The in situ stress field of the Cooper Basin and its implications for hot dry rock geothermal energy development

S.D. Reynolds[1], S.D. Mildren[1*], R.R. Hillis[1] and J.J. Meyer[2]

Abstract

Hot dry rock (HDR) geothermal energy resources are currently being investigated in the Cooper Basin, an area with a high geothermal gradient. The in situ stress field and natural fracture network are critical to the design of the subsurface circulation system in any HDR development. This study uses knowledge of the in situ stress field from petroleum-based data in the Cooper Basin to predict the likely stress conditions in basement granite bodies and thus determine the most probable fluid flow paths. In situ stress data indicate a relatively consistent maximum horizontal stress orientation of 101º in the Cooper Basin and a transitional strike-slip to reverse faulting stress regime. Exploration for HDR geothermal energy should target areas with a high geothermal gradient and a reverse faulting stress regime. In a reverse faulting stress regime, shallowly dipping fractures have the highest permeability. Fluid flow is predicted to be focussed in the intermediate principal stress direction because this is the direction in which the elements of structural permeability intersect. Hence, in a reverse faulting stress regime in the Cooper Basin, fluid flow would be focussed in the minimum horizontal stress or north-south direction. Vertical conjugate shear fractures striking 073º and 133º have the greatest permeability in a strike-slip faulting stress regime where the intermediate principal stress and thus fluid flow is likely to be focussed vertically. Production and injection wells should be aligned in the direction of maximum fluid flow and configured to intersect the greatest number of permeable fractures.

Keywords: hot dry rock, geothermal energy, stress field, Cooper Basin.

Introduction

Hot dry rock (HDR) geothermal energy has the potential to provide Australia with a new form of non-polluting, environmentally friendly energy. The HDR system consists of injection and production wells and an underground heat reservoir. The concept behind HDR involves pumping cold water down an injection well into the sub-surface heat reservoir. The water is then heated and returned to the surface via production wells and passed through a heat exchanger to ultimately generate electricity. Hot dry rock geothermal energy relies on water circulation within a network of fractures between the injection and production wells. In order to achieve economic viability, sufficient water must be retrieved from the circulation system at a high enough temperature. In initial HDR developments, it was thought that hydraulic fracture stimulation led to the development of simple, vertical, planar, tensile hydraulic fractures within the sub-surface heat reservoir. However, field evidence suggests that hydraulic fracture stimulation activates the pre-existing fracture network providing the main pathway for fluid flow within the sub-surface heat reservoir (Baria et al. 1999; Evans et al. 1999; Tezuka and Niitsuma 2000). Thus, in order to optimise the subsurface circulation system, detailed knowledge is required on which fractures the fluid will preferentially flow through.

Fluid flow within the natural fracture system is focussed in the direction of maximum bulk permeability. The in situ stress field plays an important role in determining fracture permeability, as the permeability of critically stressed fractures is much higher than that of fractures that are not optimally oriented to failure within the in situ stress field (Barton et al. 1995; Finkbeiner et al. 1997). Determination of the in situ stress field is required in order to ascertain which natural fractures are critically stressed and thus are more susceptible to fluid flow. It is also necessary to know the orientation of the pre-existing natural fractures.

The Cooper Basin, located in central Australia, is Australia's largest onshore oil and gas province. Furthermore, the basin contains Australia's most significant geothermal resource recognised to date (Somerville et al. 1994). The geothermal resource exists as a result of up to 4 km of sedimentary cover blanketing a number of hot Carboniferous granite bodies. These granite bodies exhibit a higher than normal heat production causing elevated geothermal gradients in the surrounding region (Deighton & Hill 1998). Two companies, Geodynamics and Scopenergy, are currently attempting to develop the geothermal resources in the Cooper Basin. Geodynamics has made significant progress in drilling and running fracture stimulations in their Habanero-1 well. At the time of writing they are about to commence drilling a recovery/production well. The major test for HDR geothermal energy is to create a circulation system between the injection and production wells.

The focus of this study is to investigate the in situ stress field in the Cooper Basin and subsequently determine which fracture orientations are critically stressed within the in situ stress field. Furthermore, we discuss the optimal drilling direction and well locations in order to maximise fluid return to the production wells.

Review of the in situ stress field in the Cooper Basin

Substantial amounts of petroleum data have been collected over the past 40 years of drilling in the Cooper Basin. The petroleum data provides information on the in situ stress field from the surface to a depth of approximately 3.5 km. The granite bodies being sourced for HDR geothermal energy are located

1. Australian School of Petroleum, The University of Adelaide, SA 5005, Australia.
2. JRS Petroleum Research Pty Ltd, PO Box 319, Kent Town, SA 5071, Australia.
* Now at JRS Petroleum Research Pty Ltd, PO Box 319, Kent Town, SA 5071, Australia.

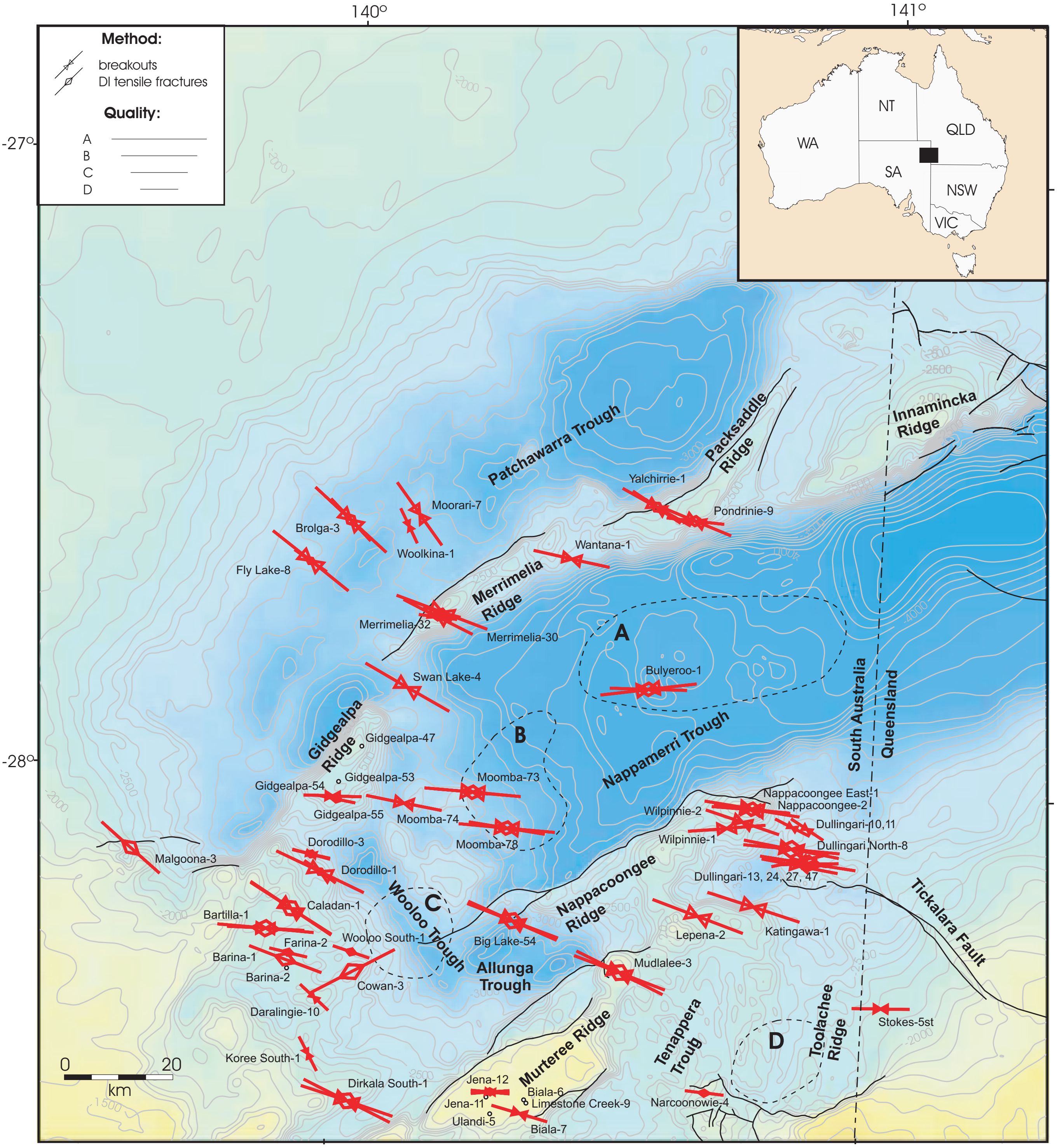

Figure 1. Location map of the Cooper Basin showing maximum horizontal stress orientations and the major structural elements of the basin. Colour background image shows depth to basement with major basement cutting faults also shown. Dashed lines indicate extent of gravity lows relating to three confirmed (A, B, C) and one proposed (D) Carboniferous granite bodies within the area of investigation.

approximately 4 to 4.5 km deep. As a consequence, the in situ stress field determined from the petroleum-based data is extrapolated to a depth of 4 km.

In order to define the in situ stress field, knowledge of the orientation and magnitude of the three principal stresses, and the pore pressure distribution is required. For the purpose of this study, we have made the common assumption that the vertical stress is a principal stress and hence the maximum and minimum horizontal stresses are also principal stresses. This assumption is likely valid given the relatively flat topography in this part of central Australia.

A number of the deeper petroleum wells in the basin, such as Moomba-73, have intersected granite bodies. Fractures have been interpreted in a granite body from Schlumberger's Formation MicroScanner (FMS) log run in Moomba-73. These fractures have been used as an example dataset to assess the likelihood of an open fracture network within the granite bodies.

Pore pressure

Knowledge of the pore pressure distribution is required for the accurate determination of the minimum and maximum horizontal stress magnitudes. A number of direct pressure measurements have been undertaken in the Cooper Basin. These measurements include drill stem tests (DSTs) and wireline repeat formation tests (RFTs). Direct pressure measurements provide the most accurate pore pressure estimates. However, their spatial and depth distribution is often limited. A comparison of DSTs with mudweights from conventionally drilled wells in the Cooper Basin has shown that they are generally consistent (van Ruth and Hillis 2000). Thus, in the absence of direct pressure data mudweights have been used as a proxy for pore pressure. Mud weight can, with caution, be used as a proxy for pore pressure, as mud weight is often just in excess of pore pressure to avoid drilling problems and maximise drilling efficiency. Care must be exercised to ensure any increases in mud weight are due to pore pressure changes and not, for example, to address wellbore stability issues.

The available pore pressure data indicates the Cooper Basin is on average hydrostatically pressured. However, a number of wells do indicate significant overpressures, which start at a depth of around 2,700 m. These wells include McLeod-1, Bulyeroo-1, Kirby-1, Burley-1, Burley-2 and Moomba-55, which are all located in the Nappamerri Trough (van Ruth and Hillis 2000). The overpressured units occur in the Toolachee formation and deeper units (van Ruth & Hillis 2000). In addition, a number of direct pressure measurements, largely from the Moomba field, indicate underpressure, which is a result of draw down due to extensive production in the basin over the past 40 years.

Due to the limited information on the distribution of overpressure, both laterally and vertically, we have assumed hydrostatic pore pressures for this study. Hence, only stress measurements at hydrostatic pressures have been examined to obtain estimates for the maximum and minimum horizontal stress magnitudes. In regions where overpressure or underpressure occurs, the results presented herein require modification.

Maximum horizontal stress orientation

The maximum horizontal stress orientation was determined from borehole breakouts and drilling-induced tensile fractures (DITFs) interpreted from Cooper Basin image logs. Borehole breakouts form when the circumferential stress acting around a wellbore exceeds the compressive strength of the rock (Bell & Gough 1979; Zoback et al. 1985). When this arises in a vertical well, conjugate shear fractures form at the wellbore wall centred on the minimum horizontal stress direction, causing the rock to spall off (Gough & Bell 1982). As a consequence, the wellbore becomes enlarged in the minimum horizontal stress direction. In contrast, DITFs form in the orientation of the maximum horizontal stress when the circumferential stress around the wellbore is less than the tensile strength of the rock (Brudy & Zoback 1999).

A total of 890 borehole breakouts and 608 DITFs were interpreted from 64 wells in the Cooper Basin. The mean maximum horizontal stress orientation from all wells with A–C quality borehole breakouts and DITFs is 101º (Reynolds et al. under review). Overall, the stress data for the Cooper Basin indicates a fairly consistent approximately east-west maximum horizontal stress orientation. However, a number of geographic/geological domains have their own distinct stress trends. Stress data from four wells in the Patchawarra Trough indicate a southeast-northwest maximum horizontal stress orientation (Fig. 1). Wells northeast of Gigealpa-47 on the Gidgealpa-Merrimelia-Packsaddle ridge appear to have a west-northwest to east-southeast maximum horizontal stress orientation. In the Nappamerri Trough, the stress data indicates an east-west maximum horizontal stress orientation. For the purpose of this study, we have used the basin-averaged maximum horizontal stress orientation of 101º, which corresponds more closely to the maximum horizontal stress orientation observed in the Nappamerri Trough (location of the majority of the hot granite bodies; Fig. 1). The maximum horizontal stress orientation does not vary significantly with depth in the basin. Hence, the approximate east-west maximum horizontal stress orientation can be extrapolated with reasonable confidence to the basement granites.

Vertical stress magnitude

The vertical, or overburden stress, at a specified depth can be equated with the pressure exerted by the weight of the overlying rocks. Density log data are commonly run in petroleum wells and was used to approximate the density of the rock column in order to determine the magnitude of the vertical stress. Vertical stress calculations require that the density log be integrated from the surface. However, the density log is not commonly run from the surface. The average density from the surface to the top of the density log run was estimated by converting checkshot velocity data to density using the Nafe-Drake velocity/density transform (Ludwig et al. 1970).

Vertical stress profiles have been calculated for 24 wells across the basin (Fig. 2). The wells were selected in order to give an even coverage across the basin. Inspection of the vertical stress versus depth profiles across the basin identified no significant regional trends within the data. Hence, an average vertical stress profile for the Cooper Basin was calculated and used in the calculations for this study (Fig. 2).

Minimum horizontal stress magnitude

The magnitude of the minimum horizontal stress was estimated from both hydraulic fracture tests and leak-off tests (LOT) conducted in the basin. Leak-off tests form the bulk of the data used to constrain the minimum horizontal stress and are routinely undertaken in petroleum wells in order to determine the maximum mud weight to be used in drilling operations for a given interval. When conducting a LOT, the pressure in the wellbore is increased until a fracture is formed. Leak-off pressures do not yield as reliable estimates of the minimum horizontal stress as fracture closure pressures from hydraulic fracture tests, largely because the leak-off pressure is controlled by the disturbed stress field at the wellbore wall and because the leak-off pressure must overcome any tensile strength of the formation. Nonetheless, it is widely accepted that the lower bound to leak-off pressures in vertical wells gives a reasonable estimate of the minimum horizontal stress (e.g. Breckels & van Eekelen 1982; Bell 1990).

Closure pressures from hydraulic fracture (minifrac) tests provide the best estimate of the minimum horizontal stress magnitude. However, only four closure pressures were available for this study. Evidence from drilling and hydraulic fracture tests indicate that the magnitude of the minimum horizontal stress varies significantly across the basin and approaches the magnitude of the vertical stress in some areas. Minifrac closure pressures indicate the minimum horizontal stress gradient varies across the basin from 0.6 psi/ft to over 1.0 psi/ft (Roberts et al. 2000). The majority of the minifrac and leak-off data suggest that the magnitude of the minimum horizontal stress is the minimum principal stress in the shallower parts of the basin. However, minifrac closure pressures from Chipperfield & Britt (2000) show a general increase in minimum horizontal stress gradient with depth, eventually reaching that of the vertical stress (Fig. 2). Thus, a reverse faulting stress regime, where the vertical stress is the minimum principal stress, may occur at the depth of the granite geothermal resource. Consequently, this study analyses three stress cases: the minimum horizontal stress being the minimum principal stress, the minimum horizontal stress and the vertical stress being equal and the vertical stress being the minimum principal stress.

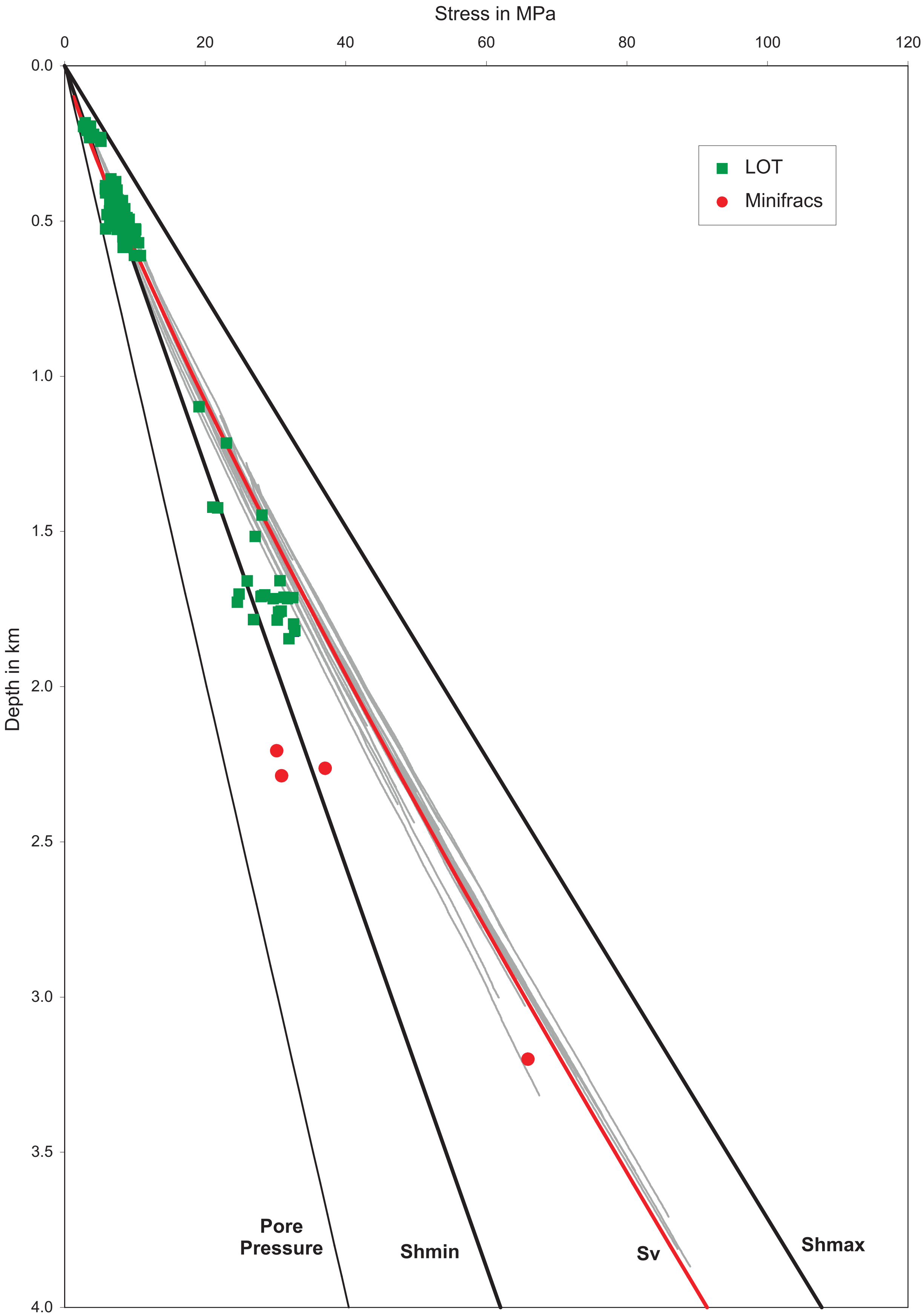

Figure 2. Stress magnitude verse depth plot for the Cooper Basin. Light gray lines are vertical stress profiles calculated at individual wells in the basin. The red line is the average vertical stress profile for the basin and was used to estimate the vertical stress magnitude in this study. Shmin: minimum horizontal stress, Sv: vertical stress, Shmax: maximum horizontal stress, LOT: leak-off tests from Hillis et al. (1998), Minifracs: closure pressures from hydraulic fracture tests as reported by Chipperfield and Britt (2000).

Maximum horizontal stress magnitude

The magnitude of the maximum horizontal stress is generally the most difficult component of the stress tensor to determine. The magnitude of the maximum horizontal stress 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 pre-existing fault (Sibson 1974). The frictional limit to stress is given by Jaeger & Cook (1979):

1 $$\frac{S_1 - P_p}{S_3 - P_p} \leq \left\{ \sqrt{(\mu^2 + 1)} + \mu \right\}^2$$

where μ is the coefficient of friction on an optimally oriented pre-existing fault, S_1 is the maximum principal stress, S_3 is the minimum principal stress and P_p is the pore pressure. For a typical value of μ=0.6:

2 $$\frac{S_1 - P_p}{S_3 - P_p} \leq 3.12.$$

This relationship can be used to estimate the magnitude of the maximum principal stress in seismically active regions (Zoback & Healy 1984) and provides an upper limit to the maximum principal stress in seismically inactive regions. In all three stress cases analysed in this study, the maximum principal stress corresponds to the maximum horizontal stress, assuming the maximum principal stress is at its frictional limits. Calculations of the maximum horizontal stress were based on a hydrostatic pore pressure.

The first stress case assumes a lower bound for the minimum horizontal stress of 0.68 times the vertical stress. The corresponding frictional limit to the maximum horizontal stress equates to 1.18 times the vertical stress (i.e. a strike-slip faulting stress regime). The second stress case assumes the minimum horizontal stress and the vertical are equal (i.e. boundary of strike-slip to reverse faulting stress regime). Consequently, the frictional limit to the maximum horizontal stress is 2.18 times the vertical and minimum horizontal stresses. Similarly, the maximum horizontal stress is 2.18 times the vertical stress in the third stress case when the vertical stress is the minimum principal stress (i.e. a reverse faulting stress regime). The relative components of the stress tensor for the three stress cases are summarised in Table 1 and can be converted to absolute stress magnitudes at 4 km depth by multiplying the table values by 91.42 MPa (vertical stress magnitude at 4 km depth). The location of the three stress cases within the stress polygon space is plotted on Figure 3.

Table 1. Stress field parameters used in the three stress cases to model structural permeability in the Cooper Basin. Absolute stress magnitudes can be determined by multiplying the value in the table by 91.42 MPa (the magnitude of the vertical stress at 4 km depth). Shmin: minimum horizontal stress, Sv: vertical stress, Shmax: maximum horizontal stress.

Case	Shmax Orientation	Shmin Magnitude	Sv Magnitude	Shmax Magnitude	Pore Pressure
1 (Strike-Slip)	101°	0.68	1.0	1.18	0.44
2 (Strike-Slip/ Reverse)	101°	1.0	1.0	2.18	0.44
3 (Reverse)	101°	1.2	1.0	2.18	0.44

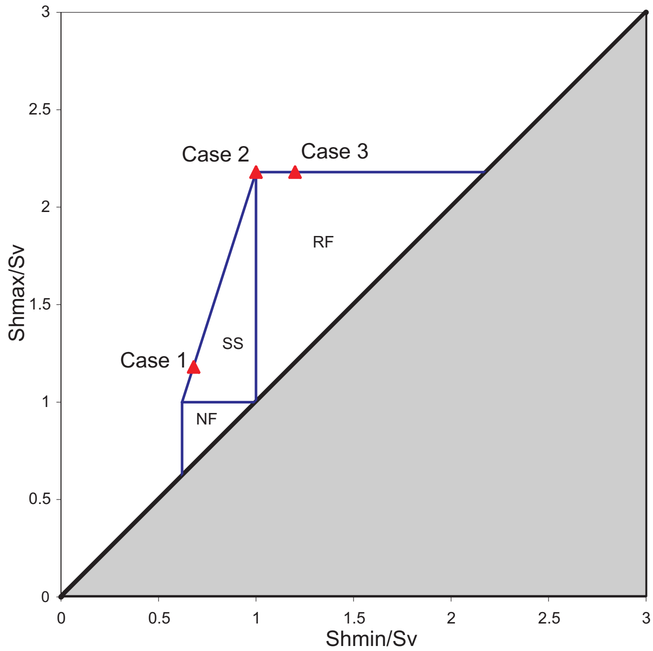

Figure 3. Stress polygon showing the location in stress space of the three cases. Bounding box of polygon (outside blue line) represents frictional limits to stress assuming a μ value of 0.6. Shmin: minimum horizontal stress, Sv: vertical stress, Shmax: maximum horizontal stress, RF: reverse faulting stress regime, SS: strike-slip faulting stress regime, NF: normal faulting stress regime.

Optimising the sub-surface circulation system

Optimising the sub-surface circulation system requires detailed knowledge of the interaction between the in situ stress field, the pre-existing fracture network and the likelihood of creation of new fractures. The ultimate goal of the circulation system is to maximise the amount of water recovered in the production wells at the desired temperature. The identification of fracture orientations that are highly susceptible to fluid flow is required to achieve this goal. Critically stressed fractures within the in situ stress field have been found to have higher permeability than fractures that are not optimally oriented within the in situ stress field (Barton et al. 1995; Finkbeiner et al. 1997).

Fracture susceptibility

Fracture criticality, also known as fracture susceptibility, can be assessed using a range of approaches, all of which require knowledge of the in situ stress field and pre-existing fracture orientations: dilation tendency (Ferrill et al. 1999), slip tendency (Morris et al. 1996), Coulomb failure function (Jaeger & Cook 1979), and the FAST (Fault Analysis Seal Technology) technique (Mildren et al. 2002) have all been used. In this study the FAST technique is used to assess fracture susceptibility, since it uses both shear and tensile modes of failure and provides a measure of the pressure increased required to induce failure. The FAST technique assesses fracture susceptibility by using the stress tensor (3D Mohr circle) and rock strength (failure envelope); (Fig. 4). Brittle failure is predicted if the Mohr circle touches the failure envelope. All fracture orientations plot within the 3D Mohr circle and those closest to the failure envelope are at greatest risk of failure and hence most likely to be highly conductive. The horizontal distance between each fracture plane and the failure envelope indicates the increase in pore pressure (ΔP) required to initiate failure and is therefore a measure of how susceptible a fracture is to fluid flow (Fig. 4). A small ΔP

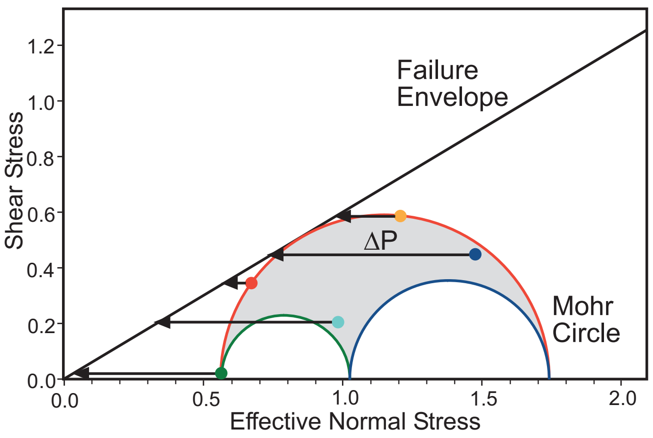

Figure 4. Three-dimensional Mohr circle with Coulomb failure envelope. All possible orientations of fracture planes lie within the grey area. The horizontal distance between each fracture plane and the failure envelope indicates the increase in pore pressure (ΔP) required to initiate failure and is therefore a measure of how susceptible a fracture is to fluid flow.

implies a high fracture susceptibility (critically stressed) and a large ΔP implies a low fracture susceptibility. The ΔP value for each plane can be plotted on a stereonet as poles to planes. The susceptibility of any pre-existing fracture orientation is then read from the stereonet. Herein, fractures are assumed to have no cohesive strength since we are dealing with pre-existing fractures. A friction angle of 0.6 was assumed (Byerlee 1978). However, if the pre-existing fractures are cemented then the addition of cohesion to the above failure envelope is required. For a more detailed discussion on the FAST methodology see Mildren et al. (2002).

Enhancement of existing natural fractures

The strength of the host rock is generally greater than that of pre-existing fractures. This is confirmed by field observation that suggests hydraulic stimulation, in most cases, enhances pre-existing fracture networks (Baria et al. 1999; Evans et al. 1999; Tezuka & Niitsuma 2000). Thus, it is important to fully understand which of the pre-existing natural fracture sets are most susceptible to fluid flow. Fracture susceptibility stereonets were generated for each of the three Cooper Basin stress cases (Figs 5–7). The same scale has been used for each stress case in order to compare the fracture susceptibilities between the different cases. For the strike-slip faulting stress regime (Case 1), vertical fractures striking approximately 073º and 133º have the greatest susceptibility to fluid flow (Fig. 5). Fractures striking between 050º and 150º with dips greater than 40º also have a high susceptibility to fluid flow. Fractures striking between 000º and 030º of any dip and fractures of any orientation with shallow dips (<40º) are the least susceptible to fluid flow within a strike-slip faulting stress regime in the Cooper Basin (Fig. 5).

A more complex situation develops in terms of fracture susceptibility for the stress regime on the boundary of strike-slip and reverse faulting (minimum horizontal stress = vertical stress). There exists a range of fracture orientations and dips that are susceptible to fluid flow (Fig. 6). Vertical fractures striking from 056º to 086º and from 116º to 146º are highly susceptible to fluid flow, similar to that of the strike-slip faulting stress regime case. However, as the dip shallows, the orientation for fractures with high susceptibility to fluid flow also changes, such that shallow dipping, approximately north-south striking fractures exhibit high susceptibility. As a result, two arcs of high fracture susceptibility are formed across the stereonet (Fig. 6). Vertical fractures striking between 000º and 030º are again the least susceptible to fluid flow.

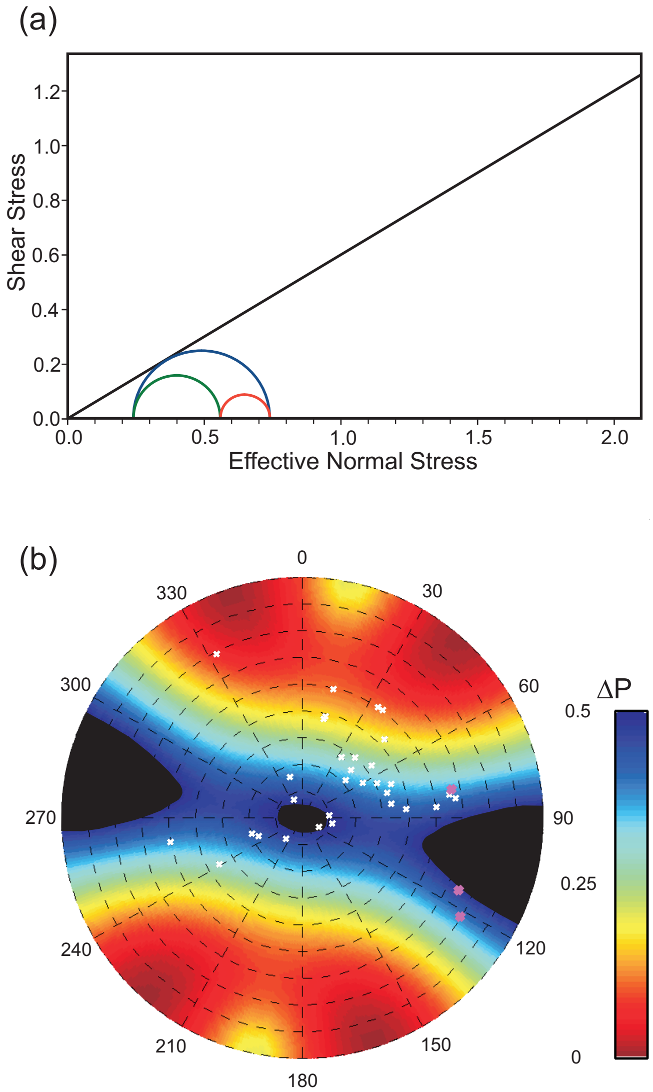

Figure 5. Mohr diagram (a) and structural permeability stereonet plot (b) for Case 1, a strike-slip faulting stress regime. Structural permeability stereonet plot represents how susceptible a fracture is to fluid flow. Numerical values on scale refer to increase in fluid pressure required to cause failure (ΔP normalised to vertical stress). Black area indicate ΔP values greater than 0.5. White and pink crosses indicate conductive and resistive fractures, respectively, interpreted in a granite body from Moomba-73. Stereonet plot is equal angle, lower hemisphere stereographic projection of poles to planes.

For the reverse faulting stress regime case, a broad arc of fractures more susceptible to fluid flow cuts across the stereonet similar to the strike-slip/reverse stress field case (Fig. 7). However, in the reverse faulting stress regime no steeply dipping fractures are optimally oriented and fractures striking between 160º and 220º and dipping between 25º and 35º are the most susceptible to fluid flow (Fig. 7). Vertical fractures striking between 000º and 030º are again the least susceptible to fluid flow.

Results from this study indicate that fractures striking between 000º and 030º with steep dips should not be expected to contribute fluid flow in developing HDR geothermal energy in the Cooper Basin whether the stress regime is one of strike-slip or reverse faulting. The fracture susceptibility stereonet for the strike-slip/reverse faulting stress regime (Case 2) is essentially a combination of both the strike-slip faulting stress regime (Case 1) stereonet and the reverse faulting stress regime (Case 3) stereonet.

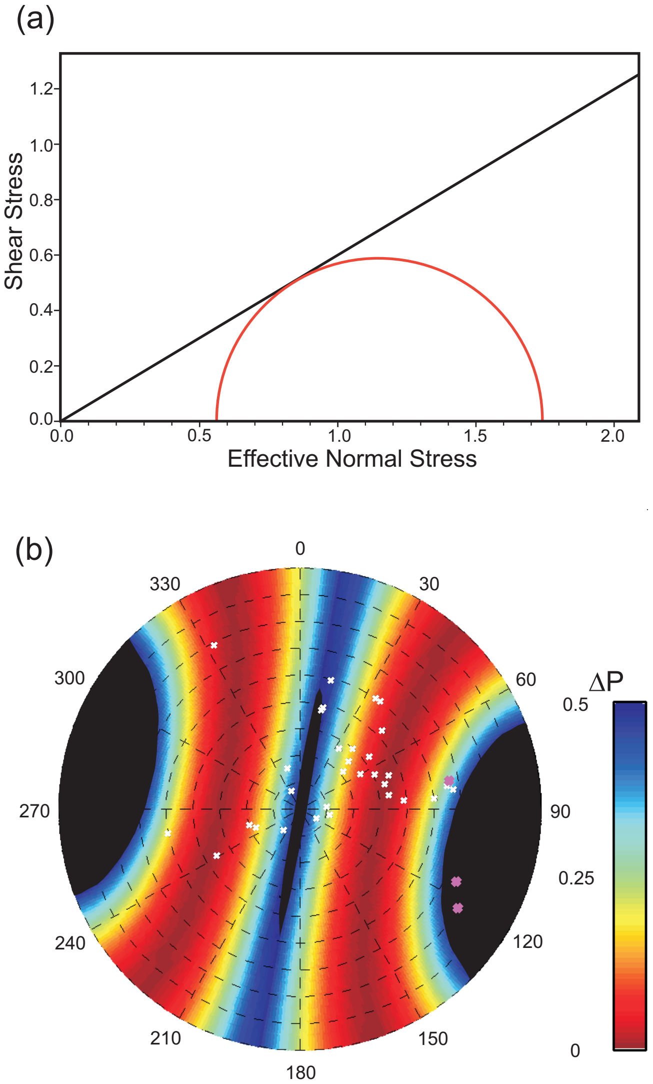

Figure 6. Mohr diagram (a) and structural permeability stereonet plot (b) for Case 2, a strike-slip/reverse faulting stress regime. Structural permeability stereonet plot represents how susceptible a fracture is to fluid flow. Numerical values on scale refer to increase in fluid pressure required to cause failure (ΔP normalised to vertical stress). Black area indicate ΔP values greater than 0.5. White and pink crosses indicate conductive and resistive fractures, respectively, interpreted in a granite body from Moomba-73. Stereonet plot is equal angle, lower hemisphere stereographic projection of poles to planes.

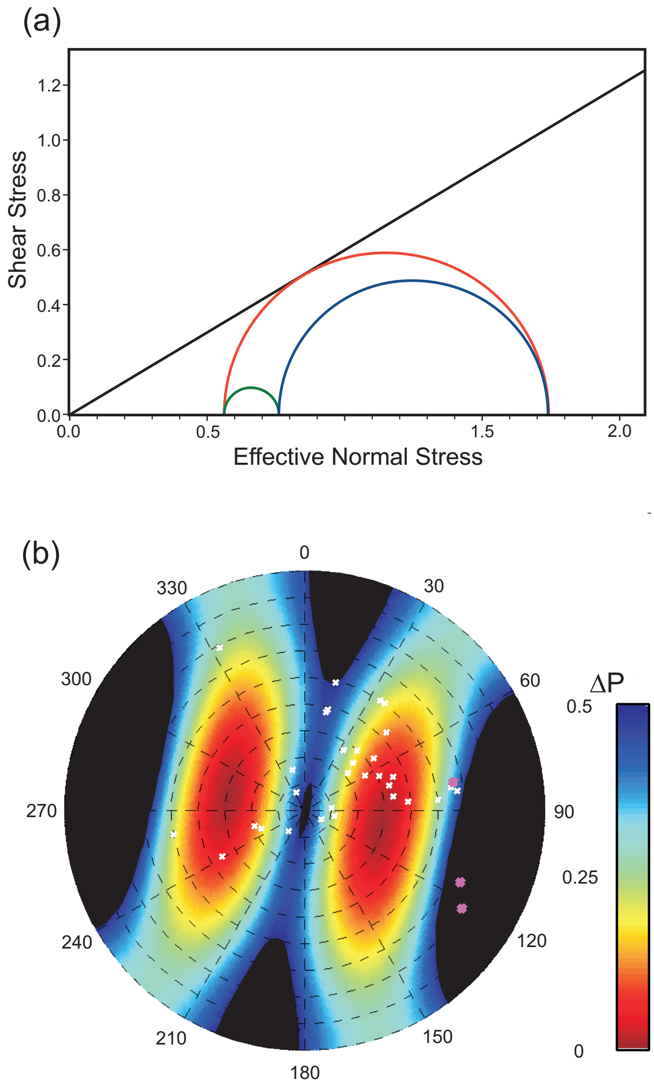

Figure 7. Mohr diagram (a) and structural permeability stereonet plot (b) for Case 3, a reverse faulting stress regime. Structural permeability stereonet plot represents how susceptible a fracture is to fluid flow. Numerical values on scale refer to increase in fluid pressure required to cause failure (ΔP normalised to vertical stress). Black area indicate ΔP values greater than 0.5. White and pink crosses indicate conductive and resistive fractures, respectively, interpreted in a granite body from Moomba-73. Stereonet plot is equal angle, lower hemisphere stereographic projection of poles to planes.

If the minimum horizontal stress magnitude is close to or greater than the vertical stress magnitude (Case 2 and 3), then the optimal fracture set to target would be the shallowly dipping fractures described above for the reverse faulting stress regime (Case 3).

Fractures interpreted in the granite using the image log from the Moomba-73 well have been plotted on the three fracture susceptibility stereonets. The majority of the fractures are electrically conductive in appearance and are shallow to moderately dipping. Three electrically resistive fractures were also interpreted in the granite and had steeper dips than the majority of the electrically conductive fractures. Electrically resistive fractures are interpreted as cemented and/or closed. Fractures that are open at the wellbore wall are filled with low resistivity (high conductivity) drilling mud. A greater number of electrically conductive fractures interpreted from Moomba-73 are critically stressed in both the reverse faulting stress regime (Case 3) and the strike-slip/reverse faulting stress regime (Case 2) than in the strike-slip faulting stress regime (Case 1). Thus, these fractures are more likely to be open and susceptible to fluid flow within both the reverse faulting stress regime and the strike-slip/reverse faulting stress regime. Most of the fractures are poorly aligned for fluid flow and are likely to be closed in the strike-slip faulting stress regime (Case 1).

Creation of new fractures

Hydraulic fracture stimulation may potentially generate new fractures, as well as reactivate pre-existing ones, especially in the immediate vicinity of the wellbore. Hence, it is important to know the likely orientation of fractures induced at the wellbore wall and the direction in which they propagate away from the wellbore wall. In this section we only discuss open wellbore conditions, since most HDR projects are likely to be completed open-hole in the basement rocks. We also assume that new fractures generated during stimulation are predominantly opening mode, tensile, hydraulic fractures.

Initiation of a fracture in an open wellbore is dependent on the near wellbore stresses. In vertical and horizontal open-hole wells, all fractures initiate axial (parallel to wellbore axis) to the wellbore assuming vertical and horizontal principal stresses. As the fractures propagate away from the wellbore they become subjected to the far field stresses and may rotate to the far-field orientation of tensile fractures, i.e. orthogonal to the minimum principal stress. As a result, induced hydraulic fractures may twist as they propagate away from the wellbore. Fracture twisting is not desirable, as it inhibits fluid flow.

Newly created fractures in a vertical well within the strike-slip faulting stress regime (Case 1), are vertical and propagate away from the wellbore in the orientation of the maximum horizontal stress, i.e. 101º in the Cooper Basin. Thus, no problem with fracture twisting is anticipated. In the Case 2 scenario, where the magnitudes of the minimum horizontal stress and vertical stress are approximately equal, newly created fractures again initiate axial to the wellbore for a vertical wellbore. The fracture propagates in the maximum horizontal stress direction away from the wellbore. However, the fracture dip could vary between vertical and horizontal, since there is no single minimum principal stress direction. The fracture dip may therefore be readily influenced by any pre-existing anisotropy in the rock fabric. For example, within sedimentary rocks the likely far-field hydraulic fracture orientation is parallel to bedding, due to bedding plane weakness.

Hydraulic fracture stimulation in a vertical well under reverse faulting stress regime (Case 3) conditions would create a vertical fracture at the wellbore. However, as the vertical stress is the minimum principal stress the newly created fracture is likely to rotate into the horizontal plane as it propagates away from the wellbore (Evans and Engelder 1989). Fracture twisting in a reverse faulting stress regime may be avoided by fracture stimulation in horizontal wells. However, it is probably of greater benefit to optimise the drilling direction to intersect the maximum number of conductive pre-existing fractures.

Optimising well trajectory and placement

Optimising well trajectory and placement is vital for economic viability of all HDR geothermal energy projects. A number of issues need to be considered when deciding on the location, deviation direction and amount of deviation of both the injection and production wells. The ultimate goal is to position and then drill the injection and production wells in the direction that will maximise fluid recovery. Injection and production wells should be configured to provide the greatest connection efficiency between the wellbore and the natural fracture network. This can be obtained by optimising the intersection of the wellbore with the greatest number of conductive fractures. In order to achieve maximum fluid recovery, the production wells should be offset from the injection well in the direction of major fluid flow. Other issues, such as wellbore stability, may also need to be considered when planning well design, however are not discussed here.

Injection and production well deviation directions

Injection and production wells for a HDR system should be drilled in the direction that maximises intersection with fractures most susceptible to fluid flow in order to obtain optimal connection between the wells and the sub-surface fracture network. The optimal drilling directions described below assume fractures are present in the direction of maximum permeability, as illustrated by Figures 4–7. However, fractures may not necessarily be present in this direction for a given location. Thus, the optimal direction the wells should be drilled is ultimately governed by which of the actual fracture orientations present in the sub-surface is the most permeable. Within a strike-slip faulting stress regime in the Cooper Basin, vertical or near-vertical fractures striking approximately 073º and 133º are the most susceptible to fluid flow (Fig. 5). Thus, wells should be drilled horizontal, or close to horizontal, and drilled in a direction perpendicular to these fractures for optimal fracture intersection.

There is a wide range of potential injection and production well trajectories under a strike-slip/reverse faulting stress regime because a range of both fracture orientations and dips are highly susceptible to fluid flow (Fig. 6). A vertical well is probably the most attractive configuration due to its simplicity and the potential to intersect highly permeable shallowly dipping fractures. Nevertheless, wells with varying trajectories are just as likely to intersect fractures with high permeability. Thus, detailed knowledge of the sub-surface fracture network is required in order to determine the optimal injection and production well deviation direction within a strike-slip/reverse faulting stress regime. Injection and production wells under reverse faulting stress regime conditions in the Cooper Basin should be vertical, or near to vertical, in order to intersect as many of the shallowly dipping (25º–35º) fractures that are highly susceptible to fluid flow (Fig. 7).

Injection and production well locations

The relative position of the injection and production wells depends on the direction of fluid flow within the pre-existing fracture network. Sibson (1996) used the concept of a structural permeability mesh to explain how strong directional permeability may develop in the intermediate principal stress direction, parallel to fault-fracture intersections and orthogonal to fault slip vectors. Conjugate shear fractures and tensile fractures, the components of a structural mesh, intersect in the intermediate principal stress direction.

Evidence from flooding of oil reservoirs suggests that fluid flow is focussed in the direction of the maximum horizontal stress (Heffer & Lean 1993). The maximum horizontal stress direction is the intermediate principal stress direction in the normal faulting stress regime to which many of the oil field flooding examples are probably subjected. In the strike-slip faulting stress regime the intermediate principal stress is the vertical stress direction and fluid flow is likely to be enhanced vertically. In the reverse faulting stress regime the intermediate principal stress is the minimum horizontal stress direction and fluid flow is likely to be enhanced in the minimum horizontal stress direction.

The intermediate principal stress is in the vertical stress direction for strike-slip faulting stress regime conditions. Hence, fluid flow is likely to be focussed vertically along the set of critically oriented vertical shear fractures striking approximately 073º and 133º in the Cooper Basin where the stress regime is one of strike-slip faulting.

The relative position of the injection and production wells in the strike-slip/reverse faulting stress regime is problematic. No intermediate principal stress exists in the strike-slip/reverse faulting stress regime and a range of fracture orientations and dips are susceptible to fluid flow. As a consequence there may be minimal focussing of fluid flow and hence, fluid recovery rates may be low in this situation regardless of well positioning.

The intermediate principal stress is in the minimum horizontal stress direction for reverse faulting stress regime conditions. Hence, the injection and production wells should be aligned approximately north-south for the reverse faulting stress regime case in the Cooper Basin. This is consistent with recent results from fracture stimulations by Geodynamics Limited in Habanero-1 that indicate a north-south focussing of fluid flow (Geodynamics Limited 2004).

Recommendations for future HDR exploration in the Cooper Basin

Detailed knowledge of the in situ stress field is currently restricted to the sedimentary rocks overlying the granite bodies in the Cooper Basin. In this study we have extrapolated the in situ stress field to the depth of the granite bodies. Future exploration should include in situ stress measurements within the granite bodies. Also, only limited knowledge of the natural fracture network in the granite is available. Detailed knowledge of the actual fracture network is critical for well placement and configuration. Information on the in situ stress field and fracture network can be obtained through the use of image logs. However, the high temperatures within the granite bodies means the image tools are at the limit of their working environment and therefore the acquisition of oriented core is also recommended.

A reverse faulting stress regime provides the best in situ stress conditions for HDR geothermal energy development. Petroleum-based in situ stress data suggests that a reverse faulting stress regime may exist at the depth of HDR development in the Cooper Basin. Future HDR exploration should preferentially select areas with a reverse faulting stress regime in combination with high geothermal gradients. In a reverse faulting stress regime, fluid flow is predicted to be along shallowly dipping fractures and focussed in the minimum horizontal stress direction (i.e. approximately north-south in the Cooper Basin). In a strike-slip faulting stress regime fluid flow will occur along vertical fractures and hence field development would be more problematic than in the reverse faulting stress regime case. Care should be taken when evaluating areas where the magnitude of the minimum horizontal stress and vertical stress are approximately equal as fracture susceptibility predictions suggest that optimal fracture orientation for fluid flow is highly variable and therefore fluid recovery at the production well may be poor.

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