Interpretation of flowing pressure transients to monitor mobility front movement around geothermal injectors

Introduction

Well monitoring is necessary in geothermal and CCS projects for multiple reasons including monitoring of injection / thermal front movement in the reservoir (Benson & Bodvarrsson, 1983; Nordbotten et al., 2005). Many injection wells nowadays are equipped with Permanent Downhole Gauges (PDGs) and flow meters that provide realtime pressure, temperature and rate data. Pressure Transient Analysis (PTA) is a well-developed and verified interpretation method in the petroleum industry (Horne, 2007), now extending scope to the geothermal (Bakar & Zarrouk, 2018) and CO_2 sequestration (Shchipanov et al., 2019) industries. A common limitation of the classical PTA methods is the assumption of isothermal flow conditions which may result in erroneous parameter estimations. This paper aims at understanding of challenges related with thermal effects of PTA interpretation of injection wells, which will facilitate use of downhole pressure measurements in modern wells for well monitoring using time-lapse PTA of both injection and shut-in periods.

Non-isothermal injection complicates conventional PTA due to temperature-dependent fluid and rock properties, e.g., fluid density and viscosity influencing cold-water front movement and injection performance. This movement has varying impact on pressure transient responses observed during injection and fall-off periods (Mangold et al., 1981; Jhon et al., 2021). Additionally, analyzing flowing pressure transients is a complex, moving-front issue, distinct from the simpler almost stationary-front scenarios of well shut-in interpretations (Benson & Bodvarrsson, 1983; Levitan, 2003). As a result, these complications necessitate careful consideration of temperature effects to accurately characterize geothermal pressure transients during multi-rate injections. Mangold et al. (1981) found that injecting fluid with a temperature different from the in-situ fluid's introduces composite reservoir zones reflecting change in mobility fronts that affect interpretation of well test data. Benson & Bodvarrsson (1983) suggested a method to track movement of the injectate front through apparent skin factor estimations causing high pressure build-ups at the near-wellbore, cold zone. Abbaszadeh & Kamal (1989) considered constant step-wise saturation profiles in the composite zones, later improved to continuous saturation function by (Bratvold & Horne, 1990; Larsen & Bratvold, 1994). Levitan (2003) proposed an analytical method accounting for multi-rate injection problem honouring superposition principle and showed that injection periods have a distinctive feature of late-time convergence to the injected fluid properties. Azarkish et al. (2006) compared the Levitan's analytical model to numerical simulations offering consistent PTA interpretation of step-rate injection and fall-off periods. These studies focused on cases of two-phase scenarios of cold-water injection into oil reservoirs. Our study focusses on cases of geothermal wells and demonstrates that similar pressure transient behaviour may be interpreted from either flowing or shut-in data. This is facilitating on-the-fly geothermal well testing to gain information on near wellbore effects and reservoir flow capacity from the flowing period without mandatory well shut-ins. This study contributes to the widespread transfer of technologies from oil- and gas-industry to geothermal well monitoring workflows.

Methodology

Numerical reservoir simulations and interpretations were carried out in this study using Kappa Workstation (Saphir and Rubis) software assuming single-phase (water) flow in a homogeneous reservoir, with large horizontal extension capped by strata that neither permit fluid passage nor thermal exchange with under or overburden. Single-well injection of 20°C water into 120°C reservoir was simulated with a fully penetrated vertical well. Table 1 lists the input parameters used in the simulation study. Figure 1 shows schematic top-view of temperature front movement during the injection process. The simulated cases assume isothermal (reference case) and non-isothermal injection scenarios, allowing for studying impact of thermal effects via comparative analysis of pressure transient responses. Injection often leads to a radially symmetric heterogeneity around the well because the fluid being injected typically differs from the in-situ fluid in terms of viscosity, compressibility, density, as well as the relative permeability to it. These parameters may also be temperature-dependent and affect the fluid mobility and diffusivity values. Such temperature effects may be often approximated by radial -

composite models widely used in PTA (Figure 1a&b) with different mobilities in the cold and hot zones (Bratvold & Horne, 1990).

Table 1 *Initial input parameters used in simulations*

Properties	Value	Units
Well radius	0.08	m
Wellbore storage	0.025	m^3/bar
Reservoir top	3000	m
Reservoir thickness	50	m
Permeability	30	md
Porosity	0.1	-
Initial reservoir pressure	300	bar
Rock density	2600	kg/m3
Rock compressibility	4.30E-05	bar-1
Initial reservoir temperature	120	°C
Thermal conductivity	2.3	W/m/°C
Heat capacity	0.835	kJ/kg/°C
Water saturation	1	-
Water viscosity	0.24	bar-1
Water compressibility	4.60E-05	cp
Water thermal conductivity	0.5	W/m/°C
Water heat capacity	4.184	kJ/kg/°C

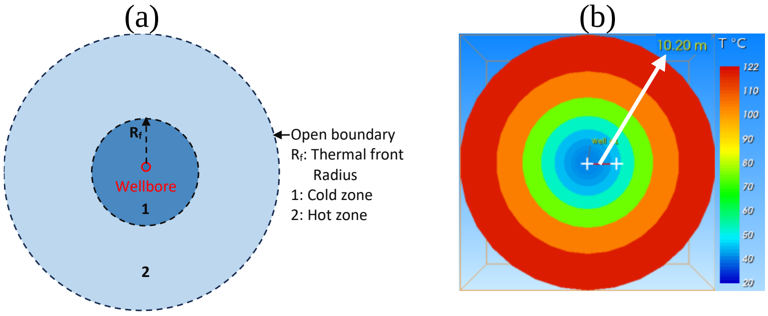

Figure 1 *Top-view at the near injection well showing composite behavior of thermal front movement (a); and temperature distribution zooming near wellbore (b)*

Results

Case-1: (see Figure 2a&b) is a sequence of flowing and shut-in periods to show that both fall-off and injection periods could provide similar information on reservoir mobility properties and near-wellbore effects. PTA interpretations in Figure 2b show two mobility levels: Mobility-1 (M_1) reflects the injected fluid mobility inside the cold zone; while Mobility-2 (M_2) reflects the reservoir fluid mobility in the hot zone. The fall-off transients coincide with subsequent injection periods at early time (M_1) and at intermediate time (M_2). This means that availability of flowing and shut-in data would allow repeatability and comparison of PTA results since similar mobility properties could be obtained. Moreover, this interpretation flexibility alleviates the challenges such as wellbore storage masking the early-time reservoir response in a single test (but this response can still be picked up in the complementary test), or, vice versa, a short transient period. Also, by comparing the isothermal injection to non-isothermal pressure transients, we see that cold water injection results in additional pressure drop (recall the apparent composite skin effect). Note that the isothermal injection transients (reference transient, e.g., Step-3) would coincide for all steps in loglog plot due to uniform fluid properties, while non-isothermal one showing dynamic radial composite signatures. This is mainly because the viscosity of the injected water is higher at cold temperatures, thus decreasing the fluid mobility near wellbore and creating a composite skin effect.

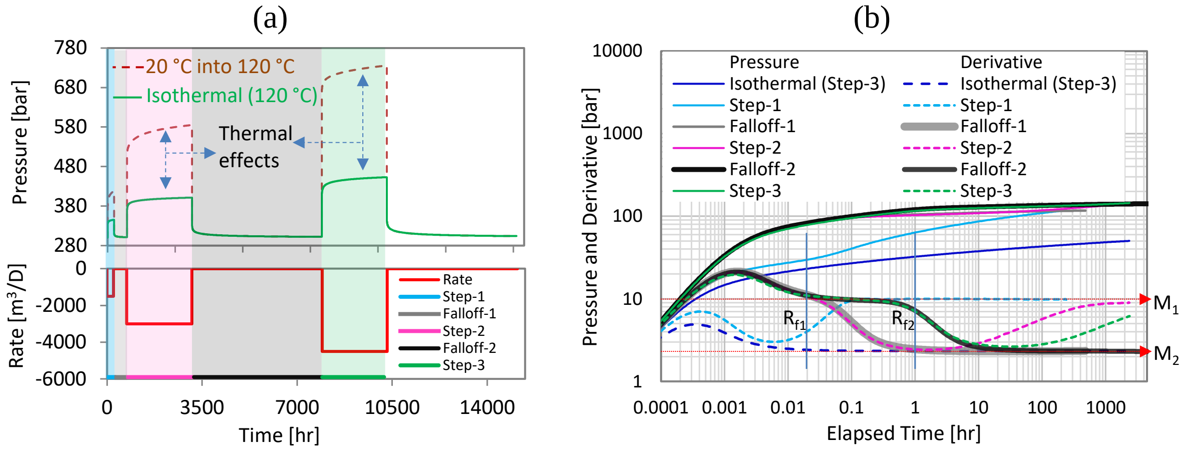

Figure 2 *Case-1: Multi-rate injection/falloff sequence (a); Standard PTA diagnostic derivative plot showing that fall-off and injection analysis provide same mobility M_1 & M_2 levels (b)*

Case-2: (see Figure 3a&b) is a step-rate test (SRT) consisting of two injection steps and a long fall-off. Figure 3a shows a history plot for the simulated synthetic SRT, comparing isothermal to non-isothermal injection simulations. Figure 3b show the interpretation in standard loglog plot with pressure and Bourdet derivatives. For isothermal injection (reference transient, e.g., Step-2), all injection steps and fall-off periods are coinciding in loglog plot as expected for a homogenous reservoir with constant fluid-rock properties.

(a) (b)

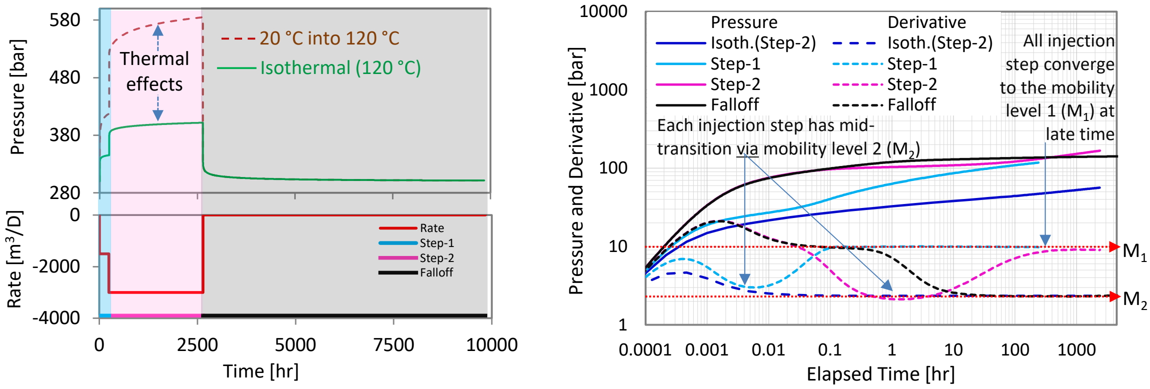

Figure 3 *Case-2: Step-rate test design (a); Standard PTA diagnostic derivative plot revealing a growing mobility front during injection periods confirmed by long falloff (b). This SRT is further interpreted in Figure 4*

On the other hand, the non-isothermal injection shows that the responses during injection steps are quite different from the fall-off period one. The growing thermal front radius (R_f) is mapped in Figure 4a, also showing the pressure front moving faster than the thermal front. Thus, the R_f at the injection time of 1000 hours is around 200 m according to the pressure and temperature (P/T) distributions (Figure 4b&c), ahead of the thermal front and behind the pressure front radius. Inside the cooling front radius, the near wellbore additional pressure due to thermal front skin effect is also highlighted (Figure 4c) beyond which isothermal and non-isotherm pressure distributions become similar, illustrating the validity of our use of the radial composite PTA model assumption explained earlier.

(a) (b) (c)

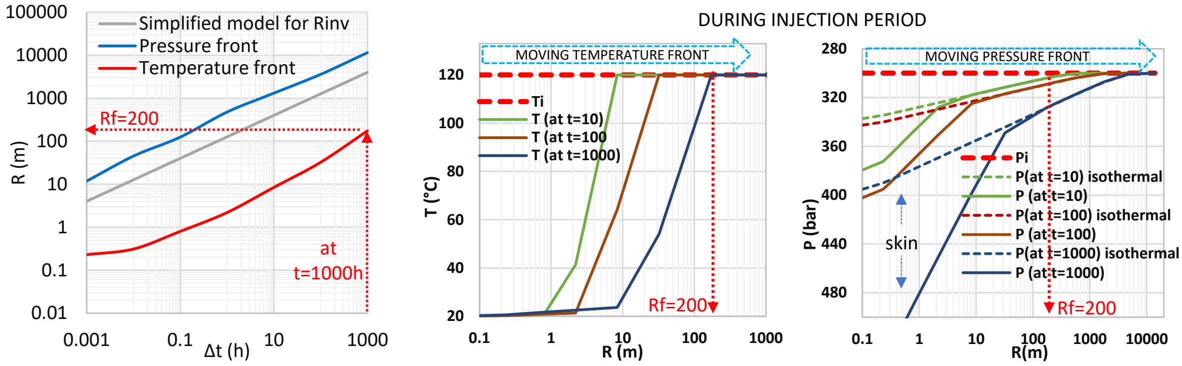

Figure 4 *Mapping of P/T fronts along radial distance (R) from the injection well (a); Temperature (b) and Pressure (c) distributions from time-lapse monitoring of mobility front, as example R_f = 200 m estimated at 1000 hours. Ti and Pi are initial reservoir temperature and pressure, respectively.*

Overall, our PTA-interpretations for geothermal cases also align with cases of cold water injection into oil-bearing reservoirs by (Benson & Bodvarrsson, 1983), (Levitan, 2003). During injection of fluids with different properties (e.g., cold water into a geothermal reservoir, CO_2 into an aquifer, water into an oil reservoir), pressure transients reveal two distinct behaviours during injection and fall-off periods:

- Injection periods: A moving front-dominated behavior, where early-time pressure transient response is indicative of the fluid properties ahead of the mobility front, while the pressure transitions manifesting changes in the reservoir fluid mobility, and reflecting the injected fluid properties at late-times (a distinctive feature observed only in transients taken during injection periods).
- Fall-off periods: A composite reservoir behavior (with a stationary front), characterized by two different mobility levels; the first mobility level reflects the fluid properties within the cold zone, while the second one represents the reservoir fluid properties in the hot zone.

Conclusion

The results of the study has shown that pressure transient responses of geothermal wells during flowing and shut-in periods could provide similar information regarding in-situ fluid mobilities and the mobility front movement. However, in contrast to the shut-in periods, widely analyzed in practice, the transients for injection periods are characterized by a distinctive feature of late-time convergence to the mobility properties of the injected fluid.

The temperature front affects the pressure transient signatures similarly to the isothermal composite reservoir behaviour: the pressure increases considerably inside the cold zone radius, while the pressure distribution outside the cold radius is the same as for the isothermal injection.

Overall, the paper results facilitate further use of the time-lapse PTA interpretation methods for:

- On-the-fly well testing for geothermal field cases without well shut-ins by enabling interpretation of well flowing periods with monitoring of hydraulic properties in near-wellbore and distant areas.
- Monitoring of mobility front movement adding value to understanding of performances of geothermal wells, water injectors in hydrocarbon reservoirs and CO_2 injectors in saline aquifers.

Acknowledgements

PhD study of Joshua Mugisha including stay at Heriot-Watt University is supported by the Research Council of Norway (grant no. 323301). Kappa Eng. is acknowledged for access to academic license of Kappa Workstation.

References

Abbaszadeh, M., & Kamal, M. (1989). Pressure-Transient Testing of Water-Injection Wells. *SPE Reservoir Engineering*, *4*(01), 115–124. https://doi.org/10.2118/16744-PA

Azarkish, A., Khaghani, E., & Rezaeidoust, A. (2006). Interpretation of Water Injection/Falloff Test—Comparison Between Numerical and Levitan's Analytical Model. *SPE International Oil & Gas Conference and Exhibition Held in Beijing, China, 5–7 December*. https://doi.org/10.2118/101749-MS

Bakar, H. A., & Zarrouk, S. J. (2018). Transient pressure analysis of geothermal wells fractured during well testing. *Geothermics*, *76*, 26–37. https://doi.org/10.1016/j.geothermics.2018.06.010

Benson, S. M., & Bodvarrsson, G. (1983). A Pressure Transient Method for Front Tracking. *58th Annual Technical Conference and Exhibition Held in San Francisco, CA. October 5-8*. https://doi.org/10.2118/12130-MS

Bratvold, R. B., & Horne, R. N. (1990). Analysis of pressure-falloff tests following cold-water injection. *SPE Formation Evaluation*, *5*(3), 293–302. https://doi.org/10.2118/18111-PA

Horne, R. N. (2007). Listening to the Reservoir—Interpreting Data From Permanent Downhole Gauges. *Journal of Petroleum Technology*, *59*(12), 78–86. https://doi.org/10.2118/103513-JPT

Jhon, R., Guerra, A., O'sullivan, J., & Omagbon, J. B. (2021). Pressure Transient Analysis of an Injection/Fall-off Test using Analytical and Numerical Reservoir Modelling. *World Geothermal Congress 2020+1 Reykjavik, Iceland, April - October*.

Larsen, L., & Bratvold, R. B. (1994). Effects of propagating fractures on pressure-transient injection and falloff data. *SPE Formation Evaluation*, *9*(2), 105–114. https://doi.org/10.2118/20580-PA

Levitan, M. M. (2003). Application of Water Injection/Falloff Tests for Reservoir Appraisal: New Analytical Solution Method for Two-Phase Variable Rate Problems. *SPE Journal*, *8*(04), 341–349. https://doi.org/10.2118/87332-PA

Mangold, D. C., Tsang, C. F., Lippmann, M. J., & Witherspoon, P. A. (1981). A Study of a Thermal Discontinuity in Well Test Analysis. *Journal of Petroleum Technology*, *33*(06), 1095–1105. https://doi.org/10.2118/8232-PA

Nordbotten, J. M., Celia, M. A., & Bachu, S. (2005). Injection and Storage of CO2 in Deep Saline Aquifers: Analytical Solution for CO2 Plume Evolution During Injection. *Transport in Porous Media*, *58*(3), 339–360. https://doi.org/10.1007/s11242-004-0670-9

Shchipanov, A., Kollbotn, L., & Berenblyum, R. (2019). Characterization and monitoring of reservoir flow barriers from pressure transient analysis for CO2 injection in saline aquifers. *International Journal of Greenhouse Gas Control*. https://doi.org/10.1016/j.ijggc.2019.102842