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Pulse Testing for Monitoring the Thermal Front in Aquifer Thermal Energy Storage

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ABSTRACT

Seasonal storage of heat in shallow aquifers for increasing the efficiency of geothermal energy systems requires a proper monitoring strategy. We expanded our earlier work on harmonic pulse testing (HPT) to incorporate the effect of a temperature front moving into the reservoir due to injection of hot (or cold) water. Our analytical solutions were applied to monitor the thermal front evolution in a doublet system. Thermal front position and average temperature around the injector could indeed be characterized through the application of the proposed HPT interpretation. Additional analyses were carried out adding noise to evaluate the robustness of the interpretation methodology.

1. INTRODUCTION

The development of Geothermal Energy in the Netherlands is mainly associated with heating. However, traditional geothermal doublets cannot operate at their optimal power due to climate seasonality and the daily fluctuations in weather and heat demand. The economics of geothermal heat could therefore be enhanced considerably by storage that evens out heat surplus and heat demand. One of the storage possibilities currently considered is seasonal storage of heat in shallow aquifers: ATEs (Aquifer Thermal Energy Storage). It would store the surplus of energy supply in the summer and harvest it in the winter. This strategy potentially increases the overall efficiency of the system.

The efficiency of an ATEs system depends on the ability to recover the stored heat. Recovery depends on the distribution of reservoir properties and on the operational design. However, the geological setting, including heterogeneities in the reservoir properties, is often

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24 poorly known. Further, the resulting temperature distribution is subject to uncertainty both after injection and after production. As a result,
25 an understanding of the heat distribution is key for being able to optimize the operational efficiency. Effective monitoring of the heat
26 distribution upon injection and production of hot and cold water is thus mandatory.

27 Well testing is an important technique for the determination of reservoir properties, including flow boundaries and mobility interfaces
28 (Gringarten, 2008). Proper production/build up testing, however, requires an initial well shut-in to approximate pressure equilibrium
29 minimizing effects of pumping operations, and a well shut-in during the build-up (Bourdet 2002). Moreover, to be interpretable, the
30 registered pressure should not be influenced by activity in neighboring wells, therefore a test usually involves also a temporary interruption
31 of nearby operations. Periodic Pumping testing (Renner & Messar, 2006) also referred to as Harmonic Pulse Testing (HPT) in the reservoir
32 engineering literature (Hollaender, Hammond, & Gringarten, 2002), on the contrary, is applicable during ongoing operations and does not
33 require significant alteration of tested well net production/injection (Salina Borello et al., 2017). Furthermore, it does not require special
34 equipment: the standard well testing equipment is sufficient, provided that well-defined rate pulses are imposed and precise pressure
35 monitoring is carried out.

36 In the present contribution, we extend the pulse testing methodology to the monitoring of thermal zones around a geothermal injector well
37 or to the monitoring of a thermal energy storage system. We will apply the interpretation approach presented by Fokker et al. (2018) that
38 is based on the strong similarity existing between the derivative of the harmonic response function versus the harmonic period and the
39 pressure derivative versus time, typical for production/build-up well testing. After detailing the theoretical basis, we will demonstrate the
40 applicability of HPT to thermal front monitoring through the application of the developed analytical solution in the frequency domain to
41 the interpretation of synthetic data generated through analytical and numerical models. As a first step, we will assess the monitoring
42 feasibility of the thermal front of a geothermal doublet system. In this case, synthetic pressure data at the injector are generated analytically
43 by mimicking the presence of a cooled zone through a radial composite model. Then, we will demonstrate the feasibility of the technique
44 in monitoring the heated zone extension in an ATEs scenario using a commercial numerical simulator, to overcome the hypothesis of
45 axial symmetry and a step function for the temperature change. Realistic thermal front evolution and the corresponding pressure
46 measurements at the heat storage well were generated, taking into account thermal convection and conduction and production and injection
47 histories of the two wells. Synthetic well pressure measurements were then interpreted adopting our analytical models in the frequency
48 domain, obtaining a reliable characterization of heated zone in terms of median temperature and equivalent radius.

49 **2. MATERIALS AND METHODS**

50 **2.1 Harmonic Pulse Testing**

51 The concept of Harmonic Pulse Testing was first proposed by Kuo (1972) and has been developed for the determination of hydraulic
52 parameters by several authors (Black & Kipp, 1981; Cardiff & Barrash, 2015; Despax et al., 2004; Hollaender, Hammond, & Gringarten,
53 2002), in different scenarios like two-phase flow (Fokker & Verga, 2011; Zhou & Cardiff, 2017), fractured wells (Morozov, 2013; Vinci
54 et al., 2015), fractured reservoir (Guiltinan & Becker, 2015), gas wells (Salina Borello et al., 2017), and horizontal wells (Fokker et al.,
55 2018). It was also suggested for the characterization of heterogeneous reservoirs (Ahn & Horne, 2010; Cardiff et al., 2013; Copty &

56 Findikakis, 2004; Fokker et al., 2012; Rosa & Horne, 1997), fault hydraulic properties (Chen & Renner, 2018), and leakage from faults
 57 (Sun et al., 2015). Some real applications of HPT have been documented in the literature for heterogeneity detection in aquifers (Renner
 58 & Messar, 2006; Fokker et al., 2013; Cardiff et al., 2019); single and multilayer reservoirs (Rochon et al., 2008); a gas storage field
 59 confined by a lateral aquifer (Salina Borello et al., 2017), a horizontal well in a gas storage field (Fokker et al., 2018) and a geothermal
 60 system (Salina Borello et al., 2019).

61 Harmonic Pulse Testing imposes the regular alternation of two rate values in a well, called Pulser. Combinations of different productions
 62 and/or injections or production/injection alternated with well shut-in, are possible. The effect is a pressure response that is also periodic.
 63 Then the harmonic components in both the rate and the pressure are determined through Fourier analysis, possibly preceded by pressure
 64 detrending (Viberti, 2016; Viberti et al., 2018). The pressure-rate relationship depends on the physics of the reservoir response and the
 65 parameters in the physical correlations. When the proper models are used, interpretation of the measured pressure response through an
 66 inversion or parameter estimation technique can be applied to derive the reservoir properties.

67 A great advantage of HPT is that it requires neither the initial static conditions (well shut-in of the tested well), nor the shut-in of any
 68 neighbor wells during the test. Under the assumption of linearity, the pressure and flow solution of a reservoir with many wells and
 69 changing production rates can then be added to the solution of the harmonic test. A Fourier transformation will provide the signal
 70 components corresponding to the imposed frequencies. Furthermore, there will be no frequency mixing; frequencies can be treated
 71 independently.

72 We present the equations for a composite radial system, which is the approximate model for an ATEs storage well that is surrounded by
 73 a region of altered temperature. In a reservoir containing single-phase slightly compressible fluid, the flow is described by the equation:

$$74 \quad \phi c_t \rho \frac{\partial p}{\partial t} = \nabla \cdot [\lambda \rho \nabla p] \quad (1)$$

75 Where $\lambda = k/\mu$ is the mobility; ϕ is the rock porosity, c_t is the total compressibility ($c_t = c_w + c_f$ where c_w is the compressibility of the
 76 water and c_f is the compressibility of the formation), k is the rock permeability, μ is the fluid viscosity, ρ is the fluid density, p is the
 77 pressure and t is the time.

78 When a piecewise homogeneous domain is assumed with approximately constant density, the equation (1) is linear and can be locally
 79 solved analytically. We obtain:

$$80 \quad \frac{\partial p}{\partial t} = \eta \nabla^2 p \quad (2)$$

81

82 where $\eta = \lambda/\phi c_t$ is the diffusivity constant. We consider each frequency component independently because they can be isolated through
 83 Fourier transformation as noted above.

84 We apply a harmonic injection rate:

85
$$q_{well} = q_{\omega} e^{i\omega t} \quad (3)$$

86 Eq. 3 is equivalent to $q_{well} = q_{\omega} (\cos(\omega t) + i \sin(\omega t))$. Thus, the real part of q_{well} represents a (co)-sinusoidal or harmonic test.

87 We write the pressure solution for each frequency as a complex-valued function that is the product of a space-dependent and a time-
88 dependent function:

89
$$p_{\omega}(\mathbf{r}, t) = g_{\omega}(\mathbf{r}) e^{i\omega t} \quad (4)$$

90 The angular frequency is defined as $\omega = 2\pi/T$, where T is the cycle time of the imposed harmonic signal. This results in a time-
91 independent differential equation for g_{ω} :

92
$$i\omega g_{\omega}(\mathbf{r}) = \eta \nabla^2 g_{\omega}(\mathbf{r}) \quad (5)$$

93 For a reservoir with radial symmetry, the diffusivity equation can be rewritten into radial coordinates. We obtain:

94
$$i\omega g_{\omega}(r) = \eta \frac{1}{r} \frac{d}{dr} \left(r \frac{dg_{\omega}}{dr} \right) \quad (6)$$

95 The general solution to this equation is a superposition of two modified Bessel functions of order 0 (K_0 and I_0) (Abramowitz & Stegun,
96 1964). For convenience, we scale the solution by the injection rate amplitude q_{ω} , and we write the general solution as:

97
$$g_{\omega}(r) = q_{\omega} C_K K_0(\zeta r) + q_{\omega} C_I I_0(\zeta r) \quad (7)$$

98 where

99
$$\zeta = \sqrt{\frac{i\omega}{\eta}}$$

100 and C_K and C_I are free parameters to be determined by imposing boundary conditions. The Bessel functions have a complex argument
101 since the differential equation has a complex parameter. As a result, the solution is complex as well, and has an amplitude and a phase
102 when translated to the real domain. At the wellbore, pressure must be corrected to include skin effect (S) as shown in detail in Appendix
103 A.

104 We consider a composite system of two concentric zones around the wellbore with different temperatures (in the literature also referred
105 to as concentric-shell model (Cheng and Renner, 2018)). The applicability of this sharp-front approximation for the actual case with a
106 continuously changing temperature will be assessed later. Different temperatures imply different fluid viscosities and possibly different
107 compressibilities. Therefore, the mobility (λ), the diffusivity (η), and the associated multiplier (ζ) for the radial distance is different in the
108 two zones. The pressure expression is thus characterized by 4 free parameters (C_K^i and C_I^i for each zone i), whose determination requires
109 4 conditions. These are given by two boundary conditions (reservoir inflow from the wellbore corrected for wellbore storage (C); vanishing
110 pressure disturbance at infinity) and two continuity conditions at the interface between the two zones (continuity of pressure and flow
111 rate). The evaluation of the parameters for the composite radial system is provided in Appendix B. The parameters and Bessel function

112 evaluations depend on the reservoir and fluid parameters, the fluid front position, and the frequency. From the resulting pressure
 113 expression, we can determine a response function for every harmonic component of the injection or production rate tested:

$$114 \quad R_{\omega}^{pulsar} = \frac{p_{well}}{q_{well}} = C_K^1 K_0(\zeta_1 r_w) + C_I^1 I_0(\zeta_1 r_w) + S \zeta_1 r_w [C_K^1 K_1(\zeta_1 r_w) - C_I^1 I_1(\zeta_1 r_w)] \quad (8)$$

115 For an observer well, the expression of the response function depends on its position with respect to the thermal front (i.e. observer well
 116 inside or outside the altered temperature area):

$$117 \quad R_{\omega}^{obs} = \frac{p_{obs}}{q_{well}} = \begin{cases} C_K^1 K_0(\zeta_1 r_{obs}) + C_I^1 I_0(\zeta_1 r_{obs}) & (r_{obs} < r_1) \\ C_K^2 K_0(\zeta_2 r_{obs}) & (r_{obs} \geq r_1) \end{cases} \quad (9)$$

118 Derivation details for eq. (8) and eq. (9) are given in Appendix B.

119 2.2 Interpretation methodology of Harmonic Pulse Testing

120 For the HPT interpretation, we focused on the response of the pulser well because we observed that the pulser response (R_{ω}^{pulsar}) was
 121 significantly more sensitive to variations of the heated zone than the observer response (R_{ω}^{obs}). Thus, eq. 8 represents the analytical
 122 solution that will be employed as interpretation model. Interpretation is the process of matching test data through selection of the
 123 interpretation model (radial composite, Infinite Acting Radial Flow, etc.) and characterization of model parameters. In eq. 8, C_K^1 , C_I^1 and
 124 ζ_1 depend on the reservoir and fluid parameters, fluid front position and frequency. Both amplitude ($|R_{\omega}^{pulsar}|$) and phase shift ($\angle R_{\omega}^{pulsar}$)
 125 were analyzed.

126 Data need to be preprocessed before interpretation because the model is in the frequency domain. To this end, rate and well pressure data
 127 are transformed through FFT obtaining Q_{ω} and P_{ω} , respectively, which represent the signal value of each frequency component $f = \omega/2\pi$.
 128 The penetration depth decreases with increasing frequency (Fokker et al., 2018). Amplitude peaks, representative of the harmonic
 129 components, are identified in the flow rate and pressure spectra and the response function is calculated as the amplitude ratio $R_{\omega} = P_{\omega} / Q_{\omega}$,
 130 for each frequency component. The derivative of the amplitude ratio with respect to the logarithm of the oscillation period (R') is
 131 calculated by a three point data differentiation algorithm (Bourdet, 2002). Then, the modulus of harmonic response function ($|R|$) and the
 132 modulus of its derivative ($|R'|$) versus the harmonic period (T) are plotted on a log-log scale allowing an interpretation analogous to
 133 conventional Pressure Transient Analysis (Bourdet et al., 1983; Gringarten et al., 1979). Flow geometries and flow regimes can be easily
 134 identified on the derivative plot. In particular:

- 135 • $|R'|$ showing a plateau (linear trend with slope 0 called horizontal stabilization in the Pressure Transient Analysis terminology)
 136 corresponds to Infinite Acting Radial Flow. The stabilization value, i.e. the ordinate value of the trend (y_M), is proportional to
 137 the investigated zone properties (Fokker et al. 2018):

$$138 \quad k = \frac{B\mu}{4\pi h} \frac{1}{y_M} \quad (10)$$

139 If the aquifer contains two zones characterized by different viscosities, two different horizontal stabilizations should be visible
 140 (Figure 1). For the injector of a geothermal doublet, the undisturbed zone is the outer one. Thus, the mobility of the system can
 141 be estimated from that stabilization.

142 • The ratio between the values corresponding to the two horizontal stabilization gives the mobility ratio (M between inner (1) and
143 outer zone (2)):

$$144 \quad M = \left(\frac{k}{\mu}\right)_1 / \left(\frac{k}{\mu}\right)_2 \quad (11)$$

145 • The critical oscillation period T^* corresponds to the transition between the two zones with different mobility and can be picked
146 up from log-log plot visual inspection (Figure 1). This allows to estimate the position of the front (r_1):

$$147 \quad r_1 = 1.5 \sqrt{\frac{kT^*}{2\pi\mu c_t \phi}} \quad (12)$$

148 • At high frequency, corresponding to the investigation of the near wellbore area, $|R|$ and $|R'|$ both show a linear trend with a unit
149 slope on the log-log plot when wellbore storage occurs (Fokker et al. 2018), i.e. when the pressure response is dominated by the
150 compression and expansion of the fluid in the well. Such phenomenon is more severe if the well volume (V) and the fluid
151 compressibility (c) are large. However, the wellbore storage can be non-negligible also in geothermal aquifers (Salina Borello
152 et al., 2019). By selecting the match point (x_M, y_M) at the intercept of the first horizontal stabilization and the linear wellbore
153 storage trend, we can quantify the wellbore storage as:

$$154 \quad C = V c_w = 2x_M \frac{kh}{\mu} = \frac{B}{2\pi} \frac{x_M}{y_M} \quad (13)$$

155 • The distance between $|R|$ and $|R'|$ on log-log plot is proportional to the well damage (skin), which is responsible for an additional
156 pressure drop at the wellbore.

157

158 The $|R|$ and $|R'|$ data points vs. oscillation period are represented on a log-log plot, while phase shift ($\angle R$) vs. oscillation period is
159 represented on a semilog plot; both are compared with an analytical interpretation model obtained for a given combination of model
160 parameters values. Similarly to conventional PTA, the values of model parameters are modified, in a trial and error process, in order to
161 obtain an acceptable match of the real data. The quality of the match is typically based on visual inspection. This trial and error procedure
162 is guided by identification of the match point, the two horizontal stabilizations and the transition between them (eq. 10-13).

163 Assuming the permeability to be constant, M represents the ratio between viscosities of the outer and the inner zone. Knowing the
164 relationship between viscosity and temperature behavior, an estimate of the inner zone average temperature (T_1) is possible. The
165 methodology is still applicable in the presence of heterogeneities, provided a preliminary characterization of the permeability variations
166 inside the test investigation distance is available. Therefore, a baseline HPT should be performed before any thermal injection. A
167 comparative analysis of the test conducted during or after the injection campaign with the baseline test will allow a correct identification
168 of the temperature front.

169

170

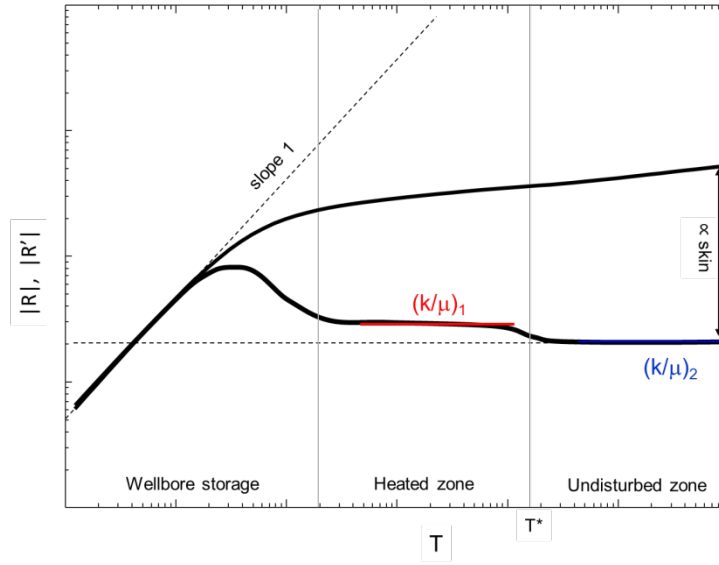


Figure 1: Schematic of HPT log-log plot for a radial composite model of aquifer (M=0.66)

2.3 Design of Harmonic Pulse Testing for thermal front monitoring

The fundamental oscillation period (T_f) of HPT needs to be selected to ensure an investigation distance (r_{max}) well into the undisturbed region ($r_{max} \gg r_1$). The fundamental injection period represents the maximum oscillation period in the Fourier analysis ($T_f = T_{max}$), thus it determines the test investigation distance (Salina Borello et al., 2019):

$$r_{max} = 1.5 \sqrt{\frac{kT_f}{2\pi\mu c_t \phi}} \quad (14)$$

At the other side of the spectrum, the sampling resolution determines the lowest oscillation period component detectable on the pressure signal:

$$T_{min} = 2\Delta t \quad (15)$$

Thus, the minimum distance investigated by the test, in ideal conditions (i.e. no noise) is:

$$r_{min} = 1.5 \sqrt{\frac{k\Delta t}{\pi\mu c_t \phi}} \quad (16)$$

Eq. 16 may be used to calculate the sampling resolution necessary to characterize the near-wellbore heated zone. However, the harmonic components corresponding to the smaller oscillation periods can be affected by wellbore storage and skin phenomena limiting the detectability of the heated zone. The threshold oscillation period corresponding to the duration of wellbore storage effect can be evaluated by converting the time domain Chen & Bringham's criterion into the frequency domain:

188

189

$$T \leq \frac{50C\mu}{kh} e^{0.14S} \quad (17)$$

190 Chen & Bringham's criterion is widely used to estimate the duration of the effects of wellbore storage in Pressure Transient Analysis
191 (Chaudhry, 2004).

192 As a consequence of eq. 17, the heated zone can be characterized if:

193

$$T^* \gg \frac{50C\mu}{kh} e^{0.14S}. \quad (18)$$

194 where T^* represents the critical oscillation period, i.e. the oscillation period of the harmonic component investigating the transition zone.

195 In dimensionless terms, defining the dimensionless period through $T_D = \frac{T}{2\pi} \frac{k}{\mu c_t \phi r_w^2}$ (Salina Borello et al., 2019), we have for the transition
196 period (T_D^*), and the maximum (T_{Dmax}) and minimum periods (T_{Dmin}):

197

$$T_D^* = \frac{1}{4.5\pi} \left(\frac{r_1}{r_w}\right)^2 \gg \frac{50C}{2\pi h c_t \phi r_w^2} e^{0.14S} \quad (19)$$

198

$$T_{Dmax} = \frac{T_f}{2\pi} \frac{k}{\mu c_t \phi r_w^2} \gg T_D^* \quad (20)$$

199

$$T_{Dmin} = \frac{2\Delta t}{2\pi} \frac{k}{\mu c_t \phi r_w^2} \ll T_D^* \quad (21)$$

200 Finally, test reliability strongly depends on the precision in the rate-change timing. In fact, errors in the rate-change timing (e_T) alter the
201 harmonic component of frequency $f \geq 1/e_T$. Acceptable errors in timing should be properly evaluated case by case in the test design phase.
202 In the case of thermal front monitoring the error should not mask the two horizontal stabilizations and the transition zone on the response
203 derivative ($|R'|$):

204

$$e_T \ll T^* = \frac{\mu c_t \phi r_1^2}{2.25k} \quad (22)$$

205 The quality of the response function is less dependent on the magnitude of the two alternating rates and their precision (Salina Borello et
206 al., 2017).

207

208 2.4 Geothermal doublet

209 Two cases representative of a geothermal doublet system were considered (Table 1): after one month of water injection (case 1), and after
210 six months of water injection (case 2). For each scenario, at the end of the injection period, a periodic test was performed at the injector
211 (Table 2). The distance from the injector well to the producing well allowed the thermal front to develop with an axially symmetric shape,
212 not altered by production at the producing well, thus representing a perfectly radial-composite scenario. We tested the reliability of our
213 analytical radial-composite model (eq. 8 with the constants as defined in Appendix B) against a well-established analytical radial-

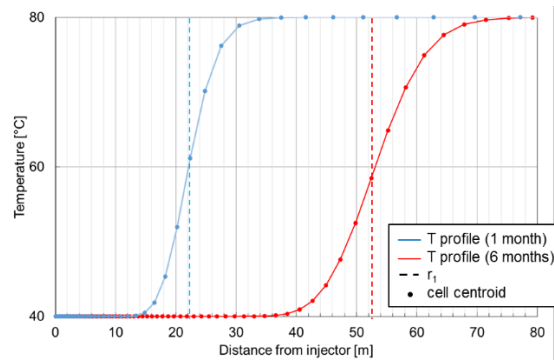
214 composite model in the time domain (Olaewaju et al., 1989), implemented in a commercial software. A synthetic pressure response was
215 generated in the time domain and interpreted with our model in the frequency domain. Furthermore, the impact of pressure gauge noise
216 on the interpretation results was evaluated in a set of additional simulations. In the remainder of the paper we will refer to an ideal gauge
217 when the simulated pressure response is not affected by noise and to a noisy or realistic gauge when the simulated pressure response is
218 affected by gauge accuracy.

219 Synthetic data were generated by simulating the dynamic propagation of the temperature front with a single active well numerical
220 simulator for fluid dynamics in porous media accounting for thermal effects (Verga et al., 2008, Verga et al., 2011, Verga et al., 2014).
221 The resulting temperature profiles are shown in Figure 2. The thermal front distance from the injector well, calculated as the distance at
222 which the temperature reaches the average value between injection and reservoir temperature (60 °C in the considered validation cases)
223 is 22 m for case 1 and 52 m for case 2 (Figure 2).

224 In order to validate our solution against a well-established analytical solution, the pressure response to the pulse test was also simulated
225 with a commercial analytical software in the time domain, where the thermal front was mimicked with a fixed mobility ratio between the
226 two zones; the heated zone extension and the mobility ratio were defined according to the results of the numerical simulation (Figure 2);
227 a sampling rate of 1 sec was imposed (Figure 3). This gives the response of an ideal pressure profile not affected by noise that is used for
228 validation purposes.

229 Finally, Gaussian noise was added to the simulated pressure data to mimic the response of a crystal quartz gauge characterized by an
230 accuracy of ± 0.083 bar (Schlumberger, 2016) (Figure 3), to verify the robustness of the interpretation methodology to noise.

231



232

233 **Figure 2: Numerically simulated thermal profiles: 1-month injection (light blue) vs 6 months of injection (red) and corresponding**
234 **radial composite radii (dotted lines).**

235

236

237 **Table 1: Simulation parameters for well, rock and water for the geothermal doublet scenario**

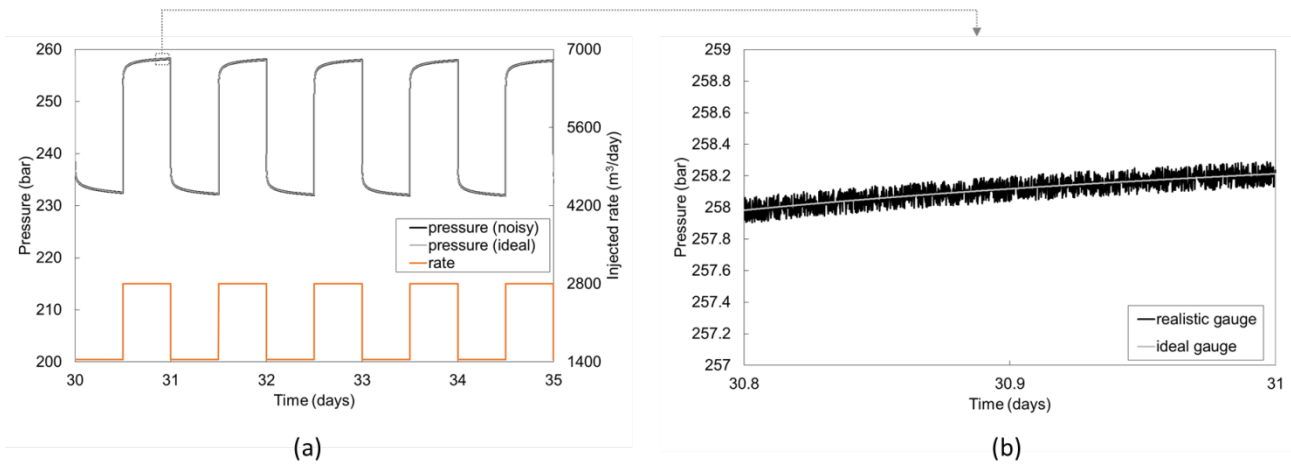
Aquifer data	
permeability (mD)	60
porosity (-)	0.2
reservoir temperature (°C)	80
pressure (bar)	200
depth (m ssl)	2000
net pay (m)	100
Well	
radius (m)	0.1
skin (-)	2
Rock	
compressibility (bar ⁻¹)	2.00E-05
thermal conductivity (W/K m)	2
heat capacity (J/kg K)	850
density (kg/m ³)	2600
Water	
compressibility (bar ⁻¹)	4.00E-05
thermal conductivity (W/K m)	0.6
heat capacity (J/kg K)	4148
salinity (ppm)	1000
density (kg/m ³)	1001
viscosity (mPa s) @ res temperature	0.34
viscosity (mPa s) @ inj temperature	0.66
injection temperature (°C)	40

238 **Table 2: Rate history of geothermal doublet scenarios**

Scenario	Test	Duration/period (days)	Rate (m³/min)	Rate variation (m³/min)	number of periods (-)
case 1	injection operations	30	2	-	-
	HPT1	1	1.5	± 0.5	5
case 2	injection operations	180	2	-	-
	HPT2	1	1.5	± 0.5	5

239

240



241

242 **Figure 3: Case 1: ideal pressure gauge (gray), generated with the analytical radial-composite model in the time domain (Olarewaju**
 243 **et al., 1989) and noisy pressure gauge (black) generated by adding Gaussian noise to the ideal gauge; (a) full 5-period duration,**
 244 **and (b) zoom.**

245 **2.5. Numerical model of ATEs**

246 Heat storage cycles were simulated through a commercial 3D fluid-dynamic reservoir modeling tool taking into account the thermal
 247 phenomena. The synthetic aquifer model was based on a real formation, a possible candidate for ATEs application in the Netherlands.
 248 Well, rock and water properties are reported in Table 3; annual heat storage cycle rate histories are reported in Table 4. The aquifer is
 249 characterized by 7 layers (numbered, in the following, from 1 to 7 starting from the top) of permeability ranging from 120 mD to 53797
 250 mD. A sketch is provided in Figure 4. Two layers are open to production/injection: number 3 and 5 from the top. They are characterized
 251 by permeability $k_h=10760$ mD and $k_z = 2690$ mD and porosity $\phi = 0.37$, separated by inter-layer 4 with porosity $\phi = 0.5$ and permeability
 252 $k_h = 2391$ mD and $k_z = 24$ mD. Layer 2, at the top of the upper perforated layer has similar properties ($\phi = 0.55$, $k_h = 2391$ mD, $k_z = 24$).
 253 Simulations of the whole domain with a grid refinement 10 m x 10 m x 10 m in the well area (Figure 5) show that the upper perforated
 254 layer behaves as separated in terms of pressure response, due to the high permeability contrast. The temperature exchange between the
 255 upper perforated layer and the surrounding layers is also negligible compared to the exchange within the layer. For these reasons, a radial
 256 composite model should fit the interpretation of tests performed on such layer. We therefore focused on the upper layer only and simulated
 257 it as a single numerical layer of 1128 m x 1128 m areal extension and 30 m thickness. A significant grid refinement (cells of 4m x 4m)
 258 was imposed in an area of about 900 m x 900 m containing the wells, with the double aim of correctly simulating the pressure gauge
 259 response and accurately describing the thermal front. Further away the grid size was increased to 20 m x 20 m and finally to 200 m x 200
 260 m. The simulation grid is shown in Figure 6. The gauge was supposed to be in the upper perforated layer, at 330 mssl. The initial pressure
 261 at datum was assumed hydrostatic (i.e., 33 bar); the initial temperature of the layer was 20 °C.

262

263 **Table 3: Simulation parameters for well, rock and water.**

Well	
radius (m)	0.7874
skin (-)	0
Rock	
compressibility (bar ⁻¹)	2.18E-05
thermal conductivity (W/K m)	2.4
heat capacity (J/kg K)	850
density (kg/m ³)	2100
reservoir temperature (°C)	20
Water	
compressibility (bar ⁻¹)	4.00E-05
thermal conductivity (W/K m)	0.6
heat capacity (J/kg K)	4148
salinity (ppm)	20000
density (kg/m ³)	1016
viscosity (mPa s) @ res. temp.	1.13
viscosity (mPa s) @ inj. temp.	0.338
injection temperature (°C)	90

264

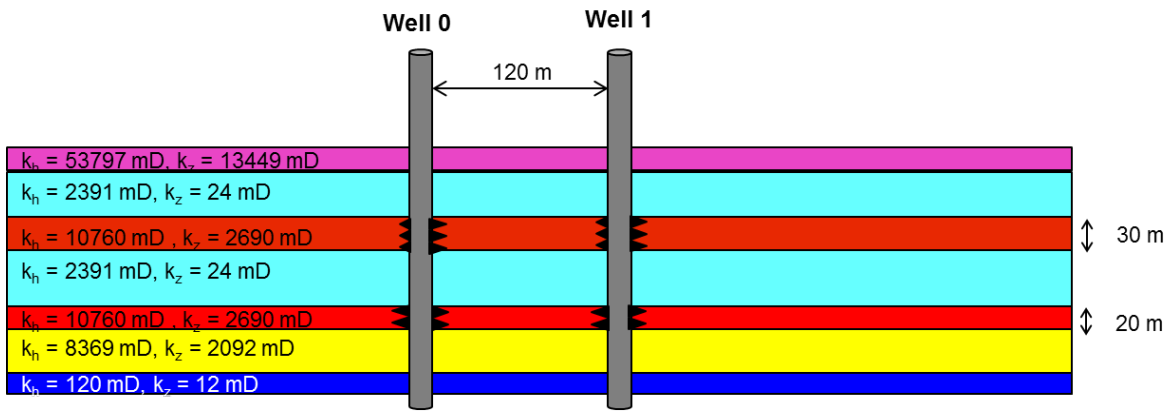
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266

267 **Table 4: Annual heat storage cycle.**

	duration (days)	Rate Well0 (m³/day)	Rate Well1 (m³/day)
summer	90	-3888	3888
autumn	60	0	0
winter	150	2328	-2328
spring	60	0	0

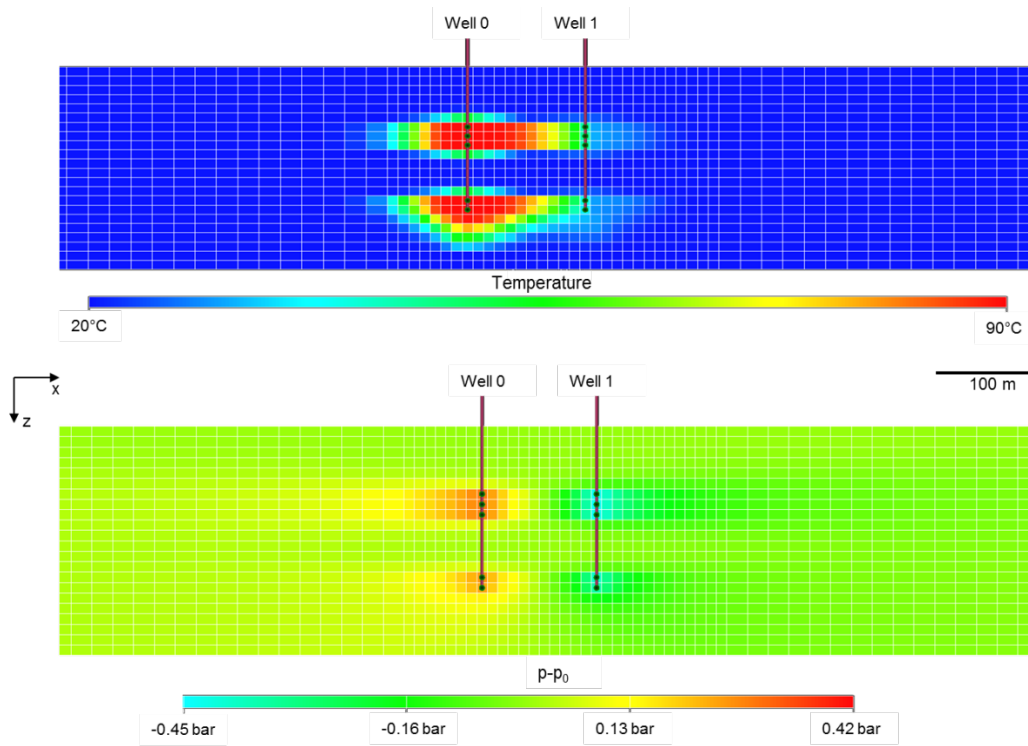
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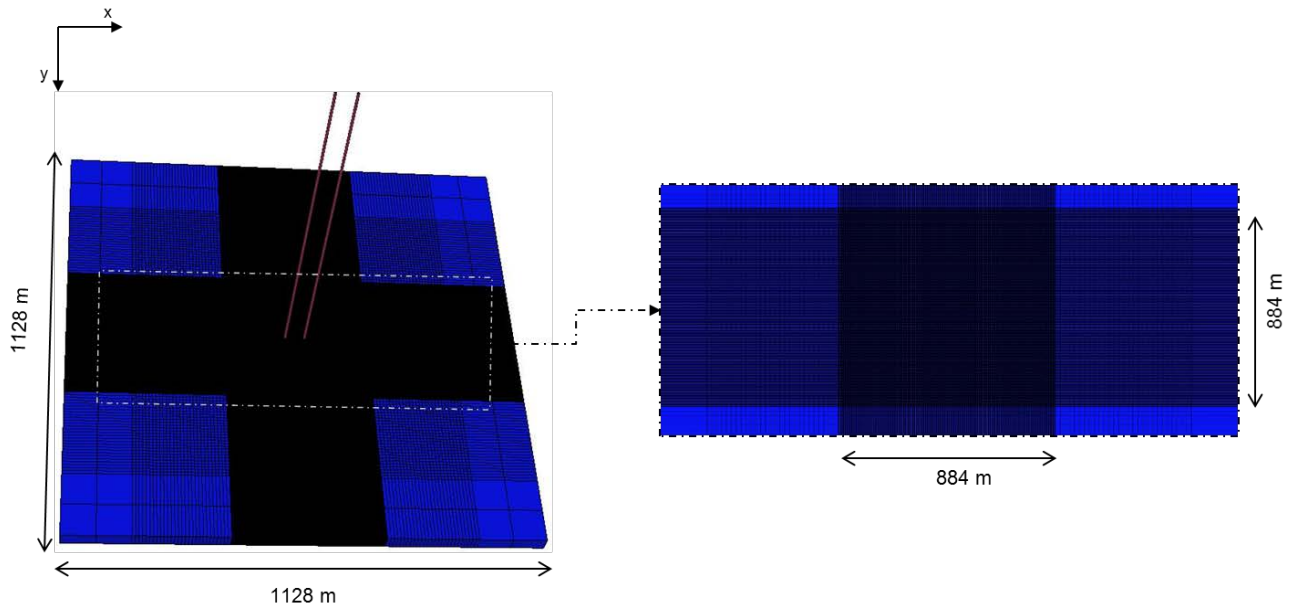
Figure 4: Sketch of aquifer layers (x-z cross section)



271

272 Figure 5: Preliminary simulation results after the 5th summer of injection (zoom of x-z cross section). Grid refinement 10m x10m
 273 x10m.

274



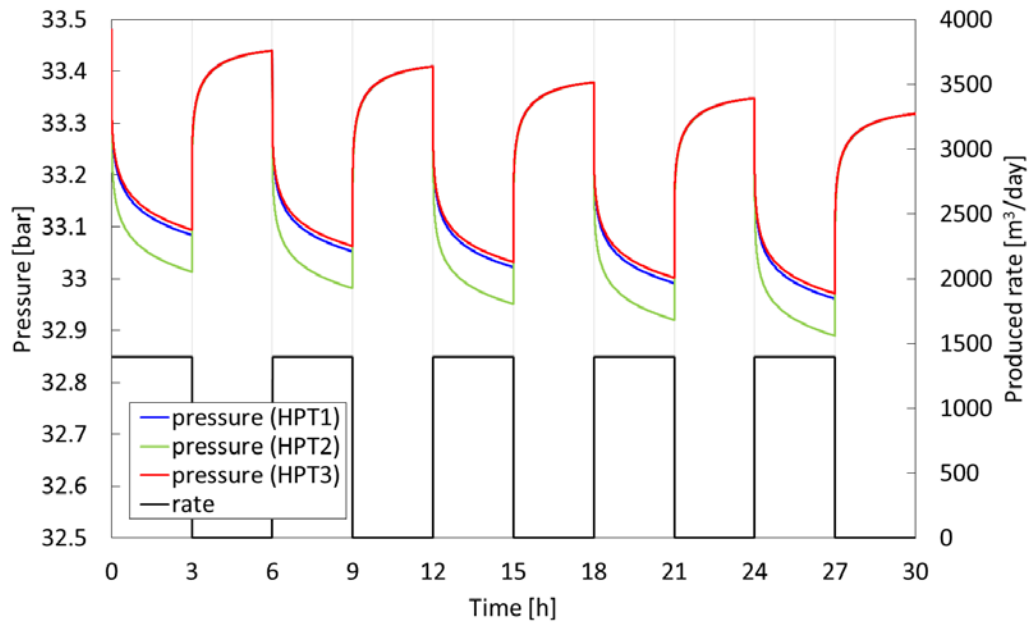
275

276 **Figure 6: Grid for final simulations (top view and zoom).**

277 The same commercial software was used to simulate the HPTs pressure response, to verify the capability of the test in monitoring the heat
 278 front. The thermal front was monitored after the 5th summer of storage (4 complete storage cycles), after the subsequent winter, and again
 279 after the 15th summer of storage (14 complete storage cycles). Each test was conducted after a shut in period of one day. The data for the
 280 three HPTs in terms of test starting time, fundamental oscillation period (T_f), oscillating rates and number of oscillation periods are
 281 summarized in Table 5. Pressure and rate data are shown in Figure 7. The HPT fundamental oscillation period (T_f) was set to 6 h (3h of
 282 injection and 3h of shut-in) to assure an investigation distance far enough to explore the undisturbed region (see eq. 14). Sampling
 283 resolution was set to $\Delta t = 1$ s to be able to characterize the heated zone properties (see eq. 16). Thus, in ideal conditions (i.e. no noise)
 284 with the applied setting we can explore the circular area between $r_{min} = 25$ m and $r_{max} = 2580$ m from Well1. In dimensionless terms
 285 (eq. 20-21), we have $70 < T_D < 7.6e5$. Preliminary synthetic tests confirmed that the first horizontal stabilization was hardly detectable
 286 with $\Delta t > 1$ s.

287 **Table 5: HPT tests for heat front monitoring on Well 0.**

HPT Test	HPT starting time	T_f (h)	Rate 1 (m ³ /day)	Rate 2 (m ³ /day)	Number of periods (-)
HPT1	after 5 th summer	6	1396.8	0	5
HPT2	after 5 th winter	6	1396.8	0	5
HPT3	after 15 th summer	6	1396.8	0	5



289

290 **Figure 7: Simulated pressure data (red, blue, and green curve, left axis) from harmonic pumping tests 1 to 3 (see Table 5) at tested**
 291 **well (Well0) with the flow-rate protocol given by the black curve (right axis)).**

292

293 3. RESULTS

294 3.1 TEST ON GEOTHERMAL DOUBLET

295 Our model was initially validated against a conventional analytical radial composite model adopted for the Geothermal doublet, assuming
 296 step-change temperature profiles. For the ideal gauge, the dimensionless log-log plot in the frequency domain (representing $|R_D|$ and $|R_D'|$
 297 as defined in paragraph 2.2) and the analytical interpretation model are shown in Figure 8a. Case 1 is depicted in blue, while case 2 is
 298 depicted in red. In both cases, the model provides a good match of the data and a correct value of the inner thermal zone radius. Analysis
 299 of the phase shift ($\angle R$) confirms the interpretation (Figure 9a). The same behavior (Figure 10) is observed when considering pressure data
 300 generated with the numerically simulated temperature profiles (Figure 2): except for the very beginning of the transition zone, the
 301 amplitude and phase behavior is very similar to the one of the step-change profile assumption. The noisy-gauge analysis is shown in
 302 Figure 8b and Figure 9b. In both cases the inner radius is still detectable. In fact, the noise mostly affects the first stabilization, while the
 303 transition zone and the second stabilization can be clearly detected (Figure 8b); a similar influence is observed on phase shift (Figure 9b).
 304 Therefore, HPT interpretation provides a reliable monitoring of the thermal front evolution.

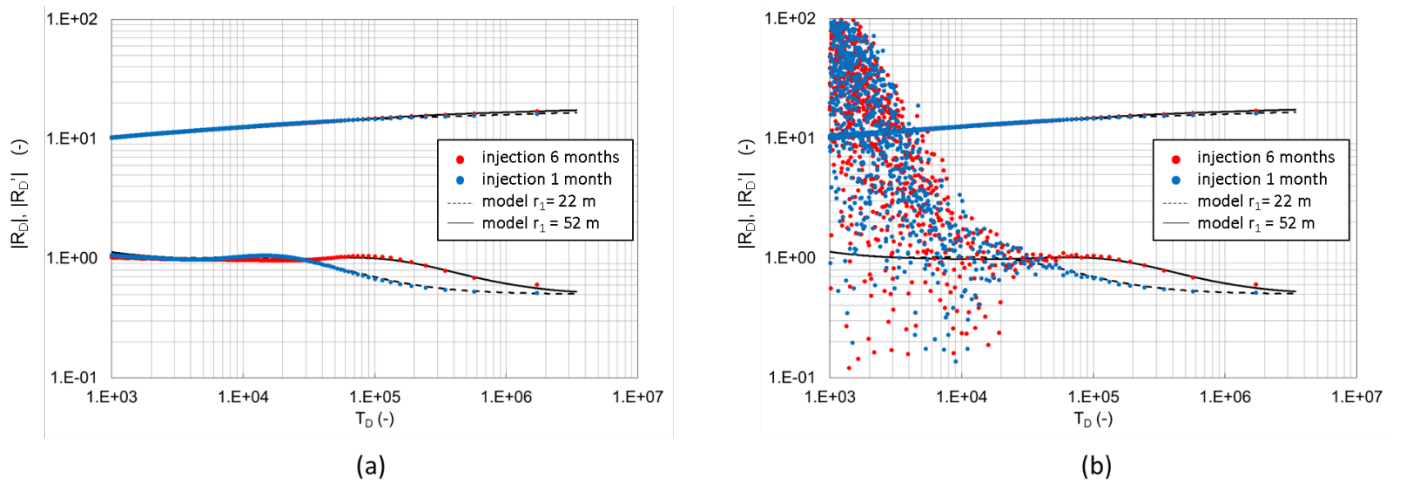
305 The complete injection history is known in these synthetic cases and the pressures are not affected by interference phenomena. Therefore,

306 conventional Pressure Transient Analysis (PTA) in time domain (Bourdet et al, 1984) can also be applied. The corresponding log-log plot
 307 for a single injection period is shown for both the ideal gauge (Figure 11a) and the noisy gauge (Figure 11b) in dimensionless terms
 308 (Bourdet, 2002). Based on that, results obtained in time and frequency domains can be directly compared (Figure 8a vs Figure 11a for the
 309 ideal gauge; Figure 8b and Figure 11b for the noisy gauge) and superposed on the same log-log plot (Salina Borello et al. 2019).
 310 Comparison of Figure 8b and Figure 11b shows the different impact of noise in time domain (PTA) and frequency domain (HPT).
 311 Conventional PTA is mainly affected by noise in the part of the curve, corresponding to the formation volume containing the thermal
 312 front (middle-time in PTA terminology). HPT is affected by noise in the part of the curve, representing the high-frequency components
 313 (smaller T) which investigate the near wellbore area (early-time in PTA terminology). As a consequence, the thermal front evolution can
 314 be more easily detected through HPT interpretation in the frequency domain. Furthermore, a combined analysis, obtained superposing
 315 PTA and HPT curves in dimensionless terms, can improve interpretation reliability minimizing uncertainties. The combined analysis
 316 follows three steps: (1) superposed representation of PTA and HPT curves in dimensionless terms (Figure 12a); (2) application of a low-
 317 pass filter to both time data and frequency data to obtain a single clean derivative plot (Figure 12b); (3) interpretation of the obtained
 318 derivative plot with the presented frequency model.

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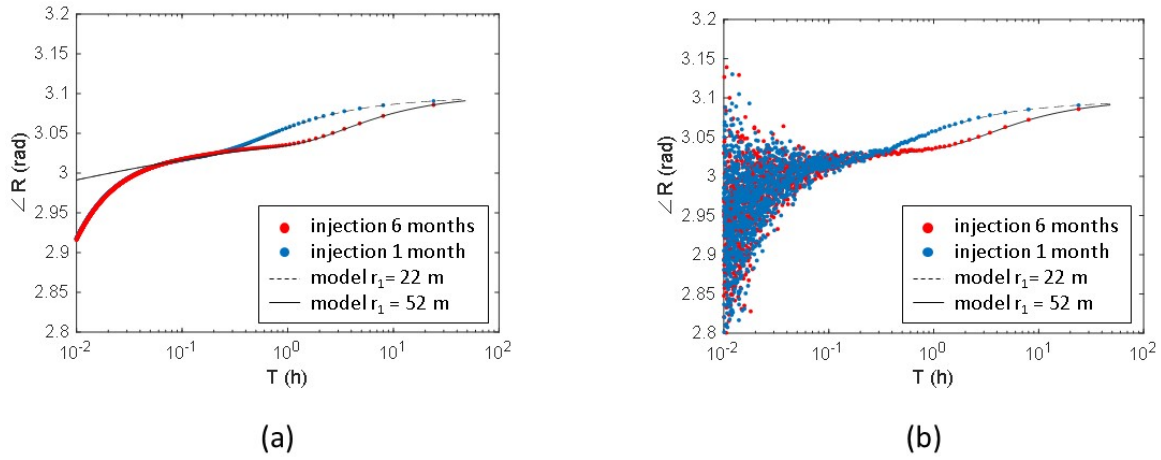


322

323 **Figure 8: Comparison of reservoir response after 1 month of injection (blue) vs. after 6 months of injection (red): frequency**
 324 **analysis of the ideal gauge (a) and of the noisy gauge (b), reported in amplitude of dimensionless response ($|R_D|$) and amplitude of**
 325 **dimensionless response derivative ($|R_D'|$) vs. dimensionless oscillation period (T_D); data generated with the analytical radial-**
 326 **composite model in the time domain (Olarewaju et al., 1989).**

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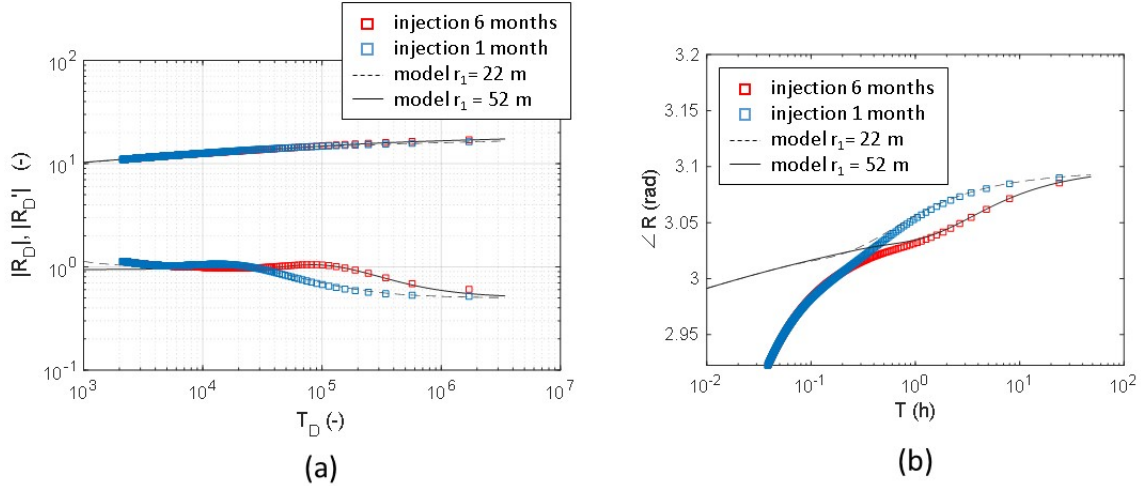
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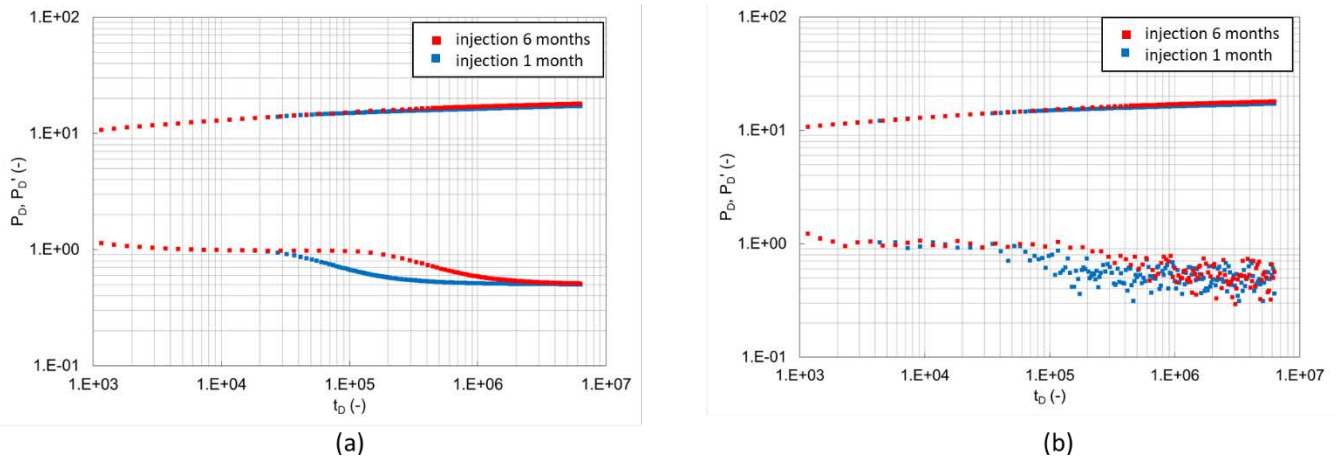
330 **Figure 9: Comparison of reservoir response after 1 month of injection (blue) vs. after 6 months of injection (red): frequency**
331 **analysis of the ideal gauge (a) and of the noisy gauge (b), in terms of phase shift ($\angle R$) vs. oscillation period (T); data generated**
332 **with the analytical radial-composite model in the time domain (Olaewaju et al., 1989).**

333



334

335 **Figure 10: Comparison of the reservoir response in the active well (pulsar) after 1 month of injection (blue) vs. after 6 months of**
336 **injection (red): frequency analysis of the response amplitude ($|R|$) and amplitude derivative ($|R'|$) (a) and phase shift ($\angle R$) (b);**
337 **data generated with the numerical simulator accounting for thermal effects.**

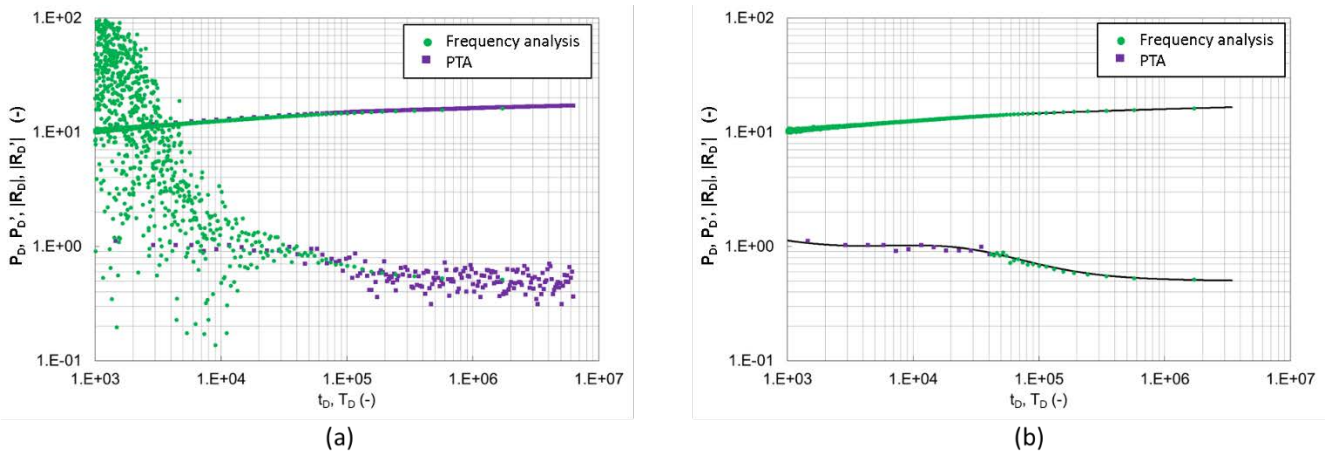


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340 **Figure 11: Comparison of reservoir response after 1 month of injection (blue) vs. after 6 months of injection (red): conventional**
 341 **Pressure Transient Analysis of the ideal gauge (a) vs. the noisy gauge (b), reported in dimensionless pressure (P_D) and**
 342 **dimensionless pressure derivative (P_D') vs. dimensionless time (t_D); data generated with the analytical radial-composite model in**
 343 **the time domain (Olarewaju et al., 1989).**

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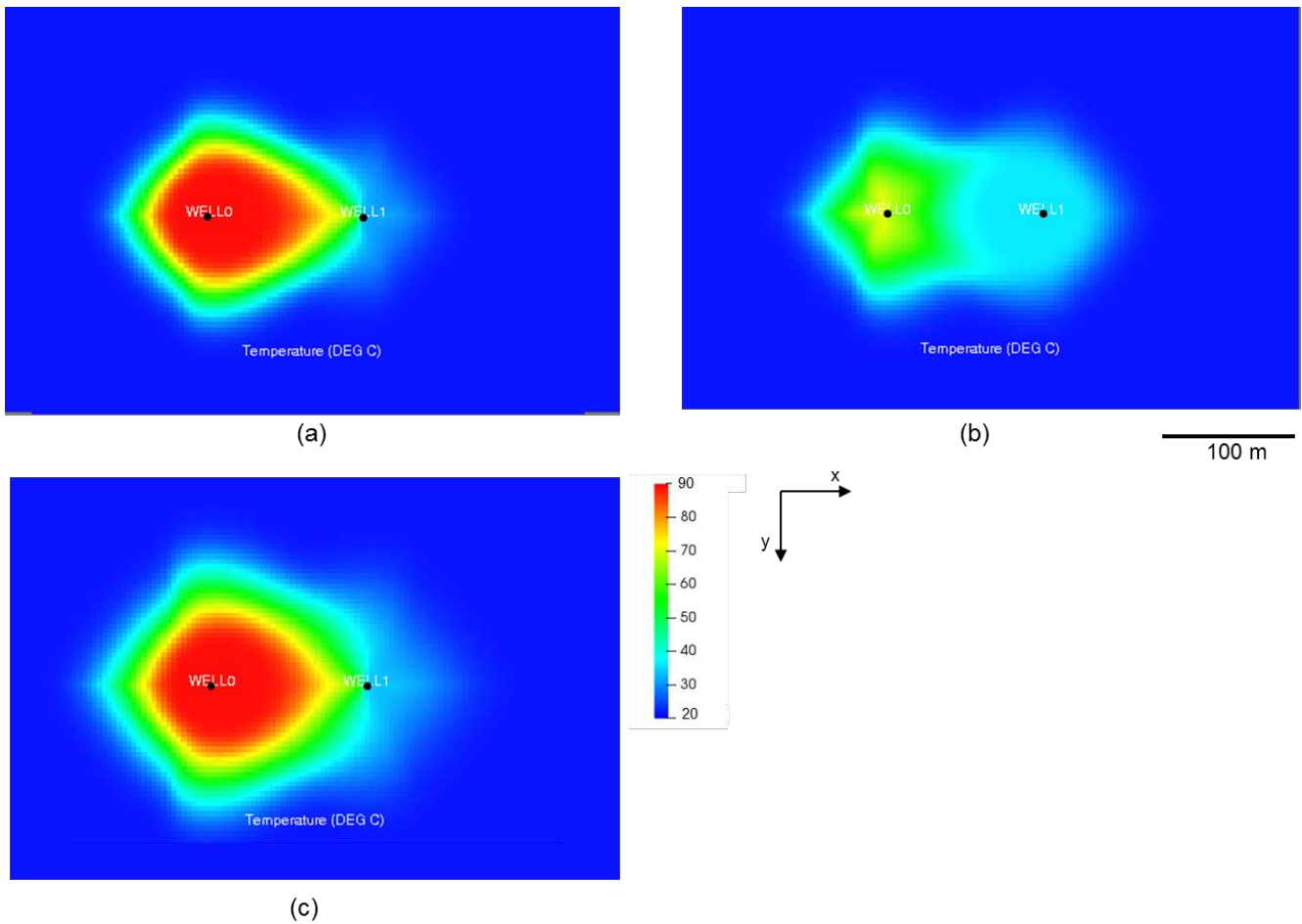
347 **Figure 12: Maximization of information extraction from the noisy gauge by combining the analysis of time and frequency data in**
 348 **dimensionless terms (case1): (a) superposition of time and frequency analysis in dimensionless term; (b) application of low-pass**
 349 **filter to both time data and frequency data to obtain a single clean derivative plot; data generated with the analytical radial-**
 350 **composite model in the time domain (Olarewaju et al., 1989).**

351

352 3.2 APPLICATION TO ATES

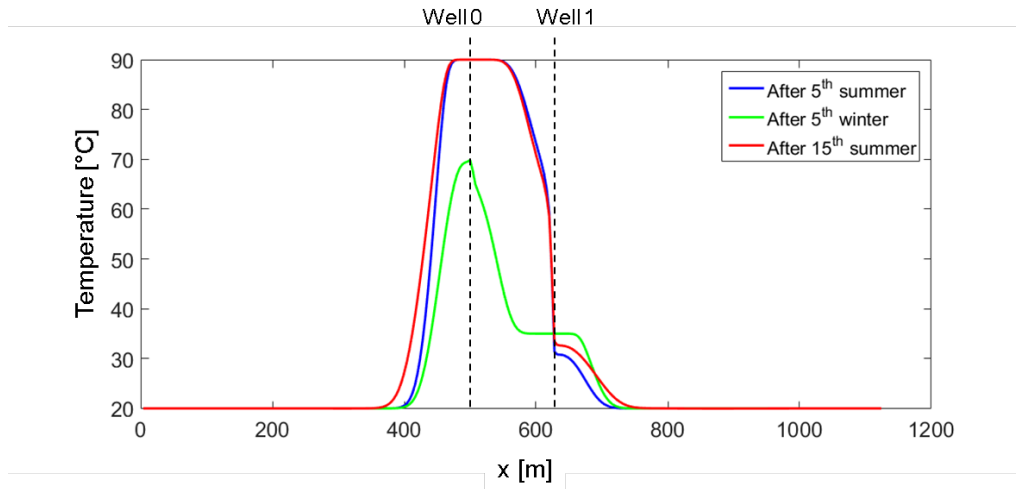
353 In the after-summer scenario of the 5th storage cycle (Figure 13a), the simulated temperature changes gradually, but not linearly, from the
354 injection temperature (90°C) to the temperature value in the proximity of the front (about 60°C), beyond which an abrupt change towards
355 the initial aquifer temperature (20°C) is observed. Due to the simultaneous production in Well1, the heated zone is off-centered with
356 respect to Well 0; it elongates toward producing Well 1, thus assuming an almost oval shape. Temperature distribution on the cross section
357 along the line connecting the two wells is provided in Figure 14 .

358 After seven months, in the after winter scenario (Figure 13b), the situation is significantly different. The temperature around Well 0 has
359 decreased to 50-70°C (Figure 14) and the heated zone extension has decreased, too. Pushed by the cold-water injection at Well 1, the
360 thermal front position along the intra-well direction moves towards Well 0 and the shape of heated zone becomes irregular. With the
361 progression of seasonal cycles, the after-summer heated zones tend to expand, becoming rounder (Figure 13c).



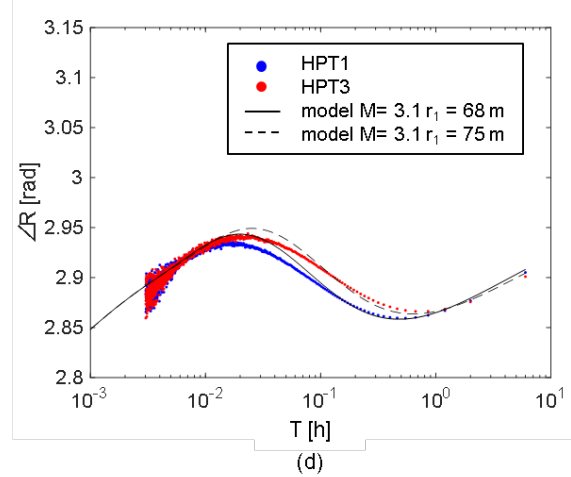
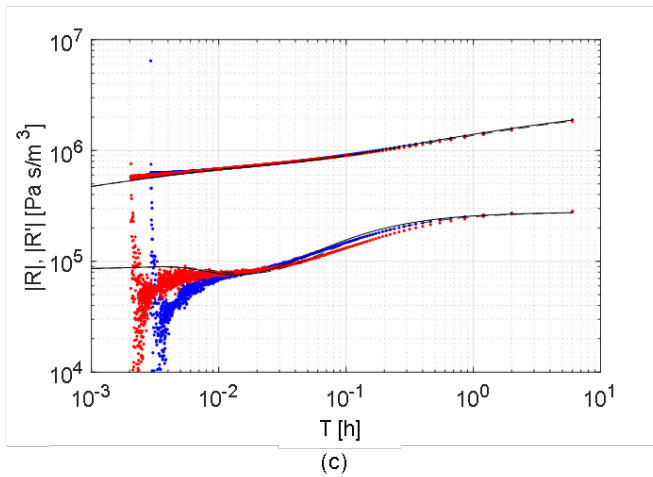
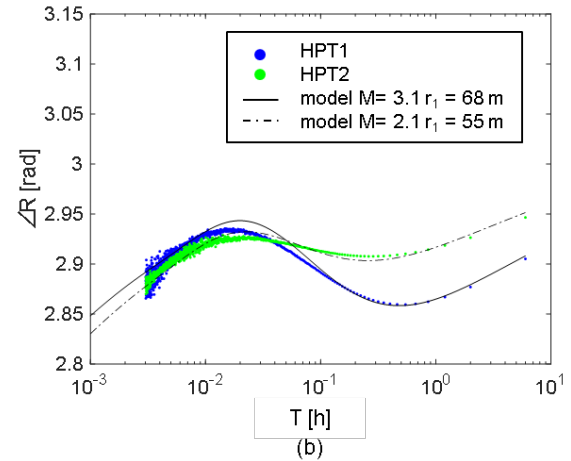
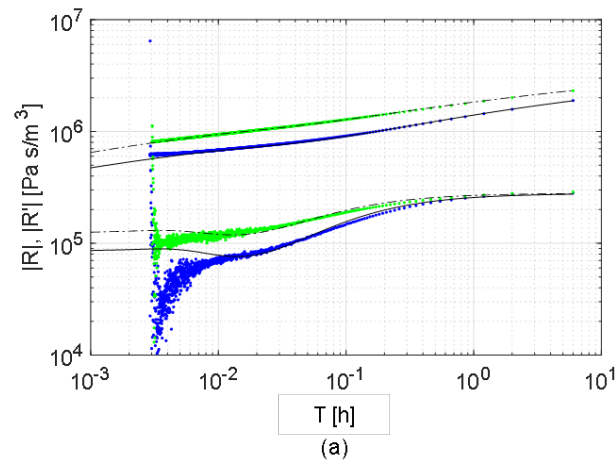
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363 **Figure 13: Simulation results: comparison between temperature profiles (a) after summer of the 5th storage cycle, (b) after winter**
364 **of the 5th storage cycle and (c) after summer of the 15th storage cycle; zoom of top views.**
365



366
367 **Figure 14: Temperature distributions along the x-direction crossing the two wells.**

368 The pressure trends of the simulated HPTs were analyzed in the frequency domain as described in section 2.2. Log-log plots of the moduli
369 of R and R' versus oscillation period ($2\pi/\omega$) and semilog plots of the phase of R versus oscillation period are shown in Figure 15. Data
370 were interpreted with our radial composite model in the frequency domain (eq. 8) to give an estimate of the extension of inner zone radius
371 (r_i) and of the mobility ratio between inner and outer zone (M), leading to an estimate of the inner zone average temperature (T_1) (Table
372 6).



373

374 **Figure 15: HPT results: comparison between reservoir response after summer (blue) vs. after winter (green) of the 5th storage**
 375 **cycle in terms of (a) amplitude ($|R|$) and amplitude derivative ($|R'|$) and (b) phase shift ($\angle R$); comparison between reservoir**
 376 **response after summer of the 5th storage cycle (blue) vs. 15th storage cycle (red) in terms of (c) amplitude and amplitude derivative**
 377 **and (d) phase shift.**

378 For all tests (Figure 15), the second stabilization allowed for correct identification of a permeability value of about 11D and a zero skin
 379 value. Comparing after-summer and after-winter derivatives (Figure 15a), a significantly different first stabilization is observable, which
 380 corresponds to a different near-wellbore viscosity and therefore a different temperature. The extent of the near-wellbore heated zone
 381 indicated by the after-summer derivative is also significantly larger than the extent indicated by the after-winter derivative. When
 382 comparing the derivatives of tests conducted after-summer of the 5th and of the 15th storage cycle (Figure 15c), the level of the first
 383 stabilization is practically the same, indicating similar temperature, but a difference is observed for the extent of the heated zone. The size
 384 is slightly larger after the summer of the 15th cycle. Phase shift analysis (Figure 15b and Figure 15c) confirms the interpretation from the
 385 modulus of the derivative of the response and allows a better calibration of the heated zone extension, showing a good sensitivity even to

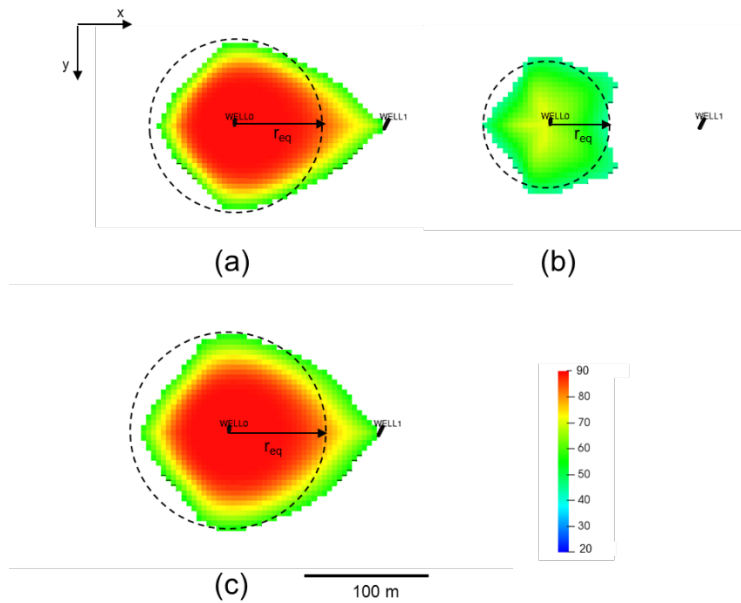
386 small heat zone changes, as in HPT1 vs HPT3 ($\Delta r_1 = 10\%$). This is in accordance with Cheng & Renner (2018), who documented that
 387 phase shift is a particularly sensitive tool for concentric-shell models.

388 **Table 6: Tests interpretation results with radial composite model in the frequency domain compared with the approximation of**
 389 **the simulated heated zone to an equivalent circumference centered in Well 0.**

HPT Starting time	Radial composite HPT interpretation			Numerical simulation		
	$M = \mu_2/\mu_1$	T_1 (°C)	r_1 (m)	heated zone (°C)	T_m (°C)	r_{eq} (m)
after 5 th summer	3.1	84	68	55°-90°C	83.4°C	69.8
after 5 th winter	2.1	58	55	45°-70°C	55.9 C°	50.9
after 15 th summer	3.1	84	75	55°-90°C	80°C	78.9

390

391 We already indicated that the simultaneous injection and production in the two wells causes a distortion from axial symmetry. The heated
 392 zone is neither centered around Well 0, nor circular (Figure 13). To facilitate a quantitative comparison between the numerical solution
 393 and the radial composite model, we calculated an equivalent radius of the heated zone from the temperature map. First, we calculate a
 394 threshold temperature ($T_{threshold}$) as the average between the temperature at the wellbore and far into the reservoir, yielding $T_{threshold} =$
 395 $55\text{ }^\circ\text{C}$ in the after-summer scenario and $T_{threshold} = 45\text{ }^\circ\text{C}$ in the after-winter scenario. Then we applied $T_{threshold}$ as a temperature filter
 396 to identify the heated zone and we calculated the median temperature values (T_m) of the selected cells. We approximated the heated zone
 397 with an equivalent circumference, i.e. the circumference with radius $r_{eq} = \sqrt{\frac{A}{\pi}}$, that have an area equivalent to the heated zone (see Figure
 398 16). The obtained approximation of the heated zone are also reported in Table 6. A good agreement was observed in all scenarios both in
 399 terms of median temperature (T_m), which differs from the estimated temperature (T_1) by less than 4°C , and in terms of heated equivalent
 400 radius (r_{eq}), which differs from the interpreted r_1 less than 10%. We conclude that the approximation with a circular heated zone and a step
 401 function for the temperature fits the synthetic data, and that the numbers derived for heated area and temperature change close to the
 402 injector characterize the actual system well.



403

404 **Figure 16: Approximation of the heated zone with the equivalent circumference centered in Well 0 (a) after 5th summer, (b) after**
 405 **5th winter and (c) after 15th summer.**

406 **4. DISCUSSION**

407 To correctly design and perform an HPT test for heat-zone monitoring in an ATEs system, some issues must be considered. To assure
 408 test interpretability, the first and the second horizontal stabilizations, representative of the heated zone and the undisturbed zone,
 409 respectively, must be clearly detectable on the log-log plot of the response derivative (see section 2.2). Thus, a proper test design is
 410 necessary (section 2.3). In the first place, such a design includes a duration of the fundamental oscillation period (i.e. the sum of the
 411 durations of the two alternating constant rates) that is long enough to investigate the undisturbed zone (eq. 14). In the presented ATEs
 412 case, in which the permeability is extremely high (about 11 D), an oscillation period $T_r \geq 6$ h is sufficient to capture the stabilization
 413 corresponding to undisturbed conditions (Figure 15). Considering that 5 oscillations are required (Salina Borello et al., 2017), the total
 414 test duration is 30 h, which is compatible with the storage operations. On the one hand, high permeability allows reducing test duration;
 415 on the other hand, it implies the need of high precision in the test execution (eq. 22) and a high pressure sampling rate (eq. 16). In fact,
 416 the first stabilization, representative of the heated zone, is investigated by high frequency components. As an example, in the presented
 417 ATEs case, the first horizontal stabilization covers oscillation periods in the range 0.003- 0.03h (from 10 s to less than 2 min). At the
 418 same time, these fast oscillation responses are impacted most by the wellbore storage. Thus, to be able to capture the first stabilization,
 419 the HPT test data must have: 1) a pressure sampling rate significantly below this range (i.e. $\Delta t \ll 10$ s); 2) rate changes performed fast
 420 enough in order to also be within this range (i.e. $e_r \leq 10$ s). Still, the wellbore storage effect may pose a lower limit to the observable radii
 421 of thermal fronts. In case of high-permeability formations, as in the considered ATEs example, gauge accuracy can have a significant
 422 impact on detectability of the first stabilization. However, a combined analysis in both frequency and time domain, when feasible, can

423 significantly enhance interpretation reliability.

424 Data interpretability of a noisy response spectrum could also be improved by the joint interpretation of a sequence of two or more HPTs
425 characterized by different fundamental oscillation periods and therefore focusing on different investigated areas. In fact, as already
426 discussed by the authors (Salina Borello et al., 2019), the area investigated by the test is directly proportional to the square root of the
427 fundamental oscillation period T_f (eq. 14). Moreover, the harmonic components are odd fractions of fundamental oscillation period (T_f ,
428 $T_f/3$, $T_f/5$, $T_f/7$, ...). As a consequence, in the frequency analysis the density of points in a range of T values corresponding to a horizontal
429 stabilization depends on T_f . Moreover, along with noise on recorded pressure due to gauge accuracy, imprecision on rate changes (delay
430 and/ or advance) is responsible of noise on the response spectrum as well. Our experience on real cases (Salina Borello et al. 2017, Salina
431 Borello et al. 2019) shows that irregularities on rate changes are often higher for tests characterized by a longer T_f , which implies that
432 usually only the first 10-20 harmonic component (T_f , $T_f/3$, $T_f/5$, etc) are undisturbed. Analogously to eq. 14, the lower limit of the
433 investigation area covered by N interpretable components is directly proportional to the square root of $T_f/(2N - 1)$. Thus, two subsequent
434 HPTs can be designed to better focus the investigations separately on the inner zone and on the outer zone.

435 When the test is well designed, changes of the heated zone within the storage cycle (i.e. between after-summer and after-winter) as well
436 as gradual changes over the years are detectable on the log-log plot from the variations in value and position of the first horizontal
437 stabilization observable on the response derivative (Figure 15). Clearly, the higher the viscosity contrast, the easier the detection on the
438 log-log plot, due to the larger difference between the horizontal stabilization levels for the two zones. However, relatively small values of
439 the viscosity contrast already allow the application of our methodology. Only values near to $M=1$, such as $0.75 < M < 1.25$, could be critical.
440 Similar criticalities arise if the heated zone extension is very limited. Harmonic Pulse Testing is thus suitable for heated-zone monitoring
441 in a wide range of viscosity contrasts.

442 The radially symmetric model in the test interpretation may not exactly correspond to reality, where the shape of the heated zone may be
443 non-symmetric because of the second well in the ATEs doublet system (Well 1, in Figure 13) or because of other heterogeneities. As a
444 consequence, the prediction of the thermal front position between the two wells is subject to uncertainty. In addition, the actual heat front
445 is gradual rather than a step function, therefore part of the injected heat is advancing the modeled front. However, the test interpretation
446 gives valuable information about changes in average heated zone extension and temperature (Table 6).

447 5. CONCLUSIONS

448 In this paper, we have expanded our earlier work on Harmonic Pulse Testing (HPT) to incorporate the effect of a temperature front moving
449 into the reservoir due to injection of hot (or cold) water. The goal was to be able to employ HPT for monitoring the heat front with
450 particular focus to Aquifer Thermal Energy Storage (ATES). Reliable monitoring requires a baseline HPT test, before injection, to assess
451 the possible presence of heterogeneities. Tests after the summer injection campaign and after the winter production campaign can then be
452 employed over the years.

453 The HPT interpretation with the presented radial composite model solution was preliminarily applied to monitor the thermal front

454 evolution in a synthetic doublet system showing axial symmetry and thus validated against an analytical model. The methodology provided
455 reliable estimates of thermal zone extension and average temperature around the injector for an ideal pressure gauge, not affected by noise,
456 and a realistic gauge, affected by noise.

457 Furthermore, we demonstrated that HPT can be applied to monitor the thermal front of a synthetic Aquifer Thermal Energy Storage
458 (ATES) if a proper test design is applied:

- 459 • duration of the fundamental oscillation period is long enough to investigate the undisturbed zone
- 460 • rate changes are sufficiently precise, i.e. maximum acceptable advance/delays are significantly lower than the oscillation period
461 corresponding to the thermal front expected position
- 462 • gauge pressure sampling is close enough to investigate the heated zone

463 Agreement was observed in all scenarios both in terms of median temperature (T_m), which differed from the estimated temperature (T_i)
464 less than 4°C, and in terms of heated equivalent radius (r_{eq}), which differed from the interpreted r_1 less than 10%.

465 The information obtained from the HPT interpretation does not exactly reproduce the shape of the heated zone of the ATES doublet
466 system, which is not a step function in temperature and is not exactly axially symmetric around the tested well. The latter is due to the
467 contemporary injection/production in the second well or to other heterogeneities in the reservoir. As a consequence, HPT interpretation
468 with the radial composite model may not correctly predict the front position in between the two wells. However, the test interpretation
469 gives valuable information on the extent of the heated zone and its temperature. Moreover, a planning of systematic HPT allows for
470 monitoring variations of the heated zone during the storage cycle and over the years, thus enabling adjustment and fine tuning of the field
471 operations.

472

473 **DATA AVAILABILITY**

474 Datasets related to this article can be found at <http://dx.doi.org/10.17632/ddzcwy53vr.1>, an open-source online data repository hosted at
475 Mendeley Data (Chen and Maloof, 2017).

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555

556

557 **NOMENCLATURE**

- 558 ϕ porosity
- 559 μ viscosity
- 560 ω angular frequency ($=2\pi/T$)
- 561 λ mobility
- 562 η diffusivity
- 563 ζ multiplier associated to diffusivity
- 564 C wellbore storage
- 565 C_K C_I coefficients multiplying Bessel functions K and I respectively
- 566 c_f formation compressibility
- 567 c_t total compressibility
- 568 c_w water compressibility
- 569 f frequency
- 570 g_ω time-independent part of harmonic pressure component
- 571 h net pay
- 572 i complex unit
- 573 I_0, I_1 modified Bessel functions of the first kind
- 574 k reservoir permeability
- 575 k_h horizontal permeability
- 576 k_z vertical permeability
- 577 K_0, K_1 modified Bessel functions of the second kind
- 578 M mobility ratio
- 579 p pressure

- 580 p_{res} reservoir pressure
- 581 p_{well} well pressure
- 582 P_D dimensionless pressure
- 583 P_D' dimensionless pressure derivative
- 584 p_ω pressure harmonic component
- 585 q volumetric rate
- 586 q_{perfs} volumetric rate actually filtrating from the well
- 587 q_{well} imposed volumetric rate at reservoir conditions
- 588 q_ω rate harmonic component
- 589 r_{eq} equivalent radius of front position (numerical simulation)
- 590 r_1 fluid front position between inner and outer zone (radial composite model)
- 591 r_w well radius
- 592 R pressure - rate ratio of harmonic components
- 593 $|R|$ amplitude of R
- 594 $|R'|$ amplitude of derivative of R with respect to $\ln(1/f)$
- 595 S skin
- 596 t_D dimensionless time
- 597 T oscillation period
- 598 T_f fundamental oscillation period
- 599 T^* critical oscillation period
- 600 T_D dimensionless oscillation period
- 601 T_1 temperature of the inner zone (radial composite model)
- 602 T_m median temperature of heated zone (numerical simulation)

603

604 **APPENDIX A**

605 In the following we incorporate skin in the well pressure expression and we derive the general system response in a radial composite
606 scenario of radius r_1 .

607 The pressure in the well is different from the pressure at the well location in the reservoir, because of skin. Skin is introduced as an
608 instantaneous pressure drop due to, e.g., a mudcake or wellbore impairment as a term proportional to the flow rate:

609
$$p_{well} = p_{res}(r_w) + \frac{1}{2\pi h \lambda_1} q_{perfs} \cdot S \quad (23)$$

610 where $\lambda_i = \frac{k_i}{\mu_i}$ is the mobility and h is the reservoir thickness. The rate is taken positive for injection.

611 Rate is related to pressure gradient through Darcy law. At the well sandface ($r=r_w$), considering eq. 3 we have:

612
$$q_{perfs} = -2\pi h \lambda_1 \left[r \frac{\partial p}{\partial r} \right]_{r=r_w} = -2\pi h \lambda_1 \left[r \frac{dg_\omega}{dr} \right]_{r=r_w} e^{i\omega t} \quad (24)$$

613 From eq. (7), applying the differential properties of Bessel functions (Abramowitz and Stegun, 1964) we obtain:

614
$$\frac{dg_\omega}{dr}(r) = -\zeta q_\omega C_K K_1(\zeta r) + \zeta q_\omega C_I I_1(\zeta r) \quad (25)$$

615 From eq. (3), eq. (7) and eq.(23-25), the response function, in the pulser well is:

616
$$R_\omega^{pulser} = \frac{p_{well}}{q_{well}} = \frac{1}{q_\omega e^{i\omega t}} \left\{ p_{res}(r_w) + \frac{1}{2\pi h \lambda_1} q_{perfs} \cdot S \right\} = \frac{g_\omega(r_w)}{q_\omega} - \frac{1}{q_\omega} S \left[r \frac{dg_\omega}{dr} \right]_{r=r_w}$$

617
$$= C_K^1 K_0(\zeta_1 r_w) + C_I^1 I_0(\zeta_1 r_w) + S \cdot \zeta_1 r_w [C_K^1 K_1(\zeta_1 r_w) - C_I^1 I_1(\zeta_1 r_w)]$$

618 (26)

619 If we monitor an observation well, we directly see the reservoir pressure at that location. From eq. (3) and eq. (7) if the observation well
620 is inside (zone 1) or outside (zone 2) the area near wellbore with altered temperature, we respectively have:

621
$$R_\omega^{obs} = \frac{p_{well}}{q_{well}} = \frac{g_\omega(r_{obs})}{q_\omega} = \begin{cases} C_K^1 K_0(\zeta_1 r_{obs}) + C_I^1 I_0(\zeta_1 r_{obs}) & (r_{obs} < r_1) \\ C_K^2 K_0(\zeta_2 r_{obs}) + C_I^2 I_0(\zeta_2 r_{obs}) & (r_{obs} \geq r_1) \end{cases} \quad (27)$$

622 where parameters $C_K^1, C_I^1, C_K^2, C_I^2$ have to be determined through imposing boundary conditions and continuity at the interface. Details
623 follow in Appendix B.

624 **APPENDIX B**

625 This Appendix provides the details on the determination of the free parameters $C_K^1, C_I^1, C_K^2, C_I^2$ in the solution for the harmonic response
626 in a pulse test in a radial composite system with two zones (eq. 26 and eq. 27). The two zones have different mobility due to the different
627 viscosity resulting from the temperatures in the two zones. Coefficients $C_K^1, C_I^1, C_K^2, C_I^2$ have to be determined through imposing the

628 following conditions: (1) reservoir inflow from the wellbore; (2) continuity of pressure at the interface; (3) continuity of flow at the
629 interface; and (4) vanishing pressure disturbance at infinity.

630 We start with the inflow condition from the wellbore (condition 1). Because the wellbore has a nonzero volume (V_{well}) and the injected
631 fluid has a nonzero compressibility (c), part of the injected fluid is “stored” in the wellbore when the pressure is changing. The resulting
632 rate sandface is thus:

$$633 \quad q_{perfs} = q_{well} - C \cdot \frac{dp_{well}}{dt} \quad (28)$$

634 where, $C = c \cdot V_{well}$ is the wellbore storage coefficient.

635 Substitution of eq. 3 and eq. 23 in eq. 28 yields:

$$636 \quad q_{perfs} = q_{\omega} e^{i\omega t} - C \cdot \frac{d}{dt} \left(p_{res}(r_w) + \frac{1}{2\pi h \lambda_1} q_{perfs} \cdot S \right) \quad (29)$$

637 The time dependence of rate (eq. 3) and pressure (eq. 4) is fully contained in the factor $e^{i\omega t}$, therefore $\frac{d}{dt} [p(r_w, t)] = \frac{d}{dt} [g(r_w) e^{i\omega t}] =$
638 $i\omega g(r_w) e^{i\omega t} = i\omega p(r_w, t)$, and similarly $\frac{d}{dt} [q_{perfs}] = i\omega q_{perfs}$. Eq. 29 thus yields:

$$639 \quad q_{perfs} = q_{\omega} e^{i\omega t} - C \cdot i\omega \cdot \left(p_{res}(r_w) + \frac{1}{2\pi h \lambda_1} q_{perfs} \cdot S \right) \quad (30)$$

640 Substitution of the Darcy expression for the rate at the sandface (eq.11) in eq. 30 gives:

$$641 \quad -2\pi h \lambda_1 \left[r \frac{dg_{\omega}}{dr} \right]_{r=r_w} = q_{\omega} - i\omega C \cdot \left(g_{\omega}(r_w) - \left[r \frac{dg_{\omega}}{dr} \right]_{r=r_w} \cdot S \right) \quad (31)$$

642 Substituting eq. 7 in eq. 31 and grouping for C_K^1 and C_I^1 gives:

$$643 \quad C_K^1 [2\pi h \zeta_1 r_w \lambda_1 K_1(\zeta_1 r_w) + i\omega C K_0(\zeta_1 r_w) + i\omega C \cdot S r_w \zeta_1 K_1(\zeta_1 r_w)]$$

$$644 \quad + C_I^1 [-2\pi h \zeta_1 r_w \lambda_1 I_1(\zeta_1 r_w) + i\omega C I_0(\zeta_1 r_w) - i\omega C \cdot S r_w \zeta_1 I_1(\zeta_1 r_w)] = 1$$

$$645 \quad (32)$$

646 This equation poses the first equation for the determination of the parameters in the solution (Eq. 7).

647 At the fluid front ($r = r_1$) between the inner zone, characterized by mobility λ_1 , diffusion η_1 , ζ_1 , and coefficients C_K^1 , C_I^1 , and the outer
648 zone, characterized by mobility λ_2 , diffusion η_2 , ζ_2 , and coefficients C_K^2 , C_I^2 , continuity of pressure (condition 2) and flow rate (condition
649 3) must be guaranteed.

650 According to eq. 4 and 7, pressure of the i^{th} zone writes:

$$651 \quad \left(C_K^i K_0(\zeta_i r) + C_I^i I_0(\zeta_i r) \right) e^{i\omega t} \quad (33)$$

652 Imposing continuity of pressure (condition 2) at $r = r_1$, yields:

653
$$C_K^1 K_0(\zeta_1 r_1) + C_I^1 I_0(\zeta_1 r_1) = C_K^2 K_0(\zeta_2 r_1) + C_I^2 I_0(\zeta_2 r_1) \quad (34)$$

654 According to Darcy law and eq. 25, flow rate of the i^{th} zone writes

655
$$-2\pi r h \lambda_i \left[\frac{dg_\omega}{dr} \right] e^{i\omega t} = -2\pi h e^{i\omega t} q_\omega \lambda_i \zeta_i r [-C_K^i K_1(\zeta_i r) + C_I^i I_1(\zeta_i r)] \quad (35)$$

656 Imposing continuity of flow rate (condition 3) at $r = r_1$, yields

657
$$-\lambda_1 \zeta_1 r_1 C_K^1 K_1^1(\zeta_1 r_1) + \lambda_1 \zeta_1 r_1 C_I^1 I_1^1(\zeta_1 r_1) = -\lambda_2 \zeta_2 r_1 C_K^2 K_1^2(\zeta_2 r_1) + \lambda_2 \zeta_2 r_1 C_I^2 I_1^2(\zeta_2 r_1) \quad (36)$$

658 Finally, vanishing pressures in infinity (condition 4) requires $[g_\omega]_{r \rightarrow \infty} = 0$. Writing eq. (7) for the outer zone and remembering that for
659 $r \rightarrow \infty$ Bessel functions K vanishes while Bessel functions I go to infinity, condition 4 yields:

660
$$C_I^2 = 0 \quad (37)$$

661 Substituting eq. 37 in eq. 36 and eq. 34 and putting together with eq. 33 we obtain a linear set of equations for the three remaining
662 unknowns as follows

663
$$\begin{pmatrix} i\omega C k_{001} + (2\pi h \lambda_1 + i\omega CS)k_{101} & i\omega C i_{001} - (2\pi h \lambda_1 + i\omega CS)i_{101} & 0 \\ k_{011} & i_{011} & -k_{012} \\ -\lambda_1 k_{111} & \lambda_1 i_{111} & \lambda_2 k_{112} \end{pmatrix} \begin{pmatrix} C_K^1 \\ C_I^1 \\ C_K^2 \end{pmatrix} = \begin{pmatrix} 1 \\ 0 \\ 0 \end{pmatrix} \quad (38)$$

664 where

665
$$\begin{aligned} k_{001} &= K_0(\zeta_1 r_w) & k_{101} &= K_1(\zeta_1 r_w) \cdot \zeta_1 r_w \\ i_{001} &= I_0(\zeta_1 r_w) & i_{101} &= I_1(\zeta_1 r_w) \cdot \zeta_1 r_w \\ k_{011} &= K_0(\zeta_1 r_1) & k_{111} &= K_1(\zeta_1 r_1) \cdot \zeta_1 r_1 \\ i_{011} &= I_0(\zeta_1 r_1) & i_{111} &= I_1(\zeta_1 r_1) \cdot \zeta_1 r_1 \\ k_{012} &= K_0(\zeta_2 r_1) & k_{112} &= K_1(\zeta_2 r_1) \cdot \zeta_2 r_1 \end{aligned} \quad (39)$$

666 The solution to this set of equations is easily obtainable by matrix inversion; the parameters C_K^1, C_I^1, C_K^2 will depend on skin S , wellbore
667 storage coefficient C , position of the temperature interface r_1 , mobility (λ_1, λ_2) and diffusion coefficient (η_1, η_2) in the two zones and the
668 angular frequency (ω) .

669

670

671

672