run to surface, a top-of-log stress value can be calculated from well velocity surveys using the Gardner, Gardner, and Gregory (1974) empirically derived velocity–density transform (Bell, 1996; Tingay et al., 2003), allowing a vertical stress profile to be constructed (King et al., 2010; Zoback, 2007).

Density logs from 23 wells within the Georgina Basin produce a mean \( \sigma_v \) gradient of 24.6 MPa km\(^{-1} \) (SD = 0.84 MPa km\(^{-1} \)). Calculated magnitudes for \( \sigma_v \) at 1 km depth range from 22.8 to 26.1 MPa km\(^{-1} \) (Figures 4, 5; Table 2).

Minimum horizontal stress magnitude

Hydraulic fracture tests, such as mini-fracture tests and LOTs, allow for direct determination of \( \sigma_H \) magnitude (Bell, 1990; Breckels & van Eckelen, 1982; Dickey, 1986; Nelson, Hillis, & Mildren, 2006; White, Traugott, & Swarbrick, 2002). In the Georgina Basin, two different sets of LOT results were observed: those where leak-off occurs below the calculated value of \( \sigma_v \) and those where leak-off occurs at or above the calculated value of \( \sigma_v \) (Figure 4). Nine LOTs and two mini-fracture tests from nine wells were analysed in this study (Table 3). An additional 24 FITs from 22 wells were used to provide estimates of lower bounds to \( \sigma_3 \) (Figure 4) (Supplementary Papers, Tables A1, A3). Calculated values of \( \sigma_3 \) from LOTs range from 2.0 MPa at 0.09 km to 41.4 MPa at 1.27 km; calculated values of \( \sigma_3 \) from the two mini-fracture tests range from 27.6 MPa at 0.90 km to 70.7 MPa at 2.54 km (Table 3).

Five LOTs in four wells had leak-off pressures that were below the calculated value of \( \sigma_v \). One of these wells, Bradley 1, was discounted owing to reported poor LOT conditions.

Maximum horizontal stress magnitude

Several methods are used to estimate \( \sigma_H \) magnitudes from petroleum wellbore data. The most commonly used is the frictional limits method (Jaeger & Cook, 1979). A maximum limit to horizontal stress magnitude can also be calculated when assuming shear failure of fractures during LOTs (Couzens-Schultz & Chan, 2010). The magnitude of \( \sigma_H \) can also be constrained by observed breakout width (Barton, Zoback, & Burns, 1988; Vernik & Zoback, 1992) and the circumferential stress relationships around a vertical well (Bell, 1996; Hubbert & Willis, 1957); however, these approaches require higher-quality data than were available for this study. Detailed one-dimensional mechanical earth models can be constructed using poroelastic stress equations that take tectonic strain into consideration (Brooke–Barnett et al., 2015; Mildren, Clarke, Holford, & Titus, 2013; Thiercelin & Plumb, 1994). However, these rely on the availability of extensive wireline log suites and laboratory rock property measurements for calibration (Brooke–Barnett et al., 2015) that are not presently publicly available in the Georgina Basin. Thus, we applied the first two approaches to estimate \( \sigma_H \) within the Georgina Basin.

(1) Frictional limits theory (Jaeger & Cook, 1979) assumes that the maximum stress is limited by the rock’s frictional properties, and that this stress is horizontal. These assumptions point to a maximum value for \( \sigma_H \) magnitude (Sibson, 1974; Zoback & Healy, 1984), as represented by the following equations:

\[
\sigma_H = f(\mu) \times (\sigma_v - \sigma_p) + \sigma_p
\]

\[
f(\mu) = \left[ (1 + \mu^2)^{2} + \mu \right]^{2}
\]

and where \( \mu \) is the coefficient of internal friction, assumed to be 0.6 (Bayerle, 1978; Zoback & Healy, 1984.)
Assuming a hydrostatic pore pressure, and that $s_v = s_h$, an average upper frictional limit boundary of 53.9 MPa km$^{-1}$ (1 SD$ = 2.6$ MPa km$^{-1}$) was calculated for the Georgina Basin (Table 2; Figure 4).

(2) Couzens-Schultz and Chan (2010) provide a method for estimating the maximum upper limits of $s_H$ when shear failure is suspected in LOTs (see Discussion for treatment of suspect LOT data). Estimation of $s_H$ can be achieved using the following equation:

$$s_{H,\text{lim}} = s_v + \frac{2\left(s_v - \left(LOP - \frac{C_0}{\mu}\right)\right)\sin^2(\theta)}{1 - \sin^2(\theta)}$$  \hspace{1cm} (4)

where $s_{H,\text{lim}}$ is the upper limit of $s_H$, $C_0$ is cohesion (assumed to be negligible), and $\mu$ is the coefficient of friction (assumed to be 0.6) (Couzens-Schultz & Chan, 2010). Using LOTs with suspected shear failure (Equation 4), $s_H$ magnitudes ranging from 2.8 MPa at 0.09 km depth to 4.7 MPa at 0.13 km depth are predicted (Table 4). This gives an extrapolated $s_H$ gradient of 34.7 MPa km$^{-1}$ (Figure 4).

The two methods applied to estimate $s_H$ magnitude yield estimates that range from 34.7 MPa km$^{-1}$ to 53.9 MPa km$^{-1}$. It should be noted that the maximum value derived from frictional limits theory is likely to overestimate $s_H$.

**Maximum horizontal stress orientation**

Two main wellbore-failure features are commonly used as stress indicators: borehole breakouts (BO) and DITFs (Figure 6). As rock is removed during drilling, stress is concentrated around the wellbore: circumferential stress is maximised at the minimum horizontal stress azimuth and minimised at the maximum horizontal stress azimuth (Gough & Bell, 1981; Haimson & Herrick, 1986; Maloney & Kaiser, 1989; Zheng, Kemeny, & Cook, 1989; Zoback, Moos, Mastin, & Anderson, 1985) (Figure 6a). Borehole failure through the creation of BOs and DITFs is a result of stress perturbations that exist under such conditions (Kirsch, 1898; Plumb & Hickman, 1985; Zheng et al., 1989; Zoback et al., 1985). BOs form in the direction of $s_v$, and DITFs occur in the direction of $s_H$ (Figure 6a). These features and their orientations can be identified using...
either four-arm caliper data (Figure 6b) or electrical resistivity image logs (Figure 6c, d).

Seven wells were identified within the study area (Figure 2) that had resistivity image logs, 4AC logs or both (Figure 7) (Supplementary Papers, Table A1). As a consequence of the low data density within the Georgina Basin, wells in the nearby Pedirka Basin and underlying McArthur Basin were included in the interpretation to establish the regional consistency of $\sigma_H$ azimuths (Figure 2). Several types of electrical resistivity image logs were used: Formation Micro-Imager (FMI), Formation Micro-Scanner, Compact Micro-Imager (CMI) and Simultaneous Acoustic and Resistivity Imager (STAR) (Supplementary Papers, Table A2).

Glyde 1 hosted no identifiable stress indicators. However, the remaining six interpreted wells hosted an appropriate population of stress indicators (Figure 7) to qualify as D quality or higher according to the World Stress Map guidelines (Table 1). The only exception to this was the BOs interpreted from the Baldwin 2 image log. Using the valid stress orientations from borehole failure data (Figure 2), a mean $\sigma_H$ orientation of 044°N was interpreted for the study area (Figure 7).

Application of the Rayleigh test (Mardia, 1975) showed that on a regional scale these data represent a non-random

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**Table 1.** Interpreted maximum horizontal stress orientations from four-arm caliper logs and resistivity image logs (using both borehole breakouts and drilling-induced tensile fractures).

| Well          | Log   | Indicator | Quality | Orientation |
|--------------|-------|-----------|---------|-------------|
| Baldwin 2    | FMI   | BO (4AC)  | C       | 58.0        |
|              |       | BO (Image)| E       | 74.8        |
|              |       | DITF      | D       | 66.9        |
| Blamore 1    | STAR  | BO (4AC)  | –       | –           |
|              |       | BO (Image)| D       | 26.2        |
|              |       | DITF      | C       | 34.7        |
| CBM 93 004   | CMI   | BO (4AC)  | C       | 48.3        |
|              |       | BO (Image)| –       | –           |
| Kilgour North 1 | FMI   | BO (4AC)  | B       | 46.8        |
|              |       | BO (Image)| C       | 45.8        |
|              |       | DITF      | D       | 33.1        |
| Owen 3       | CMI   | BO (4AC)  | B       | 26.3        |
|              |       | BO (Image)| D       | 62.6        |
|              |       | DITF      | D       | 65.4        |
| Shenandoah 1 | FMI   | BO (4AC)  | D       | 30.9        |
|              |       | BO (Image)| –       | –           |
|              |       | DITF      | D       | 30.7        |

Quality rankings are based on the World Stress Map Project criteria (Heidbach et al., 2010). Further details on the factors contributing to a given quality ranking can be found in Supplementary Papers, Table A3. Tools: FMI, Formation Micro-Imager; CMI, Compact Micro-Imager; STAR, Simultaneous Acoustic and Resistivity Imager. Indicators: BO, Borehole Breakouts; DITF, Drilling-Induced Tensile Fractures; 4AC, Four-Arm Caliper.
A. BAILEY ET AL.

This is a result of the borehole axis not being aligned parallel to one of the principal stresses in highly deviated wells (Mastin, 1988). Well deviation ranges from 1.5° to 18.5° in the studied wells (Table 1), with the majority of wells being deviated <10°. Additionally, the two wells studied with deviations of >10°, Owen 3 and Kilgour North 1, are deviated <10° for the majority of their length. As all of the wells studied are approximately vertical (well deviations <20° from vertical), we consider that our interpretations of BO and DITF provide reliable indications of σ1 and σ3, respectively (Mastin, 1988).

### Pore pressure

Formation pressure can be extrapolated from production tests such as the DST and through wireline tools such as the Modular Formation Dynamics Test (MDT) (Bradley, 1975; Horner, 1951; Kuchuk, 1998). Formation test data were obtained for 17 wells in the Georgina Basin, providing 39 estimates of formation pressure (Figure 8). Pore pressures were observed to be at or near the hydrostatic value for saline groundwater, and this was also indicated by the mud weights observed to be at or near the hydrostatic value for saline groundwater, and this was also indicated by the mud weights applied when drilling in the Georgina Basin, which closely reflect the hydrostatic gradient (Figure 8). While a hydrostatic gradient is assumed for the remainder of this study based on these results, overpressures may exist within the basin.

### Discussion

#### Diagnosis of stress regime

In determining the present-day stress regime, it is essential to determine which principal stress is the minimum. The LOT

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### Table 2. Calculated stress magnitudes for the wells featuring density logs in the Georgina Basin.

| Well               | Stress magnitude (MPa km⁻¹) | Frictional limits (MPa km⁻¹) |
|--------------------|-----------------------------|-----------------------------|
| **Northern Georgina Basin** |
| Altree 1           | 24.7                        | 54.3                        |
| Balmain 1          | 23.5                        | 50.3                        |
| Burdo 1            | 24.1                        | 52.4                        |
| Chanin 1           | 24.4                        | 53.3                        |
| Elliott 1          | 24.0                        | 52.1                        |
| Glyde 1            | 24.7                        | 54.0                        |
| Mason 1            | 22.8                        | 48.4                        |
| Shenandoah 1       | 23.5                        | 50.3                        |
| Shortland 1        | 23.4                        | 50.1                        |
| Walton 2           | 23.7                        | 50.9                        |
| **Southern Georgina Basin** |
| Baldwin 1          | 25.4                        | 56.3                        |
| Baldwin 2          | 25.7                        | 57.2                        |
| Bradly 1           | 24.3                        | 52.9                        |
| Hacking 1          | 24.4                        | 53.1                        |
| Hunt 1             | 25.1                        | 55.5                        |
| MacIntyre 1        | 26.1                        | 58.4                        |
| Mirrica 1          | 25.2                        | 55.6                        |
| Owen 2             | 25.1                        | 55.5                        |
| Owen 3             | 25.1                        | 55.5                        |
| Phillip 2          | 25.5                        | 56.8                        |
| Randall 1          | 24.5                        | 53.5                        |
| Ross 1             | 25.0                        | 55.0                        |
| Todd 1             | 25.8                        | 57.6                        |

Results are separated by well location within the basin. Vertical stress gradient ($S_v$) as calculated using Equation 1 and frictional limits to maximum horizontal stress as calculated using Equation 2 are presented.

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### Table 3. Leak-off tests and resultant estimate of least principal stress magnitude for each well in which leak-off was achieved in the Georgina Basin.

| Well      | Test | Quality | Depth (m TVDkb) | Leak-off pressure (MPa) | Leak-off gradient (MPa km⁻¹) |
|-----------|------|---------|-----------------|-------------------------|-----------------------------|
| Bradley 1 | LOT  | D       | 820.40          | 10.2                    | 12.5                        |
| Bradley 1 | LOT  | D       | 117.80          | 1.71                    | 14.5                        |
| MacIntyre 1 | LOT | D       | 125.30          | 2.6                     | 20.8                        |
| Randall 1 | LOT  | D       | 128.00          | 2.9                     | 31.3                        |
| Phillip 2 | LOT  | D       | 88.10           | 2.5                     | 34.1                        |
| Shenandoah 1 | Minfrac | Reported FCP gradient | 2539.80 | 53.5 | 28.6 |
| Shenandoah 1 | Minfrac | Reported FCP gradient | 1754.00 | 49.2 | 28.1 |
| Shenandoah 1 | Minfrac | Reported FCP gradient | 2539.80 | 53.5 | 28.6 |
| Baldwin 2 | MiniFrac | Reported closure Pressure | 895.00 | 27.6 | 30.9 |
| Baldwin 2 | LOT  | C       | 423.00          | 13.2                    | 31.1                        |
| Owen 3    | LOT  | D       | 1273.00         | 41.4                    | 32.5                        |
| Ross 1    | LOT  | D       | 101.50          | 3.3                     | 32.6                        |
| Baldwin 1 | LOT  | D       | 102.50          | 5.1                     | 49.8                        |

Quality rankings are as per King et al. (2008). Depth is given as true vertical depth as measured from the Kelly bushing (m TVDkb). LOT, leak-off test; Minfrac, Mini-Fracture Test; FCP, fracture closure pressure.
data show two types of results: values that are at or above the value of $\sigma_V$, and values that are significantly lower than the value of $\sigma_V$ (Figure 4). Values at or above $\sigma_V$ suggest that $\sigma_V = \sigma_3$, and that horizontal tensile fractures are being generated (Zoback, 2007). This would place the Georgina Basin in a dominantly reverse-faulting stress regime (Anderson, 1951). However, some data are below the vertical stress gradient, which suggests two possible scenarios: (1) fractures optimally oriented for shear failure were reactivated, or (2) vertical tensile fractures were generated (e.g. under a much reduced $\sigma_H$).

Such dichotomous LOT results have been observed in active thrust belts; in some wells leak-off pressures are close to the vertical stress, and in others much less than vertical stress (e.g. Couzens-Schultz & Chan, 2010). It has been suggested that pre-existing fractures intersecting the borehole can affect LOTs. Where cohesion is low, fractures may experience shear slip allowing for leak-off, giving abnormally low values of $\sigma_H$ (Bailey et al., 2016; Chan, Hauser, Couzens-Schultz, & Gray, 2014; Couzens-Schultz & Chan, 2010; Gjønnes, Cruz, Horsrud, & Holt, 1998; King et al., 2012). We consider the
first scenario to be more likely, i.e. data that are below \( \sigma_V \) are reflecting shear reactivation of optimally oriented fractures. This is supported by FIT data that demonstrate values obtained without reaching leak-off are close to \( \sigma_V \) (Figure 4). The magnitude of \( \sigma_H \) is, therefore, likely to be equal to or higher than the magnitude of \( \sigma_V \).

Couzens-Schultz and Chan (2010) propose the following equation to calculate a lower-bound estimate for the two horizontal stress magnitudes based on shear reactivation of existing fractures:

\[
\sigma_{H,\text{lim}} = \sigma_V - \frac{2(\sigma_V - \left(\text{LOP} - \frac{c_0}{\mu}\right)\sin \theta)}{(1 + \sin \theta)}
\]

where \( \sigma_{H,\text{lim}} \) is the lower limit of \( \sigma_H \) (Couzens-Schultz & Chan, 2010). The five data points with anomalously low LOT values (Table 4) were recalculated using Equation 5. Values of \( \sigma_{H,\text{lim}} \) from this method range from 2.1 MPa at \( \sim 0.09 \) km to 2.9 MPa at 0.13 km, giving gradients that are approximately equal to the calculated gradient of \( \sigma_V \) (Tables 2, 4), and in line with estimates from the other LOTs.

Calculated stress magnitudes demonstrate that the Georgina Basin is subject to a dominantly reverse-faulting stress regime (Table 5). It is possible that \( \sigma_3 = \sigma_2 \) \( (\sigma_V = \sigma_H) \), meaning that the Georgina Basin may host a transitional strike-slip to reverse-faulting stress regime. Given that enough stress anisotropy exists between the horizontal stresses for the formation of BOs and DITFs, it is unlikely that \( \sigma_H = \sigma_V \) (Table 5).

The orientations of the principal stresses appear to be consistent throughout the basin, with a non-random mean \( \sigma_H \) orientation of 044°-N. This orientation is obtained from widespread data; however, it agrees with previously modelled \( \sigma_H \) orientations (Dyksterhuis, Müller, & Albert, 2005; Müller & Dyksterhuis, 2005; Reynolds et al., 2002) as well as the predicted orientations of the Australian Stress Map (Hillis & Reynolds, 2000, 2003) (Figures 1, 2). We propose that \( \sigma_H \) is greater or equal to \( \sigma_V \), thereby placing the Georgina Basin in a reverse/reverse–strike-slip stress regime (Zoback et al., 1989) (Table 5).

**Lithological controls over stress**

At local scales, it is well demonstrated that lithological transitions can affect \textit{in situ} stress magnitudes, primarily owing to variations in rock properties. Stress magnitudes in units with low Poisson ratio are generally greater than those with high Poisson ratios (Thiercelin & Plumb, 1994). Variation of stress magnitudes by lithology can be beneficial for hydraulic stimulation, primarily as a means by which fracture growth can be controlled: where a ‘low-stress’ unit is located between two ‘high stress’ units, fractures formed in the centre unit can be easily compartmentalised by limiting injection pressures (e.g. Zoback, 2007). Brooke-Barnett et al. (2015) demonstrate an example in Queensland’s Surat basin where mechanical stratigraphy exerts a control over tectonic stresses, with lower-rigidity rocks supporting lower tectonic stresses than high-rigidity rocks.

Analysis of stress magnitudes derived from LOTs presented in this study reveals no distinct correlation between lithology and either high or low values for leak-off, so we suggest that the anomalously low LOT values observed are due to LOTs having been performed in the presence of pre-existing fractures as described above (Couzens-Schulz & Chan, 2010). The formation of DITFs is generally observed in fine-grained (siltstone and shale) intervals and can be a result of a strike-slip stress regime (Zoback, 2007). Hence, as DITFs in this study similarly appear to be restricted to fine-grained intervals in the Georgina Basin data, this may be an example of mechanical stratigraphy and may indicate intervals of strike-slip faulting within the basin. However, while some lithological control may be implied in our data, this study has primarily focused on the regional and basin-scale trends in stress regime of the Georgina Basin. For field-scale applications, these possible
lithological variations in stress regime should be further investigated.

**Distribution of stresses**

Although data coverage is sparse, the Georgina Basin does exhibit some trends in the distribution of stress. Contour maps of the calculated values for the principal stresses were created to highlight general trends (Figure 9), although it should be recognised that the paucity of data in the northern part of the basin means that basin-wide trends must be interpreted with caution.

High vertical stresses are common, most notably in the southern Georgina Basin in the Toko and Dulcie synclines (Figure 9a). This trend may be explained by extensive uplift, which is thought to have occurred along the basin’s southern margin during the Paleozoic Alice Springs Orogeny and the Neoproterozoic Petermann Orogeny (Ambrose et al., 2001; Hand & Sandiford, 1999; Munson, 2014). Uplifted sedimentary sections are over-compacted relative to current burial depths, leading to higher rock densities (King et al., 2010; Tingay et al., 2003). Conversely, in the northern part of the basin (including the Beetaloo Sub-basin and the underlying McArthur Basin), \( \sigma_V \) magnitudes are lower, implying less

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**Figure 8.** Pore pressure profile for Georgina Basin. Point data sourced from DSTs and modular formation dynamics tests (MDT) undertaken in wells within the basin and plotted over the recorded mud weight profiles for various wells. Hydrostatic pressure is represented as a dashed line.

**Table 5.** Summary table of all interpreted stress data demonstrating that the Georgina Basin likely hosts a reverse-faulting stress regime.

| Stress orientation | Vertical stress \( (\sigma_V) \) magnitude (MPa km\(^{-1}\)) | Minimum horizontal \( (\sigma_h) \) stress magnitude (MPa km\(^{-1}\)) | Maximum horizontal \( (\sigma_H) \) stress magnitude (MPa km\(^{-1}\)) | Interpreted stress regime |
|--------------------|----------------------------------------------------------|----------------------------------------------------------|----------------------------------------------------------|--------------------------|
| 044°               | 22.8–26.1                                                | Between \( \sigma_V \) and \( \sigma_H \)                | 53.86                                                    | Reverse                  |

Vertical stress magnitudes are given for 1 km depth.
uplift-related over-compaction of the sedimentary section at current burial depths (Munson, 2014).

As $\sigma_H$ magnitudes calculated through frictional limits are based on the values of $\sigma_H$, they exhibit similar trends, with higher $\sigma_H$ magnitudes observed in the southern Georgina Basin (Figure 9b).

Analysis of LOT results highlights few distinct spatial trends, primarily owing to the low data density (Figure 2). However, lower pressures appear to be necessary to achieve leak-off in the eastern part of the Dulcie Syncline (Figures 2, 9c). As proposed above, this may be due to the presence of pre-existing flaws in the tested rock (i.e. shear reactivation of existing fractures), rather than a reduction in $\sigma_3$ magnitudes. As such, it could indicate higher natural fracture densities in the eastern Dulcie Syncline compared with the rest of the basin. Given the low data density and the presence of low LOT results in other parts of the basin, it is possible that the clustering of low LOT values is coincidental, and further data are required to identify any reliable trends in fracture density distribution.

Implications for hydraulic stimulation

Hydraulic stimulation is commonly undertaken to improve fluid recovery, particularly in tight reservoirs in shale gas, shale oil, tight gas and coal seam gas plays (Fjaer, Holt, 132

![Figure 9. Contour maps showing the distribution of: (a) vertical stress gradients within the Georgina Basin; (b) interpreted frictional limits to maximum horizontal stress within the Georgina Basin; and (c) leak-off test results within the Georgina Basin. Moderately high values in the eastern portion of the basin are an artefact of low data density and software extrapolation.](image)
Horsrud, Raen, & Risnes, 2008; Yew & Weng, 2014). Created through injection of high-pressure fluids into a target formation, hydraulic fracture formation and propagation are primarily controlled by the present-day stress regime, rock properties, rock heterogeneity and pore pressures (Peška & Zoback, 1995). The orientation and magnitudes of the three principal stresses commonly influence the size and orientation of fractures formed through hydraulic stimulation (Anderson, 1951; Hubbert & Willis, 1957). We have interpreted the Georgina Basin to be in a reverse/reverse-strike-slip regime. In normal and strike-slip faulting stress regimes, tensile fractures (such as those induced through hydraulic fracturing) are observed to form vertically, as \( \sigma_3 = \sigma_h \) (Anderson, 1951; Hosssain, Rahman, & Rahman, 2000; Sibson, 1990; Zoback, 2007). Studies have found that in a reverse-faulting stress regime, and at distance from the wellbore, tensile fractures will form horizontally as \( \sigma_2 = \sigma_h \) (Hossain et al., 2000; Hubbert & Willis, 1957; Sibson, 1990; Zoback, 2007). In reverse-faulting stress regimes, induced tensile fractures are observed to form vertically at the wellbore wall owing to hoop stress effects (Zoback, 2007), before rotating to horizontal as they propagate out of the perturbed stress field surrounding the wellbore (Baumgärtner & Zoback, 1989; Hossain et al., 2000; Zoback, 2007).

**Implications of stress field for well stability**

Stress field anisotropy can cause wells to become unstable and form BOs and DITFs (King et al., 2012; Zoback, 2007), resulting in unacceptable reservoir and wellbore damage (Zoback, 2007). Boreholes are therefore drilled along a trajectory that minimises stress anisotropy (Zhou, Hillis, & Sandiford, 1996). In a reverse-faulting stress regime, the greatest anisotropy has been demonstrated to occur between \( \sigma_V \) and \( \sigma_H \) thus, horizontal wells drilled towards \( \sigma_h \) are proposed to be the least stable, as they are subject to the greatest stress anisotropy (King et al., 2012). In the Georgina Basin, \( \sigma_V \) and \( \sigma_H \) are interpreted to be of similar magnitudes (~25–26 MPa km\(^{-1}\)). In similar settings, studies have shown that horizontal to sub-horizontal wells oriented in the direction of \( \sigma_H \) will be exposed to the least stress anisotropy and, accordingly, will be the most stable (Zhou et al., 1996; Zoback, 2007). However, such wells would have minimal hoop stress differential and may therefore require larger pressures to initiate tensile hydraulic fracturing (Zoback, 2007). This is because having some hoop stress at the wellbore effectively reduces the magnitude of the smaller stress, thereby promoting tensile fracturing at lower hydraulic pressures (Zoback, 2007).

**Georgina Basin stress regime in context**

Our data are consistent with other studies of onshore Australian basins, which suggest reverse to strike-slip faulting stress regimes (e.g. the Cooper-Eromanga, McArthur and Bowen basins; Hillis, Enever, & Reynolds, 1999; Mildren et al., 2013; Reynolds et al., 2002; Reynolds, Mildren, Hillis, & Meyer, 2006), largely as a result of the high compressive tectonic stresses in the Australian continent (Cloetingh & Wortel, 1986; Heidbach et al., 2010; Reynolds et al., 2002). In comparison, the major producing shales in the USA, such as the Barnett, Bakken, Woodford and Marcellus, are mostly Devonian to Carboniferous (Abousleiman et al., 2007; Arthur, Bohm, & Layne, 2009; Fisher et al., 2002; Smith & Bustin, 2000) and are found in basins characterised by extensional stress regimes (Heidbach et al., 2010; Zoback & Zoback, 1980). The Neoproterozoic to Devonian sediments of the Georgina Basin have had a complex evolution, having been buried and exhumed during several major tectonic events (Ambrose et al., 2001; Munson, 2014; Summons, Powell, & Boreham, 1988). As a result, their physical properties are likely to differ from the American equivalents.

**Conclusions**

Geomechanical datasets from the Georgina Basin indicate a dominantly reverse-faulting stress regime with a regionally consistent maximum horizontal stress orientation of approximately 044°N. Vertical stress is interpreted to be the least principal stress, as the majority of leak-off test results report values at, or above, the vertical stress owing to overburden. The integration of calibrated density logs yields an estimated vertical stress gradient of 24.6 MPa km\(^{-1}\). It is, therefore, likely that vertical stress is being evaluated rather than minimum horizontal stress, as is generally assumed. Assessment of LOTs that appear to have failed through shear reactivation rather than tensile initiation provides stress estimates that further support this interpretation. Frictional limits calculations provide an upper bound for the maximum horizontal stress gradient of approximately 53.9 MPa km\(^{-1}\), while estimates of maximum horizontal stress magnitude from the assumption of shear failure range between approximately 31.0 MPa km\(^{-1}\) and 39.0 MPa km\(^{-1}\).

The minimum horizontal stress likely falls between the magnitude of vertical and maximum horizontal stress; thus, a reverse/reverse–strike-slip faulting stress regime is interpreted for the Georgina Basin.

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**Disclosure statement**

No potential conflict of interest was reported by the authors.
Supplementary Papers

Table A1. Location of each well analysed in this study and the data available from each. Total depth is given in metres below Kelly bushing (mKB). VSP, vertical seismic profile; FMI, Formation Micro-Imager; CMI, Compact Micro-Imager; STAR, Simultaneous Acoustic and Resistivity Imager. FIT, Formation Integrity Test; LOT, Leak-Off Test; Mini-Frac, Mini-Fracture Test; DST, Drill Stem Test; MDT, Modular Formation Dynamics Test.

Table A2. Interpreted maximum horizontal stress orientations from four-arm caliper logs and image logs (using both borehole breakouts and drilling induced tensile fractures). Statistical data for classification of orientation quality using world stress map quality rankings are provided (Heidbach et al., 2010).

Table A3. Location, depth and estimate of a minimum bound to the least principal stress from formation integrity tests in wells surrounding the Georgina Basin.

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