Hydro-Mechanical Selection Criteria of Engineered Geothermal Systems

Luke Mortimer
Hot Dry Rocks Pty Ltd, GPO Box 251, South Yarra, Victoria 3141, Australia
luke.mortimer@hotdryrocks.com

Stored heat geothermal resource estimates commonly extend across an extensive area and often contain more than one potential Geothermal Play. It is critical that an informed decision be made about which exploration Play has the best chance of commercial success. The decision might be between a deep Engineered Geothermal Systems (EGS) Play and a shallow Hot Sedimentary Aquifer (HSA) Play, or between several potential Plays at different levels. In any case, the critical parameters are resource temperature, depth and potential deliverability. A stored heat resource estimate constrains the first two parameters, leaving deliverability as the key risk.

In the case of HSA reservoirs, deliverability is largely dictated by the preservation of primary porosities and permeabilities at depths below the target operational isotherm. An HSA reservoir target may, however, lie at a depth where compaction processes have destroyed a significant proportion of its primary porosity and permeability. Such reservoirs should then be considered and developed as EGS or partial EGS reservoirs. In the case of EGS reservoirs, deliverability is largely dictated by the inherent hydro-mechanical properties of the reservoir rock and its fracture network, coupled with the *in situ* stress field. This paper summarizes the key datasets and knowledge required to make informed decisions about deliverability and development potential of possible EGS reservoirs.

Keywords: Engineered Geothermal Systems, Discrete Fracture Network, Numerical Modelling, Stress.

Development of an EGS Reservoir

The main mechanism for creating a geothermal reservoir and enhancing its *in situ* permeability is the shearing of pre-existing natural fractures during the process of hydraulic stimulation. This process involves the accommodation of an injected volume of water in fractures opened during elastic compression of the adjacent rock mass, rigid body block translation and permanent fracture dilation in response to shear displacement. These all depend upon the nature of the *in situ* stress field and the inherent properties of the host rock and its fracture network. In particular, shear deformation of pre-existing natural fractures is controlled by the elastic, cohesive, frictional and dilational properties of the host rock and fracture network with preferential reservoir growth and fluid flow occurring along fractures oriented ~parallel to the present-day, maximum principle stress direction. The creation of pure hydraulic fractures during stimulation has been shown to be rare and restricted to the near-well environment.

The critical information required for optimal planning of an EGS development includes:

- The nature of the *in situ* stress field (stress regime, orientation, magnitude and gradient).
- Characterisation of the primary structural features of the target reservoir (fault and fracture density, orientation and connectivity distributions).
- Characterisation of the hydro-mechanical properties of the rock material and fracture network.
- Preliminary identification of faults and fractures amenable to hydraulic stimulation.
- Predicted reservoir growth and anisotropic permeability direction in response to hydraulic stimulation.
- Estimation of fluid injection pressures required for controlled hydraulic stimulation.

The preliminary investigation of these primary features has a major impact on the planning, design, implementation and exploitation of an EGS project. For example, this information can be used to develop reservoir injection and circulation strategies that optimise reservoir growth and production whilst minimising the risk of high flow impedance or short-circuiting. These are also the key datasets required for coupled thermal-hydrogeological-geomechanical modelling of a geothermal reservoir.

Conceptual Reservoir Types

From a purely heat extraction point of view, the best reservoir host rock is that with the highest thermal conductivity (i.e. allows the greatest rate of heat extraction). At a proposed EGS site, the highest thermal conductor could either be the heat source itself (high heat producing granites) or a different rock type within the overlying insulating sequence. However, the ultimate performance of an EGS reservoir is determined by the hydro-mechanical properties and behaviour of the host rocks. These control fluid flow and residence time between injection and production wells. From a hydro-mechanical point of view, there are two broad types of conceptual EGS reservoir targets; those with zero effective natural permeability, and those with finite but low natural permeability.

Type 1 : Hydraulically tight rocks at depth (approx. ≥ 4km)

Type 1 examples include rock types such as crystalline igneous or metamorphic basement rocks with little to no *in situ* porosity or permeability. These rocks are typically of high stiffness and poor fracture density and occur at depths with relatively high confining pressures. These stronger rock types tend to develop relatively rough fracture surfaces with higher fracture shear strengths and display a strong coupling between shearing and hydraulic conductivity. Potentially these characteristics allow reservoir development during hydraulic stimulation to be more easily constrained with a lower probability of significant fluid losses. However, experience has found that creating a reservoir in stiff and hydraulically tight rocks may also be difficult. They may experience poor circulation due to high flow impedance even after stimulation and may require high injection pressures to open fractures and achieve the necessary fluid volume throughput. This may lead to increased risk of runaway fracture growth, fluid pathway short-circuiting and water losses.

Type 2 : Finite but low permeability rocks at shallower depths (approx. ≤ 4km)

Type 2 examples may include a wide range of rock types that occur within high temperature but relatively shallower depth settings such as in a graben structure (e.g. Soultz). Rocks in these locations generally have higher *in situ* permeabilities and may be more easily stimulated due to lower confining pressures and rock mass stiffness. Reservoir rock types may also include non-crystalline, weaker rock types, such as layered sediments, within the insulating horizon. Layered sedimentary units may contain higher *in situ* permeabilities due to relatively higher fracture densities including bedding planes. The potential disadvantages of Type 2 reservoir targets are that reservoir growth may be more difficult to constrain with an increased probability of fluid losses. Within a sedimentary basin setting additional complexities may arise from an increased probability of chemical alteration from basinal fluids and an increased probability of local stress field perturbations due to major basin structures or interbedded rock types with significant mechanical contrasts.

Hydro-Mechanical Coupling in EGS Reservoirs

The phenomenon of stress-dependant fracture permeability is well documented in studies of deep-seated, fractured hydrocarbon and geothermal reservoirs and nuclear repositories (e.g. Gentier *et al*., 2000; Hillis *et al*., 1997; Hudson *et al*., 2005). Specifically, *in situ* stress fields are known to exert a significant control on fluid flow patterns in fractured rocks with a low matrix permeability. For example, in a key study of deep (>1.7 km) boreholes, Barton *et al*. (1995) found that permeability manifests itself as fluid flow focused along fractures favourably aligned within the *in situ* stress field, and that if fractures are critically stressed this can impart a significant anisotropy to the permeability of a fractured rock mass. Preferential flow occurs along fractures that are oriented orthogonal to the minimum principal stress direction (due to low normal stress), or inclined ~30° to the maximum principal stress direction (due to shear dilation).

Stress-dependent fracture permeability forms as a result of the interplay between normal and shear stresses, which are the components of stress that act perpendicular and parallel to a fracture plane, respectively. In a fractured rock mass, these stresses are highly coupled and can cause fractures to deform. Fracture deformation results in changes in permeability and storage because the ability of a fracture to transmit a fluid is extremely sensitive to its aperture as demonstrated by the “Cubic Law”. This law defines the bulk hydraulic conductivity of a fractured medium in the direction parallel to the fractures assuming that fractures are planar voids with two flat surfaces within an impermeable matrix. For an isolated test interval within a borehole, it is expressed as:

$$K_b = \frac{(2b)^3}{2B}\frac{\rho g}{12\mu} \qquad (1)$$

where K_b is the bulk hydraulic conductivity (m.s^{-1}) (where K_b = Transmissivity/test interval), 2b is the fracture aperture width (m), $2B$ is the fracture spacing (m), ρ is the fluid density (kg.m^{-3}), g is gravitational acceleration (m.s^{-2}) and μ is the dynamic viscosity of the fluid (Pa.s).

Anisotropic flow behaviour or flow channelling is particularly strong in low fracture density and low permeability rocks typical of potential EGS Plays. Fluid flow is dominantly controlled by fracture network density, geometry, connectivity and mineralization whilst contemporary stress fields superimpose a secondary influence on pre-existing fracture networks by deforming them further. In numerical modelling exercises, these features are best represented through the use of coupled hydro-mechanical, discrete fracture network (discontinuum) models.

Hydro-Mechanical Characteristics of EGS Reservoirs

This study presents a methodology that attempts to describe the hydro-mechanical character and behaviour of a fractured rock reservoir from a multi-disciplinary approach prior to any hydraulic stimulation. The results of this methodology can be used to qualitatively to semi-quantitatively rank the EGS suitability of potential reservoir rock unit, to identify potentially permeable structures and to estimate injection pressures and reservoir growth directions during hydraulic stimulation. This multi-disciplinary approach consists of four key components, which include:

- Determination of the *in situ* stress field;
- Geological and hydrogeological characterisation;
- Geomechanical characterisation; and
- Hydro-mechanical modelling.

Determination of the *In Situ* Stress Field

The description of any *in situ* stress field includes the relative arrangement of the three mutually orthogonal principal axes of stress referred to as the maximum (σ_1), intermediate (σ_2) and minimum (σ_3) principal axes of stress. As the Earth's surface is a free surface with zero shear stress the vertical stress (σ_V) is assumed to be one of these principal axes of stress. The other two principal axes of stress consist of the two mutually orthogonal, horizontal stress orientations referred to as the maximum and minimum horizontal principal axes of stress (σ_H and σ_h, respectively). In practice, far-field crustal stress regimes are classified using the Andersonian scheme, which relates the three major styles of faulting in the crust to the three major arrangements of the principal axes of stress (Anderson, 1951). These three major stress regimes are:

(a) Normal faulting stress regime where $\sigma_V>\sigma_H>\sigma_h$;

(b) Strike-slip faulting stress regime where $\sigma_H>\sigma_V>\sigma_h$; and

(c) Thrust faulting stress regime where $\sigma_H>\sigma_h>\sigma_V$.

To estimate the effective stress state (σ') also requires that an estimate of the pore fluid pressures (P_p) within the rock formation, as σ' is defined as the difference between the applied stress (σ) and the internal pore fluid pressure:

$$\sigma' = \sigma - P_p \qquad (2)$$

The effective stress is critical as it controls coupled hydro-mechanical behaviour (or poroelasticity) by affecting fracture deformation processes as fluid pressures act to reduce the stress acting normal to a fracture plane. For example, high effective stresses with relatively low fluid pressures act to close fractures whilst low effective stresses with relatively high fluid pressures act to dilate fractures.

There are several techniques for measuring the magnitude and orientation of *in situ* stresses, among which the following are common (Zoback, 2007):

- Overcoring and strain relief methods.
- Hydraulic fracturing.
- Imaging of (vertical) borehole breakouts and drilling-induced tensile fractures (DITFs).
- Earthquake focal mechanisms.

All of the above techniques assume that σ_V is ~vertical and equivalent to the integration of rock densities to the depth of interest. Pore fluid pressures are often assumed "hydrostatic" and equivalent to the pressure of fluid column at the depth of interest. However, in areas of confined fluid flow, such as deep sedimentary basins, pore fluid pressures can exceed hydrostatic and require direct estimates from techniques that isolate sections of formation such as drill stem tests or through the analysis of drilling mud weights.

Each stress measurement technique has its advantages and disadvantages and any stress field determinations should ideally combine as many of these techniques over the greatest depth interval possible and be quality ranked according to the scheme developed by the World Stress Map (Heidbach et al., 2008).

Knowledge of the stress field and pre-existing fractured rock mass can be used to make preliminary predictions of fracture and reservoir growth directions during hydraulic stimulation. As a generalisation, the three major fracture growth directions are:

(a) Normal faulting stress regime ($\sigma_V>\sigma_H>\sigma_h$) form steep to vertical dipping fractures that strike orthogonal to σ_3.

(b) Strike-slip faulting stress regime ($\sigma_H>\sigma_V>\sigma_h$) form steep to vertical dipping fractures that strike $<45^o$ (commonly 30^o) to the direction σ_1; and

(c) Thrust faulting stress regime ($\sigma_H>\sigma_h>\sigma_V$) form shallow to horizontal dipping fractures that strike ~parallel to σ_2.

Geological & Hydrogeological Characterisation

Where available, the geological context of the study site should include all information pertaining to the geological setting, lithological composition, structure, geometry, weathering, deformation history and stress path for each potential reservoir rock type. For example, if a particular sequence has been metamorphosed, multiply folded or eroded at the surface before re-burial, those events would have significant implications for permeability and joint formation within the affected rock units. Fracture network data can be obtained from a variety of sources including outcrop, drill core and borehole images. Of particular use are fracture scanline maps or core logs that provide important detail relating to fracture orientation, spacing, length, type, mineralisation and age relationships. Local hydrogeological data could include any reported hydraulic data from a variety of sources including well completion reports, well yields, pump tests, core permeability tests etc. This hydrogeological data compilation adds value as an indication of likely *in situ* permeabilities, hydraulic gradients, flow rates and fluid chemistries that can also provide useful constraints in a numerical model.

Geomechanical Characterisation

The geomechanical properties of a rock mass and fracture network are essential for predicting coupled hydro-mechanical processes as the elastic properties of an intact rock material together with fracture stiffness (strength) and pore fluid pressures control the amount of fracture deformation (dilation, closure and shearing) that may occur under an imposed stress field.

Important intact rock material properties include parameters such as density, bulk moduli, uniaxial compressive strength, tensile strength, cohesion and friction angle. These parameters are commonly estimated from laboratory tests such as drill core triaxial compression or ultrasonic velocity tests or from field based rock mass classifications such as those described by Hoek (2007). Furthermore, rock formations commonly contain a fabric, which may result in a mechanical anisotropy that needs to be determined and accounted for in any numerical model.

Fracture stiffness is primarily a function of fracture wall contact area. Normal stiffness (jk_n) and shear stiffness (jk_s) of a fracture are measures of resistance to deformation perpendicular and parallel to fracture walls, respectively. Normal stiffness is a critical parameter that helps to define the hydraulic conductivity of a fracture via an estimate of the mechanical aperture as opposed to the theoretical smooth planar aperture as described in the Cubic Law. Ultimately, estimates of fracture stiffness attempt to account for more realistic fracture heterogeneity, asperity contact, deformation and tortuous fluid flow. Equations 5 & 6 below describe the simplified relationship between fracture stiffness and fracture deformation (Rutqvist and Stephannson, 2002):

$$\Delta\mu_n = jk_n \, \Delta\sigma'_n \qquad (5)$$

$$\Delta\mu_s = jk_s \, \Delta\sigma_s \qquad (6)$$

which states (a) that fracture normal deformation ($\Delta\mu_n$) occurs in response to changes in effective normal stress ($\Delta\sigma'_n$) with the magnitude of opening or closure dependent upon fracture normal stiffness (jk_n); and (b) that the magnitude of shear mode displacement ($\Delta\mu_s$) depends upon the shear stiffness (jk_s) and changes in shear stress ($\Delta\sigma_s$).

Estimates of fracture stiffness are derived by a variety of field logging or laboratory tests, which are well documented in comprehensive reviews by Bandis (1993), Barton and Choubey (1977) and Hoek (2007). Standard practice is to derive stiffness estimates based upon fundamental measurements of fracture surface topography profiles and the elastic properties of the intact rock material, although these estimates are affected by many factors including:

- Joint roughness coefficient (JRC) which is a standard measure of a fracture surface topography profile (Barton and Choubey, 1977).
- Joint compressive strength (JCS) corresponding to the compressive strength of the fracture wall rock which can be modified by weathering and mineralization.
- Magnitude of fracture stiffness increasing with increasing effective normal stress.
- Fracture spacing and density and its effect on the partitioning of strain.
- Intact rock material moduli such as Young's modulus (E), shear modulus (G), bulk modulus (K) and Poisson's ratio (ν).
- Test type (e.g. unconfined, triaxial, *in situ* direct shear, laboratory direct shear etc).
- Sample size.
- Definition (e.g. peak, initial or 50% during an applied test).

Fracture stiffness is probably the most difficult of all the geomechanical parameters to characterise accurately principally due to the large number of dependent variables, their heterogeneous nature and the scale dependence of key factors such as the JRC and JCS estimates. It is also often difficult to gain access to sufficient amounts of drill core or outcrop. Typically, these limitations are addressed within numerical models through the use of parameter sensitivity studies and/or geostatistical-based approaches such as, for example, Monte Carlo simulations (de Marsily, G. *et al.*, 2005).

Hydro-Mechanical Modelling

The aim of the hydro-mechanical modelling process is to make a preliminary evaluation of the hydro-mechanical character of each prospective reservoir unit at the inferred target depth, stress regime and pre-stimulation stage (i.e. steady state conditions). One example code is the Universal Distinct Element Code (UDEC), which is a 2.5D, distinct element, discontinuum code that represents a rock mass as an assembly of discrete rigid or deformable, impermeable blocks separated by discontinuities (faults, joints etc), which are treated as boundary conditions between the blocks (Itasca, 2004). UDEC interpolates the physical response and stress-displacement relationship of a fractured rock mass to an imposed stress field, which satisfies the conservation of momentum and energy in its dynamic simulations with fluid flow calculations derived from Darcy's Law (for a comprehensive review of the UDEC governing equations see Itasca, 2004). Based upon a conceptual fractured rock mass model of the potential reservoir target, hydro-mechanical model simulations can provide the following useful information:

- Structural anisotropy of the rock mass via estimates of the fracture deformation distribution across all individual fractures (Figure 1).
- An indication of the pre-stimulation, steady-state, bulk *in situ* hydraulic conductivity and its related anisotropy (Figures 2 & 3).
- An indication of potential reservoir growth and fluid flooding directions.
- An estimate of stress magnitudes at the target depth horizon and an indication of the injection pressures required for hydraulic stimulation.
- Model input parameters and results provide the basis for more complex, coupled thermal-hydrogeological-geomechanical models to simulate the lifetime performance (e.g. pressure and thermal drawdown) of an EGS project.

Ranking of Potential Reservoir Targets

From a hydro-mechanical context, the process of ranking the reservoir suitability for each prospective rock unit will require a qualitative to semi-quantitative assessment of the advantages and disadvantages of both Type 1 and 2 conceptual targets. It is recommended that the ranking criteria include the following factors:

- Favourable fracture set orientations with respect to the *in situ* stress field.
- Degree of fracture network connectivity (e.g. fracture density, length etc).
- Fracture set strengths, mineralisation etc.
- Rock mass stiffness (i.e. deformability).
- Estimated bulk hydraulic conductivity and hydraulic conductivity ellipse.
- Target depth with respect to the pre-defined target isotherm.
- Target depth and its expected stress magnitudes.
- Target rock unit thermal conductivity.
- Target rock unit thickness.

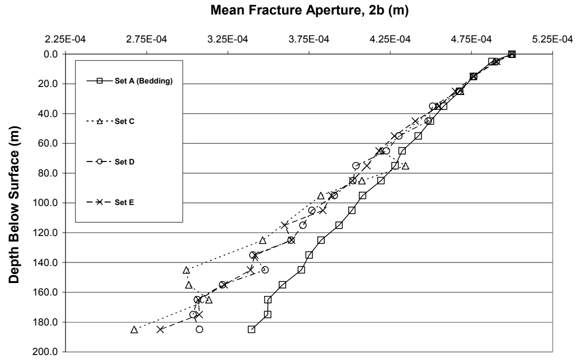

Figure 1 : Example of a UDEC fracture deformation depth profile for individual fracture sets that comprise a larger fracture network. In this example, the initial (at surface) fracture hydraulic apertures were set at 0.5 mm with data points representing the calculated mean fracture aperture for each 10 m thick depth interval. The results show a progressive divergence in the relative amounts of fracture closure (i.e. structural and hydraulic anisotropy) occurring across the individual fractures.

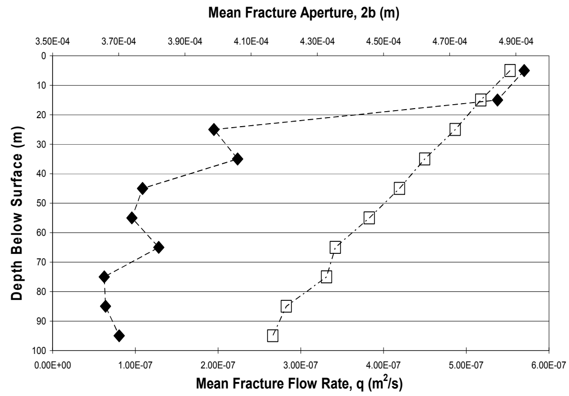

Figure 2 Depth profile example of UDEC estimated mean fracture flow rates (diamonds, lower x-axis) and fracture apertures (squares, upper x-axis). The initial (at surface) fracture hydraulic apertures were set at 0.5mm.

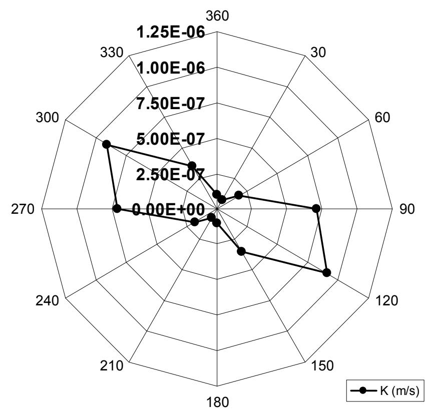

Figure 3 : Example of a UDEC horizontal planar hydraulic conductivity (K) ellipse for a fracture network at a specific depth (stress) level. The degree of ellipse elongation represents the *in situ* hydraulic anisotropy of the fracture network with the elongation direction equal to the maximum K direction.

Conclusion

This study has described how preliminary estimates of the hydro-mechanical properties of a fracture network can be combined with coupled hydromechanical, discrete fracture network models to characterise reservoir potential. This approach has several limitations, which are largely due to the complexities and uncertainties associated with data capture, sample representativeness and spatial confidence, particularly in regard to the geomechanical characterisation of *in situ* rock material and fractures. Furthermore, the computational limitations of codes such as UDEC restrict their practical application to either detailed small-scale (<100m) studies or stochastic representations of larger scale problems. However, the main advantage of this approach is that it provides an alternative method to standard borehole hydraulic tests, can be based upon outcrop or single well data, can be applied at any geological or depth setting and can account for anisotropic fluid flow by explicitly representing fractures and the effects of the *in situ* stress field. The model outputs can be used as valuable parameter inputs for larger scale, “life-of-operation” reservoir models, to identify potentially permeable structures and to estimate required injection pressures and reservoir growth directions during hydraulic stimulation.

There is no “one-size-fits-all” model or methodology and the preference for Type 1 or Type 2 reservoir host rocks is site-dependent, as each rock type has its own unique hydro-mechanical character and behaviour within its present-day geotectonic setting. Ideally, the choice of reservoir rock type should be evaluated in the context of a broader risk-based geothermal systems assessment, which characterises the four aspects of geological risk - heat flow, thermal resistance, reservoir and water. These risks can be condensed, on further modelling, to temperature risk (P_t) and flow rate risks (P_w). When combined with perceived drilling and engineering risks (P_e), these factors form the basis of a simple risk-based assessment system which can be applied to any geothermal prospect/play.

References

Anderson, E. M., 1951. The dynamics of faulting and dyke formation with application to Britain. Oliver and Boyd, Edinburgh.

Bandis, S.C. 1993. Engineering properties and characterization of rock discontinuities. In: Hudson, J. (ed.) Comprehensive Rock Engineering: Principles, Practice & Project, 1, 155-183, Pergamon Press, Oxford.

Barton, N.R. and Choubey, V. 1977. The shear strength of rock joints in theory and practice. Rock Mechanics, 10(1-2), 1-54.

Barton, C. A., Zoback, M. D., and Moos, D., 1995. Fluid flow along potentially active faults in crystalline rock. Geology, 23, 683-686.

de Marsily, G., Delay, F., Goncalves, J., Renard, P, Teles, V. and Violette, S., 2005. Dealing with spatial heterogeneity. Hydrogeology Journal, 13, 161-183.

Gentier, S., Hopkins, D., and Riss, J., 2000. Role of Fracture Geometry in the Evolution of Flow Paths under Stress. In Faybishenko, B., Witherspoon, P.A and Benson, S.M. (eds), Dynamics of Fluids in Fractured Rocks. AGU Geophysical Monograph 122, 169-184.

Hillis, R. R., Coblentz, D. D., Sandiford, M., and Zhou, S., 1997. Modelling the Contemporary Stress Field and its Implications for Hydrocarbon Exploration. Exploration Geophysics, 28, 88-93.

Hoek, E., 2007, Practical Rock Engineering. Online publication. http://www.rocscience.com/hoek/PracticalRockEngineering.asp

Hudson, J. A., Stephansson, O., and Anderson, J., 2005. Guidance on numerical modelling of thermo-hydro-mechanical coupled processes for performance assessment of radioactive waste repositories. International Journal of Rock Mechanics and Mining Sciences, 42, 850-870.

Itasca, 2004. UDEC 4.0 Theory and Background. Itasca Consulting Group Inc., Minnesota.

Rutqvist, J. and Stephansson, O., 2003. The role of hydromechanical coupling in fractured rock engineering. Hydrogeology Journal, 11, 7-40.

Zoback, M. D., 2007, Reservoir Geomechanics. Cambridge University Press.