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Inferring Production Performance from Early Injectivity Tests

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ABSTRACT

While exploring for high-enthalpy geothermal resources, getting early information on the performance of new exploration wells can accelerate the decision process. Indeed, once a new exploration well is drilled, the wellbore and its vicinity have been cooled down during the drilling because of mud circulation and mud losses. Waiting for the wellbore warm-up is necessary to be able to start the well production. Considering the significant cost of rig time, accelerating the decision process leads to an optimization of the rig usage and thus, can lead to significant savings in drilling costs, which is a large part of the exploration and development costs in geothermal developments.

The methodology proposed aims at assessing quantitatively the production performance from the results of injectivity test. A specific workflow was defined to match the results (temperature and pressure gradient) measured during the injectivity test to identify the feed zones and their respective injectivity index. The methodology also includes an extrapolation of the first heating up temperature profiles to estimate a static temperature profile relevant of the future conditions before production test. Then, the productivity index of the different feed zones are deduced from their injectivity index. The correction factor for each feed zone depends on the temperature difference between the conditions prevailing during the injectivity test and the one supposed during the production test and allows to account for the thermo-mechanical mechanisms which rules the feed zone permeability evolution as a function of the fluid circulating temperature. Thanks to an iterative process using a well flow model, the performance (rate and power) of the well once in production can be estimated. A specific program was developed to perform this workflow, including an assisted matching of the temperature profile measured during the injectivity test.

The methodology is illustrated on a well-documented case study where production data were considered as blind test. Following the proposed workflow, the production performance estimation and the resulting geothermal power were found very close to the values effectively found during the production test. It demonstrated that the methodology and its associated tools consist in an useful and convenient way to fast track estimate the well production performance from early injectivity test data.

1. INTRODUCTION

Once the drill bit has reached TD, the first tests performed on a geothermal well are generally the injection tests. Water is injected in the well and a pressure and temperature survey is performed to get the pressure and temperature profiles along the well trajectory during the injection of water. From these profiles, the fractured/permeable zones can be identified with either water injected from the well to the reservoir or water produced from the reservoir into the well. A Production Logging Tool (PLT) is often run at the same time, with a spinner in addition to the pressure and temperature survey to get a better understanding of the flow into or from the feed zones.

Once the injectivity test completed, the well is shut-in, and the fluid inside the well is progressively heated by the formation to reach the thermal equilibrium with the fluid contained into the reservoir. The static temperature profile of the reservoir can be extrapolated from the measurements of several pressure profile following the shut-in. Similar approach can be conducted for the pressure profile although its evolution as a function of time is less pronounced.

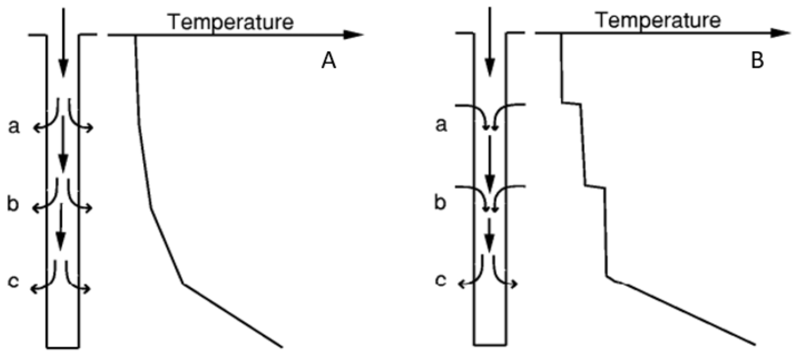

Figure 1: From Steingrímsson, 2013. The feed zones can be observed on the temperature profile. When water is injected into the reservoir (A), the feed zone causes a change of the temperature gradient. When water is flowing from the reservoir to the well (B), the feed zone induces a step on the temperature survey.

We are presenting here a quantitative methodology to infer the productivity index of the feed zones identified on the temperature profile: first, from the temperature data, the initial reservoir temperature profile is extrapolated (same is done for pressure), and, using the temperature profile during the injection test, the injectivity index of the identified feed zones is estimated. Then, from the injectivity index, the productivity index are inferred with a correction to account for the viscosity of produced water and for the temperature effect (Siega, 2014): the injectivity obtained from the injection test is higher than the injectivity at reservoir temperature, because the rock tends to shrink in contact with the cold water injected, hence enlarging the fracture aperture and the permeability around the well. This effect has to be taken into account as under production, the rock will be at reservoir temperature.

2. GENERAL WORKFLOW

The general workflow of the methodology (Figure 2) starts with the description of the well configuration (well trajectory, casing ID and thickness, casing shoe depth, cement thickness,…), the injection test duration and rate and the injected fluid temperature. The pressure and temperature measurements available can also be entered. Usually, a pressure temperature survey is available during the injection test and additional surveys are performed the well shut-in, while the temperature goes back to the initial formation temperature.

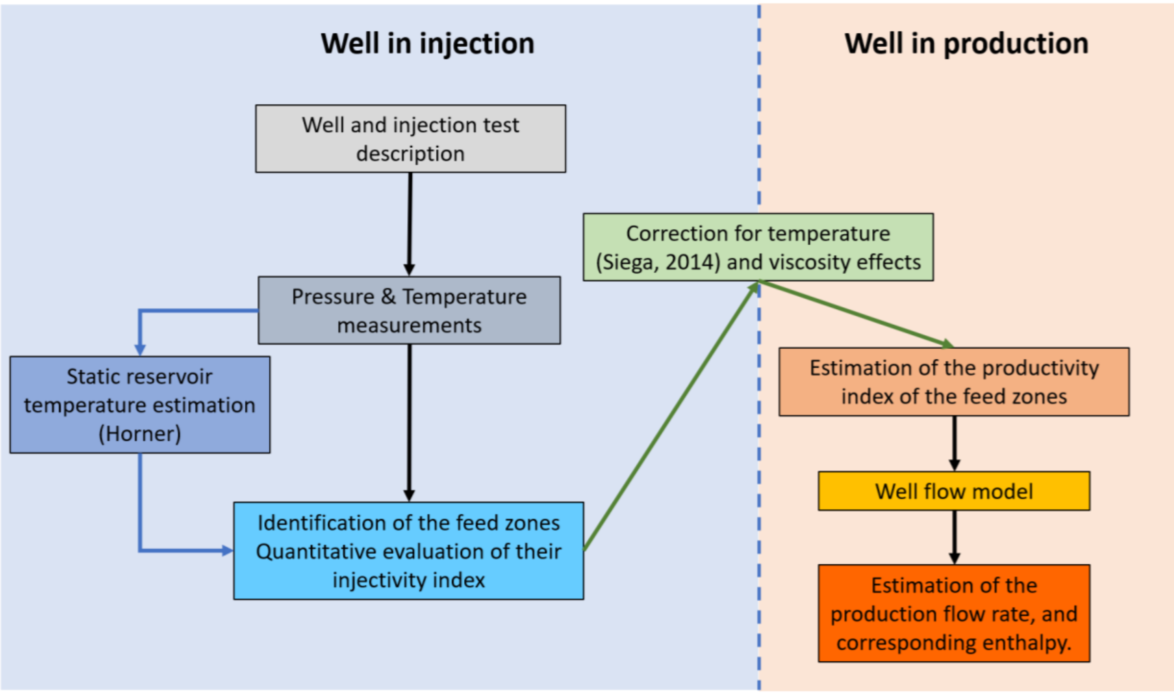

Figure 2: General Workflow of the proposed methodology, from injection test pressure and temperature profiles to production flow rate and enthalpy.

3.MODELISATION OF THE WELL IN INJECTION

The methodology considers a standard geothermal well, with a cased and cemented section from wellhead down to the top of the reservoir. From the top of the reservoir to TD, the well is considered as an open hole section in which the feed zones are producing or receiving fluids from the well, depending on the pressure gradients inside the well and in the formation.

The open hole section is generally protected by a slotted liner, but this does not impact the thermal model used in the methodology. During the injection test, the water injected flows inside the production casing from the wellhead to the open hole section where it flows inside the slotted liner if any. As a simplification, it is assumed that the temperature inside the well or inside the reservoir is only depth dependent. Below the top of the reservoir, the well exchanges fluids with the reservoir at the depth of the encountered feed zones (fractured/permeable zones). The water rate at a given depth of the well depends on the water rate injected at wellhead and the material balance of the fluid flows between the reservoir and the well at the different feed zones : the water injected in the feed zones minus the water produced from the feed zones equals the injection rate at surface.

The well trajectory is discretized into segments (of 25 meters in our examples), in each segment, the material and energy balance are respected. From wellhead to the top of the reservoir, there is no exchange of fluid between the well and the formation, only heat transfers are occurring through cement and casing via conduction. Below the top of the reservoir, in the open hole section, there are both thermal and fluid flows between the reservoir and the well.

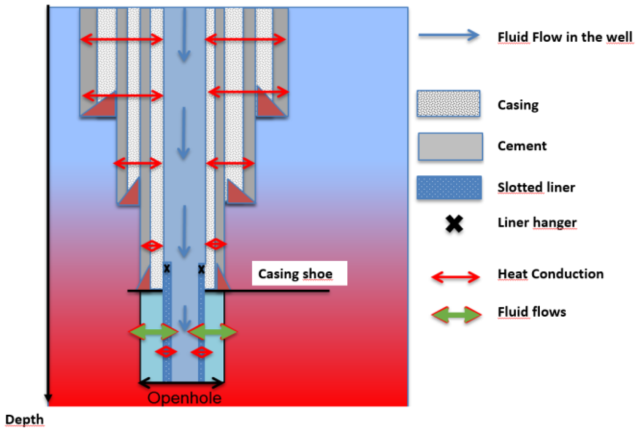

Figure 3: Typical high enthalpy geothermal well architecture. From wellhead to casing shoe, only conductive heat flows are occurring. Below casing shoe, in the open hole section, both fluid flows at feed zones depths and heat conduction are taking place.

4. STATIC FORMATION TEMPERATURE ESTIMATION

After the injection test, the well is shut-in and the fluid inside the well will progressively heat up to reach the thermal equilibrium with the reservoir. As a result, temperature profiles measured at different times after the well shut-in can be extrapolated to estimate the initial reservoir temperature. Cross flows between feed zones during this period can interfere with the temperature increase linked to heat conduction only.

The interpretation of the injection test is performed considering the thermal flux between the reservoir (assumed to be at the initial reservoir temperature at the beginning of the injection test) and the injected fluid. As a consequence, the initial reservoir temperature need to be estimated for each of the segment of the well trajectory. To do so, the methodology used in the proposed workflow is the methodology based on Horner, 1951 presented in the Appendix 1 of Grant and Bixley (2011), based on the work presented in Roux and al, 1979 and Menzies, 1981. The SFT (Static Formation Temperature) is computed for each segment of the well. For more accuracy, the mud circulation time for each segment can also be added to the injection time to compute Horner time, according to the drilling ROP in the open hole section. Keeping the same workflow, other methodology could also be implemented to obtain the SFT along the well trajectory.

5. MODEL CALCULATION

The model calculation are based on material and energy balance performed successively for each segment of the well, starting from the wellhead down to TD. At the depth z, the fluid has an enthalpy H, a pressure P, a temperature T and is flowing at a rate Q.

Along the segment between z and z + Δz:

- There is a thermal exchange by conduction between the water flowing in the well at T and the formation at the SFT (Static Formation Temperature) with a HTC (Heat Transfer Coefficient) calculated using the casing and cement thickness and their respective thermal conductivity.
- There is mass exchange, with water being injected into the formation with an enthalpy of H'=H or fluid flowing from the formation into the well at an enthalpy H' calculated from the SFT at the depth z. By convention Q' is positive (respectively negative) when water is flowing from the formation into the well (respectively from the well into the formation).

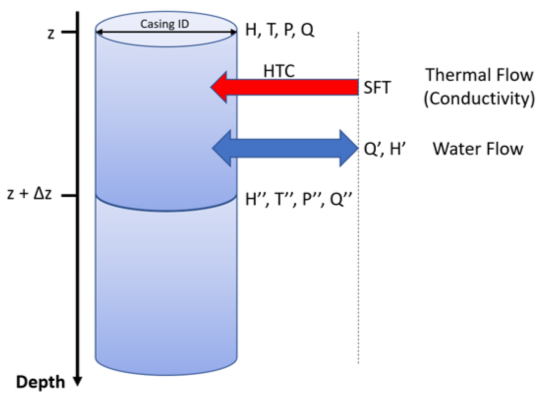

Figure 4: Modelization of the thermal and water flows between the well and the formation during the injectivity test. The properties H, T, P and Q are calculated downward from well head to TD for each segment of the well trajectory.

At the depth z + Δz:

- The enthalpy H'' is obtained by energy balance:

$$H'' = \pi \; ID \; \Delta z \; HTC \; \frac{(SFT - T)}{Q} + \frac{H \; Q + H'Q'}{Q + Q'}$$

- The temperature T'' is derived from the enthalpy H'' using water/steam tables

- The pressure P'' is derived from P:

$$P'' = P + dP(Hydrostatic) + dP(Friction)$$

- The water rate Q'' in the well is obtained by mass balance:

$$Q'' = Q + Q'$$

The well can be divided into two main parts:

- From wellhead to the casing shoe, only thermal flow by conduction is occurring.
- From the casing shoe to TD, in the open hole section, both thermal flow and water flow are occurring.

The model calculation is performed downward from the wellhead to TD, giving a value of enthalpy, temperature, pressure and flow for all the segments of the well, depending of the feed zones and their inflow/outflow. This calculation can be performed to match the temperature profile observed during the injection test. Another additional constraint will be added to match the test results: the flow at TD should be null.

6. INJECTIVITY TEST AUTOMATIC TEMPERATURE MATCHING

Using Excel Solver, an automatic temperature matching can be achieved using the well data. To do so, the well will be divided into three main sections.

The first section starts at wellhead down to the casing shoe. In this cased section, there is no flow between the well and the reservoir, thermal exchanges are occurring by conductivity between the well and the formation, the HTC depending on the casing and cement thickness. As the data available on the casing and cement is not always completely accurate (cement thickness, cement / casing thermal conductivity), this section is used to adjust a global thermal coefficient correction factor that will be applied to the entire well trajectory. The global thermal coefficient is obtained by minimizing the sum of the ΔT^2 between the calculated and measured temperature inside the well during the injection test on all the segment of the section.

The second and third sections are the reservoir sections where both thermal and fluid flows occurs:

- In the second section, going from the casing shoe to the pivot point, the pressure is higher in the formation than in the well (the fluid in the formation is at a higher temperature, hence with a lower density). In this section, the reservoir is actually producing during the injectivity test. The variable cells considered in the Excel Solver are the production rate from each of the segment of the discretized well. The objective is also to minimize the sum of the ΔT^2 between the calculated and measured temperature inside the well during the injection test on all the segments of the section. In this section, the constraint for the solver is to have positive production rate from the feed zones, in agreement with static formation pressure gradient and the pressure gradient measured during the injectivity test. Once the feed zones identified with their corresponding rates by the solver, their productivity index can be computed (at the injection test temperature).
- In the third section, going from the pivot point to TD (Total Depth), the pressure is higher in the well than in the formation: the well is injecting cold water in the reservoir. As for the second section, the variable cells considered in the Excel Solver are the rate for each segment of the discretized, but, on this section, the constraint on the sign of the fluid exchange is the opposite: the well is injecting in the formation. Once again, the objective is to minimize the sum of the ΔT^2 between the calculated and measured temperature inside the well during the injection test on all the segment of the section. Once the Excel Solver identified the feed zones and their corresponding injection rate, the injectivity index of each feed zone can be computed. Note that the Excel Solver has also a constraint: the rate in the well at TD should be null.

NB : because of the downward direction of injection, the history matching has to be conducted from the top to the bottom since any modification of upper feed zones properties will have an impact on the fluid temperature below.

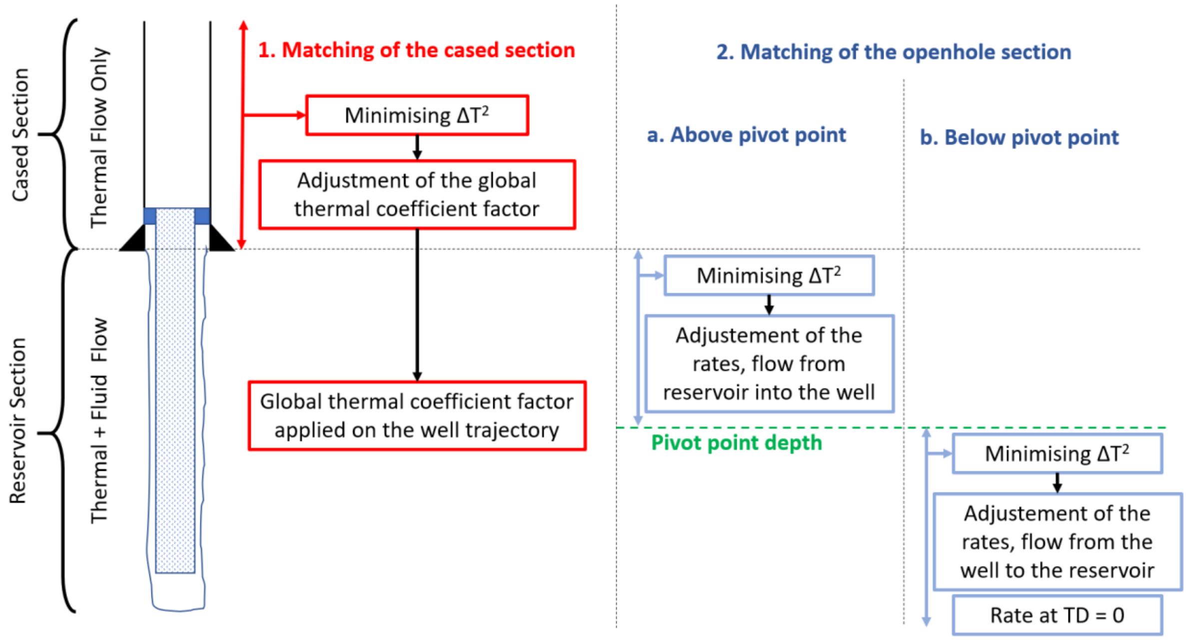

Figure 5: The two-steps automatic process implemented in Excel. First, a correction coefficient on the HTC is adjusted to get a matching of the measured temperature in the shallower cased section of the well. Then, the inflow and outflow rates are adjusted to obtain the best temperature match in the open hole section.

A visual control of the automatic temperature matching allows to check the quality of the matching. Manual adjustment of the inflow/outflow rates of the different feed zones is also possible. The pressure measurement matching can also be checked.

7. INJECTIVITY TEST MATCHING EXAMPLES

This workflow has been tested on various injectivity tests results and gave satisfactory matching. Three examples of the matching of the temperature measured during the injection test are presented below. In the following plots, the quality of the temperature matching can be checked. The SFT obtained in the process is also presented, with the cased hole section. The results of the matching process, the inflow and outflow rates obtained from the matching process are also presented. Scales and names are purposely masked for confidentiality reasons.

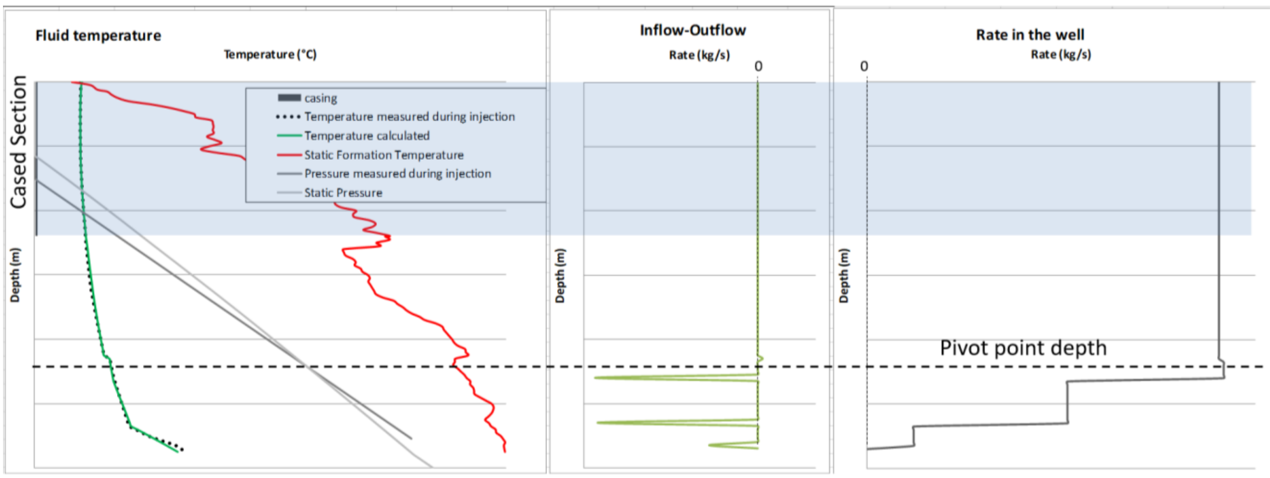

Figure 6: Matching of the temperature measurements performed during the injectivity test on Well #1 (Scales and names purposely masked for confidentiality reasons)

In the first example (Well #1) the temperature profile is marked by a small step (feed zone producing in the well) just above the pivot point followed by increases of the gradient, corresponding to feed zones accepting water flow from the well. The automatic matching of the profile is satisfactory. Note that a small production rate is sufficient to perfectly match the step increase in front of the feed zone above the pivot point.

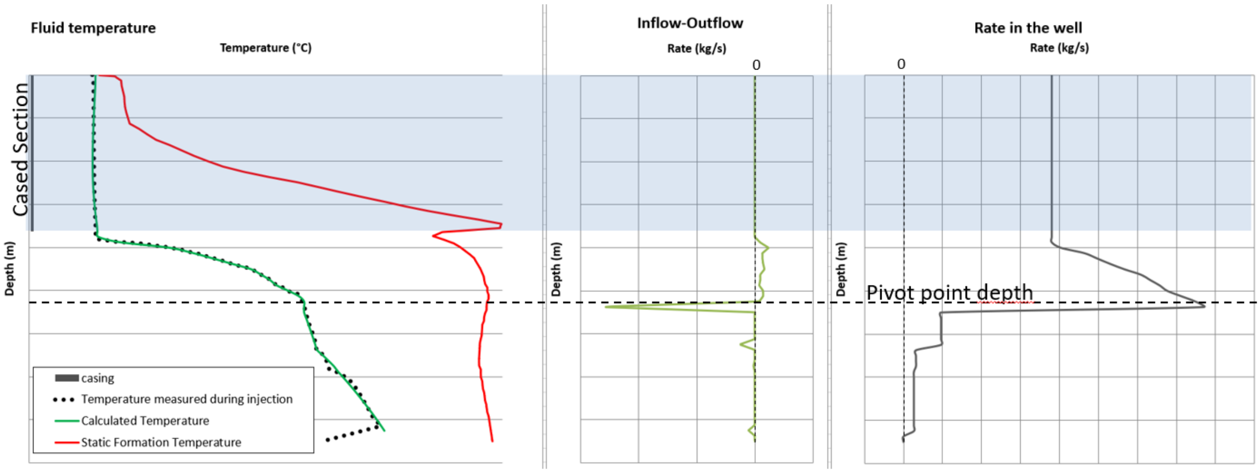

Figure 7: Matching of the temperature measurements performed during the injectivity test on Well #2

In the second example, almost all the injection rate is injected in the main feed zone, located just below the pivot point. A satisfactory matching is obtained with minor flows (from the reservoir to well) below the casing point. As for well #1, it can be noticed that minor flow from the reservoir to the well can induce significant changes in temperature. Minor feed zones were also identified at the bottom of the well detected from slight changes in the temperature profile.

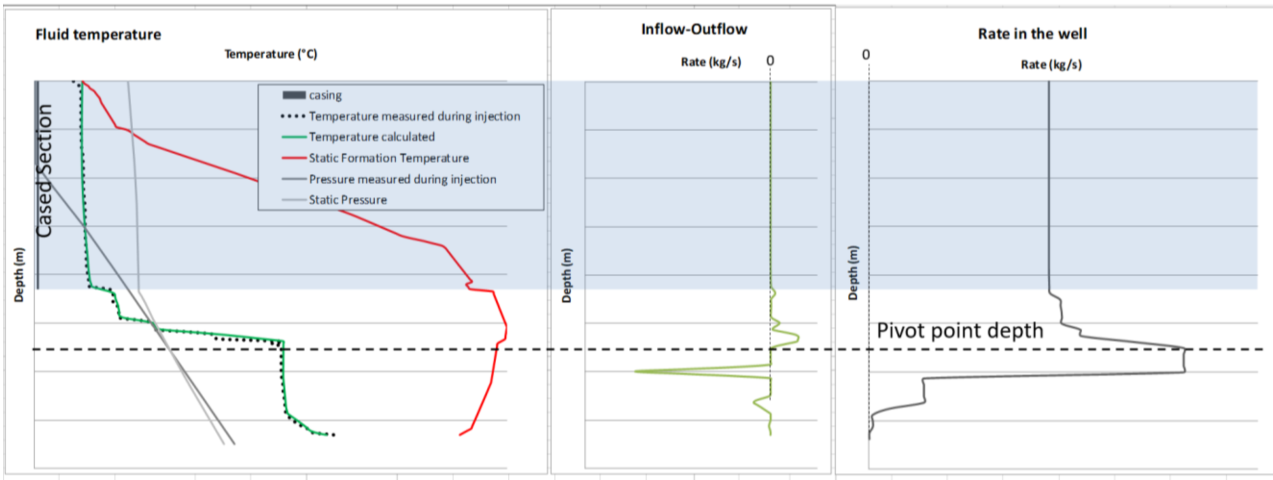

Figure 8: Matching of the temperature measurements performed during the injectivity test on Well #3

In well #3, the SFT estimated from the injection test indicates a constant formation temperature in the reservoir, with a reverse gradient at its base, which is usually an indication of the lateral limit of a convection chamber. The temperatures measurements are indicating increases of temperature (two minor steps followed by a large step), followed by an increasing temperature gradient. This temperature profile is well matched with upper feed zones above the pivot point, flowing from the reservoir to the well, with a feed zone flowing from the well to the reservoir, just below the pivot point. This last example will be used for the complete case study presented below.

8. FROM TEMPERATURE MATCHING TO PRODUCTION RATE ESTIMATION: CASE STUDY ON WELL #3

The overall objective of the workflow is to estimate the production rate and enthalpy of the well from the injectivity test interpretation. Once a satisfactory matching of the injectivity test pressure-temperature survey is obtained, the productivity/injectivity index of each feed zone should be corrected for the temperature effects: injecting cold water into the formation tends to contract the matrix blocks of the formation, increasing the fracture aperture and their permeability. From Siega 2014, a correction factor can be applied to account of the decrease in productivity linked to the increase in formation temperature. The correction factor also takes into account the change of viscosity from the injection to the production fluid.

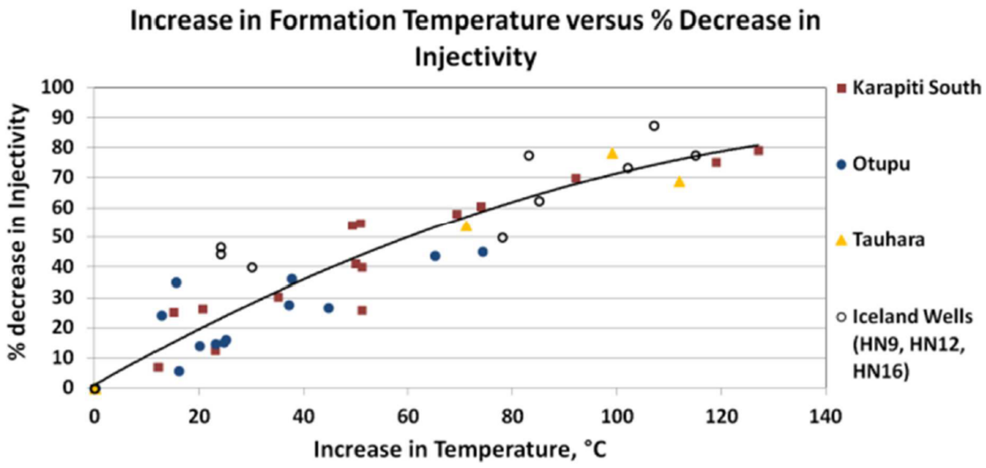

Figure 9: From Siega 2014, impact of the temperature on the injectivity/productivity index. The correlation is used to convert the productivity/injectivity index obtained from the injection test to a productivity index at the production temperature

As a result, a productivity index is obtained for each feed zone for the production temperature. Using a well flow model internally developed within Storengy, for a given wellhead pressure, a production rate and corresponding enthalpy can be calculated. The workflow presented allows us to anticipate the result from the injectivity test and to convert the injectivity test result into a production rate and enthalpy. The results obtained with the workflow were compared with the actual data from production test as a "blind test", showing that the presented workflow gives predictable results. The well flow model also provides a spinner profile which can be compared with the spinner measurements during the production test, to confirm the depth and rate of the feed zones.

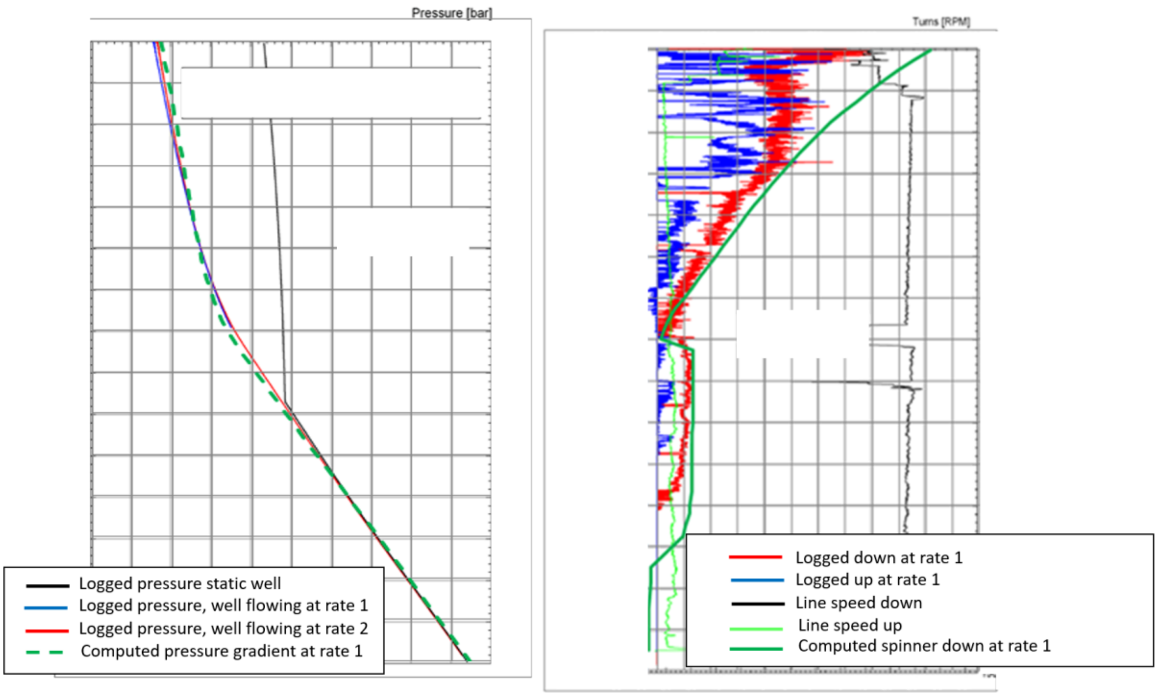

Figure 10: Pressure gradient computed with the presented workflow for a production rate 1, compared with the logged pressure profile (left). Anticipated response of the Production Logging Tool (PLT – spinner) obtained using the productivity index estimated with the workflow (right). The anticipated response is consistent with the measured spinner response.

9. CONCLUSIONS

With a focus on the matching of the temperature measurements obtained from the injectivity test, the workflow presented allows to infer the well productivity based on its injectivity test results. A discretized thermal well model has been built in order to calculate a theoretical fluid temperature along the well trajectory when injecting water in the well. This model is used to automatically match the water rate at each feed zone, either above the pivot point (flowing from the reservoir to the well), or below the pivot point (flowing from the reservoir into the well), with the additional constraint of having a null rate at the TD of the well. The HTC is calibrated in the upper cased section of the well, where only thermal conduction is occurring.

The methodology has been tested on several injection test with satisfactory results, the rate obtained for each feed zone ensuring a proper matching of the reservoir temperature inside the well. As a result, the productivity/injectivity index of each feed zones can be estimated at the injection test temperature. A correction is then applied (cf. Siega, 2014) to account for the difference of temperature and viscosity between injection and production test. The complete workflow allows to infer the performance of a geothermal well in production from the results of the injection test. Getting this information earlier in the exploration/delineation campaign can greatly accelerate the decision process in geothermal developments.

10. ABBREVIATIONS

HTC: Heat Transfer Coefficient

H: Enthalpy

ID: Internal Diameter

P: Pressure

Q: Rate

ROP: Rate of Penetration

SFT: Static Formation Temperature

T: Temperature

TD: Total Depth

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