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Engineered Geothermal Systems in the Australian Context - Resource Definition in Conductive Thermal Settings

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ABSTRACT

Conventional geothermal settings are convective and advective in nature, related to heat transfer by the physical motion of fluids and steam within volcanic and shallow magmatic environments. Early EGS development in Europe has also encountered convective conditions. However, Australia is largely a conductive geothermal setting. The embryonic Australian geothermal sector has looked towards the established European and US geothermal sectors for learnings, but little attention has been paid to the distinctly different nature of heat transfer (convection versus conduction) in these settings and what this may mean for resource estimation.

The *Geothermal Reporting Code* governs the declaration of Geothermal Resource estimates by public companies in Australia. Whilst the *Code* allows flexibility in the methods of estimation for an Inferred Geothermal Resource, the use of dynamic reservoir modeling methods at the resource estimation stage, as commonly applied in European and US geothermal provinces, is problematic where achievable fluid transmission rates are totally untested or, at best, poorly constrained. The conductive transfer of heat from the surrounding rocks is often of secondary importance in convective systems. In contrast, the use of stored heat methods to estimate an Inferred Resource should appropriately account for heat available in the geothermal systems within the Australian context.

This paper compiles the outcomes of recent 3D numerical conductive heat flow modeling exercises undertaken for various commercial projects in Australia and presents a statistical analysis of Inferred Resource distributions for EGS and other projects. These projects tend to have large stored heat values (in-place petajoules) within a normal distribution. A sensitivity analysis of the variables used in the 3D models demonstrates the unique nature of conductive geothermal resources.

1. INTRODUCTION

Geothermal reservoirs are characterized by a number of physical properties including permeability, transmissivity, porosity, thermal and hydraulic conductivity, density and heat capacity. In a single-phase system these properties are related to reservoir pressure and temperature (Bodvarsson and Witherspoon, 1989). In conventional geothermal settings with long production histories, these properties and conditions are typically well established and allow for the calculation of storativity, or in-place heat within the reservoir, using either simple volumetric methods (eg. Lovekin, 2004) or more complex numerical modeling methods (eg. Ketilsson *et al*., 2008). Geothermal potential is also commonly assessed using permeability–volume methods based on flow rates (eg. Sanyal *et al*., 2007).

However, regardless of the approach, all conventional methods for estimating geothermal resources require some knowledge of the reservoir properties and conditions. This is problematic in the Australian context, where very few potential geothermal reservoirs, including Hot Sedimentary Aquifer (HSA) and Engineered Geothermal System (EGS) plays, have been intersected by wells. The principally conductive geothermal setting in Australia means that drilling is typically required to greater depths in order to reach a target resource temperature, in comparison to conventional geothermal settings. Hence, conventional approaches to resource estimation are prohibitively costly for early-stage geothermal exploration in Australia.

As an alternative, Australia can utilize a large network of shallow water bores, minerals exploration holes and deeper petroleum wells. From these, well-constrained surface heat flow values can be calculated using rock thermal conductivity measurement and either existing temperature data or specifically acquired precision temperature logs (Cooper and Beardsmore, 2008). The distribution of surface heat flow is a function of the temperature distribution and rock properties within the underlying geological section. Numerical methods can be used to ‘invert’ the heat flow data to determine the simplest distribution of temperature in the crust to explain the observations.

The inverse modeling approach described above allows the estimation of stored heat in EGS or HSA reservoirs where rock properties are measured or reasonably constrained. This paper details the approach and sensitivities of the heat flow mapping and modeling method and its application to *in situ* resource estimation in conductive settings.

2. APPROACHES FOR ESTIMATING GEOTHERMAL RESOURCES

Although there are multiple methods for estimating geothermal resource, there are generally two broad approaches that encompass most methodologies—the ‘stored heat’ approach and the ‘dynamic reservoir’ approach. The *Geothermal Reporting Code* (the *Code*), which governs the reporting of Geothermal Resources by public companies in Australia (e.g. Lawless *et al*., 2010), does not prescribe any particular method, but requires an explanation of the approach utilized.

2.1. Stored Heat approach

The stored heat method estimates the *in situ* heat energy (petajoules, megawatt-years or equivalent unit) within a bulk volume of rock such as an EGS or HSA reservoir. The recoverability of this energy is not necessarily addressed by the stored heat method, although Williams (2007) describes various methods of estimating recovery factor.

The stored heat approach uses a minimum cut-off temperature and a base temperature to truncate the resource.

Recoverability via pumping can be estimated using a dynamic reservoir approach as a follow-up to the stored heat method, however the *Code* discourages the reporting of recoverable energy for Inferred Geothermal Resources (the category for the lowest level of confidence). Australian geothermal energy companies have therefore been reporting seemingly large inferred energy values (hundreds of thousands of petajoules) – but these values refer to total *in situ* energy and not recoverable energy.

2.1.1. 3D Conductive Heat Flow Modeling

Stored heat resource estimates can be made either simply and manually, using volumetric approximations and geothermal gradients, or by utilizing all available data within a thermodynamic conceptual framework. The latter takes the form of 3D conductive heat flow modeling. This paper broadly describes the outcomes of such an approach developed specifically for the Australian geothermal sector.

High quality surface heat flow values are first required, derived from reliable borehole temperature data and thermal conductivity values. Ideally, each of these parameters is specifically measured for the purpose of heat flow calculation. The derived surface heat flow distribution is then used, along with mean surface temperature distribution, as a boundary condition on the surface of a 3D numerical 'earth model'. The earth model is populated with physical rock properties (such as thermal conductivity, internal heat generation, density and specific heat) reflecting the 3D geological setting inferred from drilling data, geophysics (often seismic grids), or other means. The 3D conductive heat flow equation is then solved throughout the model space using a numerical 'relaxation' algorithm, as described by Beardsmore and Cull (2001).

Unlike convention heat flow and temperature modeling methods, the algorithm described above does not require user estimates of basal boundary conditions, as the principle constraints are known surface measurements. The software progresses through an iterative process to converge on an optimal basal thermal boundary condition. The iterative process stops when the thermally equilibrated 3D temperature distribution dictated by the base and surface boundary conditions produces an optimal 'fit' (ie minimum RMS misfit) to the observed surface heat flow.

The numerical algorithm accommodates the temperature dependence of thermal conductivity, anisotropic thermal conductivity, and internal heat generation. The software can also readily incorporate permeability functions to predict fluid advection or convection, although this has not yet proven necessary in the Australian context.

2.2. Dynamic Modeling approach

Dynamic reservoir modeling approaches to geothermal resource calculation are similar to methodologies used for petroleum resource calculation. The reservoir is treated as a permeable medium and, so long as temperature and pressure fields can be determined (often estimated from existing petroleum well data), it is possible to model the power output per well (MW_e) through time.

The dynamic modeling approach can incorporate dual-phase fluids, and coupled fluid, mass and heat transport, using products such as TOUGH2 (eg. Ketlisson *et al*., 2008). There remain, however, significant practical limitations with respect to discontinuum modeling of fractured reservoirs. Alternatively reservoir volumetrics can be incorporated in a parametric study to estimate recoverable geothermal resources based on estimated pump rates (eg. Sanyal *et al*., 2007).

Regardless of the method, all dynamic reservoir modeling approaches share the common need for detailed knowledge of reservoir conditions (particularly the temperature field and permeability) before a realistic estimate of geothermal resource can be made. The *Code* recognizes that many parts of Australia have limited data specific to geothermal systems, hence the stored heat method is encouraged at the Inferred Resource stage. Conversely the reporting of a resource in megawatts (MWe) assumes that the reported value is recoverable at surface. Generally, this could only be assumed with some confidence at a more advanced level of resource estimation, like a Measured Resource.

3. APPLICATION OF 3D CONDUCTIVE HEAT FLOW MODELING TO GEOTHERMAL RESOURCE ESTIMATION IN AUSTRALIA

The difference between conventional (mainly volcanic) geothermal systems and unconventional geothermal systems (as in the Australian context) is the way in which heat is transferred. Advective and convective heat transfer largely drives conventional geothermal systems, with energy being transported into the reservoir laterally or vertically (e.g. via volcanic conduits) and circulated within the reservoir. However in Australia, heat is principally transported by vertical conduction from the underlying crustal rocks and mantle (Beardsmore and Cull, 2001). Consequently, whilst there are few reliable and deep temperature data available in Australia to define geothermal systems, it is possible to predict temperature at depth using heat conduction theory and surface heat flow measurements. There are a large number of shallow bores that are suitable for precision temperature logging and the modeling of surface heat flow. Consequently, 3D conductive heat flow modeling is ideally suited to the Australian geothermal context for stored heat estimation.

We developed and tested the modeling methodology described in Section 2.1.1 in collaboration with Torrens Energy Ltd in 2008, using exploration data from Torrens' Parachilna EGS prospect in South Australia. The software has since been further refined and applied to a wide variety of geothermal plays. At the time of writing (May 2009), the methodology has been applied to over 20 individual geothermal plays (both EGS and HSA) across Australia. Fifteen of these have formed the basis for Geothermal Resource Statements in compliance with the *Code* (Fig. 1).

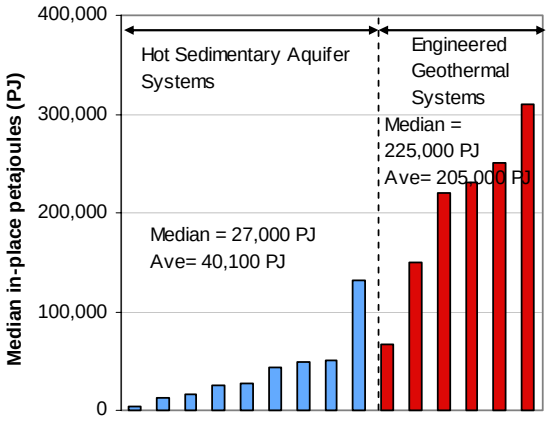

Figure 1: Distribution of inferred stored heat (PJ) as estimated by 3D conductive heat flow modeling of 15 geothermal plays across Australia.

Whilst Figure 1 appears to suggest that EGS plays are inherently more attractive as they tend to have larger amounts of *in situ* heat, this distribution is partly influenced by the generally higher target temperatures for EGS plays. However, reservoir area (and hence volume) is also a dominant variable and this is illustrated in Figure 2.

4. SENSITIVITES OF 3D CONDUCTIVE HEAT FLOW RESOURCE MODELING

Although lacking the reservoir detail required for dynamic modeling, the conductive heat flow method comprises a rigorous methodology to estimate *in situ* stored heat. Like all numerical modeling methods, the outcomes of 3D heat flow modeling is sensitive to various inputs, many of which are prospect specific and inter-related. Hence resources cannot be accurately estimated by simple heat flow or temperature–rock volume ratio comparisons.

4.1. Heat flow and temperature

If the geology in a regional model is considered to be relatively consistent, then the variable parameter of heat flow may be considered to approximate temperature. This assumes that rock properties such as thermal conductivity are uniform throughout the 3D model and that the thickness and depth of units within the model are also relatively constant. In reality this never occurs, hence it is impossible to make regional estimates of stored heat based on heat flow distribution alone.

Figure 3 shows the influence of varying heat flow within a constant geological model. Stored heat within an arbitrary volume of rock increases with increasing heat flow. The variance within a population of heat flow measurements can be relatively small for a well-constrained dataset. In this case, one standard deviation in heat flow for a group of wells is ±3.1mW/m^2 as determined from actual measurements. This variation in heat flow results in an error margin of about ±10% for the estimated stored heat using an arbitrary cut-off isotherm.

The process of heat flow modeling tends to result in a combined quality assurance process for both temperature and rock thermal conductivity data. Where continuous precision temperature log data are available, the resultant heat flow accounts for the entire temperature profile of the well to provide a single estimate of energy flow. Although conductive heat flow modeling in Australia is increasingly being accepted as the appropriate method in which to estimate temperature at depth, particularly where the reservoir target has not been previously intersected or measured, the use of geothermal gradient and absolute temperature methods (common in convective settings) also occurs in Australia. The use of temperature data alone to estimate the 'average reservoir temperature' can introduce significant errors, particularly where single uncorrected bottom hole temperature (BHT) data are used. Drill stem test data and time-series temperature data suitable for Horner correction at the reservoir level in Australian geothermal regions are uncommon, particularly for EGS plays. The use of a single BHT datum is often the 'best case' scenario.

Even in areas of Australia where temperatures are thought to be well constrained, the level of variance in temperature measurements and data quality can be significant. Figure 4 shows well temperature data (mainly un-corrected) from part of the onshore Otway Basin in Australia and the gradient trend relative to the estimated depth of the target reservoir. The common practice of combining all well temperature data to approximate 'average reservoir temperature' can, in this example, produce variance of up to ±25°C within the target depth zone.

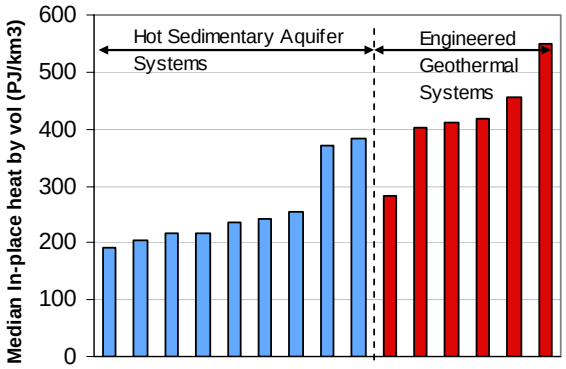

Figure 2: The same information as shown in Figure 1, but displayed as a ratio of energy/volume (PJ/km^3).

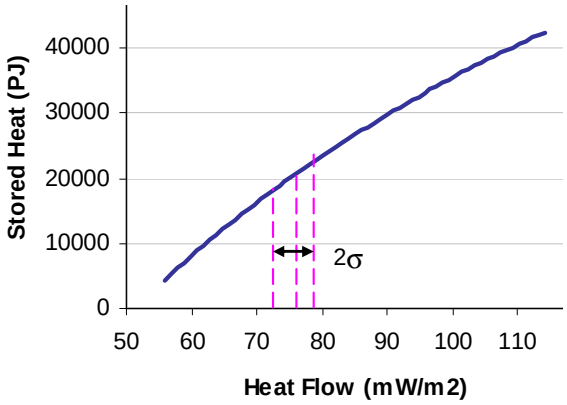

Figure 3: Stored heat versus heat flow for an arbitrary volume of rock in a hypothetical model. One standard deviation change in heat flow results in 10% change in the stored heat estimate.

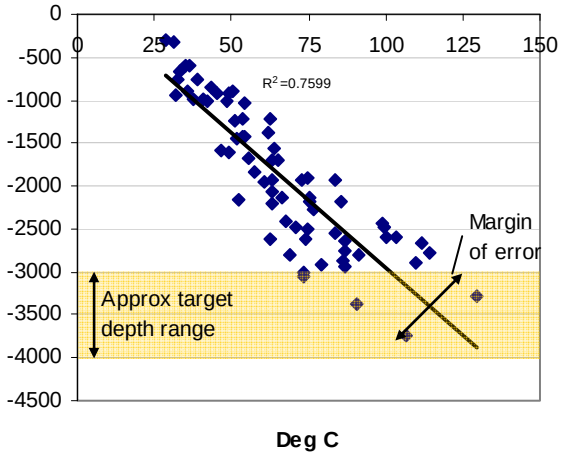

Figure 4: Raw temperature data for wells in part of the Otway Basin (Australia) showing increasing range of temperatures with depth. Within target depth range, range of measured temperature can be ±25°C.

Where the same temperature data are 'quality controlled', the difference between raw and Horner corrected temperatures in this part of the Otway Basin is an average of 9°C and can reach up to 20°C. Figure 5 shows the same hypothetical model as in Figure 3, using modeled average reservoir temperature plotted against stored heat. This model is overlain with the average and maximum difference between BHT and Horner corrected data for a target reservoir in part of the Otway Basin. This produces an error of up to 19% in the estimated stored heat.

4.2. Isotherm cut-off relative to heat flow and reservoir depth

EGS reservoirs are truncated by a minimum isotherm (surface of constant temperature). In contrast, rock volumes principally define petroleum reservoirs. The economic cut-off temperature (isotherm), relative to the average geothermal reservoir temperature, has a large impact on the size of the geothermal resource in Australia.

Figure 6 schematically illustrates how the depth of the cut-off isotherm (as determined from heat flow modeling and the resource development strategy) relative to a permeable rock formation determines how much of the permeable formation can be classified as a geothermal resource. For a geothermal play with a conductive heat flow of 80 mW/m^2, one hypothetical standard deviation of heat flow (±10 mW/m^2) allows for the definition of an upper, median and lower estimate of Geothermal Resource.

At the low end (70 mW/m^2), only the deepest portion of the permeable formation is below the cut-off isotherm (125°C in this example). In the median case (80 mW/m^2), the formation is wholly within the target temperature window. Consequently, both the resource volume and the amount of stored heat are much greater than for the low case. The formation is also wholly within the target temperature window for the upper case (90 mW/m^2), so the resource volume does not change from the median case. However, the higher temperatures (due to higher heat flow) result in a greater amount of stored heat energy for the same volume.

Whilst there is no set definition of the appropriate isotherm cut-off value for geothermal resource modeling in Australia, most published Resource Statements have, to date, assumed a minimum cut-off isotherm of 125°C for HSA plays and 150°C for EGS plays (which tend to target hotter and larger resources). Whilst it is technically possible to generate electricity from water temperatures lower than 100°C, the Competent Persons on the Resource Statements have generally held the view that the two isotherm values are appropriate cut-offs for large-scale electricity production from HSA and EGS plays respectively, based on production data for binary Rankine cycle generators.

For the same hypothetical model from Figure 3, the influence of variable isotherm cut-off on stored heat estimation can also be modeled (Figure 7). In general, increasing the isotherm cut-off temperature decreases the stored heat within the reservoir for any given model, simply because the 'economic window' is being increasingly truncated. However, the overall impact of isotherm cut-off will vary over a model, depending on the more complex relationship between isotherm cut-off, the modeled temperature field as determined by conductive heat flow modeling, and the relative position of the target reservoir formation(s).

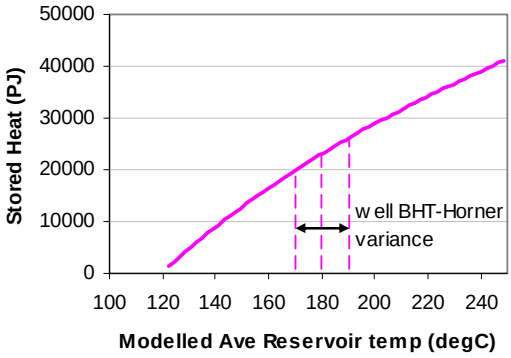

Figure 5: Average temperature of an arbitrary volume of rock as determined for same the model shown in Figure 3. The average difference between raw BHT and Horner corrected temperatures of 9°C can reduce by 10% the estimated amount of stored heat. The maximum difference can reduce the stored heat estimate by 20%.

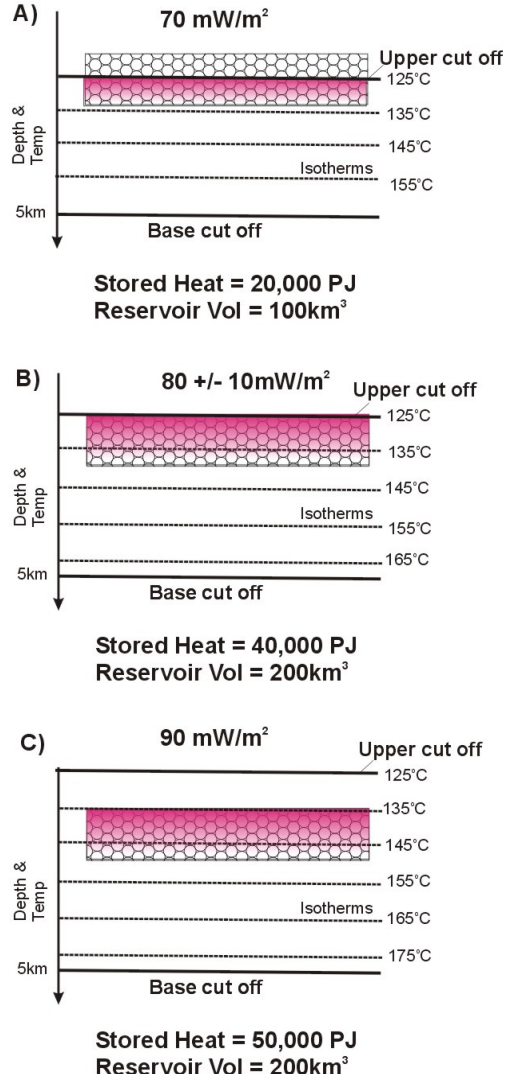

Figure 6. Schematic representation of a permeable rock formation (pattern) and Geothermal Resource (pink) showing: (A) lower, (B) median, and (C) upper case. The formation volume remains static but the Geothermal Resource volume and stored heat change with heat flow and resultant depth of the cut-off isotherm.

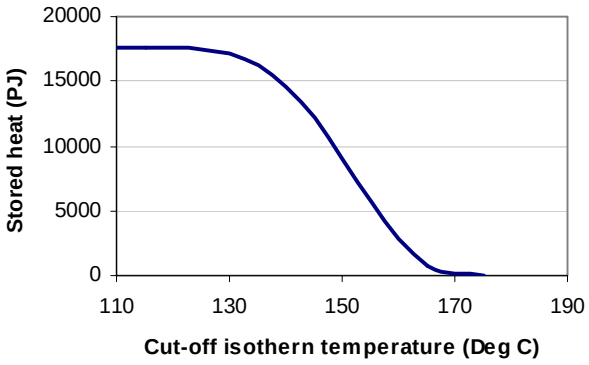

Figure 7. Stored heat versus cut-off isotherm for an arbitrary volume of rock. In general, increasing cut-off temperature reduces the stored heat within the reservoir.

This interplay between variables means that the common perception, particularly in the petroleum industry, that the economics of a prospect can be 'enhanced' by modifying the reservoir height and geometry, will typically not be the case with stored heat. In many instances in Australia, the top of the target reservoir formation is at a similar depth to the cut-off isotherm (as may be expected when trying to target the most economic reservoirs). Hence, increasing the reservoir rock volume by 'lifting' the top reservoir boundary (commonly done by lifting the seismic pick for the top of the reservoir) may have no impact on the estimated stored heat—or an adverse impact if the top of the reservoir is lifted above the cut-off isotherm. This is often a counter-intuitive conceptual issue with which explorers with petroleum or conventional geothermal backgrounds struggle.

4.3. Reservoir rock volume and area relative to heat distribution

Whilst increasing the reservoir formation thickness (and volume) by elevating the top reservoir horizon tends to have little positive influence on the resource size, increasing the areal extent of the reservoir (within the isotherm window) can have a large impact on resource estimation.

Petroleum field size distributions are strongly log–normal due to the fact that sedimentary rock permeability, pay thickness, areal closure and recoverability are also often log–normal (Capen, 1992; Megill, 1992). The same is true for conventional geothermal fields as they share many of the characteristics of a petroleum field but tend to have relatively smaller areal distributions as their heat source is localised (Figure 8A).

Compared to conventional geothermal systems, it may be expected that a conductive HSA system in Australia will tend to have a relatively larger areal distribution of stored heat, as conduction is widespread and not localised (Figure 8B). HSA systems in Australia are likely to have log–normal recoverability distributions as natural reservoir permeability will heavily influence the system. For an EGS system, the areal extent of the host rock, and hence the reservoir volume, is very large. As the reservoir is artificially stimulated, it is not constrained by natural depositional systems and related natural permeability. Hence EGS plays, with large areal extent and widespread conduction of heat, are likely to have large and normal resource distributions (Figure 8C).

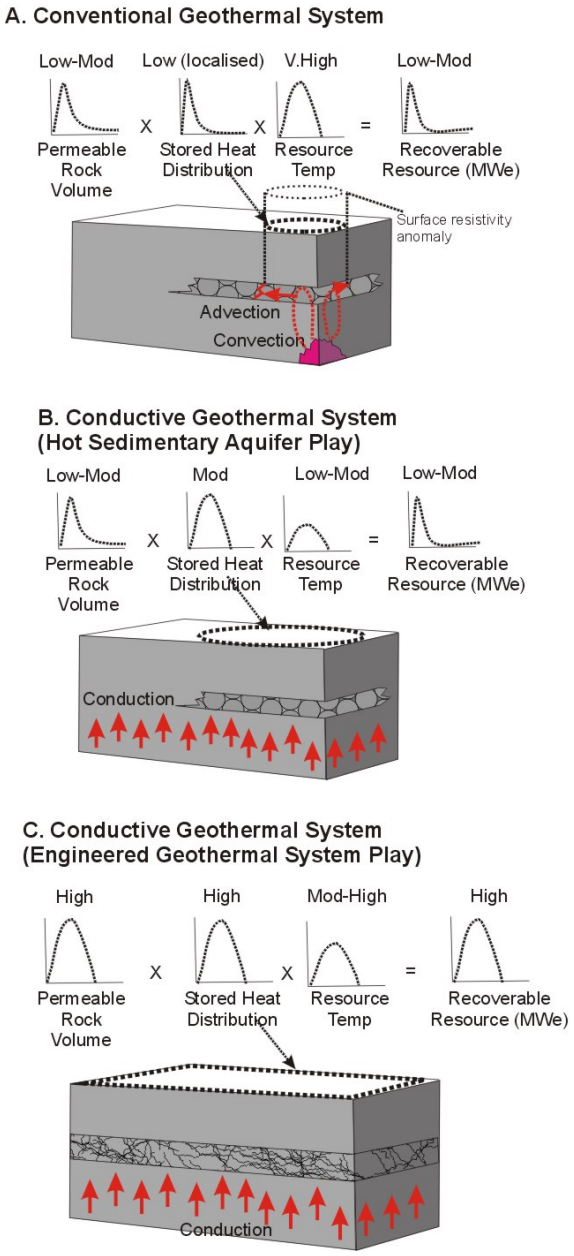

Figure 8. Key parameters that may influence the field size distributions for: (A) conventional geothermal systems, (B) conductive HSA systems, and (C) conductive EGS systems.

4.4. Thermal resistance (insulation)

Thermal resistance, or insulation, is often the neglected component of the geothermal system. There has been a global historical fixation with aspects of temperature and reservoir within geothermal systems but little reference to the importance of the resistive characteristics of units which overly the reservoir. Thermal resistance is defined as the cumulative sum of overburden thickness divided by thermal conductivity and is expressed as m^2K/W (Cooper and Beardsmore, 2008). Thermal resistance is partly analogous with the concept of 'seal' in the petroleum system.

Whilst the geothermal reservoir unit will nearly always have high rock thermal conductivity by definition, the overburden sequence should preferentially have lower rock thermal conductivity so as to 'trap' heat within the reservoir. In the hypothetical model from Figure 3, a 400 m thick 'silty' unit is interpreted immediately above the

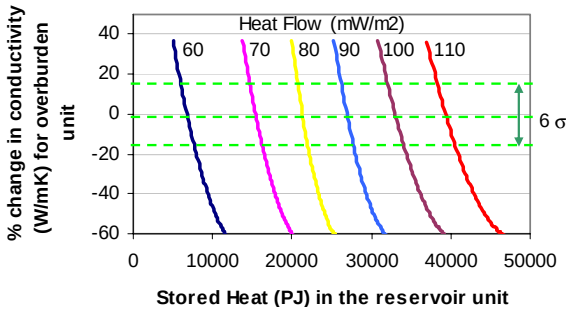

Figure 9. The impact of variable heat flow and overburden thermal resistance on estimated stored heat. In this model a 400 m thick overburden unit immediately above the reservoir is varied in thermal conductivity. Green horizontal lines represent three standard deviations from mean thermal conductivity.

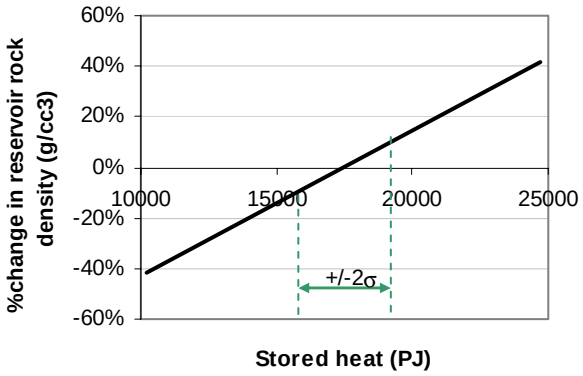

Figure 10. The influence of varying density of the target reservoir unit for an arbitrary heat flow value.

reservoir. Variations in thermal resistance (conductivity of the overburden unit) have a significant impact on the stored heat of the underlying reservoir (Figure 9).

Thermal conductivity measurements of a typical silty formation might display a standard deviation of 5%. Figure 9 illustrates that variation of ±3σ (ie ±15%) from the mean measured conductivity results in approximately ±14% variation in the stored heat of the reservoir at a modest heat flow of 70 mW/m^2. A simple halving of the conductivity of the overburden unit in the same model increases the stored heat estimate in the reservoir by about 25%.

This simple model highlights a number of important issues. Firstly it is critical to accurately constrain the rock thermal conductivity of all units within the resource model. This is best achieved by measurement of core or outcrop samples using a calibrated divided bar apparatus. Secondly, the model highlights the importance of fully assessing a geothermal prospect within the context of a holistic Geothermal Systems Assessment (Beardsmore and Cooper, 2009), before venturing into resource estimation. In particular the common approach of concentrating on the definition of reservoir and 'major' formation horizons only, can result in the omission of smaller, but considerably important resistive units. Likewise the traditional approach of 'lithostratigraphic' seismic interpretation may not provide the level of detail provided by the sequence stratigraphic approach, which should provide a better understanding of the relative distributions of silty versus sandy units.

3D conductive heat flow modeling of a numerical 'earth model' populated with measured rock properties and constrained by quality surface heat flow data provides a 'whole of system' approach to EGS and HSA resource estimation. The methodology incorporates physical rock properties of all units within the system—not just the reservoir. A number of conventional approaches to stored heat calculation tend to allow for conduction within the reservoir only.

4.5. Reservoir rock density and specific heat

The magnitude of a stored heat Geothermal Resource estimate also depends on the product of the reservoir rock density and specific heat capacity (Beardsmore and Cull, 2001). 3D conductive heat flow modeling allows for the input of both rock density and specific heat. Specific heat is temperature dependent and typically increases with increasing temperature. Specific heat will vary with the quartz–water mix of the reservoir and can be estimated from the weighted average value of the components (eg. Sekiguchi, 1984; Hemingway, 1987).

The impact of varying either of these parameters is linear with respect to estimated stored heat in a volume of rock. Figure 10 shows an example of varying reservoir density for the same model as in Figure 3. A 1σ (10%) reduction in density results in a 10% reduction in the estimated stored heat. Exactly the same relationship applies for specific heat.

5. DISCUSSION—RECOVERY FACTORS

3D heat flow modeling for stored heat estimation only addresses the *in situ* geothermal energy of the reservoir. As the geothermal sector in Australia is in its infancy, the recovery factors for this energy, in both HSA and EGS plays, remain to be quantified. However as the international geothermal sector tends to define conventional resources more-so by recoverability, comparisons between Australian and international geothermal fields will remain problematic for at least the next 10 years, until sufficient production data are acquired.

For conventional geothermal resources heat recovery factors of up to 25% are used for naturally permeable systems, although recovery factors of 10–20% are more commonly assumed in commercial projects (Williams, 2007). For resources that are dependent on fracture permeability, Williams (2007) suggests that lower recovery factors (5–20%, and on average 10%) may be more appropriate. However as EGS plays are relatively new on a global scale, there remains a tendency to estimate the recovery of *in situ* heat at very low levels.

In the USA, stored heat estimation work by the Southern Methodist University Heat Flow Laboratory has assumed a recovery factor of 2% (http://www.google.org/egs/) for EGS plays. When a 3% recovery factor and assumed power conversion efficiencies are applied to Australian stored heat estimates, nett generation capacity predictions are a 'realistic' order of magnitude (Figure 11). For example, when Australian data for HSA systems are compared with the gross estimated field sizes for conventional fields in California, the relative distributions appear similar, although the number of Australian cases is too low to draw

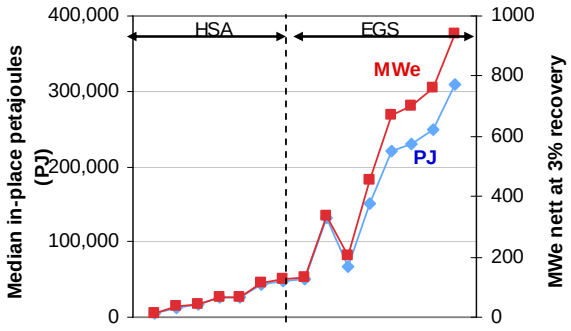

Figure 11. *In situ* stored heat estimates (blue) for 15 Australian geothermal plays. Predicted nett power output for same data assuming 3% recovery of heat, 20% parasitic load, 10% power conversion efficiency (PCE) for HSA plays and 12% PCE for EGS plays.

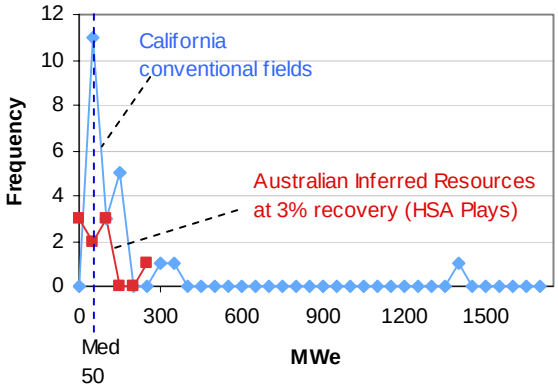

Figure 12. Estimated power generation capacity of 9 Australian HSA plays (red) compared with the distribution of 23 conventional geothermal plays in California (blue). Relative distributions appear similar. (US data from California Geothermal Energy Collaborative/GeothermEx Inc., 2006).

robust statistical conclusions (Figure 12). Whilst it remains too early to make informed comment about the recovery factors for Australian geothermal resources, the use of low factors, in the order of 3%, to estimate recovery at the inferred stage, may be appropriate

6. CONDUCTIVE STORED HEAT RESOURCE ESTIMATION VERSUS CONVENTIONAL VOLUMETRIC APPROACHES

One of the most significant barriers for the Australian geothermal energy sector is conveying the concepts of geothermal resource estimation and stored heat to investors. Increasingly, the Australian geothermal sector is turning to the petroleum sector to attract joint venture partners for exploration and development, yet the fundamentally different nature of a petroleum reservoir makes the concept of a stored heat reservoir difficult to convey. The same may be partly true for workers in the conventional geothermal field if energy is viewed only as hot water or steam within a defined volume.

The heat energy within a volume of rock is independent of volumetric factors such as interstitial porosity and trap geometry, which influence oil and gas resource estimations. This fundamental difference in resource concept and approach is illustrated using a 'tornado chart' to compare the sensitivities of a hypothetical geothermal Resource estimate and a petroleum Resource estimate (Figure 13).

We applied minor variance of key factors (±15%) to the same geothermal model as in Figure 3. Variance in the same factors was applied to a hypothetical petroleum prospect based on structural traps in the North West Shelf oil fields (Cooper *et al*., 1998).

Of the 10 factors assessed, six have a marked influence on estimated stored heat. Most notably, the tornado chart shows the influence exerted by the interplay between reservoir depth, heat flow and specified isotherm cut-off. In particular, the lifting of the top of the reservoir horizon (-15%) reduces the estimated stored heat in this model by more than 50%. Despite common perceptions that heat flow and temperature are the primary determinants of stored heat, other factors such as density, specific heat and the thermal resistance of the overburden can have an equally profound impact (Figure 13).

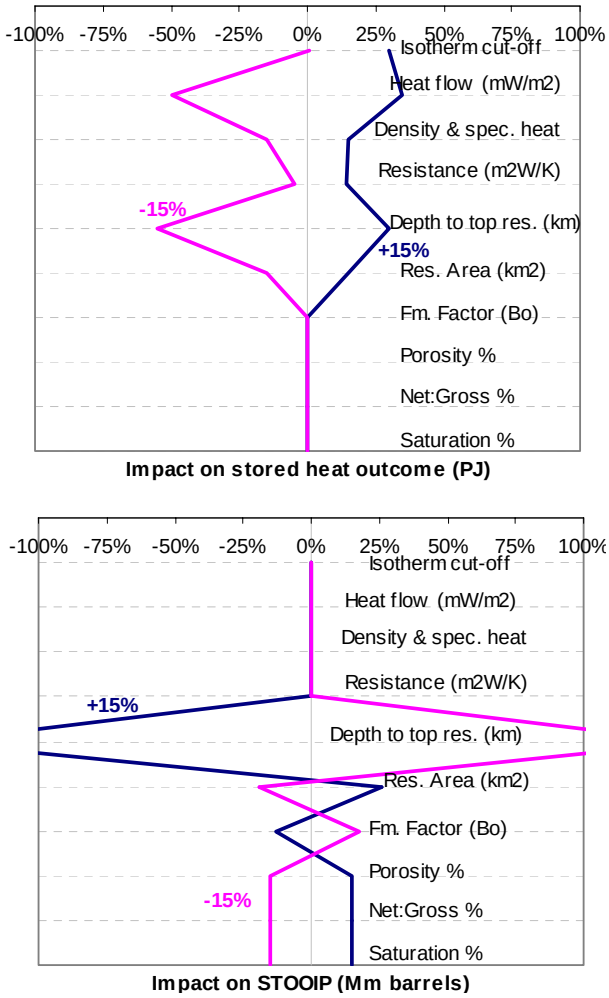

Figure 13. Tornado charts for a hypothetical conductive geothermal Resource model (top) and a hypothetical petroleum Resource estimate (bottom) showing the impact of ±15% variance in 10 key factors on stored heat and in-place oil, respectively.

The petroleum reservoir is comparatively unaffected by most of the factors which influence the stored heat model (Figure 13). The only factor that appears to have a common magnitude impact in both resource models is the depth to the top of the reservoir, although the outcomes are opposite. Lifting the reservoir pick for a petroleum prospect tends to dramatically increase the reservoir volume (defined by the geometry of closure and 'spill point'). Petroleum resources are typically hypersensitive to volume changes and, in this example, a change to the top reservoir pick of ±15% results in an off-scale resource variation. A change of ±3% in the top of the petroleum reservoir depth is sufficient to fill or eliminate the trap closure. Consequently the accuracy of seismic depth conversion is critical for petroleum resource estimation, but not so much for geothermal *in situ* stored heat estimation.

7. CONCLUSIONS

Stored heat estimation by 3D heat flow modeling provides a rigorous and cost-effective mechanism to estimate *in situ* geothermal energy in conductive settings. The methodology was specifically developed to provide solutions for the geothermal systems in Australia, where there is a paucity of deep drilling data. The methodology, when combined with expert determination of physical rock properties and heat flow, provides a means to estimate the 3D temperature distribution, which would otherwise be near impossible to determine in the Australian context with any level of confidence. This allows explorers to define an *in situ* resource at the Inferred level without the need for expensive deep drilling. The method has vast potential for application in many other countries that also lack deep drilling data and have potential for conductive geothermal systems.

Heat flow modeling will remain the staple method of Inferred resource determination in Australia, and as the method reveals much about the geothermal system, it should precede any attempt at dynamic reservoir modeling in the later life of the prospect.

Stored heat is sensitive to multiple parameters, other than heat flow and temperature, which can have a profound impact on the Resource estimation. Consequently, simple volumetric approaches and volume/heat flow ratio comparisons across regions will likely produce spurious results.

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