CGS – CONTROLLED WELLBORE-TO-WELLBORE GEOTHERMAL SYSTEM FLOW

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ABSTRACT

Uniquely in the domain of wellbore extraction of crustal fluids Enhanced/Engineered Geothermal System (EGS) fluid flow is predicated on wellbore-to-wellbore pathways. Primary oil/gas production, including tight gas and oil/gas shale fracturing operations, and hydrothermal steam production have country-to-wellbore flow geometries. Secondary/tertiary oil/gas production flow paths are wellbore-to-country loosely coupled to country-to-wellbore. EGS alone assumes detailed conservation of the production fluid.

The unique EGS wellbore-to-wellbore flow geometry leads to a second distinction, degree of control. Wells producing from country-to-wellbore and/or wellbore-to-country flow geometries typically have lognormal productivity and/or injectivity distributions. Lognormal distributions are highly skewed to a large population of weak producers and a small population of strong producers. Country-to-wellbore and/or wellbore-to-country flow systems exact large drilling costs for low-productivity/low-performance wells. A major component of reservoir economics centres on attempts to increase the drilling rate of high-productivity wells and decrease the drilling rate of low-productivity wells. As historically such attempts have had limited success, it may be said that country-to-wellbore and/or wellbore-to-country flow geometry drilling strategies allow little control of flow system permeability structure.

In distinction, EGS wellbore-to-wellbore flow is predicated on a high degree of permeability structure control. The point in question is how to exercise that control. Our wellbore-to-wellbore EGS heat transport simulations indicate that 5 x 1000m long-reach wellbores can provide ~5MW electric power over a ~30 year lifetime if the wellbore offsets are of order 100m (total heat reservoir volume ~10^8 m^3). We suggest, however, that EGS permeability stimulation of tight basement rock is nearly impossible to adequately control at the ~100m wellbore-to-wellbore offsets required for long-term heat extraction. While flow control may be possible in substantially smaller rock volumes, the consequent rapid cooling of the hot rock reservoir volume is commercially unviable.

Wellbore-to-wellbore permeability structure control has then to be exercised in a different manner. Since most well productivity/injectivity distributions are lognormal, we note three empirical rules of fluid flow in crustal rock that embody the lognormality feature of in situ permeability structures:

- **Long-range scale-independent spatial correlation of grain-scale fracture defects** Well-log data show that spatial fluctuations of rock physical properties occur at all scale lengths according to a specific power-law relationship between scale length given by spatial frequency $k$ and fluctuation power $S(k)$ at that scale, $S(k) \sim 1/k$, for five decades of spatial frequency $1/km < k < 1/cm$.

- **Multiplicative nature of percolation flow along grain-scale-defect network pathways** Well-core data show that spatial fluctuations in well-core porosity $\delta \phi$ are closely tracked by fluctuations in the logarithm of well-core permeability $\delta \log(\kappa)$, $\delta \phi \sim \delta \log(\kappa)$.

- **Permeability enhancement by increased fracture-connectivity** Fluid-system data show that the integrated form of the $\delta \phi \sim \delta \log(\kappa)$ fluctuation relation, $\kappa \sim \kappa_0 \exp(\alpha(\phi-\phi_0))$, is closely related to the presence of fracture connectivity; low values of empirical parameter $\alpha$ are associated with lower permeability and flow through diffuse fracture systems, while high values of $\alpha$ are associated with higher permeability and flow through connected fractures; accordingly, in situ fracture connectivity is a key element for in situ permeability.
If it is implausible that wellbore-specific controlled EGS-type ‘bottom-up’ permeability enhancement through enhanced fracture connectivity can be extended over 50-100m distances from the wellbore in tight basement rock, we can counter this obstacle by seeking ‘top-down’ control over the extreme manifestation of lognormal distributions by systematically shutting down high-flow pathways and restricting flow to lower-permeability pathways in existing moderate permeability structures in thick elevated-temperature sedimentary aquifers such as have been identified throughout the western US. Using the above formulation of in situ flow in crustal rock in the above noted wellbore geometry, we have systematically simulated the process of identifying and blocking high-permeability flow structures in wellbore-to-wellbore flow systems in order to create more disseminated wellbore-to-wellbore heat transport consistent with controlling long-term heat extraction from crustal volumes.

1 BACKGROUND

Geothermal reservoirs range in the degree of control or engineering intervention used to achieve commercial energy production. As pictured in Fig 1.1 (Elliot 2009), three flow regime types can be roughly control-ranked as:

- Essentially no control/intervention for commercial production from high-activity rift-structures in hydrothermal systems worldwide scaling to some control/intervention for low-activity rift structures such the Rhine Graben and Basin and Range normal faults;
- Moderate to substantial control/intervention expected to be sufficient to achieve commercial production from intermediate-permeability hot sedimentary aquifers;
- A great deal of control/intervention recognised as necessary for commercial heat extraction from low-permeability basement rock.

Spanning the Fig 1.1 visual range of practiced/expected degrees of control/intervention for crustal heat reservoir production is a less visible set of assumptions about in situ fracture/flow connectivity within a crustal volume:

- Hydrothermal reservoir fracture/fault flow systems have high degrees of country-to-wellbore in situ connectivity generally regarded in terms of ‘more or less average’ producibility;
- Aquifer-based heat extraction schemes generally assume that oil/gas field in situ flow rates are sufficiently uniform that country-to-wellbore or wellbore-to-wellbore flow can be more or less routinely achieved;
- Basement rock heat extraction is predicated on highly efficient wellbore-to-wellbore fracture/flow connectivity.

In none of these heat reservoir production scenarios, however, is the assumed degree of fracture/flow-connectivity supported by field production data or rock physical evidence. In producing geothermal and oil/gas fields, well productivities are lognormally rather than normally distributed, and the physical evidence of well-logs and well-core overwhelmingly favor spatially discontinuous rather than spatially continuous in situ flow structures at all scale lengths (Leary et al. 2012a,b; Grant 2009; Leary & Walter 2008; Leary 2002).

![Fig. 1.1—Rough guide to crustal fracture-system settings for geothermal heat extraction (from Elliot 2009).](image-url)
This paper adheres to a more accurate empirically-based conceptual and practical characterization of *in situ* flow connectivity, and considers its impact on the production of geothermal energy. The issue of flow-structure discontinuity in hydrothermal field country-to-wellbore flow can be apostrophised as “Where to drill?” To answer this question, we first discuss the physical nature of *in situ* flow based on well-log and well-core systematics, then illustrate the role large-scale *in situ* flow structure data can have in well-siting for hydrothermal reservoir flow systems that are more structurally discontinuous than commonly thought. We then consider in more quantified detail the challenges wellbore-to-wellbore flow control as yet unrealized for aquifer and basement rock heat extraction. Our results suggest that achieving continuous flow-channels between wellbores is both necessary and sufficient for controlled heat extraction.

**2 WHERE TO DRILL? – ADDRESSING THE LOGNORMAL WELL PRODUCTIVITY PROBLEM**

Geothermal (and equally oil/gas field) well productivities are lognormally distributed rather than normally distributed (Grant 2009; Leary *et al.* 2012a). *In situ* rock physics data give an explicit physical basis for lognormal statistical reality, which is readily illustrated in numerical flow simulations built around three physical ‘rules’ derived from well-log and well-core spatial fluctuation systematics.

Fig 2.1 pictures two statistical views of reservoir rock variability about a mean value. At left are spatially uncorrelated variations, and at right are spatially correlated spatial variations. Below each rock section is a numerical sequence of spatial variability ‘recorded’ by a ‘well-log’ (black line) through the section. The statistical character of each ‘well-log’ sequence appears in a log-log plot of the respective Fourier power-spectra $S(k)$ as function of spatial frequency $k$. The power spectra of uncorrelated and correlated spatial fluctuations scale with different power-law exponents: $S(k) \sim 1/k^0$ and $S(k) \sim 1/k^1$. Uncorrelated spatial fluctuations, widely known as ‘white noise’, are typically employed in conventional reservoir models, while the spatially correlated fluctuations, widely known as ‘$1/f$-noise’, are largely ignored in reservoir modeling (Leary 2002).

The default reservoir rock power spectrum on the left of Fig 2.1 embodies spatially uncorrelated fluctuations in rock physical properties: whatever is physically happening at one point in the section is independent of whatever is physically happening at any other point in the section. Uncorrelated fluctuations are statistically defined by two parameters, the mean $\mu$ and standard deviation $\sigma$ from the mean. For uncorrelated fluctuations, the ensemble mean and standard deviation (i) apply everywhere in the section and (ii) are well estimated by a few sample values from the rock section.

**Fig. 2.1 — Systematics of uncorrelated (left) and correlated (right) spatial fluctuations in rock physical properties. Upper panels: Spatially correlated fluctuations do not cluster. Central panels: Well-log records of fluctuation sequences across rock sections have (left) power equally distributed or (right) power skewed to low frequencies across scale length spectrum. Lower panels: Fourier power spectra of well-log fluctuation sequences have power-law trends with respective exponents 0 (left) and -1 (right).**

In contrast, the right-hand power spectrum of Fig 2.1 has a non-trivial unity power-law scaling exponent, signaling the presence of a scale-independent physical process that connects spatial fluctuations in one part of a rock section to spatial fluctuations in other parts of that section, and insures that the larger the scale of the system, the larger the amplitude of spatial fluctuations across the section. It is a matter of extensive observation that well-logs everywhere – independently of rock type, tectonic setting, well type, or physical property – have inverse power-law scaling fluctuation power $S(k) \sim 1/k^1$ equivalent to the
‘1/f-noise’ spectral scaling widely observed in evolving physical systems (Leary 2002). Nowhere are well-logs seen as non-scaling \( S(k) \sim 1/k^0 \) ‘white noise’.

At a statistical level, spatially correlated fluctuations in crustal rock mean that in situ reservoir-scale fluctuations are larger in general than sub-reservoir spatial fluctuations, and no feasible small-scale sampling of the section gives reservoir modelers an accurate indication of the scale and nature of fluctuations elsewhere in the section. Accurate reservoir modeling is thus dependent on a reservoir sampling strategy to determine the most significant fluctuations that occur at the reservoir scale length. No feasible small-scale sampling contains reliable information as to where, how, and to what degree large-scale fluctuations occur. Only direct observation of the reservoir gives the modeler the essential large-scale reservoir structural information (e.g., Leary & Walter 2008; Geiser et al. 2012).

The spatial correlation property of reservoir rock reflects an underlying physical process based on grain-scale fracture density as an essential physical parameter. Grain-scale fracture density is the degree to which grain-grain contacts of the rock mass are either bonded -- well-cemented and hence impermeable to fluids -- or unbonded -- poorly-cemented/uncemented and hence permeable to fluids. Well-log power-law spectral scaling means that small-scale spatial fluctuations in grain-scale fracture density grow into long-range spatially-correlated fracture-networks over many orders of magnitude in scale length (sub-mm to supra-km). \( S(k) \sim 1/k^1 \) scaling is directly attested in crystalline rock from mm scales in scientific drillhole logs.

Fig 2.2 — Normalized sequences of well-core poroperm properties along horizontal trajectory through N Sea clastic reservoir formation: (blue) normalized porosity sequence; (red) normalized log(permeability) sequence. Sequences are normalized by removing the mean and dividing by the standard deviation. The cross-correlation coefficient is 83%.

The grain-scale fracture density picture of spatially fluctuating rock properties has strong support from well-core systematics. Clastic reservoir well-core data establish that in situ porosity and permeability are extremely closely linked. Well core spatial fluctuation data show that small changes in well core porosity are almost exactly tracked by small changes in the logarithm of well core permeability, \( \delta \phi = \delta \log(\kappa) \), along a well-core sequence. Fig 2.2 illustrates the degree to which (normalized) well-core porosity fluctuations (blue) are tracked by (normalized) well-core log(permeability) fluctuations (red) along 50m of (horizontal) wellbore in North Sea clastic reservoir rock. The spatial correlation is 83% at zero lag.

The rock physics underlying the data empirics of Figs 2.1-2.2 can be directly incorporated into Darcy flow modeling whereby fluid pressure in a wellbore or at a section-boundary forces in situ fluids to migrate along heterogeneous percolation pathways subject to fluctuations in grain-scale fracture density and fracture-connectivity on all scale lengths within a numerically realised crustal rock section or volume. Fig 2.3 shows snap-shots of a 2D numerical simulation of a time-evolving pressure field as fluid moves from fixed boundary values at the top and bottom across the intervening rock section. The associated flow velocity vectors shown in Fig 2.4 indicate that the disseminated pressure field drives fluids along fracture-connectivity percolation channels within the rock section.

Darcy’s law and conservation of mass,

\[
\begin{align*}
\n\mathbf{v} &= \kappa/\mu \nabla P \\
\partial_t P &= B \nabla \cdot \mathbf{v},
\end{align*}
\]

combine to give time-evolving fluid flow velocity field \( \mathbf{v}(x,y,t) \) for media of spatially variable permeability \( \kappa(x,y) \) with essentially constant elastic modulus \( B \) for fluids of viscosity \( \mu \) under pressure \( P(x,y,t) \),

\[
\partial_t P = B/\mu \nabla \cdot (\kappa \nabla P) = B/\mu (\kappa \nabla^2 P + \nabla \kappa \cdot \nabla P).
\]

Fig 2.3 illustrates the time evolution of a pressure field developing across a 1/k-power-law scaling porosity distribution \( \phi(x,y) \), as illustrated on the right hand side of Fig 1.1, with the corresponding permeability field given by the well-core relation \( \delta \phi(x,y) \approx \delta \log(\kappa(x,y)) \) as illustrated in Fig 1.2 (Leary et al. 2012a,b).

The spatially variable pressure field begins with high pressure at the top boundary and low pressure at the lower boundary. As time progresses, the fluid moves in response to the fixed boundary pressure, realizing
a new pressure level at each point in the medium until the pressures throughout the flow system are in equilibrium.

At pressure equilibrium in Fig 2.3, steady-state fluid flow velocity fields transfer fluid from high to low pressure boundaries as given by Darcy’s law, \(v(x,y) = \frac{\kappa(x,y)}{\mu} \nabla P(x,y)\) and shown in Fig 2.4. It is clear from Fig 2.4 that steady-state fluid flow distributions in crustal media that obey (i) the power-law scaling empirical rule of Fig 1.1 for spatial fluctuations of \(\delta \phi(x,y) \approx \delta \log(\kappa(x,y))\), can be:

- highly irregular in space;
- virtually impossible to detect remotely unless the reservoir fluid is subjected to substantial pressure disturbances that induce remotely detectable seismic slip events (acoustic emissions);
- in either 2D realisation (as in an aquifer) or 3D realisation (in basement rock) highly problematic that two wellbores intersect significant crustal volumes with common flow pathways on any scale.

The near-universal properties of well-log and well-core spatial fluctuation systematics illustrated in Figs 2.1-2.2 strongly indicate that flow-simulation heterogeneity pictured in Fig 2.4 accurately represents the mechanics of \textit{in situ} flow.

A check on the physical plausibility of velocity the Fig 2.4 fluid velocity field is the distribution of simulation flow magnitudes \(|v|\) (i.e., the length of the flow vectors). Fig 2.5 shows that flow velocity magnitude \(|v|\) is lognormally distributed -- a large majority of \(|v|\) values are small while a small number of \(|v|\) values are large.
Fig 2.6 pictorially establishes the relation between degree of lognormality in a permeability population (column left) and the degree of fracture-connectivity and hence the degree by which fluid flow is channeled by fracture-connectivity percolation path ways. As the degree of permeability lognormality increases from top to bottom in the left-hand column (in population skewness to the left of the x-axis and magnitude of permeability structures registered to the right along the x-axis), the corresponding fluid flow distributions in the right-hand column indicate that permeability increases as fewer numbers of more fracture-connected percolation pathways carry an increasing proportion of the in situ fluid.

Fig 2.6 — Direct correlation exists between degree of lognormality of rock section permeabilities (column left) and degree of fracture-connectivity-borne fluid pathways (column right). That is, in 1/κ-noise poroperm media, overall permeability grows from ambient background (quasi-normal permeability distributions at top left) to high permeability (lognormal permeability distribution at bottom left) through increasing degrees of fracture connectivity (column right). Central column shows degree of pressure field irregularity with increasing flow channelization. Rich ore bodies are associated with lower tier permeability structures.

In illustrating the close association of lognormality in fracture-connectivity count with degree of in situ flow associated with long-range fracture distributions, 2.5-2.6 explain:
- the widely-documented observation that trace-element and ore-grade distributions are lognormally distributed in line with the channelized flow simulation (Leary et al. 2012a);
- why well-productivities are lognormally distributed (Grant 2009);
- why well-siting is more risky than allowed for by standard risk analysis (e.g., Grant 2009);
- why data clarifying where significant in situ flow channels exist can reduce well-siting risk (Leary & Walter 2008; Geiser et al. 2012);

Specific to wellbore-to-wellbore flow control, we rephrase the implications of the above-noted Fig 2.4 spatial flow-path uncertainty:
- low probability that two wellbores intersect significant crustal volumes with common flow pathways;
- utility of tracking near-ambient microseismicity induced by fluid pressurisation as means to map/control in situ fracture-stimulation pathways in wellbore-to-wellbore crustal volumes.

3 WELL-TO-WELL CONTROL?

In the standard reservoir paradigm, closed wellbore-to-wellbore flow pathways are a given. By analogy with an electrostatic dipole, one asked “where was the injected water to go in a quasi-uniform flow medium if not to the producer?” In common with Fig 2.4, Fig 3.1 contrasts how the nature of in situ fracture-borne flow (lower panel) violates the standard reservoir assumption about wellbore-to-wellbore flow paths (upper panel). Natural rock fracture-based flow systems can channel injected waters anywhere within and without a crustal heat volume via a large range of fracture-controlled percolation pathways. These spatially erratic disseminated fracture-flow paths cannot be expected to connect the injector to the producer wellbore without considerable (and to date far from successful, Tester et al. 2006) engineering intervention.

2D heat advection simulations illustrated in Figs 3.2-3.6 begin to quantify the scale and scope of the wellbore-to-wellbore fracture stimulation challenge for ‘real rock’. Wellbore-to-wellbore heat transport is computed for a five-spot flow system embedded in a 2D section of heterogeneous power-law-scaling 1/κ-noise porosity distribution with a given degree of fracture-connectivity controlling the overall permeability magnitude and degree of lognormality (Leary et al. 2012a,b). Fig 3.2 shows the five-spot wellbore array in terms of the pressure fields across the section: positive inflow pressure at the central wellbore, negative outflow pressure at four periphery wellbores, with the section boundary fixed zero pressure relative to a presumed ambient pressure field in the surrounding country rock. The upper panel pressure field is for a uniform permeability; the lower-panel pressure field is for a medium with
permeability channels between in the central input and peripheral outtake wells.

For purposes of computing thermal advection, the Fig 3.2 rock sections are assumed to be embedded in heat bath at fixed temperature $200^\circ C \sim 500^\circ K$, hence the section periphery is fixed at this temperature. Fluid at $100^\circ C \sim 400^\circ K$ injected into the section at the central wellbore fixes the central section temperature. Fluid exiting the input wellbore traverses the poroperm medium picking up heat, and exiting from the section at one of the four peripheral wellbores.

Fig 3.2 — Wellbore-to-wellbore pressure fields for five-spot well assemblage with a central injector well inputting heat-depleted fluid into a section of hot rock to be produced as heat-recharged fluid at four peripheral outtake wells. (Upper) Quasi-uniform poroperm medium. (Lower) 1/f-noise poroperm medium. As in Fig 2.3, pressure fields in 1/f-noise poroperm media are spatially irregular due to flow-channelization along fracture-connectivity structures.

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Fig 3.3 shows three in situ fluid flow velocity scenarios: for uniform permeability (upper), for 1/f-noise permeability (center), and for wellbore-to-wellbore fracture-channeled permeability (lower). It is our interest to determine the temperature distribution in the rock section under these permeability structure scenarios, with particular attention to the temperature at the exit wellbores.
Time-evolving heat advection can be expressed in terms of a spatially variable advective heat source \( Q(T) \equiv \rho_w c_w \nabla (\nu T) \) transporting heat at known velocity field \( \nu(x,y) \) but unknown temperature field \( T(x,y) \),

\[
\frac{\partial}{\partial \tau} T(x,y) = \zeta \left[ \nabla \cdot (\nu \nabla T(x,y)) \right] + \nu \nabla T(x,y)
\]

where \( \zeta = \frac{\rho c_p}{K} = \frac{\rho c_w}{\rho_c c_w} D \sim 10^5 \text{ s/m}^2 \) and fluid flow vector and gradient fields \( \nu_x(x,y), \nu_y(x,y), \nu_{xx}(x,y) \) and \( \nu_{yy}(x,y) \).

A sample steady-state temperature field is shown in Fig 3.4 for the case in which the peripheral outtake wellbores are connected to the central input wellbore by a range of ‘controlled’ percolation pathways. The outtake well heat transport is in principle determined by integrating the time-evolving system from fixed initial conditions, but this involved simulation procedure can be efficiently approximated by balancing inflow and outflow heat as occurs in steady-state conditions. The steady-state temperature distribution is estimated by setting the heat outtakes of the peripheral wells to a common value roughly consistent with fluid flow and temperature boundary conditions.

It can be seen in Fig 3.4 that the upper left wellbore-to-wellbore flow channel extracts heat at a rate consistent with input flow from the central wellbore reaching ambient temperature \( \sim 200^\circ C \). The remaining outtake wellbores extract heat from the medium at a faster rate than heat is supplied by the central wellbore, hence the outtake wells cool the surrounding flow medium; the lower left well extracts \( \sim 180^\circ C \) water, while the right-hand outtake wells extract water at \( \sim 150^\circ C \).

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**Fig. 3.3** — *Three fluid-flow velocity scenarios for a five-spot wellbore-to-wellbore assemblage as in Fig 3.2. (Upper) Quasi-uniform poroperm medium. (Center) Vf-noise poroperm medium. (Lower) Controlled wellbore-to-wellbore channelized flow paths due to idealized fracture stimulation.*

**Fig. 3.4** — *Temperature field for five-spot advective flow of 100°C water into central wellbore to fixed-flux outtake flow at peripheral wellbores. The section outer boundary is fixed at 200°C. Fracture-connectivity flow channels of various degrees of wellbore-to-wellbore continuity carry heat-depleted central-wellbore input fluid to the peripheral outtake wellbores. Given the fixed outtake flux boundary conditions, if sufficient fluid reaches the outtake wellbore, as in upper left flow, outtake fluid temperature is 200°C. If insufficient fluid reaches the outtake wellbore, as elsewhere, outtake fluid temperatures are below 200°C.*
Figs 3.5-3.6 examine the range of wellbore-to-wellbore flow ‘control’ in more detail. The temperature distribution of Fig 3.5 illustrates the case where one flow path is substantially greater than the other flow paths. The upper-right outtake well extracts heat at \(200^\circ C \sim 500^\circ K\), while the remaining wells, extracting heat at the same rate, again produce low temperature output flow. Fig 3.6 shows that in the absence of wellbore-to-wellbore connectivity with the upper right outtake well, the steady-state outtake flow is \(150^\circ C\) water.

**Fig. 3.5** — An ‘optimized’ version of input-outtake wellbore flow connectivity for the upper-right well-pair extracts \(200^\circ C\) fluid at the specified exist flux, while the same rate of exit flux cools the local heat reservoir below \(200^\circ C\).

The computed Fig 3.5-3.6 temperature distributions begin to quantify the importance of controlled wellbore-to-wellbore flow to the proper functioning of a heat-extraction flow system. We may infer that, in the presence of ordinary and ever-present in situ poroperm heterogeneity, leaving wellbore-to-wellbore flow to chance fluid pathways, as in Fig 3.6, greatly reduces the prospects for efficient heat extraction, as in Fig 3.5.

**Fig. 3.6** — The same temperature field as Fig 3.5 except the upper-right well-pair flow channel has been interrupted.

Figs 3.7-3.8 illustrate the numerical mechanics of attaching a wellbore to an in situ percolation flow channel. The numerical representation of the medium and the wellbore allow a range of numerically stable fracture-connectivity and spatially fluctuating percolation-permeability cases in to be investigated. The large numerical wellbore diameter facilitates numerical realization. A smaller wellbore is numerically feasible but requires attention to detail not important at present. More important than the size of the wellbore is the degree to which the percolation channel represents in situ reality. It is seen in Fig 3.7-3.8 that the present permeability-percolation allows for considerable degree of spatial continuity and discontinuity within the nature framework of in situ fracture-fluctuation systematics.

**Fig. 3.7** — Details of temperature field for 1/f-noise poroperm fracture-connectivity percolation flow heat advection. As with flow processes in general, continuity is decisive. Here fracture connectivity is elevated to achieve a degree of well-pair connectivity, but the flow channel is ‘noisy’. The temperature field is more complex than a diffusion field because of the spatially-fluctuating nature of heat advective flow in 1/f-noise poroperm media.
4 DISCUSSION

4.1 Perspective on wellbore-to-wellbore fracture stimulation

Fig 4.1 synopsizes the in situ fracture-physical framework in which crustal heat extraction has to be engineered. The volume shown is nominally 1km x 250m x 250m in extent at a nominal depth in the range 1-3km of competent rock. Within the volume, grain-scale fracture density and its spatial correlate porosity appear as spatial fluctuations distributed in the erratic manner consistent with well-log fluctuations worldwide -- that is, in situ poroperm spatial heterogeneity is numerically represented by long-range spatially-correlated power-law-scaling ‘1/f-noise’ that clusters on all scale lengths. Within the spatial clustering of fracture-density fluctuations occur the degrees of fracture-connectivity observed as lognormal distributions of permeability. The permeability distribution controls fluid flow as the fluids percolate along fracture-connectivity pathways on all scale lengths. Within this in situ heterogeneous fracture-assemblage, heat extraction proceeds by injecting heat-depleted water into the crustal volume via one wellbore and producing heat-recharged water via another wellbore. Understanding and engineering/controlling wellbore-to-wellbore flow connectivity amidst the in situ poroperm heterogeneity is thus a, perhaps the, key challenge in realizing commercial geothermal heat extraction from generic rock (Leary et al. 2012a,b; Pogacnik et al. 2012; Geiser et al. 2012).

Establishing the von Mises yield criterion in fractured rock is an important aspect of fractured rock’s response to fluid pressurization. The von Mises invariant parameterises the shear rather than the compression/tension stress induced by fluid pressures. Shear is far more likely to damage rock than compression. Fig 4.2 displays the von Mises shear invariant around an isothermal injection well. The areas of high concentration of the shear invariant indicate areas of high principal stress differences, or high shear stress. An appropriate damage model will result in a change in material behavior in the damaged areas with an appropriate change in porosity/permeability of the medium.

Fig. 3.8 — Details of a range of outtake well temperatures in related to well-pair flow connectivity.

Fig. 4.1 — Representation of a 3D 1/f-noise porosity field, into which three wellbores have been drilled. The volume is extracted from a numerical data cube 512 nodes on a side. Various shades of green denote various degrees of grain-scale fracture density and its spatial correlate grain-scale porosity. Well logs run in the displayed wellbore, or any such wellbore through medium, have the 1/f-noise power-law spectrum $S(k) \sim 1/k^1$ characteristic of crustal rock everywhere. Wellbore-to-wellbore fracture-flow connectivity cannot be guaranteed in such media without considerable controlled engineering intervention.
Thermal stresses also play a role in the in situ fracture stimulation process. Figure 4.3 (right) shows the von Mises invariant shear in the case of cold-water injection. The rock section is initially 200 degrees Celsius, with 100-degree water injected at the wellbore. The cold-water thermal front after 5 years is seen in the left figure. Thermally induced, as well as pressurization-induced, shear around an injection well is significant in determining the stress and damage state of in situ rock.

Fig 4.3 – Thermally-induced stress response of poroperm medium flooded by a cold wellbore water. (Left) Thermal breakthrough front after 5 years. (Right) Von Mises shear invariant around the injection site.

The 2D steady-state wellbore-to-wellbore advective heat extraction simulations in Figs 3.2-3.8 and Figs 4.2-4.3 illustrate how to quantify the physical process of heat transfer and fracture stimulation for in situ rock. Such simulations offer scope to begin thinking realistically about field-scale experimentation and observation relevant to controlled fracture-stimulation needed to increase in situ wellbore-to-wellbore flow from a ‘natural fractured’ state to an ‘enhanced fractured’ state. While we can begin, for instance, to quantify how important are ‘rogue’ fracture systems that ‘short-circuit’ more disseminated wellbore-to-wellbore flow channels, Figs 3.5-3.8 may begin to instruct that spatially organized and directed flow channels – essentially some sort of spatially sustained fracture-flow pathway rather than an interrupted fracture-flow pathway – may be necessary to effectively connect one wellbore to another. Figs 4.2-4.3 begin to instruct how wellbore-fluid-induced pressure and thermal mass affect existing fractures and promote new fractures and new-fracture connectivity.

To obtain field-control over the process of in situ fracture-stimulation that leads to spatially sustained fracture connectivity modeled here we may need to employ the new technology of ‘Tomographic Fracture Imaging’ (Geiser et al. 2012) where energy emitted by small-level in situ fracture-slip-events stimulated by fluid pressures and thermal stresses are (i) recorded by via a dense surface array of geophones, and (ii) located by computerized scanning of the data volume for stacked seismic signals corresponding to coherent noise arriving at the surface array from the slip-event location. The fact that in situ slip events and thermally induced stress-fracturing correspond closely to the fracture-connectivity flow structure allows TFI data to monitor the wellbore-to-wellbore fracture stimulation magnitude and geometry.

The computational means to achieve field relevance for time-evolving wellbore-to-wellbore heat-advection in 3D realizations of in situ fracture-heterogeneous poroperm system exist. Yet, given the physical complexity of such systems, numerical simulation, however accurate, cannot make significant progress without being closely coupled to field-scale flow system data. Only by interacting with field data can we establish appropriate boundary conditions, constrain physical parameter, and adequately test model predictions in order to hone modeling assumptions and numerical approximations (Leary & Walter 2008; Geiser et al. 2012). A promising sphere of activity in which to engage the above physical concepts and their numerical implementation with field reality is that of ‘fracking’ hydrocarbon-bearing shale formations. The thousands of wells drilled and the billions of dollars of energy pay recovered represents a huge resource on which to draw to support the necessary science and technology development to achieve geothermal heat energy extraction goals. ‘Fracking’ hydrocarbon-bearing shales appears to involve many of the fracture-physical processes relevant to in situ geothermal heat energy flow systems (Geiser et al. 2009).

To begin to accommodate inherently 3D wellbore-pressurisation geometry relevant to ‘fracking’, Figs 4.4-5 extend the Fig 4.2-4.3 2D cold water injection simulation to the 3D case of a vertical well in a uniform medium. The simulation was performed.
using the FALCON code of the Idaho National Laboratory (Podgoreny et al. 2011). Future 3D computation with FALCON will explore the evolution of damage around a wellbore in a poroperm medium with realistic spatially fluctuating material properties.

Future 3D computation with FALCON will explore the evolution of damage around a wellbore in a poroperm medium with realistic spatially fluctuating material properties.

**Fig 4.4** – 3D simulation of pressure field around a vertical injection well in a 500x500x500m cube at 1700 m depth in a uniform medium.

**Fig 4.5** – Temperature field following 5 years of cold water injection in the Fig 4.4 pressure field.

### 4-2 Perspective on 2D and 3D heat advection modeling

Several aspects of heat advection modeling in ‘realistic’ poroperm media favor present use of 2D sections over 3D volumes.

- For our purposes thermal conductivity is a slow process in which to embed the faster process of heat advection between wellbores. Many aquifers can be considered to be vertically restricted relative to the lateral dimensions hosting wellbore-to-wellbore pathways. Vertical heat flow by thermal conduction is essentially slow by comparison to the well-to-well advection process of modeling interest.

- Numerical modeling of heat advection by fluids percolating along fracture-connectivity pathways requires a large number of discretization nodes often involving rapid changes in permeability geometry. Only finite-element schemes with large-node capacity begin to robustly capture the spatial fluctuations on a useful range of scale lengths (say three to four decades in the range cm to Hm). Adequate node count for fracture-specific fluid and solid mechanics is at best a challenge for 3D flow systems (and at worst may be out of present computational reach) but is essentially routine for the Matlab 2D partial differential equation solver. The Matlab solver allows ready computation for ~1/2 million Delaunay triangles in adaptive meshes affording ~cm-spatial resolution at wellbores, dm resolution of fracture-flow systems and ~m poroperm spatial resolution at domain boundaries. Straightforward access to numerical heat advection simulation for realistic rock property distributions probably more than compensates for the shortcomings of the 2D approximation to in situ reality.

- The accuracy of finite element schemes increases with increasing spatial discretization. However, increasing spatial discretization requires increased computational memory. This effect is further magnified in fully-coupled multi-physics solutions because each node in the domain can have several degrees of freedom associated with it. Often single physics solvers (such as the Matlab PDE solver) are capable of exceptionally fine discretization schemes (especially in 2D) whereas multi-physics solvers are severely limited due to the large number of degrees of freedom at each node (and sometimes the necessary augmentation with additional nodes for certain degrees of freedom – i.e., mixed methods). For fully-coupled Thermo-Hydraulic-Mechanical (THM) computations (e.g., Figs 4.4-4.5), we experience approximately an order of magnitude decrease in the number of nodes that a computational mesh can utilize compared with the Matlab PDE solver.

- Unfamiliarity with the material complexity of rock suggests that 2D simplicity where simplicity is a legitimate advantage rather than a modeling defect. When the issues of material complexity of rock poroperm begin to be more routinely handled at a science level, more complex and complete engineering applications – e.g. wellbore-to-wellbore flow simulation in the crustal volume pictured in Fig 4.1 – can be effectively addressed. At this point, the level of fracture discretization can be relaxed in order to accommodate three dimensions. Flow simulations with Sutra (Voss and Prevost 2008) can be conducted on regular discretization
volumes of order 512x128x128 nodes, allowing/requiring fracture pathways to be defined at 1m resolution for a 1/2x1/8x1/8 km$^3$ model volume with the regular node spacing. Regular node spacing is not, of course, a numerical necessity, but it should be remarked regular node spacing is in the spirit of no-spatial-averaging of material properties inherent in the physics of scale-independent 1/f-noise spatial poroperm heterogeneity.

4.3 Perspective on near-wellbore flow in fractured rock

For the most part near a wellbore, fluid velocity is essentially radial. If the near-wellbore environment is heavily fractured, the effective wellbore diameter can be significantly larger than the drilled wellbore diameter. That is, at the effective radius fluid flow into the wellbore is more axial than radial. Because advected heat is proportional to the fluid velocity, and because wellbore-inflow velocity is inversely proportional to radius, there is a prima facie case that advection temperatures at a larger wellbore are less than advection temperatures at a smaller wellbore for the same axial wellbore flow rate.

Adapting the diffusion-advection heat transport equation $\rho_c \partial_t T = \nabla \cdot (K \nabla T) + \rho_w c_w \left[(v_x+x_{vw})T + (v_y+y_{wv})T \right]$ to near-wellbore radial Darcy flow in a uniform medium gives the time-evolution of advective temperature field $T(x,y)$ as

$$1/D \partial_t T = \partial_x^2 T + (1-A/r) \partial_r T + A T/\rho r^2$$

where the dimensionless factor $A \equiv \kappa P_d/D \mu$ parameterises the degree of advective transport relative to thermal conduction. The expression is derived as follows:

$$Q = \zeta \kappa/\mu P_d r^2 \left(T - x_{vw} T - y_{wv} T \right)$$
$$= \zeta \kappa/\mu P_d r^2 \left(T - x_{vw} \partial_x T - y_{wv} \partial_y T \right)$$
$$= \zeta \kappa/\mu P_d r^2 \left(T - (\chi_x^2 + y^2/r) \partial T/\partial r \right)$$
$$= A \left[ T/\partial r - 1/r \partial T/\partial r \right]$$

$$\nabla^2 T = 1/r \partial_r (r \partial_r T)$$
$$= 1/r \partial_r T + \partial_r^2 T$$

$$\rightarrow 1/D \partial_t T = \partial_r^2 T + (1-A/r) \partial T/\partial r + A T/\rho r^2$$

Parameter $A$ has magnitude of order unity, $A \sim 10^6$s/m$^2$·10$^{-15}$m$^2$·2·10$^{-7}$/Pa-s·$1/2$·10$^4$Pa $\sim$ 1, for water flowing in poroperm media of order milliDarcy median permeability and wellbore pressures of order 1MPa = 10bars. Because $A$ originates in the advective velocity field, it can be either positive or negative depending on the flow direction. Solutions to the single well advection-diffusion equation for $A < 0$ indicate that fluid extracting heat at a fixed rate via a wellbore can cool the surrounding rock at rates that decrease with increasing wellbore radius. A quantitative study may show that rubblisation of a wellbore by thermal fracturing and/or local fracture stimulation can significantly increase the effective borehole radius and hence significantly slow the rate at which a given borehole flow heat extraction regime cools the local rock mass.

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