Petrophysical Methods for Characterization of Geothermal Reservoirs

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Abstract: Australia has a unique wealth of non-volcanic geothermal resources. To tap these for local and distributed energy needs, optimal targeting and development strategies for the reservoirs are needed. In the case of Hot Sedimentary Aquifers (HSA), many tools for formation evaluation developed in the oil and gas industry for High Pressure/ High Temperature environments could be applied directly; this applies both to downhole tools and laboratory characterization methods. The standard suite of petrophysical methods is adequate for determining basic matrix and fluid characteristics, but for full characterization of flow and geomechanical parameters advanced acoustic and nuclear magnetic resonance tools could find a place, at least for high value resources. In both crystalline rock and HSA plays, image logs are a vital tool, not least for enabling improved core-to-log workflows. Understanding of the thermal properties of rock and how that relates to field scale thermal structure is another challenge unfamiliar to most petrophysicists. Modelling from pore/grain through to formations scale is vital for assessing both thermal and flow performance. CSIRO and the Western Australian Geothermal Centre of Excellence have brought together experience and capabilities in rock physical and thermal properties and in this paper review what petrophysical tools and methods are available to the geothermal industry and illustrate some of the research currently underway.

Keywords: Petrophysics, Reservoir Characterization Thermal Conductivity, Heat Capacity, Porosity, Permeability, HP/HT.

Introduction

Australia's immense geothermal energy resources have the potential to contribute significantly to our nation's demand for affordable and sustainable clean energy. However, for the efficient exploitation of geothermal energy a good characterization of the reservoir is a prerequisite.

Petrophysics is the systematic investigation of rock and fluid physical properties to understand the rock type and fluid flow performance of underground formations. Petrophysical techniques measure the physical and chemical properties of the rock either in situ (well logging) or in a lab (core and chips). The data generated from these analyses can be used to characterize the reservoir rock's composition, structure, porosity and permeability, temperature, pressure and mechanical properties, leading to a better overall understanding of the resource.

Petrophysical methods for the characterization of geothermal reservoirs have progressed significantly overseas particularly for the extreme environments such as HR and volcanic sources. In this paper we describe CSIRO's expertise in the Petroleum sector, which is directly applicable to HSA. It is our intention to grow this expertise further into the HR domain.

Our petrophysical characterization of geothermal reservoirs forms part of a larger collaborative initiative of CSIRO and Universities working with industry and government with the aim to reduce the risks of implementing geothermal technology through computationally assisted guidance of drilling programs to target locations and depths. The core of the required scientific innovation will be to develop new data assimilation inversion tools, which ensure that all available information, including geologic, geophysical, geomechanics, fluid dynamics, rock physics, geochemistry and economic data is integrated into the subsurface and above-ground geothermal design. In this contribution we focus on the petrophysical methods for characterization of geothermal reservoirs. These comprise the characterization of rock mechanical, thermal, geochemical and fluid permeability properties.

Standard petrophysical tools and characterization workflows

Since the Schlumberger brothers invented the first downhole electric log in the 1920s, the oil and gas industry has provided the platform to develop a wide range of petrophysical logging tools, (see Ellis and Singer 2007). The range of physical properties that can be sensed today is impressive (Table 1). While the uptake of down-hole technologies in water, mining and environmental sectors has largely been limited by cost to a basic suite, certain slim-hole and extreme environment tools have been developed outside of oil and gas, most notably for borehole imaging.

Petrophysical characterization serves three main purposes, each with its own workflow to: (1) define the lithostratigraphy, and therefore help in geological correlation between wells and definition of reservoir structure; (2) quantify matrix, fluid and

Table 1

Type of tool	Physics employed-what is measured	Geothermal application
Resistivity-galvanic	Direct current injected into the formation, usually focused electrode array.	Relations between porosity, water saturation and water salinity.
Resistivity-induction	Coil magnetic field transmitter induces ground loops in formation, measures conductivity of formation	Relations between porosity, water saturation and water salinity.
Gamma ray-standard	Scintillator detects total radioactivity of formation	Shaliness, heat production
Spontaneous potential (SP)	Electrochemically and electrokinetically induced potentials	Pore water salinity. Indicator of clay layers vs sand layers, permeability of the latter.
Density log	Uses backscattered gamma rays from a radioactive source, typical ^{137}Cs.	Sensitive to formation bulk density, based on atomic number contrasts.
Photoelectric effect	Measured from relative energy absorption from the density source	Indicates mineral electron density
Neutron log	Detects neutron absorption from hydrogen nuclei	Sensitive to water content including clay bound water
Sonic Log	Compressional wave velocity	Porosity and strength (stiffness) of formation
Gamma ray-spectral	Energy sensitivity detectors distinguish U, Th and K	Shaliness, rock geochemistry heat production
Magnetic susceptibility	Measures magnetic permeability of the formation by inductive coupling or other means.	Can provide good lithological discrimination, even of very thin layers, and in crystalline rocks
Geochemical Logging Tool	Measures spectra of gamma absorption-re-emission	Identifies a wide range of specific elements, especially heavy ones
Elemental Capture Spectroscopy	Measures gamma spectra from nuclei activated by neutron capture	Identifies a narrow range of specific elements, especially heavy ones
Dielectric log	Permittivity from attenuation and phase of propagating electromagnetic wave	Porosity/saturation independent of salinity. Shale and texture indicator
Nuclear magnetic resonance	Transverse relaxation time of hydrogen nuclei	Fluids content, pore size and permeability estimate
Waveform sonic	Compressional and shear waves	Geomechanics

flow properties of the reservoir and (3) assess stresses and geomechanical properties *in situ*.

1. For definition of lithology and structure one is looking to use tools, such as gamma ray, resistivity and sonic, which show substantial contrasts between different lithologies. At this stage, quantitative relationships are less important than the signatures that mark boundaries between correlated rock units. In crystalline rock situations magnetic susceptibility (not generally used in oil and gas exploration) is valuable to identify certain geological markers. At the next level of detail we require identification of features such as tilted beds, coal seams, igneous dykes, faults and fractures. Dip logs and image logs are most useful here. The best type of imaging tool for a geothermal hole (borehole televiewer for air or clean water filled holes, ultrasonic scanning tool) may be different from that used mostly in oil and gas (formation resistivity array imager). In crystalline rocks, flow properties begin and end with fractures, so image logs are especially vital. Resistivity images have the advantage that open and flowing fractures may have different contrast to closed or non-flowing ones.

In the laboratory we gain complimentary lithological information from petrographic analysis of cores and cuttings samples, usually aided by optical and electron microscopy. Structural logging of core can define fault and fracture sets, determine relative timing, and differentiate natural from drilling-induced fractures, which is not always possible from borehole images alone.

2. For quantitative formation evaluation for a HSA target reservoir, combining the basic “oilfield” tools performs a vital function. Density and neutron tools enable porosity to be delineated, along with some understanding of matrix mineralogy and especially clay content. Neutron-porosity to density porosity ratio can indicate zones not completely saturated with water, and with gamma ray, indicates clay content. Clay fraction has a first order effect on permeability, even if porosity is constant. Sonic logs can reinforce the interpretation of porosity, and indicate zones that are more or less fractured. Resistivity and spontaneous potential can be analysed together with an understanding of the clay content and porosity, to deduce pore water content, saturation and salinity. This information also helps integrate downhole observations with surface electromagnetic geophysical surveys such as deep resistivity or magnetotellurics (MT).

Wireline-conveyed formation testing (e.g. MDT*) is the final technology used in a standard “oilfield” petrophysical evaluation. Drawdown and build-up tests define permeability and can also be combined with fluid sampling. Wireline testers offer a much more versatile solution than larger scale packer tests or drill stem tests, though the latter are required in crystralline rocks or otherwise low-matrix-permeability settings.

Laboratory measurements on core substantially reduce the uncertainty in formation evaluation. At the CSIRO petrophysics laboratory for example, we routinely measure porosity and permeability of core samples under overburden conditions, electrical properties at a wide range of frequencies corresponding to different logging tools, and sonic compressional and shear wave velocities under conditions of (P, T) *in situ* stress.

3. Stresses in the Earth are complex, and defining stress conditions in a borehole can be a difficult process. Generally it is based on the analysis of break-out and fracture patterns observed in image logs, complimented by formation pressure tests designed to open natural fractures and/or induce new fractures. To interpret these results and make predictions of reservoir performance, "fracture-ability", well stability in the reservoir and overburden, it is desirable to have core suitable for geo-mechanical testing. From core tests unconfined compressive stress, cohesive strength and frictional strength parameters can be determined directly and used to construct a Mechanical Earth Model. At CSIRO we conduct such tests routinely, and have recently obtained a High Pressure (to 150 MPa confining, >500 MPa axial) High Temperature (to 200 C) triaxial rig and with 20 channel acoustic emission to monitor in 3D the development and coalescence of fractures. Sonic logs are used widely for geomechanical interpretation, and core measurement of *P* and *S* velocities and their anisotropy is very helpful for defining rock physics and mechanical property models. This also closes the loop for seismic-to-log-to-core workflows.

Smarter petrophysics: geothermal applications of non-standard tools.

The limited scope of standard tools has led to more exotic physics being applied to formation evaluation in oil and gas. Some special tools have obvious HSA applications but require cost/benefit to be proven. Extreme condition versions of some advanced oilfield tools do not even exist yet.

An obvious "upgrade" is to use a spectral gamma ray tool that quantifies the U, Th and K content of the formation. This enables quantification of *in situ* heat production, and is also useful for rock typing. Natural gamma tools can be cross-calibrated with laboratory spectral gamma ray detection instruments used for recovered cores or chips.

Geochemical Logging Tool (GLT*•) and neutron activation (e.g. ECS* or FLEX*) logs can be employed to quantify a subset of the chemical elements in the formation. The GLT has been used in both sedimentary and crystalline rocks, including hydrothermal zones, in the Ocean Drilling Program, with excellent results. The GLT is complex, having active neutron and gamma sources coupled with filtered detectors and a passive natural gamma ray spectroscopy module. Hot sources raise obvious issues of HSE permitting. The ECS approach can be engineered to use a non-chemical neutron source called a minitron, essentially a small particle accelerator in the tool. However, the number of elements detected by ECS is limited, as is its track record for hard rock situations.

Another oilfield technology of potential value in hot sedimentary aquifers is Nuclear Magnetic Resonance (NMR) spectroscopy. NMR tools measure the magnetic spin relaxation of hydrogen nuclei, and offer the only way to determine rock pore size distribution and thereby estimate formation permeability in a continuous way. This is an excellent way to interpolate point measurements from permeability tests on core, and compare with formation tests from MDT. NMR also provides a salinity-independent total porosity and an estimate of clay content. CSIRO is currently comissioning an elevated P/T NMR core testing capability which will help to assess the value proposition of NMR petrophysics for HSA geothermal applications.

Temperature limits on measurements

Some technologies such as NMR, which depends on magnets, and some spectroscopic tools with crystal detectors have inherent temperature limitation making their application to hotter geothermal settings unlikely. On the other hand, various logging tools have been developed specifically for geothermal boreholes: the extreme environment televiewer for example. The exploitation of ultra-deep (>5000 m) and High Pressure High Temperature (HPHT, or >150 C > 70 MPa) oil fields has also driven the development of sophisticated petrophysical tools that can perform in extreme environments, leading to a convergence of technology towards the needs of the burgeoning geothermal market. Major players like Schlumberger, Baker Hughes and Weatherford compete in this market with small and specialised tool suppliers, including a growing number from Australia. Standard tools are available up to at least 260 C and 200 MPa. We therefore see expanding options to deploy such oilfield tools—or cheaper versions of them—into the geothermal marketplace.

In the laboratory also, standard oilfield analysis equipment for porosity, permeability, resistivity etc. is not designed for the extremes of geothermal conditions. A typical operating range is 70 MPa and 100C. At least in a research context, systems have been engineered enabling all of these parameters to be obtained under *in*

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* MDT, GLT and ECS are marks of Schlumberger. FLEX is a mark of Baker Hughes

situ formation conditions and throughout prolonged experiments (e.g. Milsch et al. 2008).

Understanding the thermal structure

Whether it is a Hot Sedimentary Aquifer (HSA) or Enhanced Geothermal System (EGS), appraisal and exploitation of a geothermal reservoir requires a detailed characterization of thermal properties and heat flows. The temperature distribution on the underground is driven by the surface climate, the characteristics of the rocks to conduct, produce and accumulate the heat and also the fluid circulation into the rocks and the basal (or mantle) heat flow. When estimating the temperature at depth, we have to consider the main mechanism driving the thermal flow and temperature distribution according to the controlling equation.

$$\rho C \frac{\partial T}{\partial t} + \vec{V}.\overrightarrow{grad}(T) + div\left(\overline{\overline{\lambda}}.\overrightarrow{grad}(T)\right) + A(z) = 0$$

Here ρ is mass density, *C* the specific heat capacity, *T* the temperature, *V* the fluid velocity vector, lambda the thermal conductivity, and *A* the specific heat production per unit rock volume. In the absence of fluid flow, rock thermal conductivity estimation is adequate for the characterization of the thermal conduction regime. An estimation of the specific heat of the rock will provide direct insights on the stored heat. This parameter will also play an important role during the production of the reservoir as the rock releases the stored energy to the working fluid. The radiogenic heat production rate of the rocks in combination with stratigraphic information will enable us to estimate the local heat flow value. If advection is significant, in the system, then permeabilities, porosity and fracture characterization are needed to quantify *V* and thus the contribution of the advective flow to the temperature distribution.

In terms of fluid transport characterization, the key parameters to identify are the permeabilities (absolute for water only and relative, when steam and liquid are both present in the reservoir), porosity and the thickness of the targeted reservoir. Initial and time lapse values from repeat logging passes will be of interest to design and assess any well stimulation processes and to quantify the contribution of the local hydrogeology to the temperature distribution.

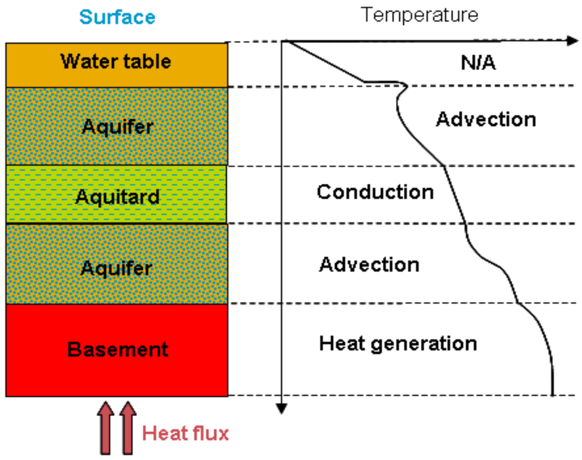


Figure 1. Isogeotherms and formation temperature/ depth profile in a hypothetical rock sequence (adapted Jorden and Campbell, 1984).

These parameter estimations are important at the exploration stage to evaluate the geothermal potential and must be refined at the production stage where the underground geothermal system will be significantly affected by the production and re-injection of a working fluid.

Determining thermal properties

Most of the research on thermal properties has focused on modeling of the thermal propagation in geological reservoirs. But the needs in petrophysical data, particularly in geothermal reservoirs, have never been so important to verify and validate models. Two main approaches are available to provide hard data on thermal structure and properties downhole logging and laboratory measurements. Both methods have their advantages and disadvantages:

• Logging data give access to a continuous records with depth but with high uncertainties because of some chemico-physical processes that actively occurs during the data recording (heat flow, fluid flow, mudcakes, fracturations...) or simply because of the limited sensitivity and depth resolution of the tools (Beck et al., 1971). Three general logging methods are available: (1) relaxation methods (Wilhelm, 1990), (2) direct thermal measurements downhole with no control at all on chemico-physical influences and (3) the classical correlation methods which combine logging parameters such as sonic traveltime, hydrogen index, density, porosity, lithology and temperature (Brigaud et al., 1989; Demongodin et al., 1991; Griffiths et al., 1992). All of these methods use empirical models and some form of averaging or effective medium theory to predict the thermal properties. To calculate the thermal conductivity and diffusivity accurately from such methods, the tools being employed must be capable of distinguishing the different minerals and fluids sensitively.

• Lab measurements enable control of all the parameters (mineralogy, porosity, water content, fractures) but the sampling (except for drill-cuttings) is never continuous and the *in-situ* reservoir conditions are difficult to reproduce in the lab. Moreover, lab equipment and protocols are not infallible. Poor sample quality, representativeness, coupling, effects of fractures etc., limit typical accuracy to around 5% or so. It is rare that specific information is gathered on anisotropy: this requires measurement of the tensor components of thermal conductivity and diffusivity. At the highest temperatures, non-linear properties and especially thermal expansion make good measurements a challenge.

One new technology that can help overcome some of these issues is Optical Thermal Scanning (Fig. 2). OTS is a non-destructive non-contact measurement of the thermal conductivity and thermal diffusivity on rocks and minerals at room conditions (Popov et al., 1999). OTS is able to scan a sample surface with 3 temperature sensors in combination with a focused mobile and continuously operated constant heat source. The heat source and sensors move at the same speed relative to the sample and are calibrated before and after each measurement with rock standards, which leads to high accuracy quoted as 1.5%, a sampling size from 1 cm to 70 cm long having any shape, short time measurements (10-30s), contactless tool and without time and cost of special sample preparation. Hence the OTC offers the opportunity to investigate direct thermal conductivity, diffusivity, pore space and geometry on full cores and anisotropic thermal properties of samples under various conditions, and with a wide range of form factor, size, and prevailing conditions (wet/dry, elevated temperature, etc).

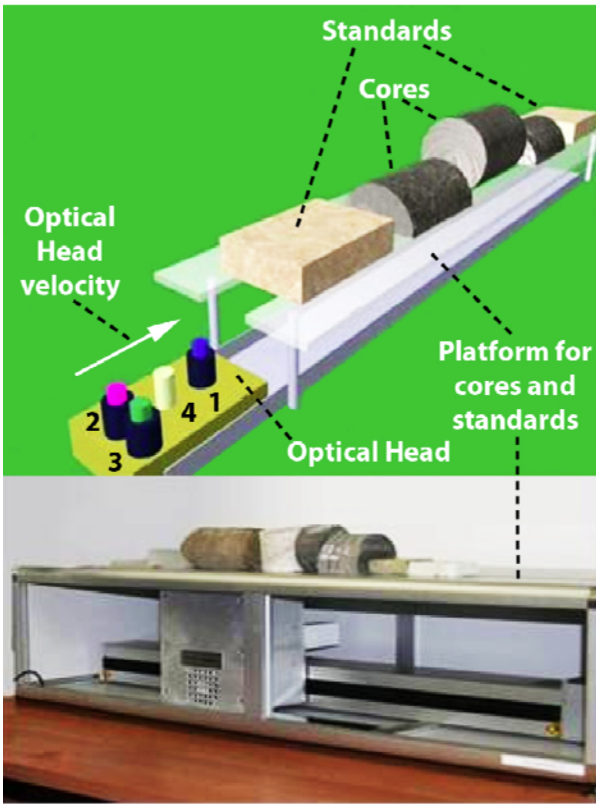


Fig. 2. Optical Thermal Scanner instrument for rock thermal property measurements on full cores (modified from Popov et al., 2010). Optical Head: sensor (1) measure the rock temperature at room condition and sensors (2 and 3) measure the rock temperature after heating from the heat source (4).

The combination of the two petrophysical approaches (lab and downhole) can be very powerful and removes most of their respective disadvantages. Lab measurements allow parameter calibrations and better control on the logging interpretations. Proper integration of petrophysical data from lab and downhole sources enables us to test, correct and enhance the existing theoretical models used to predict steady state and dynamic thermal behaviour.

Petrophysical property modelling

The characterisation of geothermal reservoirs is a typical multi-scale problem. CSIRO and WACOGS have developed a number of workflows to model and upscale rock physical properties appropriate for geothermal problems. An exciting recent advance with wide uptake in the petroleum industry is the incorporation of so-called Digital Rock or Digital Core methods whereby high resolution 3D images of real rocks form the basis for physical property calculations. In the example workflow presented here we analyse small scale rock properties in 3D based on micro-computed tomography (micro-CT), and scale up for hydraulic properties by using percolation theory.

Firstly, the original images of microtomography are converted to binary images, and 3-D binary models are built up from the tomography slices. Image processing and segmentation is crucial which recognises target phases (pores, different minerals) according to their greyscale values in the images. Fig. 3 shows the pore-structure of a synthetic sandstone sample of size 1.3*1.3*1.17 mm^3 after segmentation in which the pore interiors are "painted" light blue. Micro-scale characterisations are analysed based on 3-D binary models, including volume fraction (porosity for pores of porous media), percolation (or connectivity), specific surface area (SSA), tortuosity, and anisotropy.

Stochastic analyses of all phases are the second step of this multi-scale characterisation. It conducts scale-dependent probabilities and the size of representative volume element (RVE). Our stochastic analysis uses the moving window method, in which a cubic sub-volume with variable side-length L moves all over the model. In this way, the probabilities of volume fraction, percolation and anisotropy of different scales are obtained. The size of the RVE is determined when these probabilities are convergent with the increasing sub-volume-size L (Liu et al. 2009).

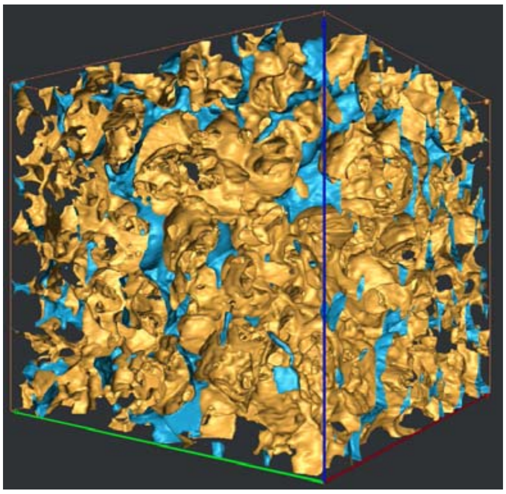


Fig. 3. Pore-structure of a synthetic sandstone sample, light blue denotes inside of pores. Model size is 1000*1000*900 voxels, resolution of voxels is 1.3 μm.

Once at the RVE size or larger, the estimated properties are reliable for application to that particular rock type. Meanwhile, the probability distribution functions can be used to create "digital rocks" at any size which have certain common characteristics, but vary in their details. For example, one may vary porosity, connectivity, or fracture density and see the effects.

Physical properties of geothermal reservoirs, in particular, permeability, elastic parameters, and thermal expansion coefficient are calculated on the digital rock elements using numerical simulations. Permeability can be simulated by using the finite difference Stokes equation solver Permsolver and based on micro-scale pore structures. Fig. 4 is a RVE of size 1 mm^3 of a synthetic sandstone sample. The simulated permeability is 1763 millidarcy. Thermo-mechanical properties are computed by using a finite element method based on the mineral properties and structure. Fig. 5(a) is a RVE of a digital rock which includes two weak minerals of different shapes. Fig. 5(b) gives the relationships of stress and strain components of the RVE and matrix, respectively. Although matrix and weak inclusive minerals are all isotropic, the microstructure makes the upscaled properties of the RVE remarkably anisotropic, see Fig.5(b), in which red and black lines correspond to x and z-directions, respectively. As stress and strain values in Fig. 5(b) are volumetric means on element sets, the relationships for the matrix show a slight anisotropy over all elements in the RVE (see blue and green lines in Fig.5b), which is reasonable. With these simulated results, thermo-mechanical properties of the representative volume element can be computed.

To extrapolate properties from microscale to macroscale it is necessary to combine micro-scale properties with scaling laws. We use percolation theory to extract the main critical parameters including fractal dimension, critical

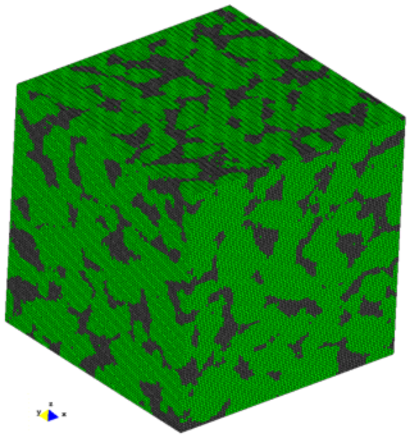
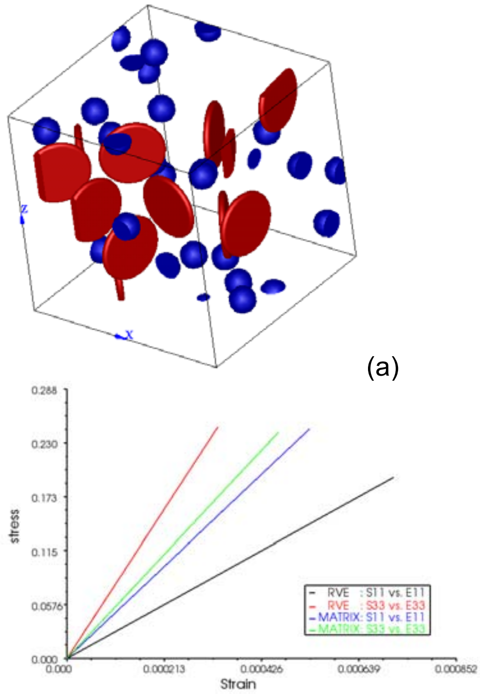


Fig.4 A RVE of a synthetic sandstone sample for permeability simulation.



(a)

(b)

Fig.5 (a) RVE of a digital rock with two weak minerals of different shapes, matrix is not shown; (b) relationships of stress and strain in x and z-directions for matrix and RVE, respectively. Oriented microstructure makes the RVE be remarkably anisotropic, although minerals of matrix and inclusions are all isotropic.

exponent of correlation length, percolation threshold, and crossover length, for the purpose of upscaling.

For the synthetic sandstone sample shown in Fig. 4, the critical exponent of correlation length and the fractal dimension extracted from micro-tomography are close to the theoretical values. The percolation threshold of this structured medium is 3.94%, while the sample has a porosity of 24.4%, which is far above the percolation threshold. In addition, the crossover length of the critical model is smaller than 50 μm. Based upon these observations, we can directly use the transport properties obtained from the micro-scale analysis for upscale modelling in the macro-scale.

The simulated permeability of 1763 md in 1 mm scale is close to the experimental test permeability on a plug sample of 2567 md. Results show that the detection of the scale dependence of permeability is accurate from the crossover length of 50 micron to the cm laboratory scale (Liu et al. 2010).

These upscaling methods based on statistical physics on small rock samples (potentially even cuttings) can be combined with more geologically informed methods of geostatistics, based on core- and log based lithofacies or flow units, to populate reservoir models at the larger scale.

Summary

The characterization of geothermal reservoirs requires the integration of field, laboratory and computational petrophysical methods. The formulation and parameterization of rock property models is based on proper combination of remotely sensed (e.g. seismic) downhole and core measurements. These methods combining interpretation and modelling provide critical inputs to the understanding of the geothermal reservoir.

From early exploration, hard petrophysical data and good physical understanding will help to constrain and develop regional and reservoir models of the geothermal resources not only to evaluate the resources but also to plan its production. At the development stage, these data contribute to reduce the risk on the well design, well stimulation, hydraulic fracturing but also the field sustainability during production.

CSIRO, with WAGCOE and other partners around Australia, is investing in applied R&D and critical infrastructure to improve the application of petrophysics to the geothermal energy sector. Demonstration projects now underway in WA will provide an excellent testbed for several of the methods described here.

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