PROCEEDINGS, 49th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 12-14, 2024
SGP-TR-227

Application of Distributed Temperature Sensing (DTS) in Geothermal Wells

Orkhan Khankishiyev, Saeed Salehi, Gurban Hasanov, Zeming Hu

Well Construction Technology Center, The University of Oklahoma

1106 Lexington Avenue, Norman, OK 73069-8427

orkhan@ou.edu

Keywords: DTS, distributed temperature sensor, geothermal, production, flow zones, flow rate, well monitoring, optimization

ABSTRACT

The exploration and utilization of geothermal energy continues to gain prominence as the world seeks sustainable and renewable energy sources. Within this context, the importance of comprehending flow zones and accurately estimating flow rates in geothermal reservoir management cannot be overstated. Current wireline tools for measuring flow rates and constructing flow profiles within geothermal wells often fall short due to the inability of their sensor and electronic components to meet the stringent temperature requirements, a particularly challenging issue in high-temperature geothermal environments. This review delves into existing research and developments concerning the use of Distributed Temperature Sensing for temperature measurement, flow zone identification, flow rate calculation, and flow instability identification within geothermal reservoirs. The review aims to uncover insights into the capabilities and limitations of DTS technology in the geothermal context, paving the way for future research and potential advancements in the field.

Temperature measurement through DTS is examined to achieve continuous and high-resolution temperature profiles in geothermal wells. The review aims to assess the capabilities of DTS in capturing temperature variations within the geothermal wellbore, providing insights into its potential for precise temperature monitoring and its implications for improved resource management. Furthermore, the review delves into the literature to uncover instances where DTS has been used for flow zone identification in geothermal reservoirs. By analyzing temperature changes along wellbores, this application offers the potential to differentiate distinct flow zones, contributing to enhanced reservoir characterization and optimized production strategies.

The study also explores the concept of DTS-based flow rate calculation, investigating the feasibility of estimating fluid flow velocities and quantities using temperature data. A comprehensive examination of relevant research reveals insights into how DTS might streamline reservoir management and enhance real-time decision-making processes within geothermal projects. By continuously monitoring temperature variations, the paper assesses the role of DTS in promptly detecting flow instabilities, potentially leading to timely interventions and improved overall well performance. Through a comprehensive analysis of relevant literature, this study aspires to contribute to the ongoing exploration of DTS applications in geothermal wells, ultimately enhancing the efficiency of geothermal resource utilization.

1. INTRODUCTION

With the rise in energy demand, the need for sustainable and environmentally friendly energy production increased significantly. While huge investments are made to decarbonize the existing energy production from hydrocarbons, vast amounts of geothermal energy are stored deep beneath the earth crust, distributed across the globe in igneous, sedimentary, and metamorphic rocks in favorable locations (Blackwell et al., 2011; Khankishiyev et al., 2023). The efficient exploitation of these resources requires the application of state-of-the-art technologies from exploration to production. The Distributed Temperature Sensing (DTS) has evolved as one of the few real-time well monitoring technologies, mainly applied in oil wells (Brown & Hartog, 2002) to monitor reservoir dynamics, detect flow anomalies, optimize well performance, and ensure well integrity by providing real-time temperature data along the wellbore. Coupled with the static reservoir data and dynamic production data, DTS can help identify the flow zones and estimate the flow contribution of multiple intervals inside the wellbore.

Understanding the thermal properties of geothermal reservoirs stands as a pivotal element in shaping decisions and predictive modeling for reservoir productivity (Patterson et al., 2017; Reinsch & Henninges, 2010). Temperature, as a key state indicator, exerts a direct influence on production potential, guiding crucial determinations such as optimal well depths, casing lengths, and various operational factors. Moreover, comprehending alterations in pressures or water levels within wells across time aids in evaluating the hydraulic interconnections among distinct reservoir sections. Temperature changes significantly impact various downhole processes, and the monitoring of temperature has been a longstanding practice to assess the effectiveness of producing wells, analyze water-injection profiles, and diagnose the success of fracture operations. Despite its importance, downhole temperature measurements were often overlooked for many years in favor of data obtained from advanced logging tools. The advent of fiber-optic technology has sparked renewed interest in temperature measurement, marking a resurgence in its relevance and application.

The Distributed Temperature Sensor (DTS) technology uses fiber optic cable to continuously measure the temperature profile along the medium covered by the cable (Bao et al., 1995). It is also available for temporary deployment for short-term investigations. Although DTS is relatively new to the geothermal industry, it has been used for several decades to record and monitor changes in temperature for multiple applications (Maughan et al., 2001). Distributed Temperature Sensing (DTS) typically operates based on similar principles to those of an Optical Time-Domain Reflectometer (OTDR) (Juarez & Taylor, 2005). Laser light pulses generated at the surface by the DTS box are sent through the fiber optic cable. When the light travels through the cable, a physical phenomenon called Raman scattering occurs (Williams et al., 2000). A part of this process is temperature dependent, thus enabling the measurement of the temperature from the light signals coming back through the cable. The DTS technology has been under continuous development, increasing measurement accuracy and reliability. Current standard specifications for DTS performance include (Bazzo et al., 2016; Chen, 2019; Soto et al., 2011):

- Maximum Operating Range (150 km ?)
- Temporal Temperature Resolution (0.1°C)
- Spatial Temperature Resolution (0.01 °C)
- Spatial Resolution (0.5m)

Distributed Temperature Sensing technology has emerged as a valuable tool in the oil and gas industry during the last decade due to its' unique advantages over Production Logging Tool for not requiring any well intervention, providing real-time measurement without interrupting production, flexible deployments in challenging environments and comparable cost of installation and data acquisition with much less risk associated with it. The DTS technology does not provide many direct benefits without detailed interpretation other than spatial temperature. For example, it can provide valuable information in the following applications after thorough analysis (Chen, 2019; Nath et al., 2006; Soroush et al., 2021; Wang et al., 2008):

- Permanent temperature logging: measuring changes in well temperature over time instead of periodic logging;
- Flow zone identification: determining different flow zones within the well based on temperature data;
- Flow metering: correlating distributed temperature data with flow rates in specific inflow regions;
- Water or steam breakthrough: identifying areas within the producing zone where water is entering the pipe;
- Gas-lift surveillance: monitoring the locations and rates of gas injection;
- Flow assurance: detecting locations where condensates or other flow hindrances form in pipes;
- Leak detection: identifying locations where produced fluid is leaking out of the tubing.

In addition to multiple potential uses, the DTS cable can be utilized for Distributed Acoustic Sensing (DAS) as well (Johannessen et al., 2012). The same optical fiber cable used for DTS can often support DAS functionality by changing the surface data transmitter and data acquisition unit. This dual functionality provides the advantage of integrated temperature and acoustic sensing along the length of the cable. It enables interchangeable or simultaneous monitoring of temperature variations and acoustic signals, offering a comprehensive solution for various applications in fields such as oil and gas, geothermal, and environmental monitoring.

This research aims to understand DTS data interpretation and investigate potential areas of application in geothermal industry. The main objective is to uncover the reservoir and well information that the temperature data directly or indirectly demonstrate. While DTS has gained popularity in the oil and gas sector over the last 15 years, this study adapts and expands its use to geothermal wells. By exploring how temperature data relates to reservoir and well dynamics, the research aims to contribute valuable insights to the evolving field of geothermal exploration and production technologies. The following section provides detailed background information on cable selection, basics of DTS components and data acquisition. The applications section investigates the potential areas of DTS deployment in geothermal wells with the theory of data interpretation. The real-world applications of DTS in geothermal wells will be reviewed in the case studies section and future research directions will be outlined at the end of this paper.

2. TECHNICAL OVERVIEW OF DTS TECHNOLOGY

2.1 DTS Components

Distributed temperature sensors (DTS) utilize optical fibers to measure temperatures, offering a continuous temperature profile along the fiber cable. These optoelectronic devices originated in the 1980s, witnessing substantial technological advancements and expanded applications in subsequent decades (Ukil et al., 2012). DTS systems exhibit remarkable accuracy in temperature measurement, often achieving precision within the range of +- 1°C at a resolution as fine as 0.01°C (Bazzo et al., 2016), with a spatial resolution of 0.5-1 m, and covering measurement distances up to 150 km (Inaudi & Glisic, 2010).

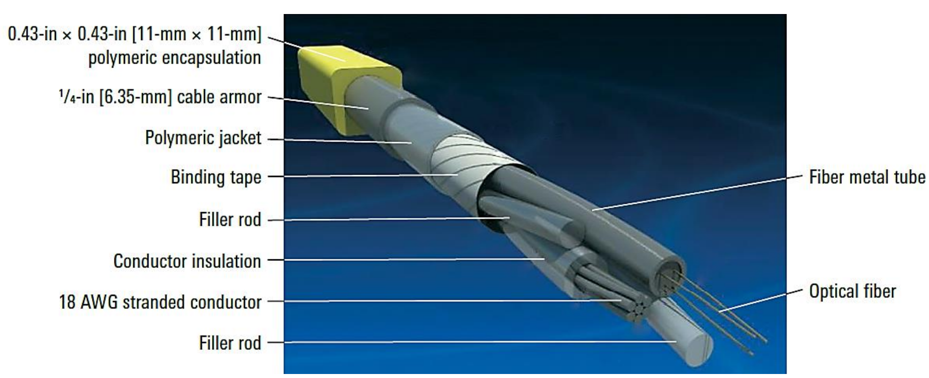

Figure 1. Schlumberger WellWatcher Neon system cable with optical fibers. (Brown, 2016)

As Brown et al. (2004) described, a DTS system, in its simplest configuration, includes a strand of optical fiber (Figure 1), a laser light source, an optical splitter, an optoelectronic signal-processing unit, and a display unit (Figure 2). The core of the fiber is extremely thin, with a diameter ranging from 5 to 50 microns, and is enveloped by a protective layer of silica called cladding, characterized by a distinct reflective index from the core (Figure 1). For the applications in the wells, the optical fiber extends from the control room through the well head, descending along the tubing, traversing the reservoir segment, and looping back to the control room. Inside the control room, a 10 ns light pulse is transmitted through the optical fiber via a laser (Bense et al., 2016). During its journey through the fiber, the light encounters glass particles, causing scattering, and is then captured upon its return to the surface. Allowing ample time for the furthest point's backscattered light to reach, this process is iterated to generate a spectrum based on the captured backscattered light. The duration taken by the backscattered light to return to the surface delineates the distance along the fiber where the scattering occurred, discreetly arranged into intervals of approximately 1 meter to construct a spectrum for each segment (John et al., 2015).

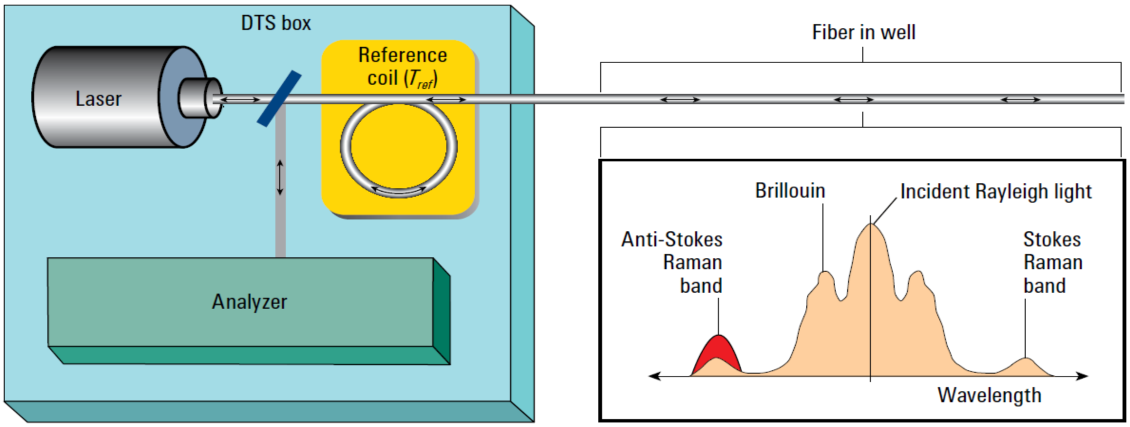

Figure 2. Schematic of the Distributed temperature sensing (DTS) measurement (Brown, 2016)

2.2 Measurement Principles

The primary measuring principles revolve around the detection of light back-scattering, employing Rayleigh (Hartog, 1983), Raman (Dakin et al., 1985), and Brillouin (Bao et al., 1994) principles. Raman backscatter occurs due to molecular vibration in the fiber, leading to the emission of photons with a wavelength shift from the incident light. The back-scattered light comprises three spectral components: Rayleigh scattering with the wavelength of the laser source, the Stokes component with a higher wavelength where photons are generated, and the Anti-Stokes components with a lower wavelength. Positively shifted Stokes backscatter remains temperature-independent, whereas negatively shifted Anti-Stokes Raman backscatter is temperature-dependent.

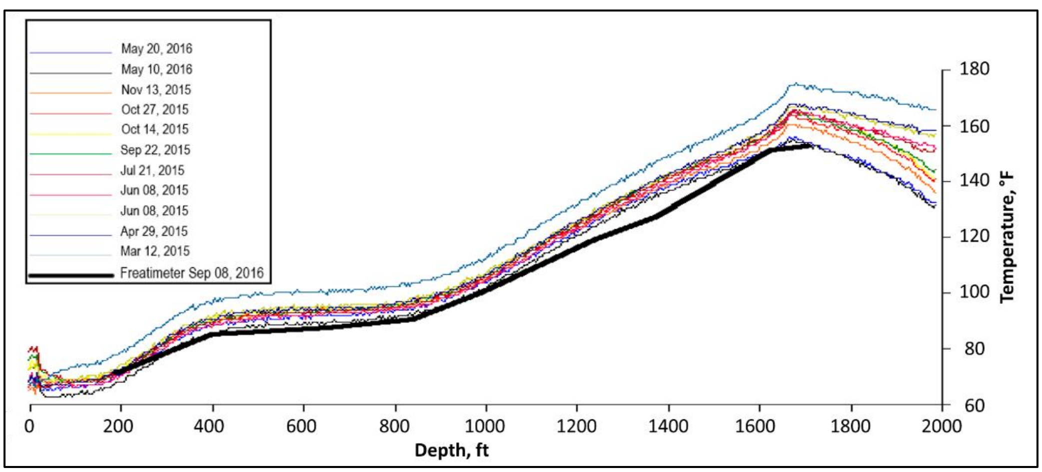

Figure 3. Example DTS temperature profiles vs depth at different days along the pilot hole compared to the freatimeter equipped with a thermocouple (recreated from Somma et al. (2019))

The temperature is calculated based on the intensity ratio of Stokes to Anti-Stokes (Equation 1). As pulses weaken following scattering loss, the accuracy of calculated temperature depends on calibration and the stability of fiber loss (Shiota & Wada, 1992).

$$\frac{1}{T_{cal}} = \frac{1}{T_{ref}} - \frac{ln\left[\left(\frac{TTS}{NTS}\right)_x / \left(\frac{TTS}{NTS}\right)_c\right]}{SLE} \qquad (1)$$

where

T_{cal} = calculated temperature (K)

T_{ref} = reference temperature (K)

SLE = temperature sensitivity

$(TTS/NTS)_x$ = anti-Stokes/Stokes ratio at the point of interest along the fiber

$(TTS/NTS)_c$ = anti-Stokes/Stokes ratio in the reference coil

Analysis of the backscattered light includes determining its origin along the length of the fiber. Given that each input pulse has a duration of 10 nanoseconds, the interval from which the backscattered light originated aligns directly with a specific one-meter segment of the fiber. As a result, temperature logs (Figure 3) can be created at one-meter intervals along the fiber's length using only the laser source, the analyzer, and a reference temperature with the surface system (Drakeley et al., 2006).

2.3 Cable Selection for High-temperature Applications

In conventional hot geothermal wells, such as those observed in high-enthalpy regions like Iceland, operational temperatures can attain levels within the range of 350–380°C (Lu, 2018). Current research endeavors are oriented towards a significant enhancement in the energy output from individual geothermal wells. This ambitious goal involves the extraction of geothermal fluids characterized by elevated temperatures, with a target range of 550–600°C, originating from depths of approximately 4–5 km (Friðleifsson et al., 2017; Markússon & Hauksson, 2015). Therefore, selecting the appropriate material for DTS cable demands careful consideration and thorough analysis of materials in in-situ conditions since the materials can undergo changes in severe subsurface conditions, potentially introducing inaccuracies in the collected data sourced from intrinsic or extrinsic energy losses in the optical fiber.

Some degrading issues arise from the presence of hydrogen around the optic fiber, resulting in modifications to the DTS material and eventually, leading to incorrect measurements (Normann et al., 2001). The absorption occurs as H_2 diffuses into interstitial sites within the silica network, impacting all silica-based glass fibers – whether single or multimode. This phenomenon involves a chemical reaction between the diffused H_2 and the glass constituents, resulting in the formation of hydroxyl (OH) groups (Williams et al., 2000). These groups exhibit distinctive absorption bands, causing significant attenuation of transmitted light. The solubility of H_2 in bulk silica follows a linear relationship with pressure but diminishes with rising temperatures. Upon removal of external pressure and/or the H_2 source, the H_2 diffuses out of the core, and over time, the light transmission characteristics are restored. The losses incurred from H_2 absorption are reversible (Girard et al., 2013).

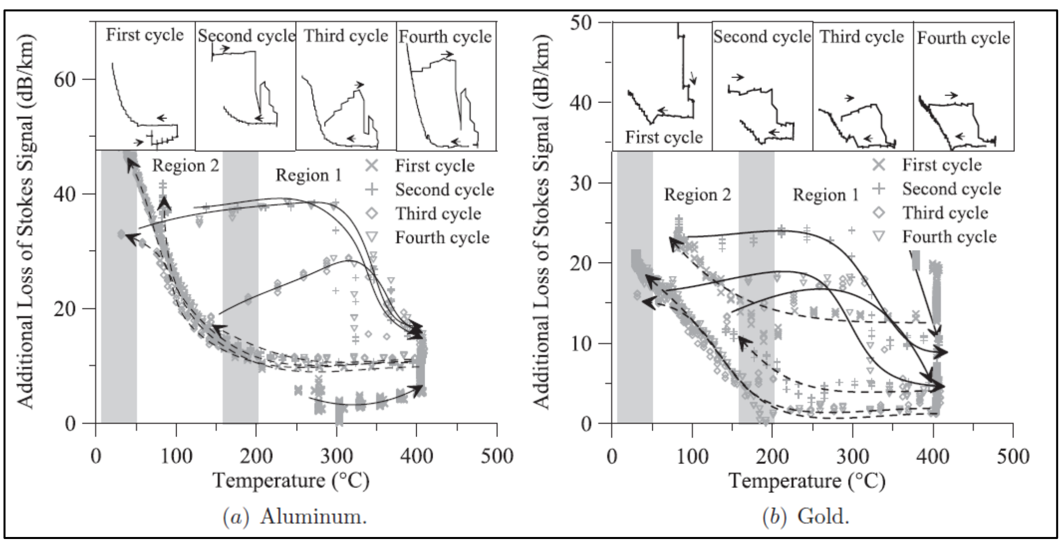

Figure 4. Additional loss of Stokes signal (dB/km) vs. temperature for aluminium (a) and gold (b) fiber samples impacted by heating and cooling cycles (Reinsch & Henninges, 2010)

In a specific experiment by Reinsch and Henninges (2010), it was determined that polyimide fibers outperformed metal-coated fibers, which exhibited high attenuation values at low temperatures (Figure 4). Additionally, it was observed that polyimide fibers can function effectively at temperatures reaching approximately 350°C which makes them more suitable candidates for high temperature geothermal wells. In another study funded by the U.S. Department of Energy, Homa et al. (2018) found out that standard telecommunications grade germanium-doped single and multimode fibers have demonstrated reliable performance up to temperatures of 1100°C, respectively, in non-hydrogen environments and/or appropriately designed sensor applications. For environments involving hydrogen and moisture, it was recommended to use pure silica core single-mode and low OH, large core step index multimode fiber, which have proven to be reliable up to temperatures of 1000ºC.

3. APPLICATIONS OF DTS IN GEOTHERMAL WELLS

Upon drilling a well into superhot rock formations, the utilization of logging tools becomes imperative for in-depth investigation. These tools serve multiple purposes, including assessing stresses on the rock, imaging fractures, surveying the angle and direction of the well, and measuring critical parameters such as temperature, pressure, and flow rate. To facilitate these measurements, instrumentation employing high-temperature stable electronics, encapsulated within an insulating barrel, has been developed (Bertani et al., 2018). This technology can withstand very high temperatures for short durations (Petty et al., 2020). However, for extreme temperatures, innovative approaches are necessary (Khankishiyev & Salehi, 2023; Konate et al., 2019), such as the integration of fiber optic sensors and cables specifically engineered to endure the challenges introduced by very high temperatures. Application of the DTS technology in geothermal wells offers numerous advantages such as improved reservoir characterization, fracture performance evaluation, identification of fractured/permeable flow zones, injection and production flow modelling/monitoring, and detection of casing/tubing leaks and scale formation.

3.1 Reservoir Characterization

Analyzing the temperature profile in geothermal wells is an initial phase in evaluating the thermal properties in the immediate vicinity of the borehole. The thermal characterization of geothermal reservoirs holds paramount significance in decision-making and predictive modeling of reservoir production potential (Kocabas, 2005). Temperature stands out as a crucial state variable within a reservoir, directly impacting production potential and reservoir management. Moreover, comprehending variations in pressures or water levels in wells over time aids in assessing hydraulic connectivity between different reservoir intervals (Patterson et al., 2017).

To achieve a comprehensive geothermal reservoir characterization, integration of subsurface near-wellbore temperature data from DTS and vertical seismic profiles from DAS data is preferable. This approach enables mapping of subsurface rock structures along with subsurface temperature distribution (Chalari et al., 2019; Kasahara et al., 2023; Miller et al., 2018). If the fiber-optic cables are installed in multiple wells in the same reservoir, continuous data acquisition and interpretation of DTS data can demonstrate the groundwater dynamics and movement of the temperature front in real-time to help better manage the production and injection strategies.

A thorough review of shallow borehole studies employing Distributed Temperature Sensing (DTS) systems to gain a deeper understanding of borehole groundwater dynamics was conducted by Bense et al. (2016). In open boreholes, areas of fracture flow were identified using DTS as a heat tracer through thermal dilution testing by Read et al. (2013) and Leaf et al. (2012). Fracture flow within boreholes under natural-gradient conditions was determined by Coleman et al. (2015) using DTS.

In downhole applications for structural underground investigations and reservoir monitoring, Distributed Acoustic Sensing (DAS) has been employed in previous publications (Barberan et al., 2012; Cox et al., 2012). Classical geophones in vertical seismic profiling can be substituted by DAS, as demonstrated in several studies (Daley et al., 2013; Götz et al., 2018; Hartog et al., 2014; Madsen et al., 2016). Additionally, DAS shows promise in monitoring production zones (Naldrett et al., 2018; Williams et al., 2015) and assessing flow characteristics (Bukhamsin & Horne, 2016). Lipus et al. (2021) provided a comprehensive review of DAS applications in wells.

Hydraulically active zones and fracture characteristics, as well as pressure profiles, can be identified in geothermal wells through DTS measurements, as evidenced by several studies (Sakaguchi & Matsushima, 2000; Sharma et al., 1990; Smithpeter et al., 1999). Pursuing similar objectives, DTS measurements were carried out in conjunction with cold water injections in a study conducted by Henninges et al. (2005). Patterson et al. (2017) illustrated the ability of DTS to capture spatiotemporal dynamics during borehole temperature recovery following injection of a cold-water slug at Brady Geothermal Field in Nevada (Figure 5). The authors mentioned that the insights gained from the DTS survey offered valuable conclusions for geothermal site operators, including the demonstration of hydraulically connected injection and production wells, identification of heat transport primarily through conduction, and the application of a heat-transfer model for estimating thermal diffusivity, providing essential information for reservoir modeling and sustainable resource management. The raw data collected during that project is available online at (Coleman, 2016).

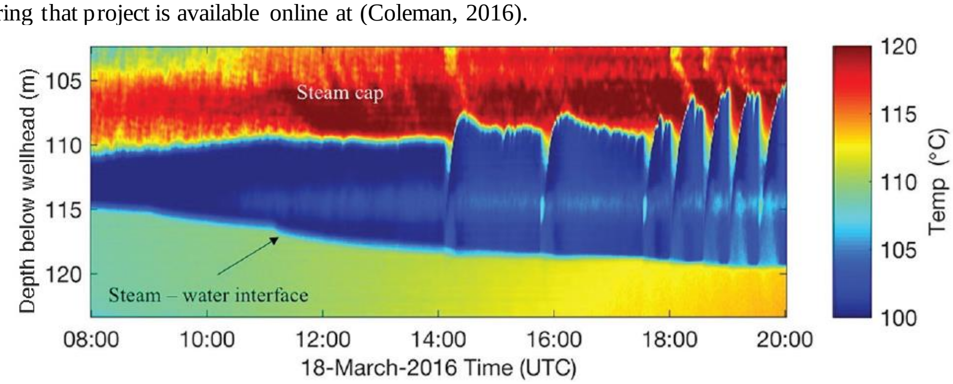

Figure 5. A 12-hour time series collected on 18 March 2016 at Brady Geothermal Field (Miller et al., 2018)

In a recent field application described in Schölderle et al. (2021), DTS and DAS technologies were permanently installed in a geothermal well located in hydraulically active zones in the Upper Jurassic reservoir of the Bavarian Molasse Basin in Southern Germany. According to the authors, the integration of the DTS data enabled an observation of the fractured intervals and dynamic change of thermal water temperature in the reservoir, and it enhanced the flow zone characterization qualitatively as well as quantitatively. It was also emphasized that thermal contraction and expansion of the fiber-optic cable took place during thermal cycles, necessitating the consideration of thermal/mechanical stresses applied on the cable during sensor calibration and data acquisition.

3.2 Flow Monitoring/Profiling

To determine the individual contribution of different zones in multizone completion types in the oil and gas industry, the Production Logging Tool (PLT) has been employed along with other supplementary data such as temperature and density. However, the fragile spinner flowmeter and electronic components of PLT tools do not meet the stringent temperature requirements of the geothermal wells, leaving a number of questions unanswered when the wells are put into commission. The Distributed Temperature Sensor, on the other hand, can help identify the individual flow zones by analyzing the temperature profiles along the production interval. Tests have demonstrated that the temperature profile changes with continuous inflow of fluid from reservoir into the wellbore.

3.2.1. Model Description

The geothermal gradient of the formations around the wellbore plays an essential role in flow profiling models because heat loss to the surrounding formation through insulation, casing and cement will occur as the fluid/steam travels up the wellbore. The alteration in temperature profiles within injector and producer wells serves as a valuable indicator of the connection between these wells through a permeable or fractured medium. This information helps discern whether the injected fluid is successfully produced at the production well or if it is lost to the formation. A more in-depth analysis, facilitated by multiphase flow simulators and finite-element thermal models, allows for a detailed estimation of fluid and steam flow rates, as well as insights into zonal contributions.

Numerous papers within the literature (Horne & Shinohara, 1979; Ouyang & Aziz, 2000; Ramey Jr, 1962) have delved into the subject of heat transfer between the wellbore and the surrounding formation forming the basis for more sophisticated solutions. Implementing a numerical multiphase thermal wellbore model, Livescu et al. (2008) fully coupled it with a general-purpose reservoir simulator (Figure 6). Another contribution to wellbore modeling comes from Ouyang and Belanger (2006), who designed a numerical model developed for interpreting Distributed Temperature Sensing (DTS) data and achieved the estimation of flowrate profiles by effectively solving an inverse problem.

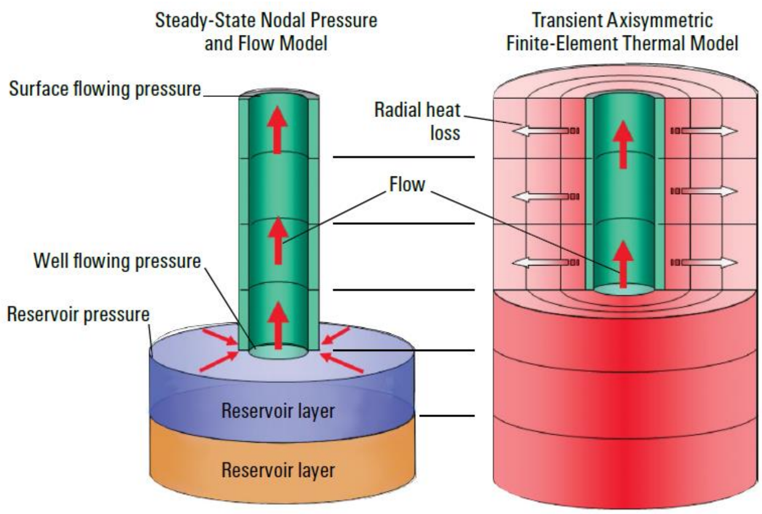

Figure 6. Schlumberger Therma Simulation model components (Brown, 2016)

A mechanism that plays a crucial role in the model is the Joule-Thompson effect (Joule, 1856). It refers to the temperature alteration of a fluid during expansion, specifically when there is a decrease in pressure in a steady flow process. This change occurs without any heat transfer or work involvement, maintaining constant enthalpy. Such processes are commonly observed in "throttling" scenarios, such as adiabatic flow through a porous plug or an expansion valve. (Steffensen & Smith, 1973). The temperature alteration, whether positive or negative, is contingent upon the composition of the fluid. In numerous instances, gases tend to cool, while liquids experience heating when subjected to a pressure drop. The Joule-Thomson coefficient (JTC) of hydrocarbon gas is influenced by factors such as composition, pressure, and temperature, typically manifesting cooling effects within the range of 2 to over 20 °F per 1000 psi. In contrast, water demonstrates a warming JTC of approximately 3°F per 1000 psi (Johnson et al., 2006; Stauffer et al., 2014).

For conducting a flow allocation analysis, the flow model necessitates the inclusion of Distributed Temperature Sensing (DTS) data, downhole pressure data, and surface flow rates. The simulator employs pressure-temperature wellbore and near-wellbore simulation, incorporating error minimization techniques to align field DTS and downhole pressure data with the response of flow rate and the Joule-Thomson effect, across both depth and time domains. At each time step, the simulator utilizes geothermal temperature, individual layer flow rates, and fluid temperature, accounting for the Joule-Thomson effect, to compute the temperature profile from the bottom to the wellhead. Wang (2012) provided a comprehensive explanation, including mathematical formulations, detailing the construction of a coupled wellbore/reservoir thermal model and the subsequent estimation of flowrate profiles based on temperature measurements. The two main heat transfer and fluid flow equations sitting behind the models are given below (Brown et al., 2005; Johnson et al., 2006):

$$\frac{\partial^2 T}{\partial r^2} + \frac{1}{P}\frac{\partial T}{\partial r} = \frac{\rho_e c_e}{k_e} * \frac{\partial T}{\partial t} \qquad (2)$$

$$\frac{\partial^2 P}{\partial r^2} + \frac{1}{P}\frac{\partial T}{\partial r} = \frac{\varphi_e c_g \mu_g}{k} * \frac{\partial P}{\partial t} \qquad (3)$$

where

T = Temperature (°F)

P = Pressure (psia)

t = Time (seconds)

r = Radius (in)

ρ = Density (g/cc)

c = Compressibility (cm2/dyne)

k = Reservoir Permeability (mD)

φ = Reservoir Porosity (fraction)

μ = Viscosity (cp)

*In the equations 2 and 3, e means effective, and g means gas

The thermal wellbore model outlined above necessitates both static and dynamic inputs for the simulation of transient wellbore temperature profiles. Static inputs encompass factors such as the geothermal temperature profile, well deviation, completion equipment, perforation depths, layer and reservoir properties, as well as the thermal properties of completion, rock, and fluid. Dynamic inputs involve surface rates, wellhead pressure, downhole pressure, and Distributed Temperature Sensing (DTS) temperature data. In prediction mode, zonal flow rates and formation temperature serve as inputs, while they function as matching parameters in analysis mode. Utilizing these two key parameters enables the achievement of thermal and mass balances within the wellbore. A typical model workflow used in the commercially available software applications is shown in Figure 7.

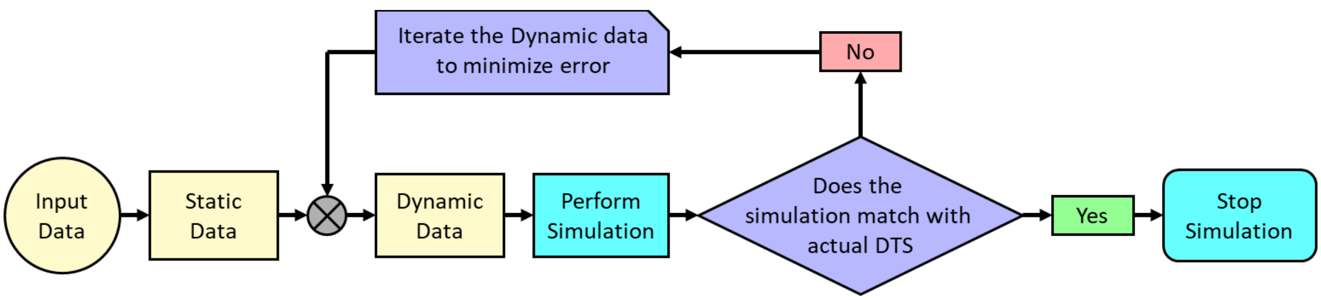

Figure 7. A simple workflow schematic to perform the wellbore simulation with the actual data (recreated based on Johnson et al. (2006))

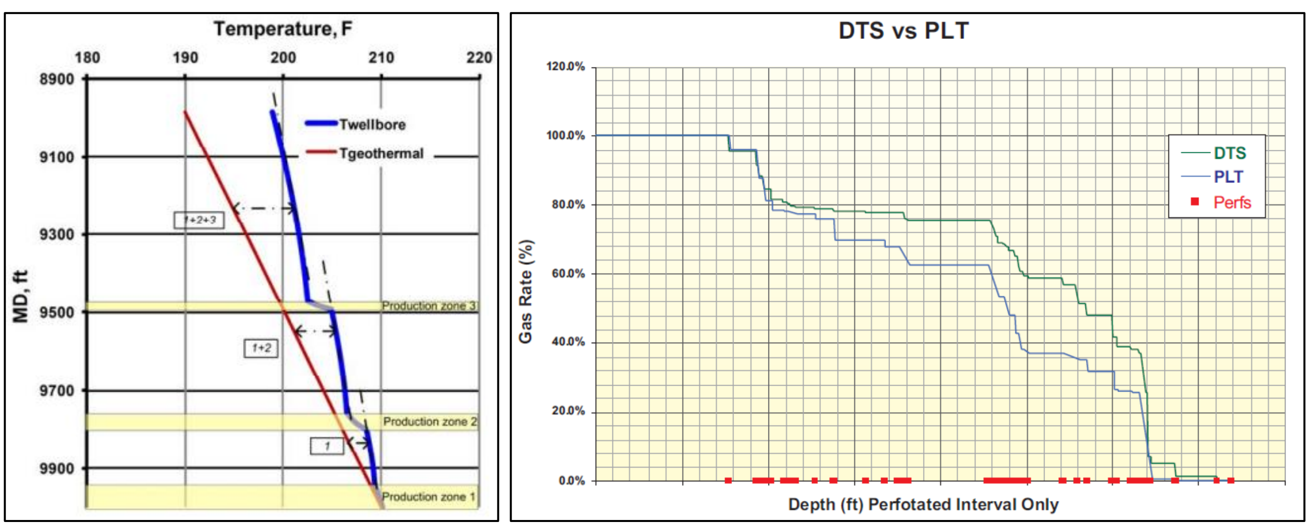

Figure 8. (Left) Production zone identification from DTS temperature profile for an oil production well by Muradov and Davies (2011) and (Right) Comparison of the DTS and PLT Gas rate for the perforated interval by Johnson et al. (2006)

3.2.2 Sensitivity Analysis

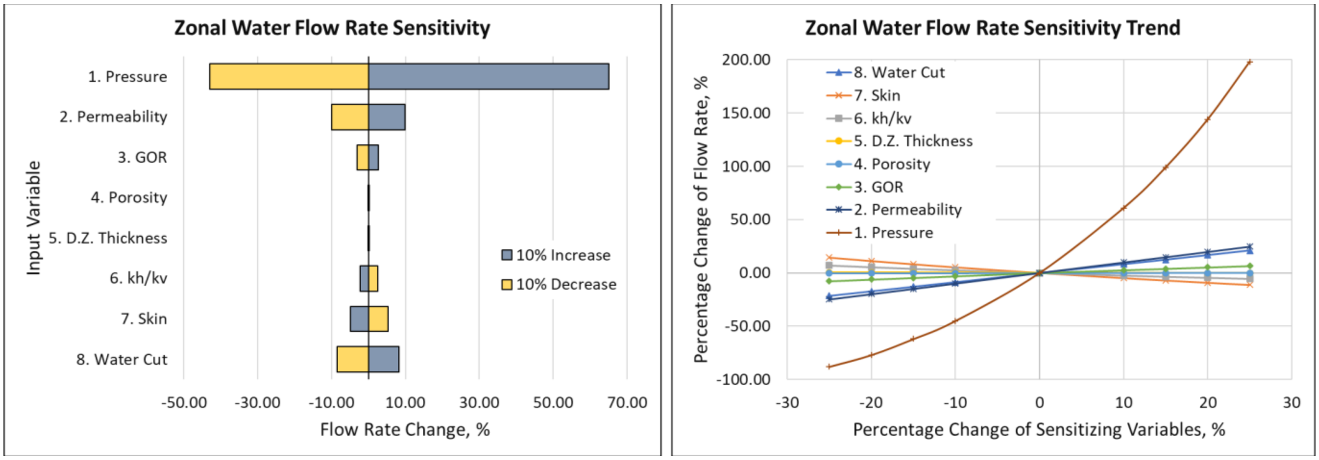

Figure 9. (Left) Zonal water flow rate sensitivity tornado chart and (Right) Sensitivity trend using an oil well production data

To evaluate the efficacy of the zonal flow rate estimation model, a two-week dataset comprising Distributed Temperature Sensing (DTS) and other relevant input data from an oil production well was processed using the outlined workflow in Figure 7. The computed zonal flow rates were found to align within an acceptable range when compared to Production Logging Tool (PLT) data (Figure 8), acknowledging the inherent uncertainty associated with each input variable. Consequently, a sensitivity analysis was imperative to assess the model's responsiveness to these uncertainties. The sensitivity analysis involved incrementally and decrementally adjusting the values of individual input variables, gauging the resultant change in the model output. The findings revealed that reservoir pressure, permeability, and water-cut emerged as the top three parameters with the highest sensitivity concerning zonal water flow rate estimation in an oil well (Figure 9, left). Notably, even a modest 10% alteration in reservoir pressure led to an approximately 50% change in zonal water flow rate, showcasing an exponential impact (Figure 9, right). In contrast, for the remaining input variables, the impact exhibited a linear trend. This sensitivity analysis underscored the critical importance of precise input variables in achieving reliable results from DTS flow rate estimation models.

3.2 Flow Assurance

The presence of aggressive chemicals and high-velocity fluid flow in the geothermal wells cause corrosion and erosion of wellbore materials, leading to casing and tubing leaks (Karlsdóttir et al., 2019). Geothermal fluids often carry dissolved minerals that can precipitate and deposit on wellbore surfaces and within the reservoir, resulting in scaling and reduced permeability (Klapper et al., 2019). Casing leaks and scaling can impede fluid flow, decrease heat transfer efficiency, and lead to equipment failures. Therefore, detection of these issues from temperature anomalies recorded by Distributed Temperature Sensing (DTS) represents a significant advancement in geothermal well monitoring. By analyzing temperature variations along the wellbore, DTS systems can identify deviations indicative of casing leaks or scale formation (Walker & Carr, 2003). Grosswig et al. (2019) and McCarthy et al. (2020) reported the use of DTS and DAS data to determine the location of casing leaks in real time during field applications. Casing leaks are often characterized by localized temperature increases due to the influx of higher-temperature fluids from surrounding formations, or vice versa, high temperature fluid leak from the tubing to behind the casing that can be captured by DTS and DAS (Figure 10). Conversely, scale formation typically manifests as gradual temperature changes along the casing, reflecting reduced heat transfer efficiency. These temperature anomalies provide valuable insights into the integrity of the well and enable proactive maintenance to mitigate potential issues, ensuring optimal performance and longevity of geothermal assets (Al-Hussain et al., 2015; Mishra et al., 2017).

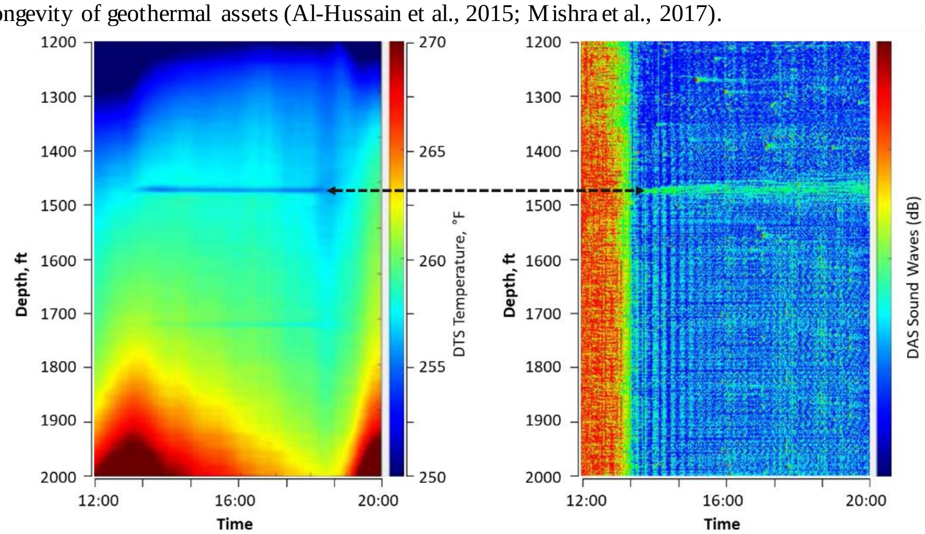

Figure 10. A casing leak at around 1470 ft determined by DTS and DAS data (recreated from McCarthy et al. (2020))

4. FUTURE DIRECTIONS AND RESEARCH OPPORTUNITIES

- Future research projects in the application of DTS in geothermal wells could focus on the exploration of innovative flow simulation techniques decreasing the concentrated sensitivity of the model on single input variable. These techniques aim to refine the conversion of DTS data, enabling the extraction of more precise and individual flow rates in diverse scenarios.

- Despite advancements in fiber optic cable designs, ongoing research is essential to identify new materials capable of enduring the challenging conditions within geothermal wells, including high pressure, high temperature, and hydrogen-rich environments. This exploration is crucial for diminishing the thermal degradation of fiber cable and enhancing the effectiveness of DTS applications in geothermal well monitoring.

- Moreover, an area for future research involves the simultaneous utilization of DTS alongside information gathered from other sensors. Integrating data from various sensors could enhance the precision of results. While DAS is currently employed alongside DTS, there is room for the development and incorporation of additional sensors to further refine the combined data, opening up new possibilities for comprehensive monitoring and analysis in geothermal well applications.

CONCLUSION

In conclusion, this review highlighted the pivotal role of Distributed Temperature Sensing (DTS) technology in advancing geothermal reservoir management. The utilization of DTS provides continuous and high-resolution temperature profiles within geothermal wells, offering valuable insights into temperature variations and their implications for resource management. The application of DTS for flow zone identification proves instrumental in enhancing reservoir characterization, allowing for the differentiation of distinct flow zones and contributing to optimized injection and production strategies.

Furthermore, the study delves into the potential of DTS-based flow rate calculation, exploring its feasibility in estimating fluid flow velocities and quantities through temperature data. The insights gained from relevant research indicate the promising role of DTS in streamlining reservoir management and facilitating real-time decision-making processes in geothermal projects. The detection of flow instabilities through continuous temperature monitoring emerges as another significant contribution, potentially leading to timely interventions and improved overall well performance.

The future research opportunities lie in innovative flow simulation techniques, aimed at decreasing the model's sensitivity to individual input variables. Ongoing exploration of materials capable of enduring extreme conditions within geothermal wells, coupled with the simultaneous utilization of DTS alongside other sensors, holds promise for refining the precision of results and opening up new avenues for comprehensive monitoring and analysis in geothermal well applications.

ACKNOWLEDGEMENTS

The authors of this paper would like to thank DeepPower Inc. for funding this research. The opinions, findings, conclusions, and recommendations presented in this publication are solely those of the authors and do not necessarily represent the views and opinions of DeepPower Inc.

REFERENCES

Al-Hussain, A. M., Hossain, M. E., Abdulraheem, A., & Gajbhiye, R. (2015). An integrated approach for downhole leak detection. SPE Saudi Arabia Section Annual Technical Symposium and Exhibition,

Bao, X., Dhliwayo, J., Heron, N., Webb, D. J., & Jackson, D. A. (1995). Experimental and theoretical studies on a distributed temperature sensor based on Brillouin scattering. *Journal of lightwave technology*, *13*(7), 1340-1348.

Bao, X., Webb, D. J., & Jackson, D. A. (1994). Combined distributed temperature and strain sensor based on Brillouin loss in an optical fiber. *Optics Letters*, *19*(2), 141-143.

Barberan, C., Allanic, C., Avila, D., Hy-Billiot, J., Hartog, A., Frignet, B., & Lees, G. (2012). Multi-offset seismic acquisition using optical fiber behind tubing. 74th EAGE Conference and Exhibition incorporating EUROPEC 2012,

Bazzo, J. P., Rodrigues Pipa, D., Martelli, C., Vagner da Silva, E., & Cardozo da Silva, J. C. (2016). Improving Spatial Resolution of Raman DTS Using Total Variation Deconvolution. *IEEE Sensors Journal*, *16*, 4425-4430.

Bense, V., Read, T., Bour, O., Borgne, T. l., Coleman, T., Krause, S., Chalari, A., Mondanos, M., Ciocca, F., & Selker, J. S. (2016). Distributed Temperature Sensing as a downhole tool in hydrogeology. *Water Resources Research*, *52*, 9259 - 9273.

Bertani, R., Büsing, H., Buske, S., Dini, A., Hjelstuen, M., Luchini, M., Manzella, A., Nybø, R., Rabbel, W., & Serniotti, L. (2018). The First Results of the DESCRAMBLE Project.

Blackwell, D. D., Richards, M. C., Frone, Z., Batir, J. F., Ruzo, A., Dingwall, R., Williams, M., & Huffington, S. (2011). Temperature-At-Depth Maps for the Conterminous U. S. and Geothermal Resource Estimates.

Brown, G. (2016). *The Essentials of Fiber-Optic Distributed Temperature Analysis* (Second Edition ed.). Schlumberger Digital Marketing.

Brown, G., Carvalho, V., Wray, A., Smith, D., Toombs, M., & Pennell, S. (2004). Monitoring alternating CO2 and water injection and its effect on production in a carbonate reservoir using permanent fiber-optic distributed temperature systems. SPE Annual Technical Conference and Exhibition, Brown, G., Field, D., Davies, J., Collins, P., & Garayeva, N. (2005). Production monitoring through openhole gravel-pack completions using permanently installed fiber-optic distributed temperature systems in the BP-operated Azeri field in Azerbaijan. SPE Annual Technical Conference and Exhibition?,

Brown, G. A., & Hartog, A. (2002). Optical fiber sensors in upstream oil & gas. *Journal of petroleum technology*, *54*(11), 63-65.

Bukhamsin, A., & Horne, R. (2016). Cointerpretation of distributed acoustic and temperature sensing for improved smart well inflow profiling. SPE Western Regional Meeting,

Chalari, A., Mondanos, M., Coleman, T., Farhadiroushan, M., & Stork, A. (2019). Seismic methods for geothermal reservoir characterization and monitoring using fiber optic distributed acoustic and temperature sensor. EAGE/BVG/FKPE Joint Workshop on Borehole Geophysics and Geothermal Energy,

Chen, J. (2019). *High Resolution Distributed Temperature Sensing For Downhole Monitoring* (United States Patent No. US20150120194A1).

Coleman, T. (2016). *Brady's Geothermal Field-DTS Raw Data* USDOE Geothermal Data Repository (United States); Univ. of Wisconsin. https://doi.org/doi.org/10.15121/1367868

Coleman, T. I., Parker, B. L., Maldaner, C. H., & Mondanos, M. J. (2015). Groundwater flow characterization in a fractured bedrock aquifer using active DTS tests in sealed boreholes. *Journal of Hydrology*, *528*, 449-462.

Cox, B., Wills, P., Kiyashchenko, D., Mestayer, J., Lopez, J., Bourne, S., Lupton, R., Solano, G., Henderson, N., & Hill, D. (2012). Distributed acoustic sensing for geophysical measurement, monitoring and verification. *CSEG recorder*, *37*(2), 7-13.

Dakin, J., Pratt, D., Bibby, G., & Ross, J. (1985). Distributed optical fibre Raman temperature sensor using a semiconductor light source and detector. *Electronics letters*, *13*(21), 569-570.

Daley, T. M., Freifeld, B. M., Ajo-Franklin, J., Dou, S., Pevzner, R., Shulakova, V., Kashikar, S., Miller, D. E., Goetz, J., & Henninges, J. (2013). Field testing of fiber-optic distributed acoustic sensing (DAS) for subsurface seismic monitoring. *The Leading Edge*, *32*(6), 699-706.

Drakeley, B. K., Johansen, E. S., Zisk, E., & Bostick Iii, F. (2006). In-Well Optical Sensing—State-of-the-Art Applications and Future Direction for Increasing Value in Production-Optimization Systems. SPE Intelligent Energy International Conference and Exhibition,

Friðleifsson, G. Ó., Elders, W. A., Zierenberg, R. A., Stefánsson, A., Fowler, A. P. G., Weisenberger, T. B., Harðarson, B. S., & Mesfin, K. G. (2017). The Iceland Deep Drilling Project 4. km deep well, IDDP-2, in the seawater-recharged Reykjanes geothermal field in SW Iceland has successfully reached its supercritical target. *Sci. Dril.*, *23*, 1-12.

Girard, S., Kuhnhenn, J., Gusarov, A., Brichard, B., Van Uffelen, M., Ouerdane, Y., Boukenter, A., & Marcandella, C. (2013). Radiation effects on silica-based optical fibers: Recent advances and future challenges. *IEEE Transactions on nuclear science*, *60*(3), 2015-2036.

Götz, J., Lüth, S., Henninges, J., & Reinsch, T. (2018). Vertical seismic profiling using a daisy-chained deployment of fibre-optic cables in four wells simultaneously–Case study at the Ketzin carbon dioxide storage site. *Geophysical Prospecting*, *66*(6), 1201-1214.

Grosswig, S., Dijk, H., Den Hartogh, M., Pfeiffer, T., Rembe, M., Perk, M., & Domurath, L. (2019). Leakage detection in a casing string of a brine production well by means of simultaneous fibre optic DTS/DAS measurements. *Oil Gas European Magazine*, *45*(4), 112-120.

Hartog, A. (1983). A distributed temperature sensor based on liquid-core optical fibers. *Journal of lightwave technology*, *1*(3), 498-509.

Hartog, A., Frignet, B., Mackie, D., & Clark, M. (2014). Vertical seismic optical profiling on wireline logging cable. *Geophysical Prospecting*, *62*(4-Vertical Seismic Profiling and Microseismicity Frontiers), 693-701.

Henninges, J., Zimmermann, G., Büttner, G., Schrötter, J., Erbas, K., & Huenges, E. (2005). Wireline distributed temperature measurements and permanent installations behind casing. World Geothermal Congress (Antalya Turkey 2005),

Homa, D., Pickrell, G., & Wang, A. (2018). *Investigation of high temperature silica based fiber optic materials*.

Horne, R., & Shinohara, K. (1979). Wellbore heat loss in production and injection wells. *Journal of petroleum technology*, *31*(01), 116-118.

Inaudi, D., & Glisic, B. (2010). Long-range pipeline monitoring by distributed fiber optic sensing.

Johannessen, K., Drakeley, B., & Farhadiroushan, M. (2012). Distributed acoustic sensing-a new way of listening to your well/reservoir. SPE Intelligent Energy International Conference and Exhibition,

John, C. P., Ramnath, L., Khankishiyev, R. V., Hasanov, H., Stephenson, J., & Keatinge, P. (2015). Integration of Distributed Temperature Sensing Technology with Open Hole Gravel Packed Completions - The ACG Field Experience.

Johnson, D., Sierra, J., Kaura, J., & Gualtieri, D. (2006). Successful flow profiling of gas wells using distributed temperature sensing data. SPE Annual Technical Conference and Exhibition?,

Joule, J. (1856). On the Thermal Effects of Fluids in Motion. *Proceedings of the Royal Society of London*, *8*, 178-185.

Juarez, J. C., & Taylor, H. F. (2005). Polarization discrimination in a phase-sensitive optical time-domain reflectometer intrusion-sensor system. *Optics Letters*, *30*(24), 3284-3286.

Karlsdóttir, S. N., Krogh, B., Sæther, S., & Þórólfsson, G. (2019). Corrosion Damage of Injection String From the Deep Geothermal Well IDDP-2 in Reykjanes Iceland. *Corrosion*.

Kasahara, J., Hasada, Y., Mikada, H., Kuzume, H., Ohnuma, H., & Fujise, Y. (2023). Seismic Study at the Mori Geothermal Power Plant, Japan using DAS and DTS in a geothermal well. Proc. 48th Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA,

Khankishiyev, O., & Salehi, S. (2023). Technology Review and Techno-Economic Analysis of Super-Hot EGS Development in Hard Rock Formations. *Geothermal Resources Council Transactions*, *47*, 2979-2997.

Khankishiyev, O., Salehi, S., Vivas, C., Nygaard, R., & Rehg, D. (2023). Techno-Economic Investigation of Geothermal Development in Sedimentary Basins. *ASME Open Journal of Engineering*.

Klapper, H., Schorling, P., Lause, B., Mok, W. M., Zonneveld, W. v., Castricum, A., & Moeller, M. (2019). Addressing Integrity Issues in Downhole Equipment by Corrosion Inhibition in Sweet Geothermal Brines. *Corrosion*.

Kocabas, I. (2005). Geothermal reservoir characterization via thermal injection backflow and interwell tracer testing. *Geothermics*, *34*(1), 27-46.

Konate, N., Ezeakacha, C. P., Salehi, S., & Mokhtari, M. (2019). Application of an innovative drilling simulator set up to test inhibitive mud systems for drilling shales. SPE Oklahoma City Oil and Gas Symposium,

Leaf, A. T., Hart, D. J., & Bahr, J. M. (2012). Active thermal tracer tests for improved hydrostratigraphic characterization. *Groundwater*, *50*(5), 726-735.

Lipus, M. P., Schölderle, F., Reinsch, T., Wollin, C., Krawczyk, C. M., Pfrang, D., & Zosseder, K. (2021). Dynamic motion monitoring of a 3.6 km long steel rod in a borehole during cold-water injection with distributed fiber-optic sensing. *Solid Earth Discussions*, *2021*, 1-26.

Livescu, S., Durlofsky, L. J., Aziz, K., & Ginestra, J.-C. (2008). Application of a new fully-coupled thermal multiphase wellbore flow model. SPE Improved Oil Recovery Conference?,

Lu, S.-M. (2018). A global review of enhanced geothermal system (EGS). *Renewable & Sustainable Energy Reviews*, *81*, 2902-2921.

Madsen, K. N. r., T∅ndel, R., & Kvam, Ø. (2016). Data-driven depth calibration for distributed acoustic sensing. *The Leading Edge*, *35*(7), 610-614.

Markússon, S. H., & Hauksson, T. (2015). Utilization of the Hottest Well in the World, IDDP-1 in Krafla.

Maughan, S. M., Kee, H. H., & Newson, T. P. (2001). 57-km single-ended spontaneous Brillouin-based distributed fiber temperature sensor using microwave coherent detection. *Optics Letters*, *26*(6), 331-333.

McCarthy, C., Williams, T., & Butz, S. (2020). High accuracy leak detection performed on entire live wellbore in real time using fiber-optic diagnostic-capable coiled tubing. International Petroleum Technology Conference,

Miller, D. E., Coleman, T., Zeng, X., Patterson, J. R., Reinisch, E. C., Cardiff, M. A., Wang, H. F., Fratta, D., Trainor-Guitton, W., & Thurber, C. H. (2018). DAS and DTS at Brady Hot Springs: Observations about coupling and coupled interpretations. Proceedings of the 43rd Workshop on Geothermal Reservoir Engineering, Stanford, CA, USA,

Mishra, A., Al Gabani, S., & Jumaa Al Hosany, A. (2017). Pipeline leakage detection using fiber optics distributed temperature sensing DTS. Abu Dhabi International Petroleum Exhibition and Conference,

Muradov, K. M., & Davies, D. R. (2011). Application of distributed temperature measurements to estimate zonal flow rate and pressure. International Petroleum Technology Conference,

Naldrett, G., Cerrahoglu, C., & Mahue, V. (2018). Production monitoring using next-generation distributed sensing systems. *Petrophysics*, *59*(04), 496-510.

Nath, D. K., Finley, D. B., Kaura, J. D., Krismartopo, B., & Yudhiarto, W. (2006). Real-time fiber-optic distributed temperature sensing (DTS)—new applications in the oil field. SPE Annual Technical Conference and Exhibition,

Normann, R., Weiss, J., & Krumhansl, J. L. (2001). Development of Fibers Optic Cables for Permanent Geothermal Wellbore Deployment.

Ouyang, L.-B., & Aziz, K. (2000). A homogeneous model for gas–liquid flow in horizontal wells. *Journal of Petroleum Science and Engineering*, *27*(3-4), 119-128.

Ouyang, L.-B., & Belanger, D. (2006). Flow profiling by Distributed Temperature Sensor (DTS) system—Expectation and reality. *SPE Production & Operations*, *21*(02), 269-281.

Patterson, J. R., Cardiff, M., Coleman, T. I., Wang, H. F., Feigl, K. L., Akerley, J., & Spielman, P. (2017). Geothermal reservoir characterization using distributed temperature sensing at Brady Geothermal Field, Nevada. *Geophysics*, *36*.

Petty, S., Cladouhos, T., Watz, J., & Garrison, G. (2020). Technology Needs for SuperHot EGS Development. *45th Workshop on Geothermal Reservoir Engineering*.

Ramey Jr, H. J. (1962). Wellbore heat transmission. *Journal of petroleum technology*, *14*(04), 427-435.

Read, T., Bour, O., Bense, V., Le Borgne, T., Goderniaux, P., Klepikova, M., Hochreutener, R., Lavenant, N., & Boschero, V. (2013). Characterizing groundwater flow and heat transport in fractured rock using fiber-optic distributed temperature sensing. *Geophysical Research Letters*, *40*(10), 2055-2059.

Reinsch, T., & Henninges, J. (2010). Temperature-dependent characterization of optical fibres for distributed temperature sensing in hot geothermal wells. *Measurement Science and Technology*, *21*, 094022.

Sakaguchi, K., & Matsushima, N. (2000). Temperature logging by the distributed temperature sensing technique during injection tests. Proceedings World Geothermal Congress, May,

Schölderle, F., Lipus, M., Pfrang, D., Reinsch, T., Haberer, S., Einsiedl, F., & Zosseder, K. (2021). Monitoring cold water injections for reservoir characterization using a permanent fiber optic installation in a geothermal production well in the Southern German Molasse Basin. *Geothermal Energy*, *9*, 1-36.

Sharma, W. S., Seki, A., Angel, S., & Garvis, D. (1990). Field testing of an optical fiber temperature sensor in a geothermal. *Geothermics*, *19*(3), 285-294.

Shiota, T., & Wada, F. (1992). Distributed temperature sensors for single-mode fibers. Distributed and Multiplexed Fiber Optic Sensors,

Smithpeter, C., Norman, R., Krumhansl, J., Benoit, D., & Thompson, S. (1999). *Evaluation of a distributed fiber-optic temperature sensor for logging wellbore temperature at the Beowawe and Dixie Valley geothermal fields*.

Somma, R., Troise, C., Zeni, L., Minardo, A., Fedele, A., Mirabile, M., & De Natale, G. (2019). Long-term monitoring with fiber optics distributed temperature sensing at campi flegrei: the campi flegrei deep drilling project. *Sensors*, *19*(5), 1009.

Soroush, M., Mohammadtabar, M., Roostaei, M., Hosseini, S. A., Mahmoudi, M., Keough, D., Cheng, L., Moez, K., & Fattahpour, V. (2021). An industry overview of downhole monitoring using distributed temperature sensing: Fundamentals and two decades deployment in oil and gas industries. SPE Western Regional Meeting,

Soto, M. A., Nannipieri, T., Signorini, A., Bolognini, G., Di Pasquale, F., Lazzeri, A., Baronti, F., & Roncella, R. (2011). Advanced cyclic coding technique for long-range Raman DTS systems with meter-scale spatial resolution over standard SMF. *2011 IEEE SENSORS Proceedings*, 878-881.

Stauffer, P. H., Lewis, K., Stein, J. S., Travis, B. J., Lichtner, P., & Zyvoloski, G. (2014). Joule–Thomson effects on the flow of liquid water. *Transport in porous media*, *105*, 471-485.
Steffensen, R. J., & Smith, R. C. (1973). The importance of Joule-Thomson heating (or cooling) in temperature log interpretation. SPE Annual Technical Conference and Exhibition?,
Ukil, A., Braendle, H., & Krippner, P. (2012). Distributed Temperature Sensing: Review of Technology and Applications. *IEEE Sensors Journal*, *12*, 885-892.
Walker, I., & Carr, D. (2003). Fibre Optic Leak Detection. Offshore Technology Conference,
Wang, X., Lee, J., Thigpen, B. L., VachonGuy, P., Poland, S. H., & Norton, D. (2008). Modeling Flow Profile using Distributed Temperature Sensor (DTS) System.
Wang, Z. (2012). *The uses of distributed temperature survey (DTS) data* Stanford University Palo Alto].
Williams, G. R., Brown, G., Hawthorne, W., Hartog, A. H., & Waite, P. C. (2000). Distributed temperature sensing (DTS) to characterize the performance of producing oil wells. Industrial Sensing Systems,
Williams, T., Lee, E., Chen, J., Wang, X., Lerohl, D., Armstrong, G., & Hilts, Y. (2015). Fluid ingress location determination using distributed temperature and acoustic sensing. SPE Digital Energy Conference and Exhibition,