Conceptual framework for orebody-EGS

CHPM2030 Deliverable D1.4

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CHPM2030 DELIVERABLE D1.4

CONCEPTUAL FRAMEWORK FOR OREBODY-EGS

Summary:

This document provides a summary of outcomes from Task 1.1 – 1.3. A methodological framework is created, which will be used as a guide for the laboratory measurements in WP2. In this report, there is also a framework for data collection for modelling heat transport. A review of currently existing reservoir enhancement technologies is also provided. Collecting, evaluating, and defining critical success factors during the establishment of a CHPM facility were in the focus.

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1 Executive summary

In the envisioned CHPM technology an enhanced geothermal system would be established in a deep metal-bearing geological formation, which would be conducted in a way that the co-production of energy and metals could be possible.

In this report a framework is provided for data collection and laboratory measurements in Chapter 3.

Chapter 4 provides clarification of the tectonic situation having crucial importance to the applied reservoir enhancing technology with particular attention to hydroshearing.

Vertical heat transport provides long term sustainability for geothermal energy utilization, making heat conductivity and geothermal background data analyses necessary. To obtain this information, several databases have been covered and laboratory measurements on core samples with the suggested instrument needs are taken into account in Chapter 5.

Chapter 6 discusses the profound importance of in situ stress to create the sufficient heat exchanger surface to avoid thermal breakthrough and to minimize the risk of induced seismicity. However, as local stress patterns change drastically, field measurements are suggested in every case with the proposed method.

In Chapter 7, a review of relevant reservoir stimulating technologies is provided and a framework for data collection is granted.

The essence of the outcomes of similar projects in the USA is collected and benchmarked in Chapter 8.

Chapter 9 integrates the outcomes of project documents (D1.1, D1.2 and D1.3) and creates a conceptual framework for the following laboratory investigations and defines critical factors during the development of a CHPM facility, too.

This report showcases some of the best available technologies based on our own experiences and on the newest reports which are relevant during the creation of a CHPM facility. However, laboratory experiments to be carried out in the following work packages and evolution of various technologies by 2030 may influence the feasibility of this project.

Although, there are several limitations in drawing general CHPM-relevant conclusions from the examination results, they will serve as a good base and practical input for the following phases of the project, mainly for the planning and interpretation of the leaching and petrophysical tests.

2 Introduction

2.1 Objectives and role of the CHPM2030 project

The strategic objective of the CHPM2030 project is to develop a novel technological solution (Combined Heat, Power and Metal extraction from ultra deep ore bodies), which will help reducing Europe's dependency on the import of metals and fossil fuels, and at the same time, lower the environmental impact of the energy supply.

In the envisioned technology, an Enhanced Geothermal System (EGS) is established on a metal-bearing geological formation, which will be manipulated in a way that the co-production of energy and metals will be possible. The project, at a laboratory scale, intends to prove the concept that the composition and structure of ore bodies have certain characteristics that could be used as an advantage when developing an EGS.

It is also planned to verify that metals can be leached from the ore bodies in high concentrations over a prolonged period of time and this may substantially increase the economics of the EGS. The project also aims to find proof for the concept that continuous leaching of metals will increase the performance of the system over time in a controlled way without having to use high-pressure reservoir stimulation. According to our expectations, this will provide new impetus to geothermal development in Europe. In the frame of the project, a roadmap will also be developed to support the pilot implementation of CHPM systems before 2025, and full-scale commercial implementation before 2030.

2.2 Scope and structure of Work Package 1

The CHPM2030 project consists of nine work packages. Work package 1 – Methodology framework definition provides a conceptual framework for the technology of energy production and the extraction of metals from ore deposits located at depths below conventional mining, where the temperature is above 100°C. Within this work package, we synthetize our knowledge of potential ultra deep metallic mineralisations in Europe that could be converted into an "orebody EGS". The characteristics of these bodies and their implications for EGS will also be investigated. By working on the boundaries of geophysics, geochemistry, hydrogeology and geoenergetics we aim to discover and examine the geological, tectonic, geochemical, and petrologic factors that define the boundary conditions of such novel EGS both in terms of energy and potential for metal recovery.

Work package 1 consists of four tasks. Task 1.1 involves literature research and the summarisation of Europe's metallogeny from EGS-relevant aspects. Task 1.2 focuses on the extension of the current metallogenic models to greater depths, based mostly on our knowledge about the test areas, with a complete European outlook. Task 1.3 will investigate rock properties at laboratory conditions, and Task 1.4 will provide a synthesis of the outcomes of the former tasks within this work package.

2.3 Scope and role of Task 1.4

The goal of Task 1.4 is to synthetize the outcomes of the previous work package 1 tasks. A methodological framework was set up for the concept of orebody-EGS and a definition for laboratory experiments, simulations, and modelling.

In the following sections data collection and definition regarding tectonics was done for the vertical heat transport model. A study on tectonic situations was prepared. Relevant projects taken place in the United States of America were collected and the outcomes were summarized. Already existing unconventional

reservoir stimulating technologies were studied and the pros and cons were highlighted with particular attention to the CHPM concept.

Critical success factors and their effect to the laboratory investigations – and to the whole project – are also defined during this work.

3 Standardization of laboratory measurements in order to define ore content

Samples taken from the surface are not representative for the suspected geochemical enrichment zones at great depth. However, they may provide important qualitative information about the geochemistry of rocks, ores, their textural relationships, and structural state. These physical and chemical characteristics can be used as basis to estimate the recoverable/extractable element content of the host rocks.

The following methods and equipment will be used:

3.1 Rock and ore optical microscopy

To determine mineral phases, their respective proportion in the sample, average grain size of components to be leached and ore particle surface characterization.

- Equipment: Zeiss Axio Imager A2m (polarised light, transmission and reflection mode, APO objectives, AxioCam MRc 5 camera.

3.2 X-ray diffraction – XRD

To determine mineral phases, their crystallinity and chemical bonds, clay mineral content and respective proportion of mineral phases in the sample.

- Equipment: Bruker D8 Advance diffractometer: Cu-Kα radiation, parallel beam geometry (Göbel-mirror), Våntec-1 position sensitive detector (40 kV, 40 mA), Rietveld fitting for quantitative analyses.

3.3 Scanning electron microscopy, EDX spectroscopy

Detailed characterization of samples, which have already been studied under a microscope. To reveal further mineralogical parameters, determine mineral phases through their chemical composition, studying intimate textural details like zonation, inclusions, grain boundaries and trace element contents.

- Equipment: JEOL JXA-8600 Superprobe electron microprobe with upgraded SAMX control system (15–20 kV, 20 nA).

3.4 Wavelength-dispersive X-ray fluorescence spectrometry

Bulk chemistry of samples, with information on trace element content.

- Equipment: Rigaku Supermini 200 spectrometer (Pd-tube, 50 kV, 4 mA, LiF200 / PET / XR25 crystals, 4 g pressed pellet, ZSX software).

4 Clarification of the tectonic situation/tectonics in order to build the 3D model

Clarification of tectonics is very important to build 3D fluid flow and heat transport model, because a complete understanding of basin evolution and paleostress field is the prerequisite in the assessment of geothermal resources and for defining the present fracture network (Figure 1).

Several methods for highlighting faults, that is, for computing 3D images of faults from 3D seismic images, are commonly used today. Some compute a measure of the continuity of seismic reflection, others compute a measure of discontinuity, such as variance, entropy, or gradient magnitude. All of these methods are based on the observation that faults may exist where continuity in seismic reflections is low or equivalently, where discontinuity is high (Hale, 2013).

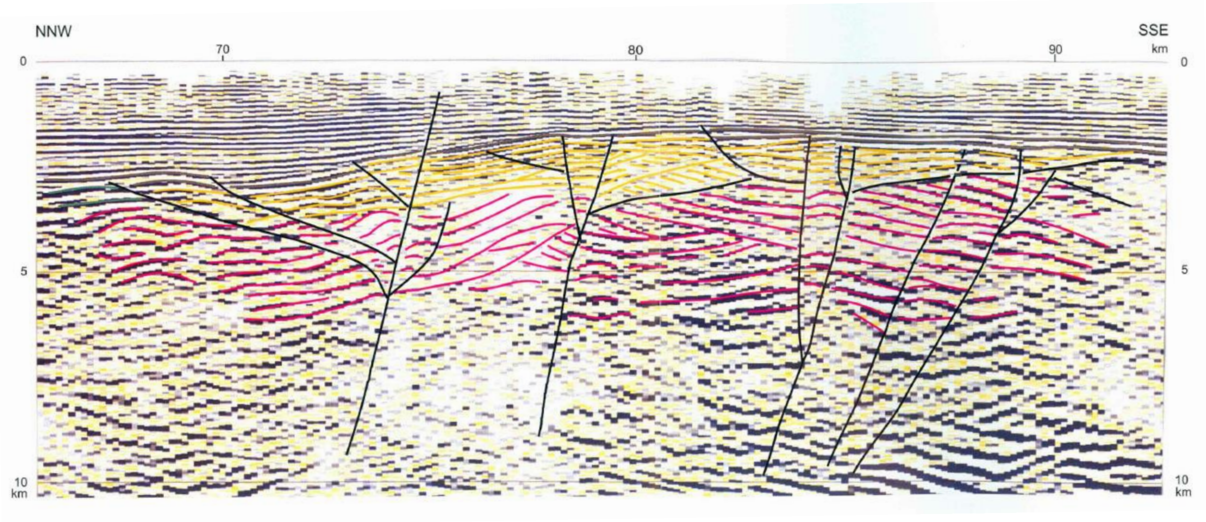

Figure 1. Seismic profile (section PGT-1 Hungary) with interpretation of reflection depths and fracture network (Posgay et al. 2000)

On the one hand, understanding a fault's slip behaviour, as well as its length and connectivity, is important for constraining the magnitude range and frequency of earthquakes that a particular fault is likely to produce during stimulation. On the other hand, the application of the tectonic model for the porphyry polymetallic vein kin-deposit system is used to assess the undiscovered metallic mineral resources like in northern Hungary (Drew and Berger, 1998).

Generally, a fractured reservoir system can be divided into two subsystems; more permeable discontinuities surrounded by a less permeable matrix. This theoretical model is the base of the tectonic concept, which is characterized as a combination of more transmissive zones and the less transmissive blocks among them.

In addition to the descriptive structural, geological and microtectonic parameters routinely used to characterize fractures and fracture networks in rock bodies, the use of quantitative parameters has increasing importance. Individual fractures can be regarded as finite, multiply bent two-dimensional surfaces, which can usually be approximated using simple planes (Chiles and de Marsily 1993).

For modelling, most studies approximate fractures by using penny-shaped disks. More specifically, the following descriptive geometric parameters of individual fractures must be determined: the radius of the circle representing the fracture and the spatial location of the midpoint of the circle and its orientation (strike and dip). For fracture networks, these parameters can be regarded as functions describing the

fracture length distribution, the spatial density of midpoints and strike and dip data pairs (M. Tóth and Vass, 2011).

Fracture networks can be characterized from numerous structural geological points of view, and also by diverse measurable geometric parameters. During the fracture network modeling process several methods are used. One of them deals with determination of fracture network geometric parameters (length distribution, spatial density of fracture midpoints, fracture aperture, fracture orientation). Prior to fracture network simulation using the above parameters, they should be interpolated for the whole study area. Finally, appropriate simulation software should be applied for 3D modelling (M. Tóth et al. 2004).

Several studies have described the size distribution of fractures of a given generation. There is a general agreement that the size distribution of fracture lengths is usually highly asymmetric; the number of small fractures significantly overwhelms the number of large ones.

The task of setting up a correct definition of fracture aperture is not without its difficulties, as the original aperture size of the fractures created by deformation of the rock body can be modified secondarily because of various water–rock interaction processes. The degree of transformation can differ from point to point along the line of the fracture itself, either as an increase in aperture size as a result of dissolution or as a decrease as a result of cementation. The opening and closing of fractures with a given orientation within a fractured reservoir largely depend on the stress parameters at a given depth. Thus, the aperture of fractures cannot be objectively determined by surficial measurements (M. Tóth and Vass, 2011).

In contrast to the length and aperture, where definitions are relatively straightforward, spatial density of fractures is an attribute that has been defined in several ways due to theoretical considerations. It has been systematically proven by empirical data that fracture networks behave geometrically as fractal-like objects, regardless of the lithological parameters or the structural evolution of the rock body (Barton and Larsen 1985; La Pointe 1988; Hirata 1989; Roberts et al. 1998). This enables a complex analysis of the disks representing discrete fractures, specifically in terms of their size (diameter, aperture) and spatial distribution at a given scale.

Several brittle deformation events cause fracturing of rock complex following its post-tectonic evolution. Thanks to fractal dimension of fracture system very wide range of data are usable from the large scale (stereo photos or satellite images, seismic data) through medium scale (acoustic borehole logging) up to the small scale (hand specimens and thin sections) to model the tectonic situation.

5 Data collection for the vertical heat transport model

5.1 Material properties for heat transport

Material properties describe the relevant properties of the porous medium to be simulated on an elemental basis. The material properties for heat transport simulation are:

- Aquifer Thickness (heat)
- Porosity (heat)
- Volumetric Heat Capacity
- Heat Conductivity
- Anisotropy Factor of Solid Heat Conductivity
- Dispersivity (heat)
- Source/Sink (heat)
- In-/Out-Transfer (heat)

Units: E- Energy, L – Length, t – Time, T – Temperature

5.1.1 Aquifer thickness

Unit: [L]

In confined two-dimensional horizontal models the aquifer geometry is not defined for the flow simulation as transmissivity is used as the input parameter. The transport simulation, however, is based on pore velocities that are calculated by dividing the Darcy velocity by the aquifer thickness.

5.1.2 Porosity

Unit: [none]

For the heat transport simulation, only the part of total porosity contributing to fluid flow, and thus to advective transport, is relevant. This so-called effective porosity is to be input as porosity for mass transport. In heat transport, porosity is also used to calculate bulk parameters of each element for heat conductivity and heat capacity where the input is done separately for fluid and solid.

5.1.3 Volumetric heat capacity for solid and fluid

Unit: [$E/L^3/T$]

Volumetric heat capacity is the energy needed to increase the temperature of a certain volume of a medium by a certain temperature interval. During modelling, heat capacity is split into capacity of the fluid and the matrix (solid). Total capacity is obtained internally by calculating the bulk heat capacity from the fluid and solid values and the porosity.

5.1.4 Heat conductivity of solid and fluid

Unit: [E/L/t/T]

Heat conductivity is the ability of a medium to conduct heat. In FEFLOW, underground conductivity is split into conductivity of the fluid and the matrix (solid). Total conductivity is obtained internally by calculating the bulk heat conductivity from the fluid and solid values and the porosity.

5.1.5 Anisotropy factor for solid heat conductivity

Unit: [none]

This factor applies anisotropic conditions to the thermal conductivity of the matrix. Heat conductivity of solid is hereby interpreted as horizontal thermal conductivity, and the factor defines the ratio of vertical heat conductivity and horizontal heat conductivity.

5.1.6 Dispersivity

Unit: [L]

Dispersivity is introduced in the equations to consider effects of inhomogeneities not considered in the model properties. On one hand, these are microscale inhomogeneities such as pore directions not parallel to flow direction, and on the other hand also macroscale properties such as layer structures and lenses not considered due to missing knowledge and model discretization.

Dispersivity in FEFLOW is handled by a linear Fickian relationship, distinguishing a longitudinal dispersion length (in flow direction) and a transverse dispersivity (perpendicular to the flow direction).

Practically, estimations for dispersivity are often hard to obtain, so that literature values are used. Dispersivity highly depends on the length scale of the transport phenomenon.

5.1.7 Source/Sink for solid or fluid

Unit: [$E/L^2/t$] (2D), [$E/L^3/t$] (3D)

The source/sink parameter for heat transport simulation describes a source (positive) or sink (negative) of energy per area (2D) or per volume (3D).

Typical applications include heat production in radioactive waste storages or in deep rock layers.

5.1.8 Transfer rate

Unit: [$E/L^2/t/T$] (2D confined), [$E/L^3/t/T$] (other 2D / 3D)

The inflow/outflow of heat at heat-transfer boundary conditions is calculated from the relevant area, the transfer rate, and the difference between reference and groundwater temperature:

$Q_{heat} = A*\Phi*(T_{ref} - T)$, where

Q_{heat}: inflow or outflow of heat to/from the model
A: relevant area
Φ : transfer rate
T_{ref}: reference temperature
T: current temperature in groundwater

The transfer rate for heat transport is a conductance term describing the transfer of heat from an (external) reference temperature to groundwater.

FEFLOW distinguishes between two different transfer rates for heat inflow from the external fixed temperature (Transfer rate in) and heat flow to the outside (Transfer rate out). According to the gradient direction, FEFLOW automatically chooses the correct value. The transfer rate as a material property is defined on an elemental basis. It is typically set to all elements whose edges (2D) or faces (3D) are covered by the transfer boundary condition.

5.2 Heat transport boundary conditions

By default, all model boundaries in FEFLOW are assumed to be impermeable for heat flux, i.e., no energy can flow into the model or out of the model. Exceptions are flow boundary conditions where water enters or leaves the model without the specification of a heat transport boundary condition. Their handling depends on whether the convective or divergence form of the transport equation is used. At boundaries that are not assumed as impermeable, boundary conditions must be specifically set. Boundary conditions can be placed both at outer model borders and inside the model.

The following four types of boundary conditions for mass transport are available in FEFLOW (Table 1). All of them can be used as time-constant or in combination with a time series. The application of all the boundary conditions can be constrained by additional physical constraints (constraint conditions).

Boundary condition	Short description	Examples
Temperature BC	Fixed temperature (1st kind/Dirichlet boundary condition)	• Well-known temperature at inflow boundary
Heat-flux BC	Fixed heat flux across a model boundary (2nd kind/Neumann boundary condition)	• Temperature of groundwater recharge
Heat-transfer BC	Fixed reference temperature with additional heat transmission coefficient (3rd kind/Cauchy boundary condition)	• Hot tank/building in the aquifer • Air temperature
Heat nodal sink/source BC	Fixed extraction/injection of thermal energy at a single node	• Ground-source heat exchangers in regional models

Table 1. Boundary conditionsTemperature boundary condition

Unit [T]

A temperature boundary condition applies a pre-defined temperature to a node. Instead of calculating temperature as a simulation result, at these nodes the temperature is given by the boundary condition value. This can lead to an inflow of energy into the model when neighboring nodes have a lower temperature or to an outflow from the model when there is a temperature gradient from the neighboring nodes towards the boundary condition.

Temperature boundary conditions are applied in cases where the temperature in groundwater is known in advance. This can be the case for example for fixing the undisturbed ground temperature around a model for the local influence of a ground-source heat exchanger.

5.2.1 Heat-flux boundary condition

Unit [E/(L*t)], [E/(L^2*t)]

A heat flux boundary condition applies a pre-defined heat flux to nodes along a line (2D model) or to nodes enclosing faces of elements (3D). For the calculation of temperature as a simulation result, at these nodes an additional inflow/outflow is considered.

A typical application of this type of boundary condition is the geogenic heat flow at the bottom of a heat transport model.

5.2.2 Heat-transfer boundary condition

Unit [T]

A heat transfer boundary condition applies a pre-defined reference temperature combined with a conductance parameter.

Transfer boundary conditions are applied in cases where a reference temperature is linked to the temperature of groundwater via a separating heat-conductive medium.

The inflow/outflow of a solute is calculated from the relevant area, the transfer rate, and the difference between reference and groundwater concentration:

$Q_{heat} = A*\Phi*(T_{ref}-T)$, where

Q_{heat}: inflow or outflow to/from the model
A: relevant area
Φ: transfer rate
T_{ref}: reference temperature
T: current temperature in groundwater

The transfer rate is the heat transmission coefficient describing the properties of the material between the reference temperature and the temperature in groundwater, or the properties of a boundary layer. The heat transmission coefficient for a single material is defined by

$\Phi = \lambda/d$, where

λ: heat conductivity
d: thickness

When setting the boundary condition, the reference concentration is defined as the value for the boundary condition. The transfer rate is set separately as a material property.

5.2.3 Heat nodal sink/source boundary condition

Unit [E/t]

A nodal sink/source boundary condition for heat transport applies a pre-defined extraction or injection of thermal energy to a node.

Nodal sink/source boundary conditions are applied in cases where the injection/abstraction of energy at a certain location is known. A typical example is the simulation of heat extraction by borehole heat exchangers in regional models.

5.2.4 Heat transport constraints

The application of all boundary conditions in FEFLOW can be constrained by physical limits. The combination of boundary conditions and time-constant or time-varying constraint conditions allows the representation of a broad variety of specific boundary properties. Examples in heat transport include heat transport conditions depending on hydraulic head.

Most constraint conditions are complementary constraints, i.e. boundary conditions of a temperature type (temperature BC, heat-transfer BC) can be constrained by a minimum and maximum heat flow, boundary conditions of a heat flux type (heat-flux BC, heat nodal sink/source BC) can be constrained by a minimum and maximum temperature. For all heat transport boundary conditions, an additional hydraulic-head constraint is available.

5.3 Measurement techniques

Thermal conductivity can be measured in the laboratory on rock samples, i.e. cores or cuttings, or in-situ in boreholes. There are numerous steady state and transient techniques available for measuring thermal conductivity, the most prominent being the “divided bar” and the “needle probe” method.

As is the case with most other petrophysical properties, in-situ thermal conductivity may deviate significantly from laboratory values, even if the effect of temperature, pressure and pore-fluid is accounted for. The reason for this problem is a certain scale dependence in which different aspects are involved: in-situ measurements, as a rule, represent an average over a much larger rock volume than laboratory measurements performed on small samples. On the other hand, small-scale variations may thus be lost.

5.3.1 Steady-state methods

In general, steady-state techniques perform a measurement when the temperature of the material measured does not change with time.

The most common method for consolidated rock samples is the divided bar. A sample of unknown conductivity is placed between two samples of known conductivity (usually brass plates). The setup is usually vertical with the hot brass plate at the top, the sample in between then the cold brass plate at the bottom. Heat is supplied at the top and made to move downwards to stop any convection within the sample. Measurements are taken after the sample has reached a steady state (with zero heat gradient or constant heat over the entire sample), this usually takes about 30 minutes or more.

5.3.1.1 Standard method of test for thermal conductivity of rock using divided bar (AMTS 1982) as an example

This method presents a laboratory procedure for determining the thermal conductivity of hard rocks in the temperature range 5-95°C (40-203°F) using a steady state divided bar technique. Thermal conductivity can be used in thermal analysis of petroleum reservoirs, geothermal sites, electrical transmission lines, oil pipelines, radioactive waste disposal sites, and ground solar thermal storage.

The apparatus shall consist of a thermal stack comprised, in order, of a heat source (usually supplied by a constant temperature circulating bath), an upper heat flow meter, the test sample, a lower heat flow meter, and a heat sink (usually another constant temperature circulating bath).

The stack is insulated or supplied with guard heaters to minimize heat loss through the sides. An axial load of 100±25 bars is applied to the sample so that a reproducible contact resistance is obtained and the sample is saturated to approximate the crack closure characteristics of in situ conditions.

The average temperature drops across the test sample and the relative thermal conductivity is thus determined. The apparatus is calibrated by use of quartz and silica glass reference standards run in place of the test sample.

5.3.2 Transient methods

The transient techniques perform a measurement during the process of heating up. Transient methods are usually carried out by needle probes, which are inserted into a sample and heat it for a set time while temperature readings are taken at regular intervals. Once this heating period is completed, temperature readings are taken at the same intervals during the cool down period. The signal is studied as a function of time.

5.3.2.1 The TK04 as an example

TK04 determines thermal conductivity based on the transient heat flow method (needle probe method) according to ASTM D5334-08. (ASTM Standard D5334-08, "Standard Test Method for Determination of Thermal Conductivity of Soil and Soft Rock by Thermal Needle Probe Procedure") A line source is heated with constant power, and source temperature is recorded simultaneously. Thermal conductivity is calculated from the resulting heating curve (i.e. the rise of temperature vs. time). The method yields absolute thermal conductivity values and does not require reference or calibration measurements.

TK04 (Figure 2) can measure the thermal conductivity of solids or solid fragments (including sediment, rock, drill cores or drill cuttings from boreholes), pastes, powders, and viscous liquids in a measuring range of 0.1 to 10 W m-1K-1 and a temperature range of -25 to 125°C.

Figure 2. Thermal Conductivity Meter TK04

A standard size needle probe for laboratory use (Standard VLQ) and a large and particularly robust needle probe for field measurements, the Field VLQ, are available. For hard or brittle sample materials, which are difficult to prepare for inserting a needle probe, TK04 uses a modified line-source method for plane surfaces. The needle is embedded in the underside of a cylinder-shaped probe body (HLQ probe) which is just placed on top of the sample surface (Figure 3). No drilling is required. In addition to the Standard HLQ probe for laboratory use a Mini HLQ for small samples is available.

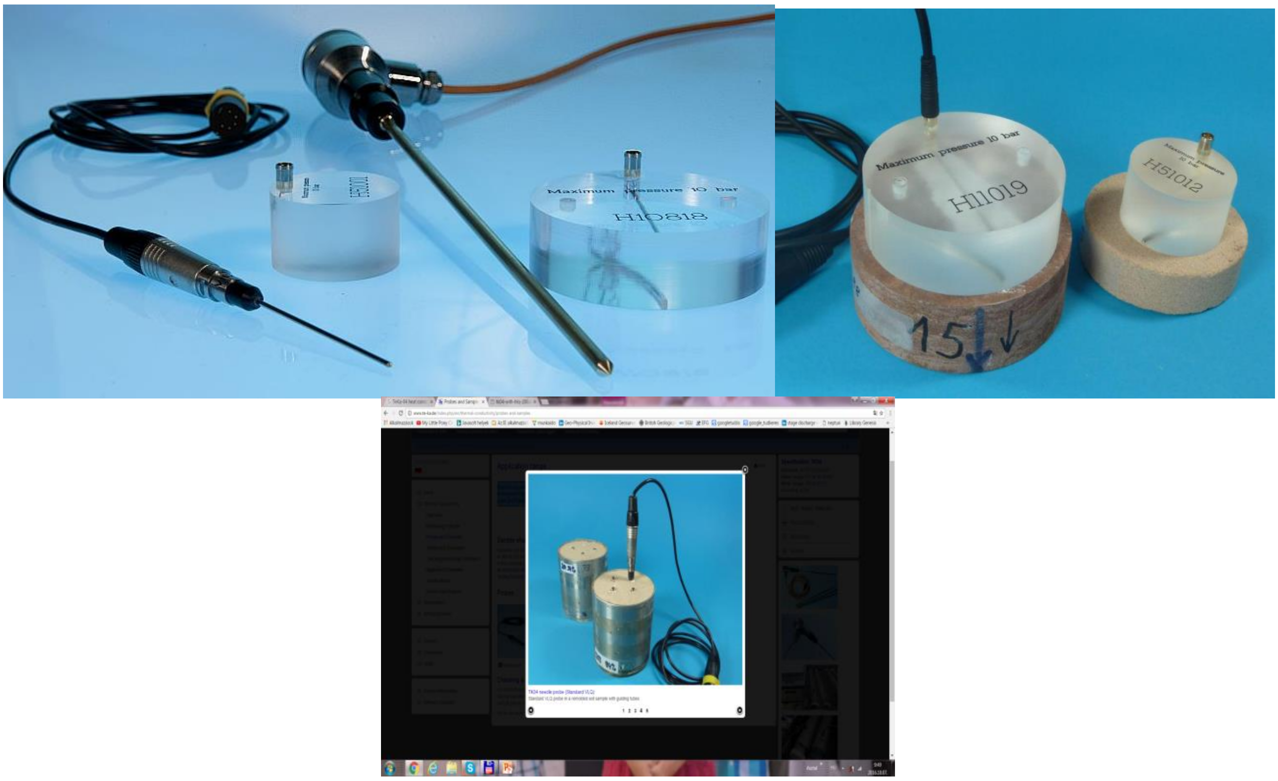

Figure 3. Samples and probes

TK04 is fully software-controlled by a connected computer or notebook. The TK04 software runs complete measuring series unattended and evaluates the data, results are saved directly to the computer's hard disk and can be analysed in detail and printed after a measuring series is completed.

As thermal conductivity tests are sensitive to factors like the contact between probe and sample, sample size, heating power, convection (for moist samples) or temperature changes, the software automatically monitors and corrects the temperature drift of the sample and provides tools for detecting sample preparation problems and instable measuring conditions.

The TK04 software combines measuring and evaluation under a single graphical user interface. The software connects directly to the graphical presentation and analysis software TkGraph for creating result diagrams and checking the data for influences of sample preparation, measuring conditions and external disturbances.

5.3.3 Indirect methods

When no direct measurements can be performed, thermal conductivity can be inferred from a number of indirect data: mineralogical composition and saturating fluids, well-log correlations, and correlations with other physical parameters. While some of these methods are based on well-defined physical models, others are purely empirical.

Thermal conductivity of rocks may be estimated from their mineral content. Minerals, due to their well-defined composition, exhibit a much smaller variance in thermal conductivity than rocks.

Similarly, as a porous rock's bulk thermal conductivity varies with different saturants, it may be of interest to know the thermal conductivity of a rock when it is saturated with other fluids than those used in the laboratory measurement. Numerous models have been proposed for this, but all have their disadvantages:

some overestimate while others underestimate systematically the true bulk thermal conductivity. Most of them are valid only for a specific range of volume ratios (or porosities), and yield completely unreasonable results outside this range.

Given the typical conductivity ratios we observe in nature, most of the conductivity models work to within 10–15% accuracy. For larger ratios, some break down more than others, and the geometric mean is one of them.

5.3.4 Well-log correlations

There are different ways in which well-logs can be used to infer estimates for in-situ thermal conductivity:

(1) One approach is to establish empirical relationships between thermal conductivity and parameters derived from well logs, such as porosity, bulk density, sonic (p-wave) velocity, and seismic travel times.

(2) The second approach is, in principle, an extension of the mixing-model approach to the borehole scale: the volume fractions of the different mineral (or fluid) phases are either taken directly from induced gamma ray spectroscopy logs or determined from a joint analysis of other logs such as gamma ray, sonic travel time, gamma density, and neutron porosity. Then an appropriate mixing model is applied.

6 Development of methods to define the in situ stress pattern according to the ore content

Understanding stresses acting in the Earth's crust is of great importance for Earth sciences and energy industries such as nuclear or geothermal. Before, during and even after energy production, one should gain knowledge about in-situ stress field of deep rock near a wellbore. Although in situ stress determination has been developed over several decades it still suffers from uncertainties due to the complex nature of rock stresses. Due to the complexity of rock stresses the magnitude and orientation of stresses in any domain of the Earth's crust can only be inferred from indirect measurements. Therefore, wellbores must be drilled in order to gain knowledge on them. Such information enables production of geothermal energy and site specific geological (seismologic, tectonic) data.

One characterizes stress component acting in any plane intersecting a deformable body by a stress vector. The unambiguous stress field at a given point of this body can be described by 9 stress vectors: in 3D, Cartesian coordinate system two tangential (in-plane) shear and one perpendicular (out-of-plane) normal stresses act at that point. The three mutually perpendicular directions result in stress tensor composed by 9 vectors which reduces to 6 independent components (3 normal and 3 shear stresses) due to symmetry of the system. In this sense, one may describe stress as pressure quantity acting at an infinitesimal point (SI unit: N/m^2=Pa).

The Earth's crust behaves as free surface from mechanical point of view, hence, by rotating the spatial coordinate system described by the stress tensor in distinct orientation one can describe the stress field by principal stresses in which no shear stresses act. The transformed coordinate system is characterized by two, mutually orthogonal principal axes and a third, perpendicular vertical principal axis. Principal stresses are usually not equal, therefore, they are referred to as minimum, maximum horizontal as well as vertical (principal) stress, S_{Hmin}, S_{Hmax} and S_v, respectively (Zang and Stephansson, 2010). By using the magnitude and orientation of these the stress distribution in a given volume of the crust, the so-called stress field can be described. In the following section, the fundamentals and main methods of in situ stress measurement required for obtaining stress field are presented.

6.1 Fundamentals and methods of in situ rock stress measurement

According to ISRM suggested method (Stephansson and Zang, 2012), establishing a stress model of a given site, generation requires an assessment of sources of stresses that can exist at the site. Following Zang and Stephansson 2010's terminology the main potential sources of in-situ solid stress are of tectonic, topography and gravity origin. Stresses that arise from topography conditions are mostly concerned in mountainous areas. Stress due to gravity is referred to as weight of overburden and assumed to be vertical. The lithostatic stress is equal to vertical stress, consequently. Therefore, rock stress measurement usually focuses on determining horizontal stresses.

Rock stresses are rather unevenly distributed and influenced by rock structure, heterogeneities (discontinuities, bolds, faults, etc.) and temporal effects (not only) on geological scale. However, rock stresses also influence the rock structure, i.e. rock mechanical parameters, such as permeability and strength values, thus, these must be known prior to any stress measurement. Otherwise, distinction between measurement errors and local stress anomalies might be challenging.

Table 2 shows typical in situ stress measurement methods used in deep boreholes as well as the core-based methods. Among those hydraulic fracturing (HF) or mini (or micro) fracking in the oil industry) is the most

widely used one at greater depth. This method can not only be applied virtually at any depth but it samples relatively great rock volume. Hydraulic Test on Pre-existing Fractures (HTPF) follows the same principle and theory used in HF, however, it is more time-consuming and thus usually not used at greater depths.

Before and usually after hydraulic fracturing borehole logging tools can also deliver important in situ stress data. Acoustic Borehole Televiewer (BHTV) and in some cases Schlumberger Formation MicroImager enforced by caliper logging provide identifying borehole breakouts (drilling induced compressive failure) and drilling induced tensile failures (DITF).

Category	Method	Rock volume (m^3)	Deepest testing (m)
Rock fracture in borehole	Hydraulic Fracturing (HF/Minifracking)	0,5–50	9066
	Hydraulic Test on Pre-existing Fractures (HTPF)	1–10	973
	Analysis of Borehole breakouts (BBO)	10-2–100	11600
	Analysis of drilling induced tensile fractures (DITF)		
Elastic strain relief by coring	Overcoring, undercoring	10-3	2100
Crack-induced strain relief in drill cores	Anelastic Strain recovery (ASR)	10-4–10-5	4544
	Kaiser effect (KE)		1600
	Core disking (CD)		3582
	Wave velocity analysis (WVA) techniques		8080
Other	Focal Mechanism/Plane Solution (FMS)	1010	-
	Induced Seismicity (IS)	105	0

Table 2. In situ stress measurement methods for geothermal research, rock volume involved and published greatest measurement depths (references in Zang and Stephansson (2010)) based on Amadei and Stephansson (1997) and Zang and Stephansson (2010)

Other valuable in situ stress determination methods are the relief methods in borehole, i.e. coring. Relief methods are the most widely used techniques in the engineering application of stress measurement. Overcoring methods measure in situ stress based on stress relief around the borehole. The relief of external forces by overcoring or undercoring causes changes in borehole strain that can be converted to in situ rock stress. Zang and Stephansson (2010) point out that overcoring methods are limited by the magnitude of in-situ stress which can only be determined at depths for which the strength of rock near the borehole wall is not exceeded. Consequently, the sampling volume and borehole depth are rather limited regarding geothermal purposes.

In situ stresses estimated from drill cores also rely on (strain) relief. In other words, microcracking occurs when rock is cut from in-situ stress field at the bottom or the wall of a deep well and results in strain (stress) relief. The most important methods are the anelastic strain recovery (ASR), analysis of wave velocities, Kaiser effect (KE) as well as core disking (CD). ASR is applied to freshly recovered cores to obtain in situ stress magnitudes and orientations, whereas the Kaiser Effect is based on recalling previous maximum stress from relaxed cores (detecting acoustic emissions). Core disking observed in recovered drill cores is an obvious sign of in situ stresses exceeding rock strength. All these methods are also valuable for obtaining in situ stresses, however, they can be applied at greater depths with limitations since, for example, the sampled rock volume is smaller compared to borehole-based methods.

For geothermal purposes, seismometers (in borehole and/or on surface) are of great importance to monitor induced seismicity (IS) following fluid injection as these also contribute to understand deeper rock (stress) properties, like focal-mechanism (plane) solutions (FMS).

To sum up, the most important methods to obtain in situ stresses in greater depth for geothermal purposes are hydraulic fracturing and methods based on analysing fractures in borehole (borehole breakouts and DITF, respectively). However, combining these with borehole and core relief methods can provide a better understanding of stresses in the Earth's crust in area of interest. Whichever methods are applied, designing, and performing in situ stress measurement requires great expertise as well as experience in device and tool operation. In the following subsections, two selected important in situ stress measurement methods, hydraulic fracturing or minifracking and analysis of fractures in boreholes are presented.

6.2 Minifracking

Typical method to measure the horizontal component of rock stresses is minifracking (hydraulic fracturing), or extended-leak off test. It must be pointed out that the terminology might be confusing, that is, hydraulic fracturing can be both a stress measurement and a production enhancement method. In this section, the method is understood as the former. A mini fracture is induced to determine the least principal stress (usually horizontal). Using the tensile strength of rock and measured pore pressure, one can estimate the maximum horizontal stress. The vertical stress is calculated from the lithostatic load (weight of overburden) using density logs.

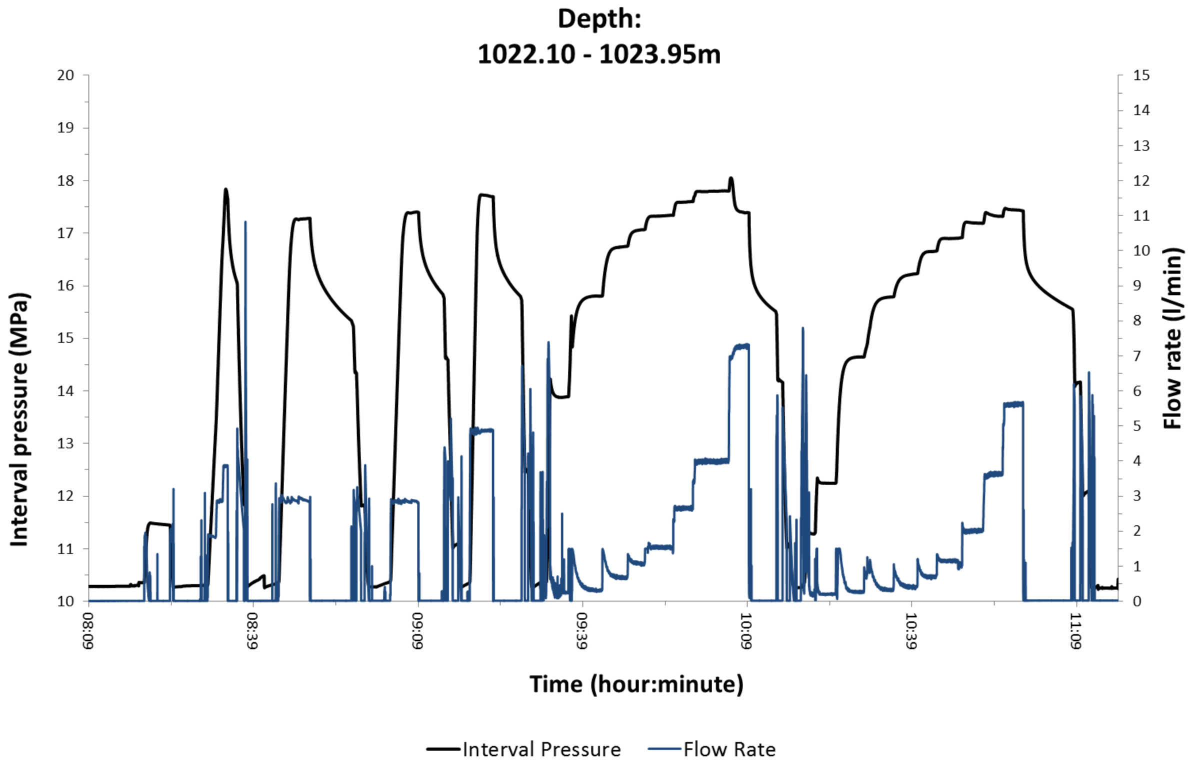

Figure 4. Example of shallow hydraulic fracturing data. Note that both outflow from and inflow into interval are on the same positive vertical axis (courtesy of Golder Associates Hungary)

A selected, optimally intact, approx. 1–1.5 m long section of an open borehole is sealed off by two inflatable straddle packers. At a constant flow rate, fluid (usually water) is injected into this interval. Initially, pressure increases linearly with time from hydrostatic load. At the leak-off point, the pressure increment becomes nonlinear which indicates hydraulic fracture initiation and leakage into rock mass. A sudden drop in the

pressure curve is observed due to the tensile fracture breakdown pressure which is a clear indication of induced hydraulic fracture. The fluid flows into the newly induced fracture and the pressure curve shows the fracture propagation pressure. Pumping is shut-in, the section remains isolated. Fracture closes, fluid flows back into the interval and eventually, the pressure curve stabilizes at a level below the fracture closure (shut-in) pressure. Eventually, the interval is bleeded, pressure drops to initial hydrostatic level.

The upper procedure is repeated several times to increase confidence in the data. The first cycle is usually the fracturing followed by several reopening phases in which the fracture is reopened at reopening pressure at a lower level than the fracture breakdown pressure, usually by step-rate or jacking cycles (Doe et al., 1987) in which flow rate is controlled against pressure and vice versa, respectively. During jacking, the flow rate is increased in step-rate, i.e. linearly with pressure until the flow rate increase with higher pressure step becomes nonlinear at jacking pressure which is a clear indication of transient flow, fracture reopening. All cycles are illustrated in Figure 4.

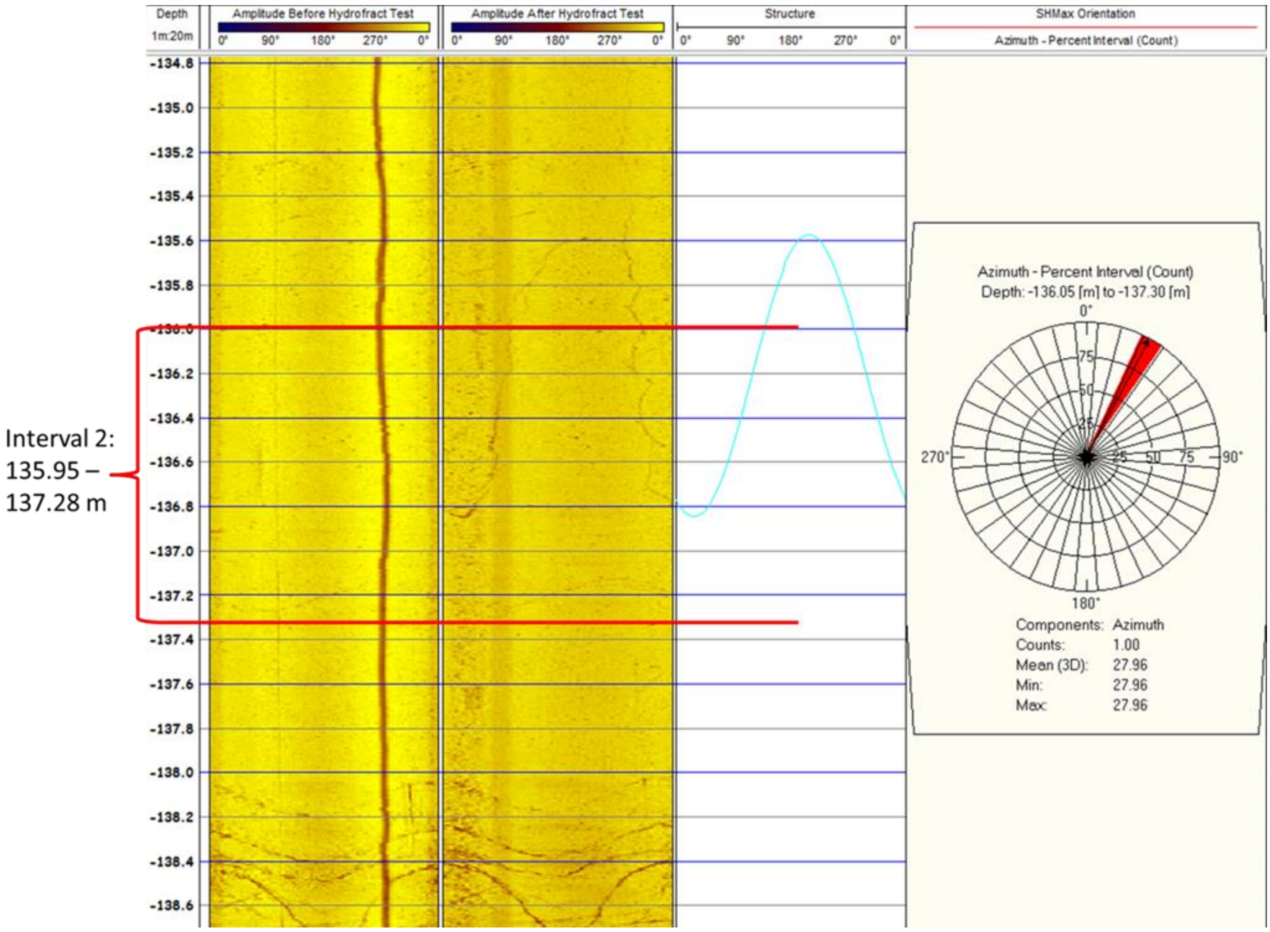

Figure 5. Pre-testing (first column from left) and post-testing (second column from left) BHTV amplitude logs. The post-testing log shows the induced hydraulic fracture. The third and fourth columns from left show the determined stress location and orientation (azimuth), respectively (courtesy of Golder Associates Hungary)

Mathematical analysis is performed on the pressure curves of each cycle to calculate the least principal stress through determining fracture breakdown, reopening, shut-in (closure), derived shut-in pressure as well as jacking pressures. Shut-in pressures are determined by studying instantaneous pressure drop due to fracture closure and jacking pressures are obtained from jacking cycles.

Hydraulic fracture is always generated perpendicular to the least principal stress. In most cases, induced fracture propagates vertically and opens parallel to maximum horizontal stress. Therefore, induced fracture

can be detected using BHTV or FMI logs that enable determining the orientation of horizontal stresses (Figure 5).

However, if generated fracture propagates horizontally (e.g. in thrust fault regime), the direction of measured stresses cannot be interpreted. Another limitation of hydraulic fracturing is that the magnitude of maximum horizontal stress can be only estimated.

6.3 Analysis of borehole breakouts and drilling induced tensile fractures

In a vertical wellbore, the stress field of interest will be perturbed around it. This often results in borehole deformation or failure processes that can also provide rock stress data following careful analysis. Analysis concentrates on stress concentration at single points around a cylindrical 2D borehole in horizontal plane characterized by higher magnitudes than in situ stress.

Given a vertical, cylindrical borehole in homogeneous and isotropic rock, stresses can be calculated around and close to a circular borehole section using biaxial Kirsch equations (Zang and Stephansson, 2010). Horizontal stresses are considered in polar coordinate system using radial and tangential (hoop or circumferential) stresses ($\sigma_{\Theta\Theta}$). The equations show that if hoop stress is maximum ($\sigma_{\Theta\Theta max}$), compressive failure happens (rock stresses overcome compressive rock strength), i.e. borehole breakouts are induced 180° apart. If hoop stress is at minimum ($\sigma_{\Theta\Theta min}$), borehole failure overcomes tensile rock strength, i.e. drilling induced tensile failures 180° apart are generated (Zoback, 2010, see Figure 6). Borehole breakouts are wider while tensile failures are usually thin and penetrate deeper into rock mass. Maximum hoop stress ($\sigma_{\Theta\Theta max}$) is parallel with minimum horizontal stress and $\sigma_{\Theta\Theta min}$ is parallel with maximum horizontal stress, thus BBOs are parallel with minimum horizontal stress and DITF (and hydraulic fracture) is parallel with maximum horizontal stress, respectively.

Borehole breakout and DITF orientations are determined using BHTV or FMI tool and with 4-arm caliper logs to increase confidence in measured data. All these enable determination of stress orientations. Zoback (2010) presented studies in which stress magnitudes are inferred from BBO widths.

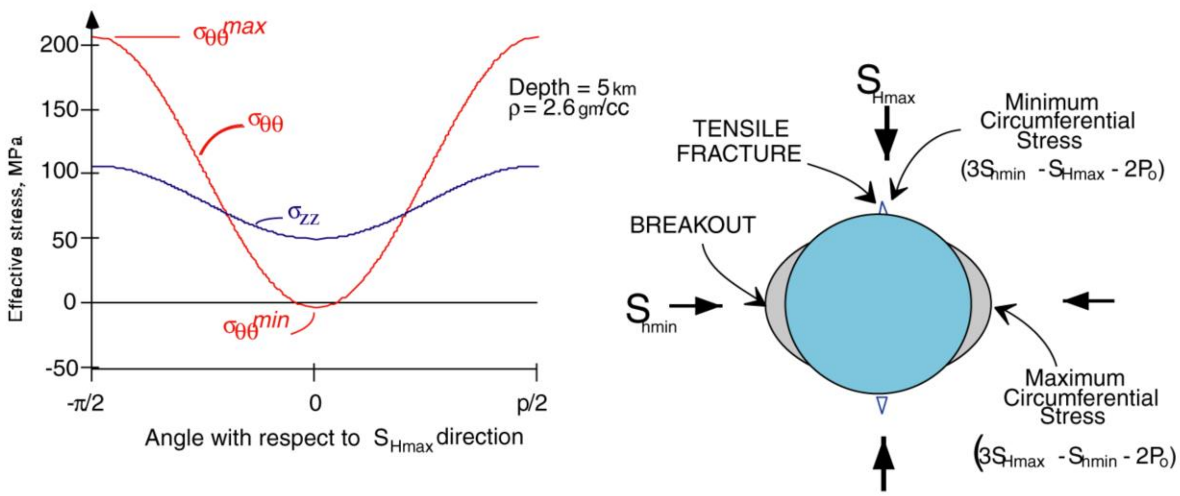

Figure 6. Left: effective circumferential (hoop) stress ($\sigma_{\Theta\Theta}$) with orientation (against S_{Hmax}). Right: theory of location of borehole breakouts and tensile fractures based on the Kirsch equations (Zoback 2010)

7 Summary and evaluation of potential unconventional reservoir engineering technologies to develop the necessary surface for heat exchange and metal extraction

When harnessing geothermal energy with engineered geothermal system techniques, it is important to have appropriate contact surface between the geological formation and the circulated fluid (Breede et al. 2013). The contact surface will serve as a heat exchanger and warm up the fluid to a temperature which is close to the temperature of the surrounding rocks (Ungemach and Antics, 2010). The necessary surface for heat exchange will be provided by a well-communicating fracture system between doublets, possibly through an ore body.

There are already existing technologies to investigate and stimulate the fractures, such as hydraulic fracking, hydroshearing and fracture enhancement by laser; which methods will be introduced in the following section.

7.1 Hydraulic fracturing

Hydraulic fracturing (also fraccing, fracking, hydrofracturing or hydrofracking) is an old-fashioned method to create fractures. The first successful experiments were in the late 1940's to increase production from petroleum reservoirs (Howard and Fast, 1970). The technology has evolved since and is now a major, essential technique in oil and gas production.

Field experiments to extract geothermal energy from rock at depth by hydraulic fracturing were started in 1970 by scientists of the Los Alamos National Laboratory, USA (Fairhurst, 2013). Two boreholes were drilled into crystalline rock (one 2.8 km deep, rock temperature 195°C; the other 3.5 km, rock temperature 235°C) at Fenton Hill, New Mexico. Hydraulic fracturing was used to develop fractures from the boreholes in order to create a fractured region through which water could be circulated to extract heat from the rock. Commenting on what was learned from the Fenton Hill study, Duchane and Brown (2002) note:

"The idea that hydraulic pressure causes competent rock to rupture and create a disc-shaped fracture was refuted by the seismic evidence. Instead, it came to be understood that hydraulic stimulation leads to the opening of existing natural joints that have been sealed by secondary mineralization. Over the years additional evidence has been generated to show that the joints oriented roughly orthogonal to the direction of the least principal stress open first, but that as the hydraulic pressure is increased, additional joints open."

This is an early indication that pre-existing fracture mass significantly affects how hydraulic fractures propagate in a rock mass. During hydraulic fracturing new tensile fractures propagate from the borehole by means of a fluid pressure overcoming the minimal principle stress plus the tensile strength of intact rock (Gischig and Preisig, 2015).

The use of proppants is a characteristic of hydraulic fracturing. Proppants are a mix of different chemicals, sands, and ceramic particles. They are used to prop open the fractures, thereby ensuring the free flow of fluids.

The risk of induced seismicity is high, and this technology already has a bad reputation due to many negative environmental effects, like polluting drinking water reservoirs. Therefore, it would be optimal to operate the CHPM without hydraulic fracturing (Breede et al. 2013).

7.2 Hydroshearing

Hydroshearing is a technical intervention, during which (compared to the hydraulic fracturing,) low pressure is applied (70-140 bar on surface) to increase the hydraulic conductivity of already existing fractures in the rock mass. Through injection, well water is pumped into the reservoir. The applied fluid pressure is smaller than would be needed to create new fractures. During hydroshearing the reopened fractures are not closing due to lithostatic pressure, because during the stimulation the rock dilates and slips in shear. The slip is caused by the tectonic forces that exist in the earth's crust and are enabled by the lubrication from the water in the opened crack. This creates small (1-2 mm) fractures and keeps them open when the external pressure is not applied anymore. Therefore, proppant or any other substances are not used to keep the fractures open.

According to Chabora et al. 2012, hydraulic shear stimulation is intended to promote the propagation of shear displacement along existing fracture planes, ideally resulting in self-propping dilatation that yields permanent gains in permeability after fluid pressures are reduced. With the goal of maximizing the stimulated volume at the reservoir depth for increased reservoir contact, shear stimulation is deemed appropriate in the context of EGS (Table 3).

A small amount of chemicals could be used during this technology as well, however, the goal of these additives is not to transport proppant (because in this case there is no proppant used), but to match the chemical composition of the pumped fluid with the geofluid in the reservoir as closely as possible (Nádor, 2015).

Target medium (reservoir)	Crystalline rock (granite)
Original permeability	Low (semipermeable)
Presence of natural fluid in the target reservoir	Present in a small amount (this would not be sufficient for utilization)
Composition of shearing fluid	Water (+additives)
Treatment of shearing fluid	Stays underground and becomes part of the natural water flow
Stimulation	Once (Small number: the recirculated water makes the system self-sustained)
Number of wells	Few (A few number of wells in each project)
Water need	Significant (tens of thousands m^3), but only once

Table 3. Summary table of the requirements for the hydroshearing (according to Nádor 2015)

According to Altarock 2016, "Thermally-degradable zonal isolation materials (TZIMs) are a family of biodegradable polymers used during EGS well stimulations. After a reservoir zone has been stimulated, TZIMs are pumped downhole. These biodegradable plastics temporarily block fractures intersecting the wellbore, allowing the next zone of fractures to open. Once several fracture zones have been created within a single reservoir, stimulation stops. The cold water pumped into the well during stimulation heats up, and

the TZIMs biodegrade. Fractures are unblocked in the stimulated zones, and an interconnected network of permeable fluid flow zones develops. AltaRock's TZIM technology makes multiple-zone geothermal reservoirs a reality.

Unlike other similar techniques, there are no residues or environmentally harmful byproducts resulting from TZIMs. Moreover, there is no need for gel breakers or acid washes to remove TZIMs from the wellbore after stimulation. Once the material is exposed to heat it biodegrades, leaving no residue or formation damage to the well."

7.2.1 Hydroshearing vs. hydraulic fracturing

According to Altarock 2016, hydroshearing "appears to be similar to hydraulic fracturing (aka fracking) used in the oil and gas industry, but there are key differences. AltaRock's hydroshearing process uses moderate pressures to open very small cracks (1–2 mm) with the goal of creating a network of thousands of permeable cracks within a reservoir. These small cracks are more efficient at transferring heat into the circulating water. Fracking uses much higher pressures to initiate new tensile fractures. These propagate rapidly away from the well and result in wide cracks that require proppants to hold them open. Hydroshearing utilizes the rough surface texture of rock fractures to allow self-propping of open fractures. Furthermore, hydroshearing does not use chemically-based fracking fluids; only water is pumped into the well during hydroshearing, eliminating the problem of ground water contamination." Figure 7 shows the main differences between hydroshearing and hydraulic fracturing.

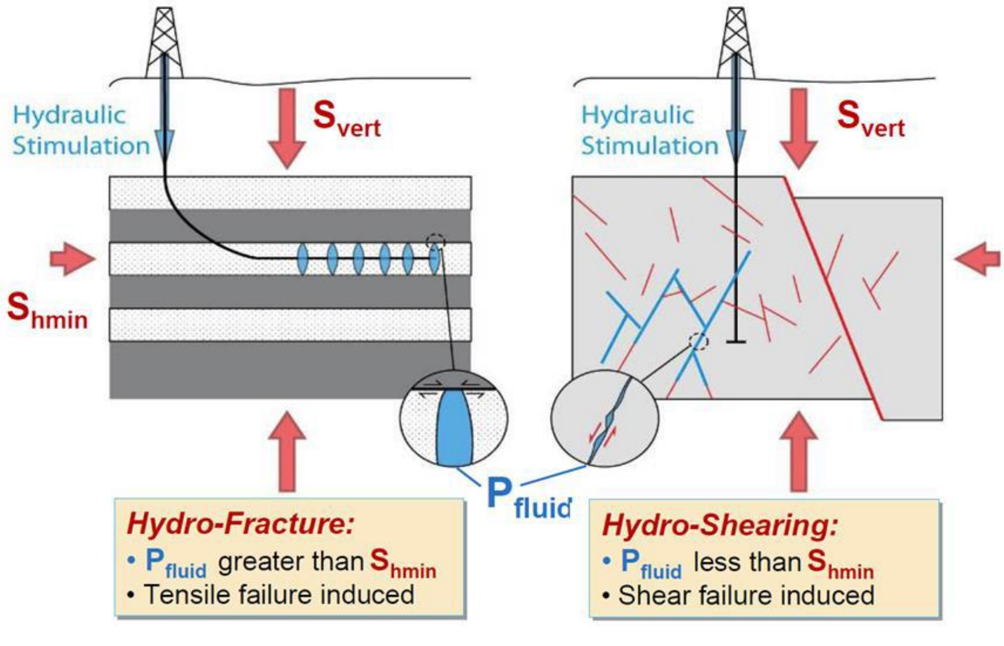

Figure 7. Comparison between hydroshearing and hydraulic fracturing (Altarock, 2016)

The issue regarding induced seismicity is one of the main concerns when it comes to social acceptance. Previously felt induced earthquakes has turned the public opinion against many geothermal projects and to project suspension like in Basel (Gischig and Preisig, 2015). Even though induced seismicity is an important issue, it has not caused any substantial damage, it is impossible to rule out earthquakes. Many authors describe a correlation between induced seismic events and the volume of reinjected fluid (McGarr, 2014; Gischig and Wiemer, 2013; Gischig and Preisig, 2015). This means, induced seismicity is not only linked to the reservoir stimulation technique, but to the rate of injection/reinjection of fluid. According to Gischig et al.

2014, for a given project, the reservoir permeability and size are strongly linked to the expected induced seismic hazard via the fluid volume needed.

7.3 Laser

Involving laser technology in geothermal energy utilization is an interesting point. The idea of laser drilling, permeability increase (therefore reservoir stimulation) by laser is promising, however, considering the novelty of the technology, economic sustainability, maneuverability, and real utility is still a question. There are many arguments with and against laser drilling, but if this technique will improve over time and prove its practical benefits, it can be a great tool for reservoir enhancement, which will be crucial during an establishment of a CHPM facility. The "principles of laser drilling technology" section is based on a paper of Szanyi et al. (2016) and Kovács et al. (2014).

7.3.1 Principles of laser drilling technology

Recent development on the field of laser technology enables us to use low energy loss high power laser devices (HPLD) even at large depths via the new standard high carrying capacity optical fibers. The HPLD will utilize a cutting-edge, underbalanced laser well completion and rework technology in fluid mining, including oil and gas as well as the geothermal industry. The system is comprised of a high power laser generator and a specially designed directional laser drilling head. The laser head is attached to coiled tubing or an umbilical system to maximize production and to carry out special jobs. The laser tool will superheat the subsurface formation, melt the target material and will remove the molten debris while the borehole is being drilled (Figure 8, Bajcsi et al. 2015).

The technology allows the operator to adjust the permeability of the borehole wall. The result of this process is a highly permeable approximately 1–2 inch diameter lateral pointing into any desired direction (Figure 9), with large active surface to increase either water production yields or to reduce the pressure gradient near the opened section of the well.

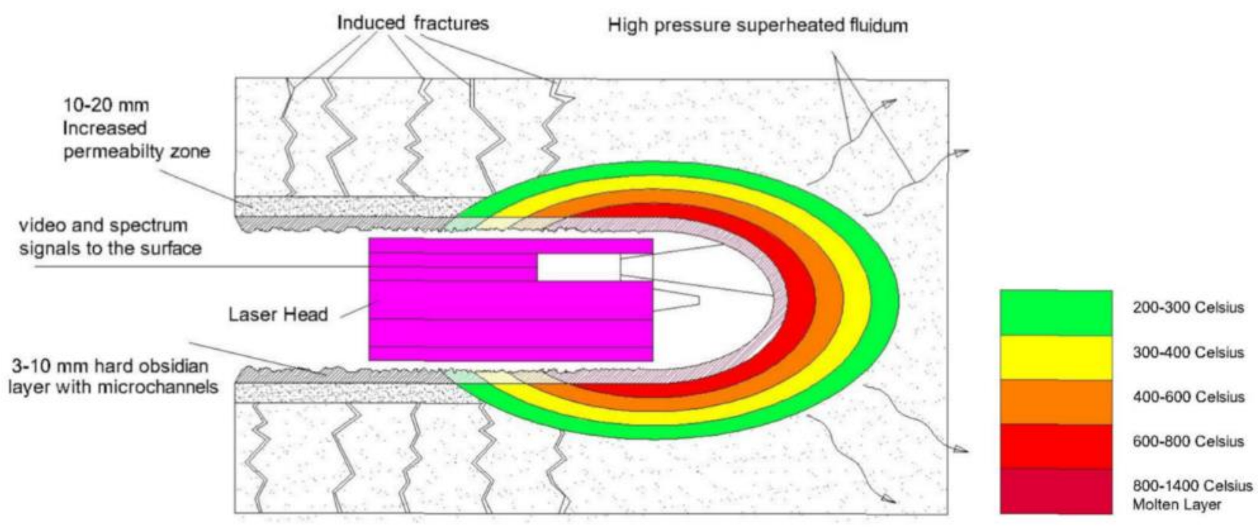

Figure 8. Scheme of laser drilling procedure

Figure 9. Laser drilled holes with melted smooth and bubble containing surfaces with and without heat shock induced fractures

7.3.1.1 Permeability changes

During the development of high power laser device, the permeability of several hundreds of samples was measured. Besides air, water and aliphatic hydrocarbons were used as test liquids. The permeability of unaltered original samples that were collected from the lowest permeability sections of the sandstone reservoir was measured in the range of 0,01–200 mD.

After the laser treatment, the average permeability of the samples was increased by a factor 1.5–4. In some cases, discrete fractures could be observed in radial directions but there were several samples where only invisible micro-fissures were formed due to the treatment. The increase in permeability was both due to the matrix and due to the fractures, therefore, this was called apparent permeability.

In less than 5% of the tests the fractures did not reach the sidewall of the samples, in these cases a slight reduction of permeability was observed. In few cases, the increase in permeability reached 2–3 orders of magnitudes (Figure 10).

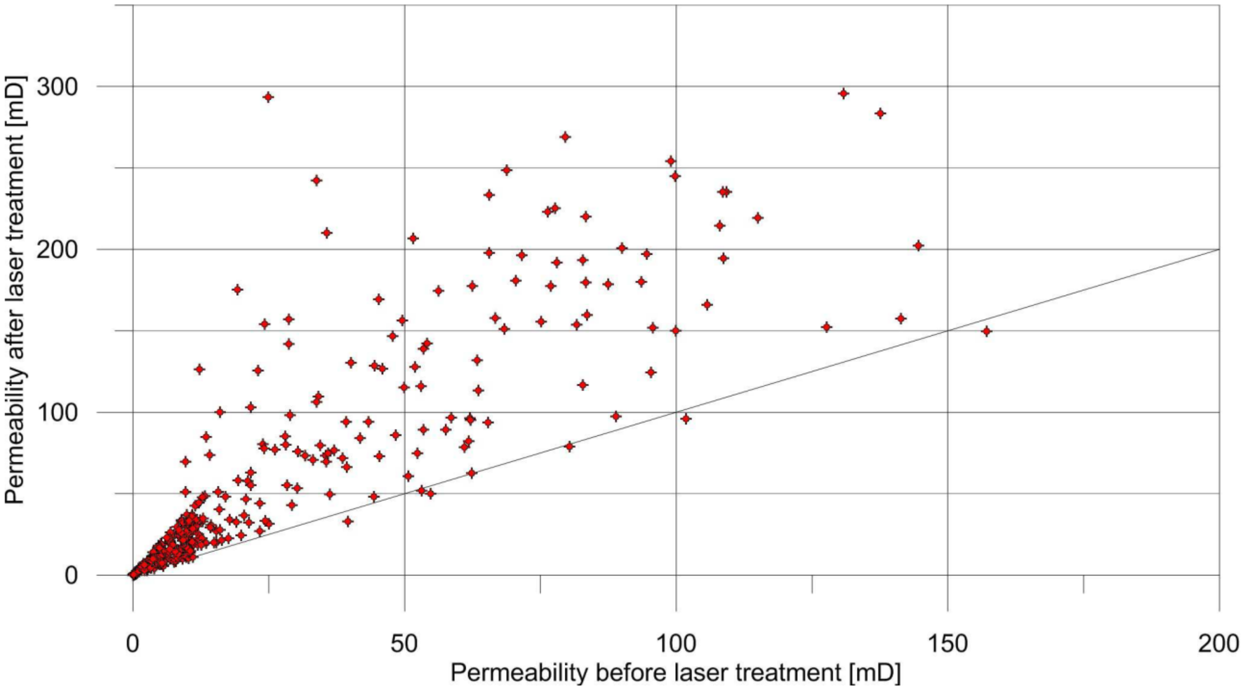

Figure 10. The apparent permeability increase due to heat shock induced fracturing caused by laser drilling

Based on the experiments the range of heat shock induced fractures is larger than 2 centimeters from the wall, which is coherent with the previous studies and CT investigations. Based on the test results, it was proven that a 1 inch diameter laser drilled borehole acts as an approximately 3 inch diameter drainage system which has a large side wall stability. During the tests no sand infiltration or leakage was experienced even at large hydraulic gradients (i > 600–800 m/m). The tests showed that the laser drilled lateral may function even at unfavorable geological and geotechnical conditions as wet silty formations or soils liable to liquefaction.

7.3.1.2 Conclusions

A series of permeability tests have been completed in order to determine the effect of laser drilling on the aquifer. Measurements indicate that the use of this technology increases the permeability around the laser lateral due to heat shock induced fracturing but it also keeps the reservoir integrity. During the laboratory investigation of the HPLD no sand intrusions or leaking was detected.

The technology may help to complete injection wells in geothermal industry with higher productivity (Szanyi et al, 2011, 2012), to build remedial wells to inject nanoliquids right on the spot or to reach hot spots on highly covered industrial sites. During the development of the HPLD only small permeability reductions were in some cases detected, so we assume that this may work in underground systems too.

7.4 Summary

There are conventional and unconventional reservoir stimulating technologies of which some will successfully be used in the future to enhance the permeability of a reservoir and to create a well-communicating discrete fracture network system. However, at the current development state, these technologies are either harmful to the environment and forbidden by law is many countries (hydraulic fracturing) or they are only in the proof-of-concept development phase and done only by a few companies (hydroshearing) or never been tested in a real (underground) reservoir (laser).

Nevertheless, by 2030 these enhancing technologies will have evolved, and hopefully the CHPM project will be able to rely on them with certainty.

8 Evaluating the outcomes of case studies from relevant US-based projects

America's Energy Department is the largest governmental office which is dealing with renewable energy. The Energy Department is responsible for ensuring energy-, environmental- and nuclear security through science, engineering, technology, research and development and of course, policies. It has many laboratories, power marketing administration facilities and operations offices all over the USA.

They also promote the utilization of renewable energy sources via financing many geothermal (and a broad scale of sustainable energy resources) related projects. Their website (http://energy.gov) and many official documents through it will be the basis of the following section.

8.1 Fenton Hill

The hot dry rock (HDR) project of Fenton Hill, New Mexico was launched in 1971, by Los Alamos National Laboratory to investigate the feasibility of a man-made geothermal system. In 1973, the Department of Energy approved funding for drilling an exploration well and then the research and development continued for 20 years (Brown et al. 2012, White et al. 2016).

During the project 8 major wells were drilled and around 100 experiments were made with relation to hydraulic fracturing. It was confirmed that heat could be extracted from a hydraulically stimulated part of a low-permeability crystalline rock (Brown, 2009).

Even though the project was discontinued due to budget cuts, these experiments justify today's hydraulic fracturing technology. As the manager of the Hot Dry Rock Project summarized the conclusions:

"…to create an effective HDR geothermal system, the stimulated region should first be created from the initial borehole, and then accessed by two production wellbores drilled to near the elongated boundaries of the seismically determined, ellipsoidal reservoir region. To first drill two boreholes, and then try to connect them by hydraulic pressurization, is almost impossible. (The reason for two production wellbores is twofold: First, to double the productivity; and second, to permit even higher reservoir pressures to further dilate the flowing joints and reduce the body impedance, while constraining additional reservoir growth.)

Reservoir productivity is the most critical remaining issue related to HDR technology development, and this is inexorably linked to the near-wellbore outlet impedance. This impedance can be significantly reduced by operating the production wells at elevated pressure, which tends to dilate these otherwise tightly closed flow outlets."

8.2 Ormat Technologies at Desert Peak

Location: Churchill County, Nevada

Partner: Ormat Technologies

Department of Energy funding: $5.4 million

Leveraging $5.4 million in DOE funding matched by $2.6 million in industry investment, Nevada-based Ormat Technologies increased power output by 38% within an operating geothermal field at Desert Peak, Nevada, generating an additional 1.7 MW of power. Extending the life of unproductive wells using new technologies is one example of these innovations. With an increased injection rate up to 1500 gpm, the well stimulation at Desert Peak establishes new revenue, greater resource reserve, and production certainty, which boosts

investor confidence. The Desert Peak success demonstrates that EGS technologies are within reach right now.

EGS projects capture power from intensely hot rocks, buried thousands of feet below the surface, that lack the permeability or fluid saturation found in naturally occurring geothermal systems. EGS technologies utilize directional drilling and pressurized water to enhance flow paths in the subsurface rock and create new reservoirs, capturing energy from resources that were once considered uneconomical or unrecoverable. With the support of research and development investments across the Energy Department's renewable energy and oil and gas portfolios, American companies like Ormat Technologies are now taking advantage of this untapped resource (energy.gov).

8.3 Newberry volcano EGS Demonstration project

Location: Bend, Oregon

Partner: AltaRock Energy, Inc.

Department of Energy funding: $21.4 million

AltaRock's EGS demonstration project at Newberry Volcano near Bend, Oregon, represents a key step in geothermal energy development, demonstrating that an engineered geothermal reservoir can be developed at a greenfield site. Preliminary results from the AltaRock Energy EGS demonstration suggest that the project successfully created three separate zones of fluid flow from a single well where none existed before—a first-of-its-kind achievement. AltaRock completed reservoir stimulation in January 2013, and data are being analysed to confirm this significant technical milestone.

Newberry marks a critical achievement in lowering the cost of geothermal development. As the generation capacity of geothermal wells improves, costly drilling can be minimized, dramatically reducing project costs (energy.gov).

The project is composed of 3 phases:

Phase 1: review existing data, conduct baseline measurements, develop plans, and obtain permits

Phase 2: create EGS reservoir around an existing well – hydroshearing

Phase 3: summarise the collected information to develop a conceptual model of a commercial scale EGS system

The Newberry Volcano is a large forest-covered shield volcano with a caldera containing two large alpine lakes that are popular recreation destinations. The volcano was identified as a potential site for geothermal energy development several decades ago, and geothermal exploration began in the 1970s. Although geothermal resources were identified inside the caldera, resistance to industrial development led to creation of the Newberry National Volcanic Monument (NNVM) in 1990 and all geothermal leases were moved outside the monument boundary. Stakeholders from industry, government and the public were involved in creation of the Monument, and dedication of NNVM solved critical issues for protecting the scenic and recreational values in the area while providing for continued geothermal research and development outside of the caldera.

In 2008, Davenport Newberry, LLC., the holder of geothermal leases covering several thousand acres outside NNVM, drilled two 3 km (10,000 ft) deep geothermal wells on the flanks of Newberry. The company hoped to locate and tap into a natural hydrothermal system to produce electricity. Almost two miles below the surface of the volcano, they found very hot rock (315°C), but no hydrothermal fluids. The rock here is

impermeable, and no water naturally percolates down to the depth of the hot rock; thus, no steam flows out of the deep wells that could be used to turn a turbine.

In 2009, to prepare a proposal to the U.S. Department of Energy, AltaRock evaluated several known geothermal areas with idle hot wells for suitability for an EGS demonstration project. Factoring in geologic and hydrologic assessments, permitting and land use, water rights/access and proximity to population centers, roads, potential transmission line routes, Newberry was chosen as a prime candidate. The two Davenport wells on Newberry Volcano met all of these criteria, and AltaRock formed a partnership with Davenport to use one of their dry geothermal wells for an EGS demonstration project. In 2010, the DOE awarded a matching grant to help fund the Newberry EGS Demonstration proposed by AltaRock. The project is supported by Lawrence Berkeley National Laboratory, University of Utah, Temple University, and scientists from the U.S. Geological Survey and Pacific Northwest Seismic Network.

Since 2010, AltaRock Energy has conducted ongoing research at the site. In 2012, a network of 15 seismometers was deployed at the field site, making Newberry Volcano one of the world's most well monitored volcanoes. Wellbore surveying activities were completed in 2013, and repairs to well NWG 55-29 were completed in early 2014. An EGS stimulation was conducted using AltaRock's patented thermally-degradable zonal isolation materials (TZIMs), and microseismic monitoring remains ongoing today.

Future plans for ongoing work at the Newberry EGS Demonstration include drilling a production well which will complete the closed-loop system with the current injection well. Flow and circulation testing will be used to determine productivity of the stimulated EGS reservoir. With good management practices, the geology at this unique site could provide environmentally friendly baseload (24/7) power for decades to come. Ultimately, the Newberry EGS Demonstration site could lead to construction of a 35 MW binary geothermal power plant utilizing a state-of-the-art dry cooling system. A power plant of this size produces roughly enough electricity to power 35,000 homes with clean, renewable energy. The binary system and dry cooling towers are environmentally friendly, generate zero air emissions, and the recirculating reservoir water remains in a closed-loop system at all times.

Newberry Volcano is now home to the Newberry Geothermal Energy (NEWGEN) project, part of the Department of Energy's Frontier Observatory for Research in Geothermal Energy (FORGE) initiative. The NEWGEN site is being used to improve and develop new geothermal technologies and practices. Click the link above to learn more about the NEWGEN project (energy.gov).

8.4 Calpine Corporation at The Geysers

Location: Middletown, California

Partner: Lawrence Berkeley National Lab

Department of Energy funding: $6 million

The Geysers represents the first sustained EGS demonstration success, following a year-long stimulation along the outer edges of an operating geothermal field. Using cost share from the Geothermal Technologies Office, Calpine Corporation's EGS demonstration in Middletown, California completed stimulation at an abandoned well in the largest geothermal complex in the world. The new and distinct reservoir that was created has successfully yielded enough steam to produce 5 MW of electricity. Because of existing infrastructure, this EGS reservoir demonstrates that stimulating hot rock on the margins of existing hydrothermal fields can secure higher productivity at low cost (energy.gov).

8.5 University of Utah's Raft River

Location: Raft River, Idaho

Partner: University of Utah

Department of Energy funding: $8.6 million

At the Raft River, geothermal field in Idaho, the University of Utah is developing and demonstrating the techniques required to create and sustain EGS reservoirs, including thermal and hydraulic stimulation, with the ultimate goal of improving the overall performance and output of the field. The University of Utah successfully completed well rework operations at US Geothermal's Raft River field in March 2012. This sets the stage for the thermal and hydraulic stimulation of the target well and ultimately, demonstration of the technical viability of EGS technology at this site. Like Bradys field, the Raft River demonstration will encourage future EGS well stimulations to improve the flow characteristics of sub-commercial wells to the levels of commercial production. Phase II demonstration activities are underway (energy.gov).

8.6 Ormat Technologies at Bradys Field

Location: Churchill County, Nevada

Partner: Ormat Technologies

Department of Energy funding: $4.5 million

At the Bradys field EGS demonstration site in Nevada, Ormat is working to improve well injectivity to commercial levels and to ensure a robust hydraulic connection between the well and the producing field. To this end, Ormat for planned stimulation, and hydraulic stimulation of the target well using EGS technology is underway. The project's success would encourage future utilization of EGS well stimulations to improve flow to commercial production levels, yielding clean, domestic, baseload geothermal energy. DOE has partnered with the Bureau of Land Management to collaborate on environmental permitting efforts (energy.gov).

8.7 Greenfield EGS, Weyerhaeuser Leases, WA, OR, CA

In 2008 AltaRock Energy made an agreement with Weyerhaeuser Company (NYSE:WY) to explore the potential for developing geothermal projects on 667,000 acres of land in California, Oregon, and Washington. After 3 years of exploration and evaluation, AltaRock exercised its option to lease the geothermal right to approximately 45,000 acres of the land with the best potential for geothermal development. These geothermal leases further AltaRock's goal of developing EGS in a cost-effective manner in order to provide baseload renewable energy to U.S. power markets, and to meet the renewable portfolio standard needs of utilities in states such as Washington, Oregon, California, and Nevada (energy.gov).

8.8 Summary

AltaRock has developed a revolutionary new technology which makes multi-zone EGS reservoirs possible. One way to think about it is stacking reservoirs on top of each other like a high-rise building stacks office space. Just as the multiple floors in a high-rise office building allow dramatic increases in density on a single piece of real estate, multi-zone stimulation increases the amount of rock (and heat) that can be accessed from a single well. Multi-zone stimulation increases the size of the reservoir and the amount of energy that can be produced from the well by a factor of three or more. Stimulating multiple zones requires that one zone be sealed off before another zone can be stimulated. While other companies have tried using mechanical techniques borrowed from the oil and gas industry to block successive stimulation zones.

9 Definition of critical success factors for validating the conceptual framework

Power generation and metal extraction by using high-temperature ore body is appealing, but limited both economically and technologically. A general overall assessment is ideally based on representative laboratory investigations, that averages the different geological, thermal, and technological conditions. Even if different technologies such as binary and flash steam plant types are distinguished, however, site-specific factors will govern their ultimate environmental performance (Bayer et al. 2016).

The combined heat, power and metal extraction designed for EGS is associated with specific requirements on hydraulic and geological properties of typical EGS reservoirs and, hence, on the laboratory experiments. Before laboratory experiments we summarized the critical success factors for validating the conceptual framework. As a summary of the critical factors during a CHPM facility, a table is shown (Table 4). Some critical factors can be defined after the laboratory experiments. Selection criteria are based on Schill and her co-authors work (Schill et al. 2016) among others. According to them one of the most important geological-geotechnical criterion to avoid are complex geological boundary conditions. A homogenous crystalline matrix with a high density of connected fractures is the best.

The planned laboratory investigations can be applied in both hydrothermal (aquifer existing) and petrothermal (no natural aquifer) aspects but our focus is on the petrothermal case, the closed loop operation. Table 4 summarises the critical factors during a CHPM facility.

Critical factor	Design parameter /technology/limiting factor	Impact on lab experiments? yes /no
Depth limit > 4km?	Not necessarily! The temperature is more important	No
Target orebody type and structure?	Magmatic, hydrothermal and sedimentary. Alternatives allowed, based on leaching test	Yes
Is EGS necessary or enough to find an orebody with permeability?	Probably stimulation is necessary, but in some hydrothermal case it can be skipped	No
Enhancement method: Fracturing excluded?	Not hydro-fracturing, only hydro-shearing or other new technologies	Yes
Stress field	Maximum variation in magnitude of the principal stress of < 10%	No
Volume/extension of the engineered underground heat exchanger (swept pore volume)	Higher than 2 * 10^8 m^3, and the total effective heat exchange surface need to be higher than 2 * 10^6 m^2	No
Well head temperature range?	Min. 150°C	Yes

Table 4. continued on next page

Critical factor	Design parameter /technology/limiting factor	Impact on lab experiments? yes /no
Permeability range flow impedance	Flow impedance < 0,1 MPa/kg/s; the lower limit of matrix hydraulic conductivity 10^{-11} m/s, but after the stimulation > 10^{-7} m/s	No
Size/density and distribution of fractures?	Fracture density > 2 m^{-1}, mean fracture aperture ~1 mm (minimum 1 µm) 10^{-7} m/s	Yes
Heat flow range	Min. 80 mW/m^2	No
Minimum flowrate for operation?	200 m^3/hour	No
Metal composition and concentration range in geothermal fluid? Also non-metal content	To be investigated	Yes
Type of geothermal (working) fluid(s); alternatives allowed?	Water, supercritical CO_2, Water+CO_2, Water+additives	Yes
Definition of mild leaching	Technique for economically extract products	Yes
Range of pH and redox potential	To be investigated	Yes
Closed loop operation?	Ideally yes, but hydrothermal also available	No
Closed loop underground; ratio of fluid loss tolerated?	Max. 10%	No
System designed to operate with/without down-time operation?	With down time	No
Water use for drilling	2,5-5 m^3/m	No
Lifetimes	30-80 years	No

Table 4. The critical success factor and their impacts on laboratory experiments

10 Conclusions

In this report a framework is provided for data collection and laboratory measurements, and several related projects are summarised to extract their outcome. The major reservoir stimulating technologies are discussed in this report, including a novel technology using laser.

The standardization of laboratory measurements could be done only partly because the laboratory investigations will be done in work package 2, whose results will influence the parameters of the working fluid and the extracted metals, therefore a final definition of the methods can only be done after laboratory measurements.

The clarification of the tectonic situation has crucial importance to the applied reservoir enhancing technology with particular attention to hydroshearing.

Vertical heat transport ensures the supply of long term sustainability of geothermal energy utilization, therefore heat conductivity and geothermal background data are needed. To obtain this information, several databases (through linked third parties) were covered and laboratory measurements on core samples with the suggested instrument needs were taken into account.

In situ stress has profound importance to create the sufficient heat exchanger surface to avoid thermal breakthrough and to minimize the risk of induced seismicity. However, as local stress patterns change drastically, field measurements are suggested in every case with the proposed method.

This report highlights some of the best available technologies based on our own experiences and on the newest reports which are relevant during the creation of a CHPM facility. However, laboratory experiments during the following work packages and evolution of different technologies by 2030 may influence the feasibility of this project.

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