Estimating the Static Formation Temperature Using the Drilling and Logging Data of the RN-15/IDDP-2 Well in Iceland

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Background

- The RN-15/IDDP-2 deep geothermal well of the DEEPEGS project at Reykjanes, Iceland, is a demonstration site for EGS geothermal research.
- The RN-15 well with 2.5 km depth is the drilling start point for the IDDP-2 well, which reaches to a final depth of 4,659 m after 188 days’ drilling.
- The well was drilled under continuous injection. A complete loss of circulation fluid occurred below 2,300 m.
- The measured temperature at well bottom was 426°C, the fluid pressure 340 bars, which confirmed supercritical reservoir condition.
- Estimation of the static formation temperature around the well is one of the scientific tasks of the project.

Synthetic Simulation Scenarios for the RN-15/IDDP-2 Well

Model setup

- 2D axis-symmetric domain, multiple casings and cementing programs included, injection both into the drill pipe and the annulus
- Mesh dimension 4589 m x 50 m is determined from pre-run tests
- Scenario one: 7°C cold water injection, Q2 (15 L/s) in drill pipe, Q1 (45 L/s) in the annulus for 10 days; then shut-in at the drill pipe (Q2 = 0 L/s), reduced flow in the annulus (Q1 = 0-5 L/s)
- Scenario two: 7°C cold water injection, total flow rate (Q1 + Q2) varied between 5-50 L/s; different fluid losses from annulus at 3.35 km depth (0-100%)

Simulation results and analysis

Scenario one

- Temperature measurements of the drill pipe fluid are used to estimate SFT using the Horner-plot method

Figure 1: (a) Schematic of a simulated scenario: co-existing flow without the losses (left), co-existing flow with the losses of 3.35 km depth (right); (b) two static formation temperature profiles assumed for each of the scenarios.

Figure 2: SFT estimates under different flow rates in the annulus during the thermal recovery when assuming: (a) a linear SFT profile and (b) S-shaped SFT profile (black, blue, and red line represent the SFT estimates assuming 0%; 10% fluid loss; 50% fluid loss, respectively)

Figure 3: Comparison of the SFT profile shape for the linear (a) and S-shaped (b) cases with the temperature measured in the drill pipe.

Figure 4: The generated temperature logs for the S-shaped SFT profile case considering different percentages of fluid loss at a depth of 3.35 km. (a) Results for the injection flow rate of 15 L/s. (b) Results for the injection flow rate of 50 L/s.

Figure 5: The case of temperature distribution on a plane 20 km below the annulus shows increasing temperature along the well depth.

Figure 6: SFT estimates under different flow rates in the annulus during the thermal recovery when assuming: (a) a linear SFT profile and (b) S-shaped SFT profile (black, blue, and red line represent the SFT estimates assuming 0%; 10% fluid loss; 50% fluid loss, respectively)

Simulations Using Real Drilling Data

- Temperature log simulation using integrated drilling data such as injection flow rate, logging speed, static formation temperature (estimated and provided by ISOR)
- The simulated fluid temperature profile is compared with data from one temperature log, which lasted two hours (Figure 5)
- The compensation between the measured and simulated temperature log varies along the well depth which may due to several uncertainties (rock heat conductivity, heat capacity, SFT, etc.)

Figure 6: Input data and simulation results: flow variation with time before and during the logging (upper left), static formation temperature profile until 2.3 km depth (upper right), change of the logging depth with time (lower left), comparison of the nugget temperature and the simulated temperature along the well depth (lower right).

Conclusions and Perspective

- Significant under-estimation errors in SFT using non-shut-in temperature even under very low cooling flow rate (24°C and 74°C at bottom-hole for a flow rate of 0.7 L/s for the linear and S-shaped SFT, respectively)
- Non-monotonic relationship between the increase of the temperature gradient and the percentage of fluid loss
- Temperature gradient increase depends on the flow rate, the percentage of fluid loss and the lateral heat transfer between the fluid and the rock formation
- The impact of the flow rate and the lateral heat transfer on the temperature gradient increase can be ignored under low fluid losses (<30%) or relatively higher flow rates (>20 L/s)

Conclusions

- Temperature logs can be used to estimate the static formation temperature (SFT) and to characterize the fluid loss along the borehole.
- The temperature distribution of the wellbore relies on various factors such as wellbore flow conditions, fluid losses, well layout, heat transfer mechanisms, etc.
- The numerical modeling approach offers the capability to investigate the influencing parameters/uncertainties in the interpretation of borehole logging data.
- Questions related to some specific logging conditions in the high-temperature environment, such as whether simple temperature correction methods are still applicable to obtain accurate SFT estimates using non-shut-in data, need to be answered.

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