PERSPECTIVES ON GEOTHERMAL PERMEABILITY

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ABSTRACT

How does a geologist's concept of permeability differ from that of a reservoir engineer? Permeability is a fundamental question in geothermal resource development, but it's typically discussed through jargon that varies between these two groups of specialists. This paper explores the parameterization of permeability from both perspectives and shows that a combined approach supported by careful observation, data analysis and modeling is more likely to accurately characterize the subsurface by increasing the breadth of observed data and reducing bias. Core concepts such as porosity, fracture volume, fracture spacing will be discussed. The paper uses conceptual, visual and numerical examples from three Taupo Volcanic Zone geothermal systems, including a recently developed geothermal system where the strategic acquisition of high quality resource data has shed new light on the nature of permeability.

1. INRODUCTION

A geothermal development leverages permeability, either natural or engineered, to extract heat energy from rock using a fluid and transporting that fluid to surface for electricity production. Permeability is, in essence, the capacity for fluid to flow though rock. Townend and Zoback (2000) determined that crustal permeability at the km scale to be ~10^{-17} to 10^{-16} m^2 (10-100 µd). Natural geothermal systems, such as those in the Taupo Volcanic Zone of New Zealand, have much higher bulk permeability that typically lies somewhere in the range of 10^{-14} to 10^{-13} m^2 (10-100 md: Figure 1). However, parts of the geothermal system, such as highly fractured zones associated with faults, have permeability >10^{-12} m^2 (1 d: Figure 1).

Successfully and sustainably developing a geothermal resource requires an interdisciplinary sub-surface team focused on defining, targeting, monitoring, and in some cases enhancing the permeability. In the present paper we focus on two groups of specialists within that interdisciplinary team: the reservoir engineers and the geologists. These specialists have different datasets with their own bias, toolkits with various uncertainties and discipline specific jargon. The key tool of the geologist is the geologic model which, based on data acquired though surface mapping and from wells, comprises one or more hypotheses about the extent of rock units and hydrothermal alteration in the subsurface. The key tool of the reservoir engineer is the numerical model where, based on well temperature, pressure and permeability, the heat and mass transfer of the system is described and forecasted for specific development scenarios. Linking the geologic and numerical models is the conceptual model of a geothermal system—a mental model of how the geothermal system works and the basis of parameterization. One core challenge facing both the geologist and reservoir engineer is scaling observations from core, log or wellbore scale to reservoir scale. In their study of crustal permeability, Townend and Zoback (2000) found that discrepancies of between three and four orders of magnitude existed between permeability measured at large (*in situ*, inferred from seismicity and reservoir impoundment) and small scale (core). Challenges like this issue of scaling highlights that careful consideration must be given to the conceptual model of permeability and the parameters we use to define it.

Herein we focus on parameterization, in particular how a cross-functional approach can yield numerical model start-point values with higher confidence than rules of thumb often applied. In the process of building more confident start-points, we also explore concepts like the value of improving data resolution and the relationship between what is measured in rock vs. input into models.

2. MATRIX

Porosity is a commonly discussed reservoir parameter, perhaps because it's relatively easily measured rather than because of its relevance. In a numerical model of a geothermal system where fracture-hosted flow dominates, porosity (and matrix permeability) plays a nominal role. In contrast, in a system where the total permeability is much lower or where boiling occurs, the magnitude of porosity may be more important. In a low permeability environment, where system recharge may not be readily available to support well flows, the volume of porosity represents storage: the smaller the storage the less buffering occurs, and high well decline rates could mean un-sustainable production. In a system where boiling occurs due to pressure draw-down in fractures, the porosity again represents storage. The lower pressure in the fractures allows mobilization of pore fluid at a rate depending on the matrix permeability. It follows that the value of determining porosity depends on the type of geothermal system.

Lab-based measurements of porosity are common practice in the geothermal industry and are typically undertaken using gravimetric methods. Gravimetric methods are low cost but require the acquisition of core (which comes with a high cost) and the results represent only a single point in the subsurface. Wireline methods, where density and neutron porosity tools are deployed to measure *in situ* porosity prior to running the liner, are less often utilized because of operational challenges associated with tool temperature limitations. However, such wellbore measurements offer higher value because they sample a greater volume of rock and can map porosity change along the logged interval.

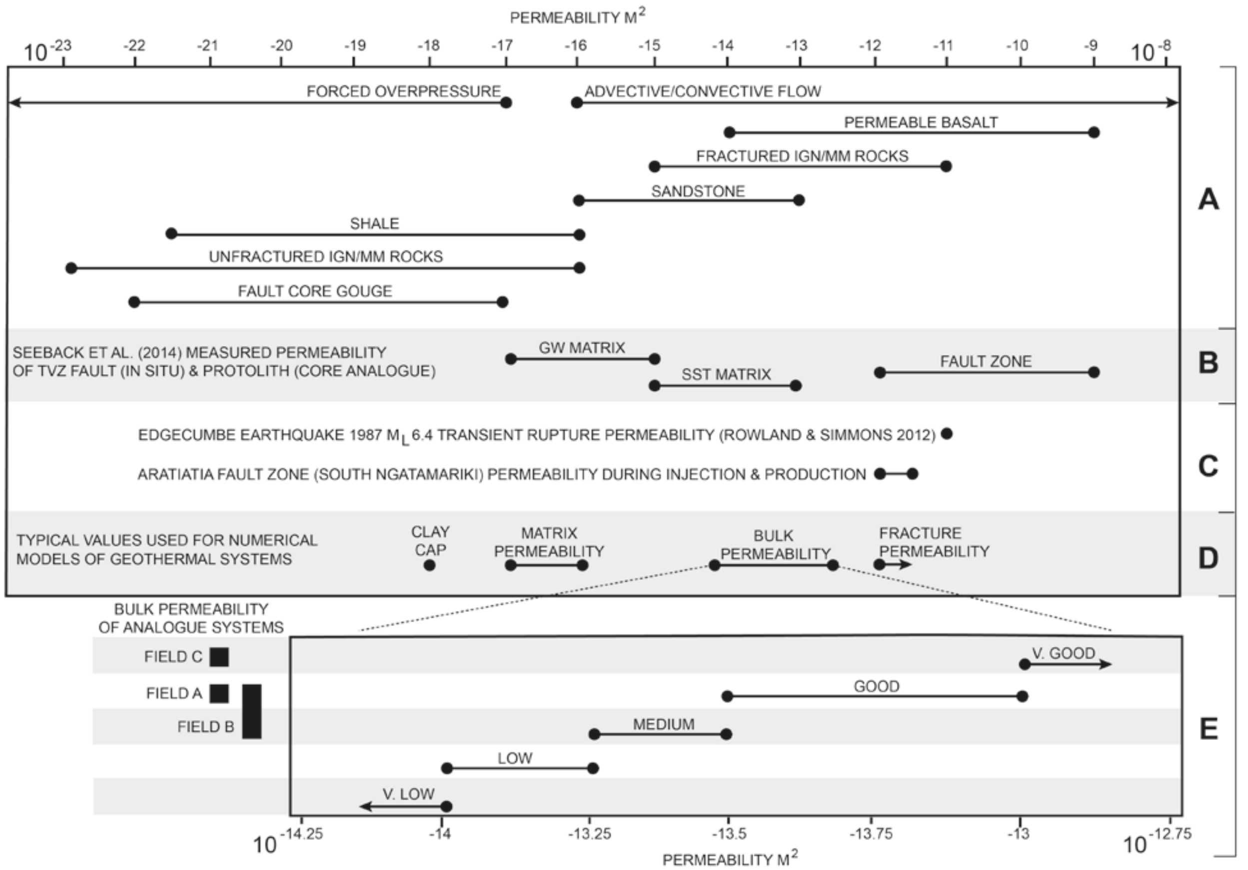

Figure 1: Scales of permeability (m2) building on the values compiled by Rowland and Simmons (2012) which show the critical bounds of convective flow and overpressure, as well as permeability ranges for a number of rock types (panel A). Typical permeability ranges used for numerical modeling of geothermal systems (panels D and E) are compared with measured values for matrix and fracture permeability (panel B), values for active faulting (panel C) and bulk permeability ranges for three Taupo Volcanic Zone geothermal systems (Field A, B and C).

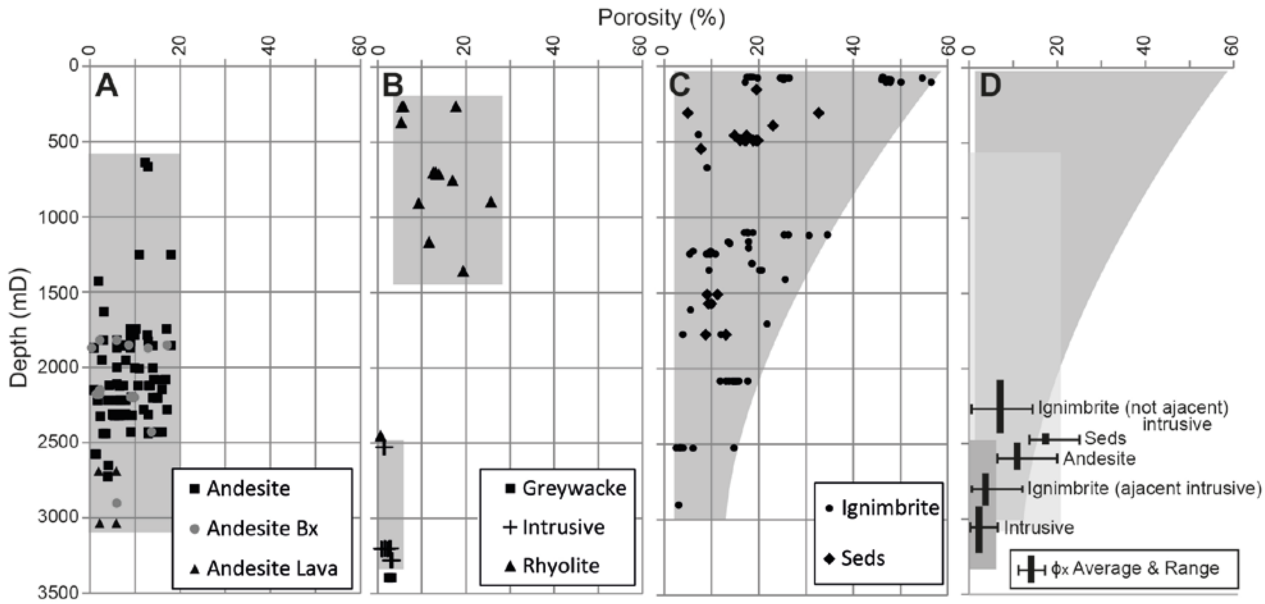

Figure 2: Porosity – The grey shaded areas in panels A-C are limiting envelopes for the lab-based porosity data both commensally acquired and those published in Wyering et al. (2014) for three TVZ geothermal systems. Note that only the lithology in panel C indicates some kind of compaction/diagenesis trend of decreasing porosity with depth. Porosity measured using wireline logging in two wells in Field A are presented in panel D overlaid on the limiting envelopes from A-C.

Figure 2A-C collates lab-based measurements of porosity from three Taupo Volcanic Zone (TVZ) geothermal systems herein referred to as Field A, B and C. These data have been separated by lithology because in these two systems the rock type can play a greater role in dictating porosity than compaction. The dominant influence of lithology contrasts with sedimentary basin-hosted resources where compaction curves are often used as the key feature defining porosity with depth. Rejeki et al. (2005) observed a similar dominance of lithology over compaction as the factor controlling porosity at Darajat, perhaps indicating that the types trends shown in Figure 2 may be applicable to volcanic-hosted systems outside the TVZ. Given these lithologic controls, we recommend separating porosity data by lithology and constructing limiting envelopes that represent the maximum likely porosity at a given depth, rather than lumping all data together and constructing a reservoir trend from that.

The limiting envelopes presented in Figure 2 may seem a very coarse way of looking at porosity, but it may be sufficient accuracy for numerical models where porosity plays a minor role. The limiting envelopes presented in Figure 2 do, however, disguise detail which may be useful for understanding and therefore targeting permeability in future wells.

Cross-plot porosity (ϕ_x) is an average of density and neutron log porosity, with those data corrected for formation absorption. In Figure 2D, ϕ_x ranges and average for several lithologies are plotted on a background of limiting envelopes prescribed by lab-based data. There is general agreement between these envelopes and ϕ_x, but the differences are of key interest to understanding permeability structure of the resource.

Based on comparison with the limiting envelope from Panel C, ϕ_x recorded in a short section of volcaniclastic sediments overlying andesite lava and buried by ignimbrite deposits in a Field A well has a higher porosity than expected for a sedimentary deposit at this depth (Figure 2D dataset labeled *Seds*). The reason for the anomalously high porosity values in comparison to the core values is likely due to the fact that this particular sequence of volcaniclastics contains cemented breccia and a large number of fractures. Because the wireline tools don't differentiate between primary and secondary porosity, the values are high in comparison to gravimetric methods conducted on core plugs which would be biased toward sampling competent rock matrix. The sedimentary interval in the Field A well, notably, is also a key feed zone in this well.

ϕ_x in *ignimbrite (adjacent intrusive)* is systematically lower than ϕ_x in the equivalent lithology group in the south of the resource (*ignimbrite not adjacent intrusive*). The difference here lies in the alteration mineralogy, where ignimbrite adjacent the intrusive is impacted by high temperature alteration associated with the emplacement of an intrusive body in the north preceding the formation of the geothermal system (Chambefort et al., 2015 reviewed). The logged southern well contains no evidence of intrusive-related alteration. Alteration has been shown to change the physical and mechanical properties of rocks (Wyering et al., 2014) and, as we will see later in the fracture volume section, the alteration associated with the intrusive body has also impacted how fracturing occurs.

Matrix permeability and porosity are two quite independent parameters in the numerical model. In reservoir modeling the matrix permeability can be used as a tool to match heat exchange and the nature of recharge (i.e., varying the degree of recharge from the matrix). These parameters are linked with concepts of pore space morphology forming the bridge. Porosity morphology, especially pore shape, connectivity, and tortuosity, influences the way fluid is transported in rock.

In the first instance, the pore space magnitude and its connectedness is dictated by the rock type though depositional process. For instance, some high porosity volcanic rocks, such as ignimbrites, can have a large degree of isolated, unconnected porosity because of the way they solidify with trapped gas. The depositional morphology is then later changed by processes of compaction, diagenesis, tectonic activity in the crust, and alteration—as can be seen in the ignimbrite adjacent the intrusive described above.

Hydrothermal alteration can both create and destroy porosity and its connections. For instance, mineral deposition which creates a small, almost imperceptible, change in porosity, can result in an associated great change in permeability if deposition of minerals is occurring at throats between pores (Adam et al., 2013). In contrast, greywacke—a rock with near-zero inter-granular porosity—has porosity that formed as leach cavities and micro-pores within clay minerals (i.e., illite and chlorite) and are connected by micro- and macro-cracking of the rock mass (Brathwaite et al., 2002).

The typical range of matrix permeability values used in numerical modeling of volcanic-rock hosted geothermal systems is 10^{-17} to 10^{-16} m^2 which lies at the upper end of the range determined for unfractured volcanic and metamorphic rocks (Figure 1). This range is, perhaps, reasonable for natural geothermal systems where the overall permeability is higher than expected in the crust in general. A touch of caution should be applied to comparing permeability determined at different scales as the data may be subject to systematic bias. When comparing laboratory determined permeability data with *in situ* permeability for the wells where the cores were retrieved, Townend and Zoback (2000) found that laboratory results were two to three orders of magnitude lower than *in situ* determined permeability.

3. FRACTURES

Fractures have a great influence on the magnitude and distribution of permeability in a geothermal system. However, when a geologist and reservoir engineer discuss the nature of fractures, they use the same terms but with somewhat divergent mental models. Fracture volume and fracture spacing are two such terms and the following section discusses these from both perspectives. In doing so we hope to show that a joint approach improves total understanding.

Fracture Volume

Fracture volume is defined as the volume of a rock mass that is open to flow and the fracture volume controls the rate of flow though the rock mass. There are no specific rules or fracture volume ranges for numerical modeling, but a fracture volume range from 0.05 to 3% is generally applied. The following describes geologic and numerical testing of this range which indicates that the low end is the best start-point when modeling TVZ geothermal systems.

We constructed a TOUGH2 process model which aimed to match reservoir tracer returns and observations of a fault-controlled channel between injection and production (c.f., Buscarlet et al. 2015 for a full description of the model). The process modeling matched tracer arrival time and curve shape, but did not match the magnitude of returns, perhaps because the model environment is more conservative than the real world. Fracture volume was a key controlling parameter for tracer first arrival in the model, and to get a match the model fracture volume was 0.81%. This fracture volume is low considering 1-2 % is most typically used in modeling, but it is consistent with geologic observations of fracture widths (Figure 3).

Since the process model was built using TOUGH2, it's useful to understand how fluid flow is calculated in TOUGH2 using pressure, viscosity, and gravity forces according to Darcy's law.

Equation 1:

$$q = \frac{-k}{\mu}(\nabla p - pg)$$

Where q is the flux (discharge per unit area, with units of length per time expressed as m/s), ∇p is the pressure gradient vector (Pa/m), μ is viscosity, k is permeability, p is density and g is gravity. It follows that a change in fracture volume does not change the flux of fluid in TOUGH2—instead what changes is the rate. Fluid velocity is related to flux by effective total porosity (or fracture volume) such that a decrease in fracture volume will increase the fluid velocity as shown in Equation 2.

Equation 2:

$$v = \frac{q}{\emptyset}$$

Where v is fluid velocity, q is flux and $\emptyset$ is porosity. Note that fracture porosity is equivalent to fracture volume in a dual porosity system.

Therefore, the calibration undertaken to match measured tracer return was generally conducted by varying conduit permeability (k) and facture volume ($\emptyset$) in a fault-zone conduit.

The process model reservoir temperature was uniform at 280°C and the reservoir pressure was calculated by TOUGH2 at steady state conditions. All edges of the model were set to no-flow. In this process model, viscosity (μ) was set based on temperature and pressure changes (∇p) were only influenced by production and injection. It follows that in our effort to constrain fracture volume using TOUGH2 (and Equations 1 & 2), reservoir permeability (k) is the greatest uncertainty. In our process model, reservoir permeability was constrained using interference testing and prior numerical modeling experiments.

Calibrating the process model to measured tracer returns required a fault conduit permeability of 1-3 Darcy (9.8 x 10^{-13} to 2.9 x 10^{-12} m^2). Interestingly, this flux is within the range measured in faults intersecting a southern TVZ tunnel (Figure 1: Seebeck et al., 2014) and nearly as high as the transient permeability associated with fault rupture during the 1987 Edgecumbe Earthquake in the northern TVZ (Rowland and Simmons, 2012).

Fracture volume can be measured *in situ* using in-well borehole imaging technologies. We have only used apertures calculated from micro-resistivity imaging technologies, because acoustic images cannot provide quantitative fracture aperture estimates (Halwa et al., 2013). Schlumberger's Formation Micro-Imager (FMI) logs were acquired in two wells in Field A (Halwa et al., 2013), one log in the north where it imaged rock adjacent to and within an intrusive complex and one in the south where the rock sequence is unaffected by the high-temperature alteration.

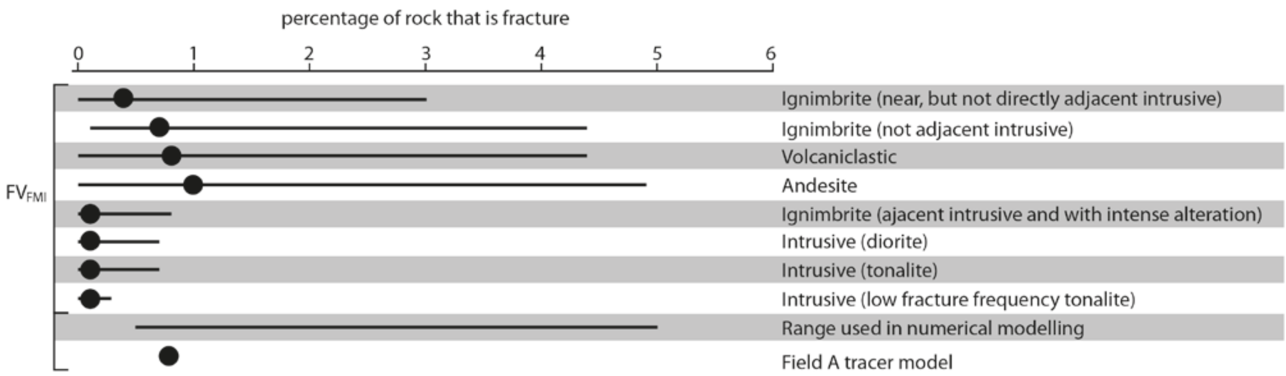

Figure 3: Fracture Volume calculated from FMI logs compared with the values typically used in numerical modeling and a model developed for Field A to match reservoir tracer testing results.

In situ fracture volume ($Ø_{fmi}$) is the maximum fracture aperture (height) multiplied by the drill bit size (width) and presented as a proportion of total borehole wall area assuming the borehole is in-gauge (Figure 3). We expect $Ø_{fmi}$ to overestimate the true *in situ* fracture volume of that area of the reservoir because: (a) thermal contraction of rock during drilling will increase fracture apertures; (b) fractures that truncate on others and do not fully cross the borehole are overestimated because of the height-width method used; and (c) fractures filled with moderately conductive minerals, such as clays, are indistinguishable from open fractures and are therefore included. Fractures which are drilling-induced, drilling-enhanced, filled with very conductive minerals such as pyrite, or filled with conductive minerals were excluded from $Ø_{fmi}$. Micro-fractures, which are common in formations like greywacke, are too numerous to be picked by the FMI log analysis, and therefore not included in $Ø_{fmi}$. However, one could reason that from a reservoir perspective this micro-fracture population is better considered as part of the matrix porosity.

For the purpose of sense checking the *in situ* estimates of fracture volume, we made a rough fracture volume estimate using two cores recovered from reservoir depths (Figure 4). The number of natural fractures (as opposed to drilling/handling-induced) was counted in each core: 20 in the andesite and 2 in the ignimbrite. Based on the asperities present that would prevent fracture closure under load, we made a simplifying assumption that the *in situ* fracture aperture for andesite fractures was 2 mm and ignimbrite fractures was 4 mm, which is consistent with the aperture trends observed in borehole logging (Halwa et al., 2013). As with $Ø_{fmi}$, all fractures were assumed to cross the entire core. Resultant fracture volume estimates were 0.89% in the andesite and 0.23% for ignimbrite.

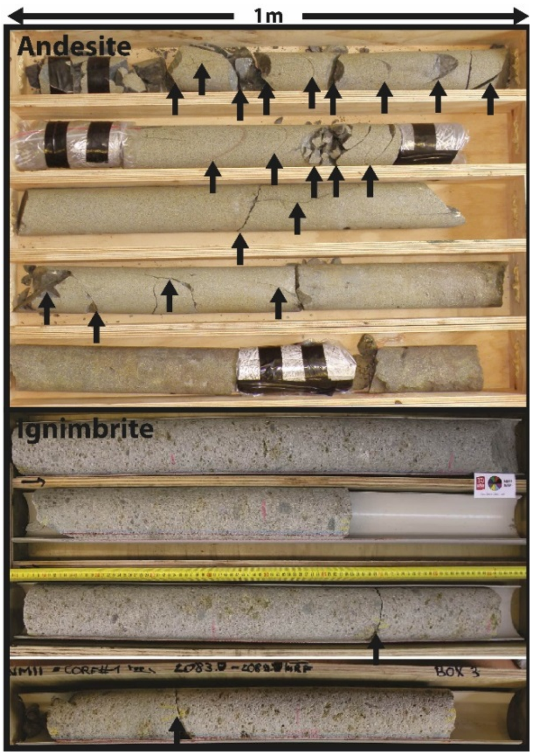

Figure 4: Basis for the back of the envelope estimate of fracture volume for andesite (upper core) and ignimbrite (lower core).

The consistency between all three methods used above to investigate the magnitude of fracture volume (process modeling, wireline logging and estimation constrained by simple assumptions) lends weight to the argument that fracture volumes <1% are generally the most reasonable starting point in a model.

Fracture Spacing

Fracture spacing in a numerical model represents the efficiency of heat exchange between matrix and fractures, such that lower fracture spacing values result in better fluid-rock heat exchange. When a geologist hears *fracture spacing*, a mental image of measured distances between fractures at the meter and centimeter scale springs to mind (to avoid confusion, from here on the term *fracture frequency* will be used for this geologic concept where a high fracture frequency equates to low fracture spacing). We will show below that although these two concepts of fracture spacing are not the same, joint understanding may spawn ways to decrease uncertainty.

Because fracture spacing dictates the thermal interaction between fluid flow in the fracture and matrix, using fracture spacing values which are too low may underestimate the impact that marginal recharge or injection has on production well enthalpy. It is common to use starting values of 100-150 m for fracture spacing. Decline in temperature measured in the compressed liquid section of wells or enthalpy decline for wells in a compressed liquid system where all produced fluid (minus the non-condensable gasses) is reinjected can be used to calibrate fracture spacing. However, in a system where enthalpy or temperature decline has not been detected, another method should be developed to constrain fracture spacing. We propose that the distance between feedzones may provide such a constraint.

The spatial location of feedzones as determined using pressure, temperature and spinner (PTS) log interpretation is our clearest window into where fluid is flowing in a reservoir. Spinner logs use recordings of impellor rotation according to fluid velocity at a controlled tool rate down or up a producing, injecting or static well to detect fluid entry and exit. Pressure and temperature profiles provide additional information and better constraints on feedzone location and strength. Figure 5 depicts the spacing of feedzones in three TVZ geothermal systems. These frequency distributions were produced by determining the distances between identified feedzones, such that wells with only one feed would not get a distance and a well with two feeds would have a value representing the distance between those zones. Various PTS test types, such as those conducted under different rates of injection or while the well is producing, will often result in identification of different feedzones in a well—in particular, flowing PTS analysis will commonly identify multiple feeds within a single feedzone picked from an injecting test. We have used the highest resolution data available for each well and as such accept that those production wells tested with flowing PTS will appear to have clusters of closely spaced feedzones and therefore skew the distribution.

Despite the variability in source data, there is a high degree of consistency between the three fields presented in Figure 5; of particular note is that all three plots have a long tail distribution. The long tail shows that although feedzones are typically <600 m apart, they can be >1,000 m apart.

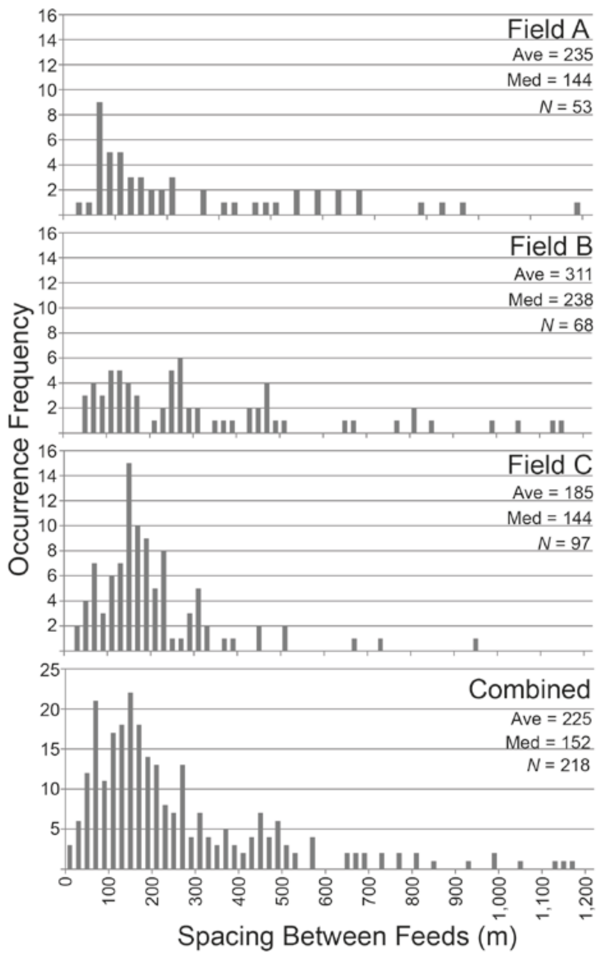

Figure 5: Feedzone spacing at Field A, B and C, and the spacing's of all fields plotted together in "Combined"

Fracture spacing <10 m in a numerical model is essentially single porosity, and can be conceptualized as a system where permeability is highly distributed and fluid flow in the fracture interacts greatly with the matrix. Conversely, fracture spacing >300 m can be thought of as a highly discrete, channelized system where there is less thermal interaction between fracture and matrix. All distributions in Figure 5 show that most feedzone spacing is <300 m. Field B has a higher spacing between feedzones than the other two fields, which may be related to the much more variable permeability found in this resource. As can be seen in Figure 1, Field B has a greater range of permeability than the other two and it is the only one of the three fields which shows significant compartmentalization (Quinao et al., 2013).

Fracture frequency varies systematically across rock types depending on their mechanical properties, such that rocks which are brittle are more likely to form fractures than those which are more ductile. Systematic variation of fracture frequency has been observed though micro-resistivity image logging of wells at Field A (Halwa et al., 2013).

The problem of matching fracture frequency and fracture spacing may be one of scale—where instead of comparing apples with apples, we are comparing apples with the apple tree. The scale of fracture spacing in numerical models is typically at the hundreds of meters, an order of magnitude greater than the fracture frequency observed at the borehole and analogue outcrop scale. Fracture networks are well known fractals, but permeability in the volcanic hosted geothermal environment cannot be solely attributed to faults and their associated fractures. At the 100 m scale we find other geological phenomena, such as lithological contacts and units of varying physical properties that contribute to the permeability structure of the resource. Better characterization of why permeability exists at each particular feedzone (i.e., fractures, faults, contacts, breccias, etc.) through the acquisition of microresistivity and petrophysical wireline logs will eventually allow us to build mental models which relate the apples to the apple tree.

4. APPLICATION

Accurate numerical modeling forecasts for geothermal resources depend, to varying degrees, on the accuracy of input parameters. The sensitivity of a numerical model of Field A to the variation of the different input parameters was tested by Moon et al. (2014). They found that the key parameters influencing the goodness of temperature and pressure match in a model representing the 'natural state' or pre-development state of the system, was fracture permeability and upflow rate (Moon et al. 2014); two parameters not wholly improved by the kinds of collaborations discussed in the present paper. Monte Carlo testing of production scenarios told a different story. The model forecast of a perturbed system were most sensitive to fracture permeability, matrix porosity and fracture spacing (noting that Field A is nearly 100% injection: Moon et al. 2014). In a system with lower overall permeability, and therefore a higher dependence on storage, the impact of matrix porosity would be even more exaggerated. Moon et al. (2014) found that fracture spacing was the greatest influence on forward modeling enthalpy changes in the Field A reservoir (Moon et al. 2014). It follows that the parameters of interest—those which most deserve our time and monetary investment—vary depending on the model purpose.

We have only brushed past some of the input parameters which would benefit from joint disciplinary analysis. And there is ample scope for more work. For instance, volcanic-hosted geothermal systems can demonstrate a high degree of anisotropy in the permeability (Buscarlet et al., 2015; Stimac et al., 2010): in particular the differences between vertical and horizontal permeability which are often required in numerical models to get a match. Looking at overall permeability style in system can also be informed by joint analysis and shared definitions. For instance, investigating the contrast between the homogenous pressure distribution at Field A with the compartments observed at Field B: two fields with very similar lithologies, but quite different structural settings.

By jointly looking at matrix porosity, fracture volume and fracture spacing, we have touched on key issues of collaboration: understanding each other's terminology, defining useful scales and then crossing them, and openly questioning what is being measured.

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