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GEOTHERMAL SYSTEMS ASSESSMENT—IDENTIFICATION AND MITIGATION OF EGS EXPLORATION RISK

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ABSTRACT

The conventional view in Australia (and many other places) is that achieving optimal temperature is the critical risk in exploration for conductive geothermal resources. This view has often resulted in other areas of risk being overlooked. A Geothermal Systems Assessment (GSA) investigates and ranks four largely independent critical risk areas—heat source, thermal/hydraulic insulation, reservoir potential, and working fluid. These four factors determine the probability of encountering an economic conductive geothermal resource. The GSA approach is synonymous with risk methodologies used in Petroleum Systems Analyses.

Heat source risk can be quantified via a detailed assessment of surface heat flow. Developments in hardware and software tools and methodologies have resulted in a rapid increase in the number of reliable heat flow measurements in Australia, and the quantification of uncertainty in existing measurements.

Thermal insulation can be routinely and rapidly measured on core or cuttings samples using new electronic steady state thermal conductivity meters. Combining these data with precision surface heat flow measurements allows the prediction of temperature distribution at depth in one, two or three dimensions.

Reservoir risk assessment for 'classic' Engineered Geothermal Systems (EGS) requires detailed measurement and modeling of tectonic stresses, fracture densities/orientations and rock strength. Increasing interest in Deeply Buried Sedimentary Aquifer (DBSA) systems for geothermal exploitation in Australia suggests that forward geological modeling techniques such as seismic sequence stratigraphy may reduce reservoir risk.

Water availability and quality risk, whilst largely a developmental issue, can impact on exploration decisions and needs to be considered at an early stage of planning.

INTRODUCTION

The petroleum exploration industry has a well-developed process of assessing exploration risk, which has benefited from 150 years of learning since the Drake Well was drilled in Pennsylvania in 1859. This vast database of knowledge allows probabilistic assessments of a range of key risk parameters based on statistical analyses of historical data. Combined with a firm understanding of the factors that control the accumulation of commercial petroleum fields, 'petroleum system analysis' (Magoon and Dow, 1994) has evolved into a robust tool for targeting exploration towards identifying reservoirs that are larger than the 'minimum economic pool size (MEPS)'. Much of the early work in understanding geological uncertainties in the petroleum sector and applying probabilistic analyses was undertaken by Capen (1992) and Rose (1992), and their methods have become embedded within the operating procedures of most petroleum explorers. Probabilistic risk analyses of the four key geological risks of petroleum systems—source, reservoir, trap and seal—are 'bread and butter' aspects of modern petroleum exploration (Otis and Schneidermann, 1997).

The same cannot be said about exploration for conductive geothermal resources. Although Australia is considered a world leader in 'Hot Rock' geothermal exploration technology, the relative infancy of the sector means that a full understanding of geological risks involved in 'Hot Rock' exploration is yet to be developed. This paper addresses some of the key risk parameters impacting on ‘Hot Rock’ viability and describes a structured framework—or Geothermal Systems Assessment—for addressing and quantifying those risks.

Geothermal Systems Assessment

The perception that ‘Hot Rock’ geothermal exploration is all about finding high temperature rocks is prevalent amongst the geological community. All geothermal exploration is actually about finding a resource capable of delivering economic quantities of thermal power at the surface. Thermal power is related to both the temperature and the deliverability of the geothermal resource. The Geothermal Systems Assessment (GSA) framework, developed and utilized by Hot Dry Rocks Pty Ltd, evaluates the geothermal potential of a conductive system as the product of four key, but largely independent, geological factors—heat source, thermal insulation, reservoir potential, and working fluid (Figure 1).

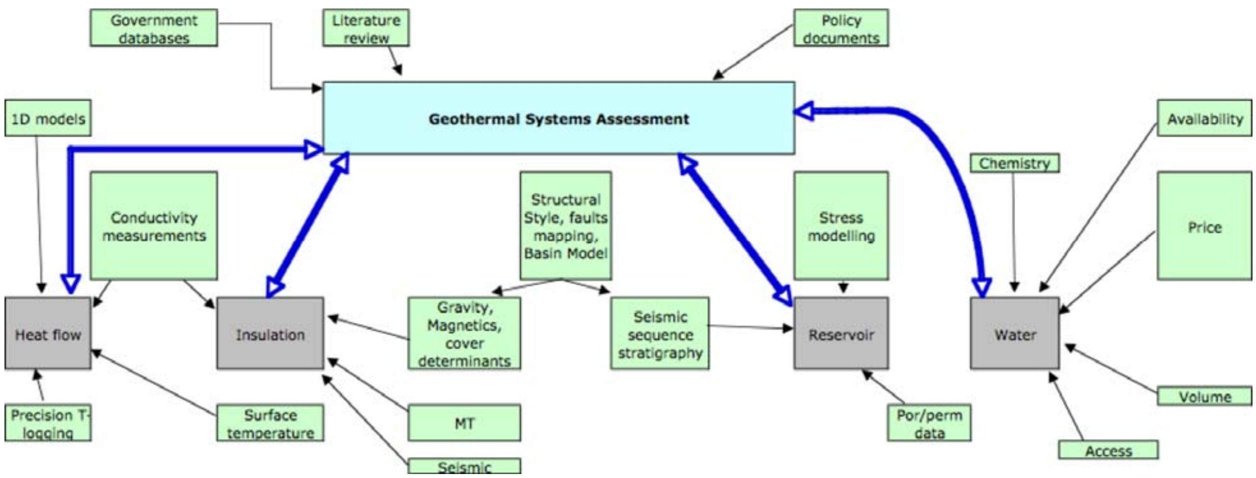

Figure 1. The Geothermal Systems Assessment framework for Hot Rock exploration risk identification and mitigation, showing the key risk areas and some of the data sets that influence risk in each area.

The two main forms of exploration risk are ‘geological risk’ and ‘data risk’ (although ignorance of the underlying processes that govern geothermal systems also introduces unnecessary risk into many exploration programs.) Geological risk is the finite probability that the actual geological setting does not match the assumptions and models relied upon for exploration. It was geological risk that set back the European Union ‘Hot Rock’ project at Soultz-sous-Forêts in France, when convection-influenced low thermal gradients were discovered in granite that was previously assumed to be purely conductive. The Earth is an incredibly complex system so geological risk is inherent in all resource exploration. It can be minimized incrementally by collecting new geological data, but will always be implicit in any exploration program.

Minimizing exploration risk is, therefore, primarily about optimizing the reliability of data pertaining to all four key risk areas (as well as building knowledge about the underlying processes that govern geothermal systems). For example, a confident determination that a geothermal play is *non*-economic is a positive outcome if it stops an expensive failure. Risk is greatly increased if decisions are based on poor or uncertain data.

To quantify the risk inherent in each of the four key parameters, it is necessary to understand the significance of each parameter to the geothermal potential of a region; what are the key risks inherent in each parameter; what existing data may be used to quantify the parameter and the risk; what are the optimal geological, geophysical or geochemical techniques for reducing the risk. We will examine these different aspects for each key parameter.

HEAT FLOW

Significance

Shallow heat flow data serve two purposes. They give a direct indication of the existence and magnitude of anomalous heat sources within the crust, and they provide a firm basis from which to predict the increase in temperature with depth.

Heat flow (**Q** watts per square meter; W/m^2) is a power density vector, the product of rock thermal conductivity (λ watts per meter per kelvin; W/mK) and the thermal gradient vector (**G** Kelvin per meter; K/m). The flow of energy is in the opposite direction to the thermal gradient, so the equation is written:

Equation 1 $\boldsymbol{Q} = -\lambda \times \boldsymbol{G}$

Temperature is a key parameter for a Hot Rock geothermal system, but temperature at depth cannot be measured without direct access to the rocks via drilling. Conductive 'heat flow', however, can be measured at the surface, or at least in relatively shallow bores. In a purely conductive thermal setting, heat flow remains effectively constant with depth (Figure 2; although there may be minor variation due to heat refraction or generation within the rock body), as governed by the First Law of Thermodynamics ('conservation of energy'). Thermal gradient, on the other hand, varies according to the conductive properties of the rocks. Shallow heat flow measurements, therefore, can be extrapolated to depth with much greater confidence than shallow 'thermal gradient' measurements.

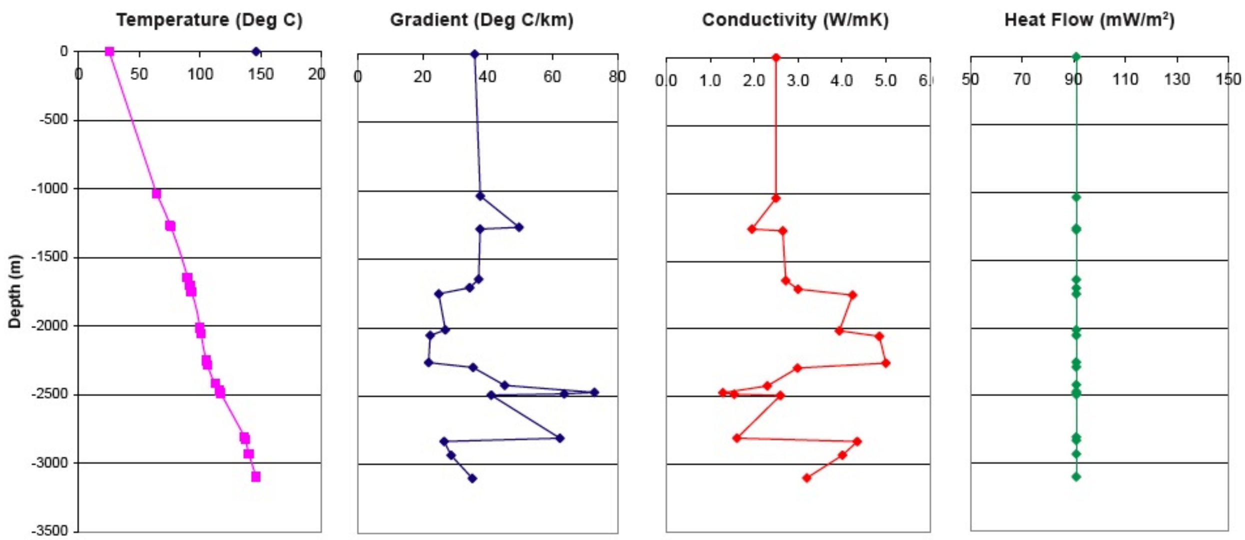

Figure 2. The relationship between temperature, geothermal gradient, rock thermal conductivity and heat flow. Geothermal gradient varies inversely with thermal conductivity.

The more confident we are of heat flow data, the more confident we can be about the 'Hot Rock' geothermal potential of a region. High heat flow is a clear indictor of an active buried heat source. However, high heat flow does not always translate into high temperatures at depth, and low heat flow does not always mean low temperatures at depth. Measuring heat flow and processing the results to predict temperature at depth are specialist skills, poorly understood by most people.

Main Risks

The main geological risk associated with heat flow is that the assumption of purely conductive heat transfer does not hold true (as was the case at Soultz-sous-Forêts.) This may be due to convection cells developing at depth, or lateral flow of groundwater through the system. Any evidence of such phenomena could invalidate the assumption of purely conductive heat transport. It is generally the case that high thermal gradients cannot be maintained in permeable media because convection cells spontaneously develop and lower the gradient.

The main data risk is that heat flow data are poor or unreliable. A reliable heat flow measurement requires reliable thermal gradient *and* thermal conductivity data over a finite depth interval in a borehole (see Equation 1). Many of the issues associated with temperature data collection, modeling and interpretation have been well defined in both the petroleum sector (Deming, 1994) and the geothermal sector (Wisian *et al*, 1996). Despite this, deriving a reliable estimate of rock temperature from down-hole measurements disturbed by the circulation of drilling fluid remains problematic.

In spite of the issues surrounding temperature measurement, thermal conductivity typically contributes a disproportionate amount of the error and uncertainty in a heat flow measurement because measurements are prone to random and systematic errors if equipment is not carefully designed, calibrated and maintained. Accurate and reliable measurements of thermal conductivity require specialist equipment and experienced personnel.

Even the most reliable thermal conductivity measurements, however, are made on discrete rock samples. The thermal properties of large rock volumes must be categorized through measurements on small samples. The greater the number of independent, accurate conductivity determinations over an interval of known thermal gradient, the lower the uncertainty in the derived heat flow estimate, and associated exploration risk.

Existing Data

Exploration company personnel initiate the vast majority of geothermal projects in Australia after an appraisal of existing temperature data. In the Australian context, these data are almost always derived from existing petroleum or water wells, and were often measured within hours of the cessation of drilling and mud circulation. The accuracy of temperatures measured in these circumstances improves with time-since-drilling, but several times the drilling time is usually required for substantial thermal re-equilibration (Bullard, 1947). A ‘bottom hole temperature’ (BHT) is almost always lower than the true formation temperature. Beardsmore and Cull (2001) estimate that raw well temperature data can understate the true formation temperature by 10-20°C.

Raw BHT data can be corrected to account for the non-equilibrium state through various statistical methods when sufficient circulation and drilling time data are available. The most commonly used method is the Horner Plot (Horner, 1951; Lachenbruch and Brewer, 1959), but there are a large number of other published methods (Hermanrud *et al.*, 1990).

The influence of uncorrected temperature data on assessments of heat flow can be profound. Based on uncorrected temperature data, the example well shown in Figure 3 has a thermal gradient of 0.029 K/m (or 29°C/km), whereas the corrected temperatures (using a Horner Plot) suggest the average gradient is probably closer to 36°C/km. The uncorrected gradient may suggest a geothermal resource window (>150°C) at a substantially greater depth than is really the case. It is possible that many geothermal prospects in Australia, and internationally, may have been inappropriately assessed, or even overlooked entirely, because of a reliance on existing, uncorrected well temperature data.

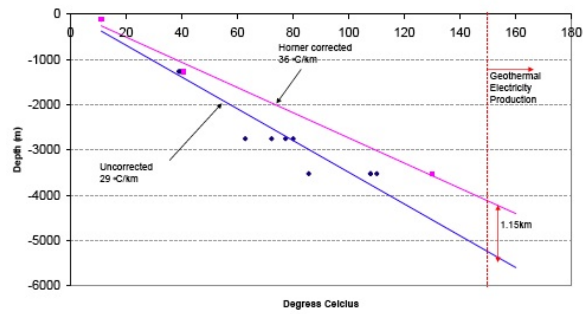

Figure 3. Average geothermal gradient (blue) indicated by uncorrected BHT values for an arbitrary well. The Horner corrected temperature suggests a higher average geothermal gradient (pink).

Existing thermal conductivity data are few and far between. In Australia, there have historically been very few laboratories with the capacity to measure thermal conductivity, and very little incentive to do so. The public database of measurements is therefore small and of questionable reliability. As thermal conductivity is best measured on samples that come from the actual borehole under investigation, new measurements are almost always required for a reliable heat flow estimate.

New Data

Existing temperature data are often inadequate for characterizing heat flow, even in the deepest of wells. However, precise measurement of heat flow is possible in relatively shallow wells if ‘fit for purpose’ precision temperature logs and thermal conductivity data are specifically collected.

A precision temperature log generally requires a thermistor (or similar sensitive temperature sensor) to descend a well in a controlled manner so that changes in electrical resistance across the thermistor can be monitored and recorded at regular intervals. A properly calibrated thermistor can measure temperature to a precision of 0.001°C, or thermal gradient at the meter scale to a precision of 1°C/km.

A precision temperature log is a powerful tool for understanding the true temperature profile in a well, and its relationship to lithology and thermal conductivity. For example, the precision temperature log for the Loy Yang bore in Victoria (southeast Australia) illustrates the precision and value of the process (Figure 4). The 2 m sliding average temperature gradient reveals significant variation (between 30 and 200°C/km). This indicates lithologies with highly variable thermal conductivities (in this case interbedded sands, shales and coal.)

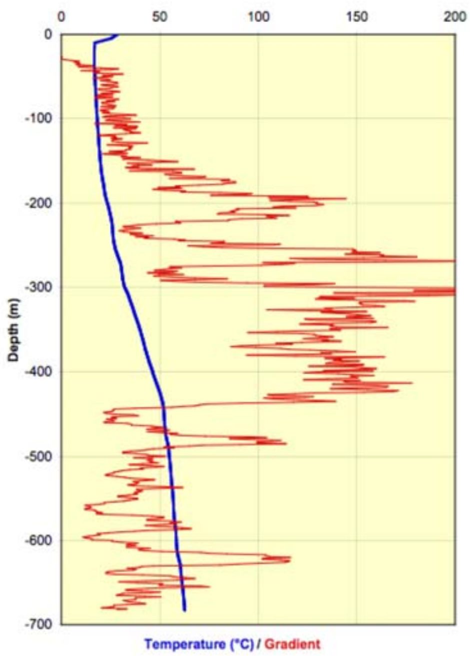

Figure 4. Example of a precision temperature (blue) and 2 m sliding average thermal gradient (red; °C/km) log from Loy Yang bore, Victoria.

The thermal conductivity structure of a borehole is best characterized by measurement of core samples collected at regular intervals of several meters down the hole. The most reliable thermal conductivity measurements (and hence heat flow estimates) are obtained from measurements on solid core or rock samples in their *in situ* state of water saturation. A number of different methods exist for measuring thermal conductivity of solid samples, but the steady state divided bar (first described by Benfield, 1939) is arguably the most precise and reliable (Figure 5).

Figure 5. A modern electronically controlled steady state divided bar for measuring the thermal conductivity of solid samples.

THERMAL RESISTANCE

Significance

Thermal resistance (m^2K/W; commonly referred to as 'insulation') is the cumulative sum of overburden thickness (m) divided by thermal conductivity (W/mK). In a conductive setting, temperature increases linearly with thermal resistance, proportional to the heat flow. In general terms, the greater the thermal resistance overlying a geothermal resource, the greater the temperature of the resource for a given heat flow. A conductive geothermal system requires adequate insulation, usually provided by sedimentary formations deposited in a basin setting, to constrain or 'trap' heat.

It is common practice to qualitatively assess thermal resistance only in terms of the thickness of cover sequence (e.g. "An EGS play needs a granite buried under 3–5 km of sediment."), but this approach ignores the equal importance of thermal conductivity, related to the lithological characteristics of the sequence. There is, in fact, no minimum physical thickness of cover necessary for adequate thermal insulation. Even relatively thin cover sequences can provide high thermal resistance if the thermal conductivities of the constituent layers are low (e.g. coal-rich).

In the Cooper Basin, which can be considered a benchmark for conductive geothermal plays in other parts of Australia and the world, the total thermal resistance of 3,000 m of sediment is typically on the order of 1,600 m^2K/W (Beardsmore, 2005). Many Australian Mesozoic basins may provide thermal resistance comparable to the Cooper Basin because of the prevalence of thick coal measures and mudstone (low thermal conductivity). Two kilometers of a typical shale and 300 m of coal, for example, can provide 1,600 m^2K/W of thermal resistance, equivalent to the Cooper Basin.

Main Risks

The main geological risk associated with thermal resistance lies in accurately predicting or characterizing the thermal conductivity of deeper, typically unsampled, units. Older basins, and areas that have been subject to significant structural deformation, may provide less thermal resistance because coal and mudstone are less prevalent, the degree of compaction is greater, and cleavage and fracturing may enhance vertical thermal conductivity by increasing anisotropy. Even where coal is present, small variations in the proportion of coal in the sequence can have a significant impact on the total thermal resistance.

Predicted deep geological formations may be known and characterized only from distal boreholes or outcrop. In those cases there is geological risk that the formations vary in lithology (and thermal properties) between the 'type' location and the *in situ* location under consideration.

Data risks associated with thermal resistance are closely related to heat flow data risks because of the dependence of both factors on measurements of rock thermal conductivity. Thermal conductivity is the dominant source of error and uncertainty in thermal resistance estimates because measurements are made on discrete rock samples, and are prone to random and systematic errors. The thermal properties of large rock volumes must be categorized through measurements on small samples that are typically collected at a distal location.

Existing Data

Estimates of thermal resistance rely on estimates of thickness and thermal conductivity of the (usually) sedimentary sequences. Thickness is usually constrained using datasets such as seismic reflection; magnetotellurics; interpolations of data from previous petroleum wells; and/or other potential field (grav/mag) inversions. Initial estimates of thermal conductivity are usually derived from previously published measurements on core; analogy with similar local lithologies; global average values for similar lithologies.

New Data

If thermal resistance is identified as a significant exploration risk, then the exploration program may warrant collecting specific new data to address this risk. Reducing the uncertainty in thermal resistance requires constraining the thickness and thermal conductivity of all lithological units to the target depth. This is optimized by delineating the three dimensional geological structure of the geothermal play as best as possible.

A 3D seismic survey optimized for the geological conditions and target depth gives the most valuable data about the 3D geological structure, but typically at a high cost. Cheaper options that may still provide valuable data include magnetotelluric soundings; 2D seismic transects; passive seismic tomography.

Existing core samples may be located for thermal conductivity measurements from previous drilling activities. Alternatively, in some circumstances, relevant geological formations may outcrop in the region, allowing fresh hand specimens to be collected and measured. Geological risk remains, however, that these specimens to not adequately categorize the formation at the depth and location under consideration.

Ultimately, there is no substitute for drilling and coring to determine the thermal properties and thicknesses of formations that make up the thermal insulation.

RESERVOIR POTENTIAL

Significance

High temperature rocks provide an energy source, but this energy can only be exploited if it can be brought to the surface. In order to do this, a working fluid (typically water) must be brought into extended physical contact with the hot rocks within a geothermal reservoir. Engineered Geothermal Systems (EGS) within artificially stimulated granitic reservoirs are only one end-member of conductive geothermal systems. There is significant potential for EGS within suitably fractured sedimentary host rocks, and conductive geothermal systems in sedimentary rocks with naturally occurring primary porosity and permeability - Deeply Buried Sedimentary Aquifer (DBSA) systems.

An assessment of the conductive geothermal potential of a region requires careful consideration of the potential for natural or artificial reservoirs. Different temperature resources require different deliverabilities to make them economic. Therefore, reservoir potential is a critical consideration when assessing the most attractive conductive geothermal target level for a project.

For EGS developments, hydraulic stimulation aims to enhance the permeability of a Hot Rock by shear reactivation of existing fractures (Kohl and Megal, 2005). Hydraulic stimulation projects must be designed with reference to the prevailing stress regime (direction and magnitude) to ensure that an open fracture network is achieved, but not to the extent of causing a 'short circuit' in the reservoir.

Main Risks

One of the principal risks in assessing a conductive geothermal system is the uncertainty in identifying the optimum target for reservoir development. The thermal power achievable at the surface is a function of temperature and deliverability; the cost of a development is a function of the reservoir depth; identifying the optimum target for economic development is, therefore, a complex function of predicted temperature, predicted deliverability and depth. A careful assessment may reveal that a shallower, cooler resource is a more viable target (economically speaking) than a deeper, hotter resource (e.g. Sanyal *et al*., 2007).

Another principal risk associated with EGS reservoirs is that there are presently only a very small number of examples of effective reservoirs artificially stimulated by hydraulic stimulation. There is, therefore, a poor statistical basis for predicting the outcome of a specific hydraulic stimulation program.

Geological risk is greater in connection to reservoir potential than for temperature. A potential EGS host rock must have an existing fracture network at an orientation to the prevailing stress field that makes it amenable to hydraulic enhancement. Success or failure of a hydraulic stimulation program rests to some degree on the fracture density, their orientation and extent. Predicting the extent and orientation of fracture networks prior to drilling, and estimating how amenable those fractures are to hydraulic stimulation, poses the greatest risk for any EGS project.

Reservoir risks for DBSA targets revolve around the fact that porosity and permeability generally decrease with depth due to compaction. Permeability and porosity can also be severely affected by diagenesis, and facies changes can lead to large lateral variations in permeability within the same reservoir formation. As with potential EGS reservoirs, predicting the permeability of DBSA reservoirs prior to drilling typically poses a much higher risk than the temperature prediction.

Data risks for reservoir potential also lie in the number and quality of constraints on regional and local stress fields; quality and reliability of any existing porosity/permeability data from DBSA target formations; and quality of seismic data and interpretations (e.g. identification of faults and formation boundaries.)

Existing Data

There are a number of cost-effective methodologies available to mitigate stress risks, and some make use of existing datasets. For example, information about the regional stress field may be gleaned from earthquake mechanism fault-plane solutions (although these are typically non-unique solutions.) Also, in some locations, boreholes may have been previously cored and logged with relevant wireline tools. In such case, structural analyses of fractures in core specimens, in combination with bore hole acoustic televiewer (BHTV) and/or acoustic emission (AE) logs (Soma *et al*., 2002) can reveal the orientation of fractures that are most likely to provide permeable pathways.

Shallow wells located in areas not presently subject to significant tectonism may provide viable data for these sorts of assessments. Numerical modeling of these data, in conjunction with structural mapping, can significantly mitigate risk when predicting the response of target formations to hydraulic stimulation, although all data need to be considered within the framework of continental scale tectonic stress fields delineated by regional studies such as that published by Hillis and Reynolds (2000).

For DBSA plays, seismic sequence stratigraphy offers potential as a geothermal exploration tool where existing reflection seismic data are available and of sufficient quality. The distribution of permeable sand units can be forward modeled through depositional systems tract mapping constrained by palynological data (Emery and Meyers, 1996). Deep basin sequences may not have permeable sands deposited in high-energy environments near basin margins (where petroleum exploration is often focused), but this can only be discerned through detailed seismic sequence stratigraphic analysis. Seismic sequence stratigraphy can also provide insight into potential areas of increased thermal resistance by predicting sites where shale or coal may have been deposited.

New Data

Minimizing EGS reservoir development risk involves reducing uncertainty in local stress conditions and reservoir rock mechanical properties. Minimizing DBSA reservoir risk involves maximizing the accuracy of permeability prediction in deep formations. Ultimately, these risks will remain substantial until the potential reservoir sequence has been drilled and tested. However, even incremental decreases in risk at an early stage of development may provide considerable value for money if specific geographic locations or depth intervals are identified as lower risk.

A 3D reflection seismic survey provides arguably the most valuable new data that might be collected over a conductive geothermal play. Although expensive, 3D seismic data can be processed to reveal not only the accurate structural geometry of a play, but also fracture networks (e.g. Neves and Triebwasser, 2006), zones of varying porosity in sediments (e.g. Boult and Donley, 2001), seismic stratigraphic sequences (e.g. Hart, Sarzalejo and McCullagh, 2007), and other parameters of relevance to geothermal developments.

While not giving the same level of information as a 3D survey, one or two carefully targeted 2D seismic lines can still provide valuable information at a fraction of the cost of a 3D survey. Similarly, magnetotelluric (MT) soundings can be used in a conductive setting to identify naturally permeable, conductive, wet layers. This is different to the conductive clay 'cap' that is often the target of MT surveys in conventional geothermal projects.

WORKING FLUID

Significance

A working fluid is essential for the extraction of geothermal energy from the buried Hot Rocks to the surface. While some groups are investigating fluids such as supercritical CO_2 (e.g. Pruess and Azaroual, 2006) for their potential as working fluids, water is presently the only practical option. Water has a high thermal capacity to transport heat rapidly and often occurs naturally in the resource formation (as liquid or steam). No project can proceed beyond the pre-feasibility stage unless all the water requirements for the project can be met.

Main Risks

In conductive geothermal systems, the risks that concern water revolve around its availability, accessibility, price, and chemistry. These risks are often not considered until late in the pre-feasibility stage of the project life, even though they are as important (if not more so!) to the overall success of the project as temperature and deliverability.

The geological risk associated with water for EGS projects primarily relates to the potential for underground loss of fluid into the surrounding formation via 'leak-off.' If there is a significantly lower volume of water extracted from an EGS or DBSA system compared to the volume injected (i.e. too much water is lost into the surrounding formations so a significant amount of 'make-up' water is required), then the project will quickly become sub-economic. This was one of the lessons from the Ogachi Hot Dry Rock Project in Japan (Kaieda *et al*., 2005), for example.

EGS and DBSA projects in Australia, and other arid/semi-arid regions, are also likely to encounter risks associated with water supply and/or disposal. Access to ground or surface water poses a number of political and regulatory risks, especially in a time of growing water consciousness amongst the general community. There is inevitably competition for limited water resources and individual projects may have to compete against alternative users for access rights. Consider, for example, a hypothetical EGS project consisting of six wells each producing hot water at 100 liters per second. If all the water is reinjected with 1% loss per cycle, the project has to make up six liters per second, or half a mega-liter per day, throughout its entire life. While that may not necessarily be a problem, it does imply that a permanent supply of water will be required for such an EGS project, and that water supply security is an additional risk to be considered. This may be especially important in jurisdictions where water rights are renewable and alternative users may bid for access to the same resource in the future.

Unlike conventional (volcanic) geothermal systems, EGS systems in Australia and elsewhere should be relatively unaffected by water chemistry problems such as scaling, corrosion and noxious by-products if operators control the quality of water introduced into the system. Although there will inevitably be chemical dissolution, transport and precipitation as the enthalpy of the working fluid changes throughout the production cycle, numerous treatment strategies have been developed to counter such problems in the production phase (e.g. Klein, 2007). Obtaining rights to reinject spent geothermal fluid, however, may still require that certain environmental objectives be met.

Existing Data

Water access and availability risks increase in more arid environments, but do not necessarily pose an insurmountable obstacle. In some cases, groundwater may provide sufficient water volumes, but meteoric sources can also be considered. Procedures for securing access to water resources are clearly defined in many jurisdictions, as are the limits on rates of use and the requirements for reinjection. Risks concerning access to, availability of, and disposal of water are therefore generally addressed using existing databases and regulatory instruments.

The volumes of water that may be required during the life of a project can be estimated at little expense and factored into economic models. For an EGS project, these include estimates of water required during the drilling, hydraulic stimulation, circulation testing, and production phases. For a DBSA project, the geothermal fluid will likely be in situ, but 'make-up' water may be needed to maintain aquifer pressure over the lifetime of the project. This is difficult to estimate at the pre-feasibility stage.

Addressing the geological risk of water loss for both EGS and DBSA systems is more problematic during the early stages of development. In many ways this risk is intimately tied to reservoir risk, with the risk here being that the reservoir will be *too* permeable, or that the natural or engineered reservoir volume will not be laterally or vertically constrained. It is unlikely that there will be any data on reservoir performance prior to drilling and flow circulation testing.

New Data

New data related to water risks are unlikely to be obtained for a project until the target reservoir has been drilled, engineered and flow tested. Only at that time will the hydraulic properties be known with anywhere near the certainty required for precise reservoir modeling and economic projections. Also only at that time can *in situ* fluids be sampled for chemical analyses to predict possible scaling, corrosion or noxious by-product issues that will need to be addressed.

DISCUSSION

The qualitative identification of the key risk factors in exploration for conductive geothermal resources is the first step in developing quantitative risk models. By assigning uncertainty distributions to the key risk parameters of heat flow, thermal resistance, reservoir deliverability and water quality/availability, economic viability may be quantified in a probabilistic fashion at an early stage in an exploration program.

A probability distribution for resource temperature can be estimated based on the stated precision of heat flow estimates and the estimated precision of thermal resistance profiles. The predicted temperature distribution will typically be normal about a mean value with a standard deviation dependent primarily on the precision of thermal conductivity data.

A probabilistic prediction of reservoir deliverability from a conductive system is much harder to constrain because of the very small number of projects so far developed. However, if we assume a log-normal distribution for deliverability, then we can start to assign probability values to different levels of deliverability.

Multiplying the deliverability by the temperature of the resource gives a reasonable first-pass estimate of the potential achievable thermal power of a resource that has yet to be drilled. Monte-Carlo simulations across the range of probable values of temperature and deliverability result in a probabilistic range of power output (Figure 6).

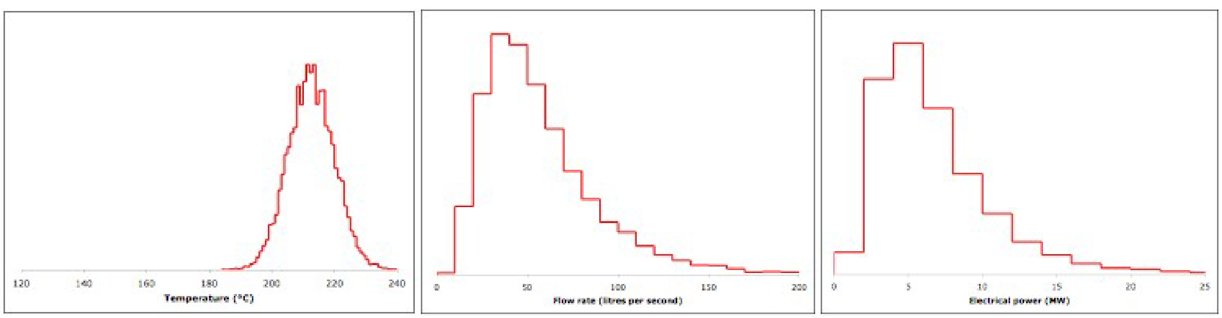

Figure 6. (left) An example of the probabilistic temperature distribution predicted for a 'Hot Rock' conductive geothermal play at 5,000 m depth; (middle) A log-normal probabilistic deliverability distribution for the same geothermal play; (right) A Monte-Carlo generated probabilistic power generation distribution based on these temperature and deliverability distributions.

CONCLUSIONS

The geothermal potential of a region is best investigated using a risk-based Geothermal Systems Assessment. Geothermal prospectivity is controlled by four related geological factors—heat flow (conductive and advective), thermal resistance (insulation), reservoir characteristics (including prevailing stress regime) and working fluid (water or steam). Identifying and addressing issues in these factors earlier in the evaluation process can potentially lower risks, and hence costs.

Historical approaches to assessing temperature risk have lacked standardization. Inaccurate assessments may be derived from uncorrected wireline temperatures, particularly in the absence of measured bulk rock thermal conductivity data. Reliance on such data may result in significant under or over-estimations of the true thermal regime within a region.

Geological reservoir risks will remain high for conductive geothermal systems until a sufficient number of successful projects are completed to allow statistical predictions of critical underground flow parameters. Until such time, even incremental decreases in uncertainty through careful analyses of existing datasets can have profound effects on the development costs of projects.

Risks related to water supply are best addressed early in a project through established regulatory channels. Full life-cycle water requirements should likewise be estimated at an early stage of development, and strategies put in place to ensure that water requirements can be physically and financially met at each stage.

The conventional paradigm of targeting high resource temperatures in conductive geothermal systems has been driven by past global experiences in volcanic or convective geothermal systems where self-flowing dry or wet steam dominated systems prevail. However, higher temperatures do not necessarily optimise Engineered Geothermal Systems (EGS) or Deeply Buried Sedimentary Aquifer (DBSA) geothermal systems. Instead, the best development target should be assessed in light of risk-based assessments of temperature, reservoir potential and drilling costs. There may be engineering and economic advantages to targeting lower enthalpy (150–200°C) geothermal systems where single-phase (liquid) production can effectively produce electricity.

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