Validation of Geothermal Exploration Techniques for Analysing Hot Sedimentary Aquifer and Enhanced Geothermal Systems.

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Validated geothermal resource estimates are based on geological models that combine the geology from the surface to basement incorporating properties such as lithology, structure, fluids, compaction, porosity and permeability with thermal models consisting of heat flow, conductivity and thermal gradients. These models must extend beyond single point well analysis, and provide a balanced and geologically reasonable estimate of the size, structure, accessibility and maturity of a subsurface thermal system. To achieve a geologically reasonable model, all available geological and geophysical data must be considered. However, data sets and measurements must be analysed, interpreted and weighted in a manner that reduces error for thermal models.

This paper focuses on building validated geothermal resource evaluations from geological and geophysical interpretations for Hot Sedimentary Aquifer (HSA) and Enhanced Geothermal Systems (EGS). This paper also focuses on limitations of some data sets, and this can be realized when modeling.

Limitations in Thermal Modeling

For any given geological data set (field, well, seismic, remote sensing, temperature) virtually an infinite number of 2D and/or 3D interpretations can be made. However, the set of physically possible geological interpretations are far more limited. The tests for such physical plausibility derive from our knowledge of the processes which control sediment deposition, structural evolution, and geothermal systems. Interpretations which can pass these tests may not be correct, but they are more likely to be so, and can be labeled with that highly sought appellation: Validated.

Limitations occur with thermal modeling that are not as prevalent in other forms of subsurface modeling. The main limitation is the abundance and representation of temperature throughout the system. Temperature measurements are typically limited to single point measurements obtained from wells and bores previously drilled.

While heat is the basis of all geothermal systems, temperature is only ever measured from a single point. This provides the vertical component of a temperature gradient at that point source making it an isotropic analysis of temperature. While this is an ideal measurement for volcanic and plutonic rocks where heatflow is primarily in the vertical domain, it does not account for the anisotropic ‘radial’ heat distribution that occurs in sedimentary and metamorphic rocks (Clauser & Huenges 1995). The temperature-depth profile from a well can therefore be thought of as the vertical summing of the geothermal gradients established within the individual layers within the sediment pile at that location. Such a profile is rarely linear with depth.

However, when extrapolating temperature from the well profiles, the anisotropic component of heat distribution within a sedimentary basin must be accounted for. Because of this, the thermal component of the model is highly dependent on incorporating other factors such as structure, lithological distribution, fluids, porosity and permeability, hydrocarbons and fracturing to control the distribution of heat throughout the model. Because of this, a geological model must be created first. This will help to generate the properties needed to consider for the anisotropic extrapolation of temperature. Thermal modeling will be revisited later in this paper.

Subsurface Geothermal Modeling

Utilizing all the available data to construct a geological model will aid in validating a geothermal resource. In terrains currently being explored with Australia, available data includes: wells, 2D-3D remotely sensed imagery, 2D-3D seismic, potential field data sets (namely gravity and magnetics), petrophysical logs and occasionally magnetotelluric data sets.

Wells

Wells provide geological truthing to any subsurface model. Basic information such as lithology, formation depth, fluid presence and temperature are recorded.

Because temperature is currently only measurable in situ, wells provide the basis of the thermal modeling. Down hole tools deployed during drilling and after drilling are used to record temperature at different stages within the well. This information is combined with estimates or measurements of conductivity to generate information on heatflow. This is in turn used as the basis for extrapolating a temperature model across the area.

Wells often have vital information collected from down hole logging tools employed during drilling or just after. These tools collect information on temperature, pressure, flow rates, densities and even fracturing. A seldom used, but highly beneficial technique for EGS and HSA is down hole vertical conductivity and horizontal resistivity measurements. These techniques are designed to identify fracture orientation as well as what orientation of fracture is open (that is, a potential fluid conduit) in the well. Both measurements are obtained while drilling. Horizontal resistivity measures the resistivity of a formation by dispersing a current flowing in a horizontal plane. Vertical conductivity is measured in a similar manner, however in the vertical plane. These measurements are obtained by using wireline logging tools such as laterologs and propagation logs. Two survey types are used, as single orientation plane surveys (i.e. vertical or horizontal) cannot take measurements in the plane parallel to the plane where the electromagnetic current is flowing. Vertical conductivity is used for imaging high angle fracturing (fractures with dip 20-70^o) and sub-horizontal fracturing (dip <20^o). Horizontal resistivity is better at imaging sub-vertical fracturing (dip >70^o). The surveys are analysed and plotted as frequency diagrams indicating the primary orientation of the open fracturing.

Information about the contemporary stress fields in the area can be obtained from well data. Borehole breakouts reflect a measurement of the orientation of disintegration of the well during drilling as a result of compressive stress failure. The orientation of the breakout is parallel to the orientation of the minimum horizontal stress. This orientation is perpendicular to the orientation of the drilling induced tensile fractures, the orientation in which the tangential stress is below tensile rock strength. This orientation is parallel to the maximum horizontal stress. Information about contemporary stress can assist with drilling and also with determining the nature and orientation of any structure that may be active or ‘open’ within the system.

Surficial Geology and Remotely Sensed Imagery

Geothermal exploration is greatly aiding from surficial geology and remotely sensed imagery as it provides approximate ground truths to structure and morphology interpreted in the subsurface. Not all subsurface geology has a surficial representation, a significant portion does. Actual exposure of these features helps to understand the magnitude and style of structure and the physical properties of rocks at depth. An important component of this is developing an understanding of the cover rocks and how they may aid in assisting or impeding the success of the geothermal resource. Regolith mapping and remotely sensed imagery such as radiometrics are being used to find areas of surface fluid leakages and potential conduit faulting in seal analysis and reservoir integrity studies.

Magnetotellurics and Potential Field Surveys

Magnetotellurics (MT) and potential field surveys can be used to define the basic limits of a reservoir. MT has been an industry standard for over 20 years for defining geothermal reservoir limits and boundaries. The 'fuzzy' imaging produced by MT can pick up resistivity anomalies typically associated with fluid bodies, large scale structures, and cap rocks. This technique has been used within Australia with varying success, which is often a product of survey design as opposed to the reliability of the technique. MT modeling requires trial and error of forward modeling (Arango et al. 2009). This process generates different models that could fit the data, and tries to assign the most likely model. Reliability of the MT is compromised as a result of this. Accessory data refines this error; such the technique is better used in conjunction with other modeling techniques. The most important result from MT models is the ability to identify the presence of geothermal fluids. This is particularly useful in the identification of HSA reservoir systems. However, the recognition of the fluid is still limited to the errors defined above.

MT is commonly being combined with potential field modeling. Magnetic and gravity surveys have been used with geothermal projects to define large scale structures and also as the basis for deterministic lithological variance identification subsurface. Potential field inversions are often coupled with petrophysical logs such as sonic and density logs to create 'layer cake' models that accumulate to the potential field signatures produced by the surveys. These techniques provide approximately the same resolution of data as the MT techniques do; however can be cheaper, and manipulated in different ways to account for different geological scenarios.

Seismic Interpretations

Seismic interpretation is not commonly used as a tool for EGS and HSA resource model evaluation. Seismic is typically used as a tool in the petroleum industry to extrapolate lithological boundaries across large areas with the assistance of wells. Features included on seismic are: formation and stratigraphic boundaries, sedimentary features such as onlap and down lap patterns, facies and sequence stratigraphy, structure, and tectonostratigraphic relationships. These features are all essential for creating balanced geological models.

A benefit of seismic interpretation is that 2D and 3D seismic surveys are available from most basin and foldbelt terrains in Australia as a result of previous petroleum or academic work conducted.

Basic interpretations can create the basis of a geological model, and can be truthed to other aspects such as wells and potential field surveys.

Advanced seismic interpretations can be conducted by procession of the seismic data such that the mechanical signatures of the seismic traces are transformed in particular ways to highlight specific features (Nourollah et al. 2010). An example of this technique that is beneficial in HSA systems is a process called Neural Network Inversion Modeling (NNIM). NNIM attempts to builds relationships between data sets similar to the way the human brain perceives and analyses data. The mechanical signature of a seismic wavelet is compared to a known source, such as a well log, and particular features characterized in the log are matched to their corresponding seismic signature. Once relationships are built between well logs and seismic traces using well defined data sets, this model can be applied to other seismic traces away from the known well locations to generate target logs from seismic sections. This process can be used to define sand bodies in a potential reservoir, fluids such as gas and water and associated migration pathways, potential seals and different lithological patterns that were not obvious in the initial seismic interpretation and to highlight structures. Other forms of seismic processing can produce similar results.

Integration of Geological Interpretations

The integration of interpretations in geothermal systems is rare. Exploration techniques are often considered to be unique sources of information, rather than part of a dynamic system. However, this is far from the truth.

The integrating of the full suite of available data constraints, including 2D/3D remote sensing, field, 2D-3D seismic, and well logs/picks/production validates geological models and provides the basis for a constrained HSA and EGS model.

Techniques such as gravity and magnetic inversion which are considered to be low resolution interpretations can have their resolution increased by using petrophysical logs, seismic interpretations, and surface data to better constrain the layers in the model. Seismic can also betide to surface features, particularly structure to help define attitudes and confirm structure. The combination of these techniques increases the validation of the model.

Revisiting Temperature modeling

Thermal Conductivity

Thermal conductivity of a rock determines the efficiency (or otherwise) with which heat is propagated through it. It is controlled by lithology and state of the rock (that is compaction, fracturing and metamorphic attributes). Accessory factors such as the presence of fluids such as water and gas also play a big role in this (Clauser & Huenges 1995; Vasseur et al. 1995; Beardsmore 2004).

Two primary methods are employed with respect to measuring conductivity: *in situ* measurements conducted within the subsurface using logging tools; and, laboratory measurements preformed on small sections of rock. *In situ* measurements are considered to be the best form of measuring conductivity as they are done so within the actual surroundings that the rock exists within. This incorporates factors such as fluids, fracturing, pressure and compaction better than a sample done in a lab. In situ measurements also represent an average over a large area of rock (Clauser & Huenges 1995).

Lab measured samples have a higher precision, because factors inhibiting to the *in situ* measurements such as equipment difficulties, drilling interference and general control issues are negated. This makes the measurement more precise, however, not more accurate.

In places where there is no data available for this modeling, default thermal conductivities for end-member lithologies that can be mathematically averaged to reflect lithological mixtures as necessary, and so do not rely on the laboratory measurement of conductivities on down-hole samples can be used. This has been recognized as a useful and reasonably accurate tool as it does not have the large extrapolation and errors that are associated with the precise laboratory measurements (Clauser & Huenges 1995). Estimating the conductivity of a rock can occasionally miss factors such as minor lithological changes, small fracture zones and pressure changes (Vasseur et al. 1995). However these tent to have minimal impact when averaged over the system, especially when used within a detailed geological model.

Temperature Modeling

Modeling temperature across a large area requires the measured temperatures to be fed into a constructed geological model and propagated according to the physical constraints interpreted. Comercially available software can then be used to construct a more anisotropic thermal model. Burial history modeling software that is routinely used in petroleum exploration for the prediction of the degree and timing of source rock maturation, reservoir temperature is favored as it can incorporate the physical properties of rocks as well as structure. Lithostratigraphic data from a well, or from seismic interpretation, can be input to the burial-history modeling software package and modeled across larger areas with geological and thermal reason. Such packages also take into account burial-compaction effects (in particular, increase in conductivity with increasing compaction), permitting the calculation of a temperature-depth profile from which predictions of depths to key isotherms can be made. This process also accounts for structure, fracturing and fluids.

Conclusions

By creating a validated set of interpretations a constrained geothermal model can be created. These thermal models can be used to better constrain geothermal targets, reservoirs and production and can be used to monitor the progression of the resource throughout the life of the project.

Temperature, when projected amongst a validated model is no longer a source data set, but an accurately extrapolated potential field.

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