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Modelling of Application of Autonomous Flow Control Devices in Geothermal Systems to Optimise Heat Efficiency

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ABSTRACT

As demand for cleaner energy sources grows, geothermal operators must maximize production efficiency from geothermal reservoirs used for power and heat generation. One of the critical challenges shared between geothermal and oil and gas reservoirs is thermal short-circuiting, a phenomenon where cooler injected fluids bypass heat exchange processes by flowing directly to production wells via high-permeability pathways or dominant fractures. This issue, reported in projects such as FORGE and Soultz-sous-Forêts, leads to significantly reduced heat extraction efficiency, as fluid flow distribution within the reservoir is suboptimal. While several techniques have been deployed to address thermal short-circuiting, many have resulted in limited success or even adverse effects on production efficiency.

Autonomous Flow control devices (AFCDs) offer a promising solution to these challenges. These tools, already proven in reservoir management for oil and gas wells, can optimize geothermal system efficiency by distributing fluid flow more uniformly, increasing contact between injected fluids and heated rock and enhancing heat absorption.

This study explores the potential of autonomous flow control technologies in Enhanced Geothermal Systems (EGS) to address thermal short-circuiting and improve reservoir heat management. For the first time, this paper presents the functionality of autonomous flow control devices, designed to regulate the flow of cold and heated water plus steam, under laboratory conditions. Additionally, results from a comprehensive modelling practice that applies this technology to a geothermal system are discussed. The study simulates multiple possible scenarios which under those cold fluids are injected through an injection well into a naturally fractured and/or hydraulically fractured, high-temperature medium, while heated fluid is subsequently produced via a production well. The impacts of a few uncertain parameters and how the devices mitigate the risk associated with such uncertainties are also addressed.

The results highlight that the integration of AFCDs significantly mitigates operational inefficiencies by ensuring uniform fluid distribution, reducing thermal short-circuiting, and maintaining stable reservoir conditions. Furthermore, autonomous flow control devices enable dynamic flow regulation, adapting to changing reservoir conditions in real-time. These advancements lead to delayed cold-water break-through for four years while improving thermal recovery by up to 16% and significantly improving economics of the projects.

This study illustrates that incorporating AFCDs into geothermal systems represents a significant leap in geothermal reservoir management, offering enhanced heat efficiency, improved sustainability, and greater economic viability for geothermal energy projects. The findings underscore the importance of leveraging advanced flow control technologies to meet the growing global demand for renewable energy

1. GEOTHERMAL SYSTEMS AND THEIR CHALLENGES

Recovery of geothermal energy is expected to play an important role in the energy transition from fossil fuel to renewable resources. The utilization of geothermal energy has the potential to reduce greenhouse gas emissions and provide a source of baseload energy. To ensure efficient heat utilization the produced fluid should have high enough temperature to support downstream power generation.

Geothermal reservoirs, much like oil and gas reservoirs, can suffer from non-optimum and/or over-production if not properly managed. Excessive extraction can drastically reduce a reservoir's productive lifespan and result in significant financial losses. To maintain reservoir pressure and ensure sustained productivity, most geothermal systems require the reinjection of produced water. Effective reservoir management based on sound reservoir engineering practices enables operators to forecast changes in pressure, temperature, production rates and the chemical composition of geothermal fluids. These forecasts are vital for designing power plants and associated infrastructure to maximize the resource's economic potential. Engineers must base plant design on projections of well and reservoir performance, as unexpected shifts in fluid characteristics or output can significantly impact the project's profitability.

A wide variety of temperatures, from 60°C to 350°C, are accessible for the geothermal energy sources and several countries involved in the investigation and development of geothermal energy, such as the United States, Canada, Italy, Turkey, Kenya, Germany, Mexico, Iceland, New Zealand, and the Philippines. Various classifications are provided for geothermal projects. However, in general, two different types of geothermal energy sources exist in the world: (1) high enthalpy and (2) low enthalpy geothermal energy reservoirs based on Geological characteristics and local temperature as shown in Figure 1. Low enthalpy geothermal systems are located at around 1000 m depth and often with temperatures not exceeding 150°C. Sedimentary resources, including relatively hot sedimentary aquifers, are an example of a low enthalpy geothermal system which occurs in sediments with naturally occurring porosity and permeability. The dominant heat transfer mechanism is mainly conductive. These geothermal resources share many characteristics with oil and gas resources, particularly related to reservoir characterization. These are widely available resources; however, the major issue remains the economics of such projects at low temperatures and their overall low heat efficiency.

While traditional geothermal systems rely on naturally occurring, high-permeability reservoirs close to the surface, enhanced geothermal systems (EGS) delves deeper, unlocking the huge energy reserves trapped within hotter, lower-permeability rock formations known as Hot Dry Rock. This type of system was developed in Cornwall (UK) and Los Alamos (USA) for utilizing the huge energy resource first and Fervo and Utah FORGE projects are the latest development on this category [2]. In such system, induced high conductivity pathways for fluid circulation are generated and a working fluid is injected into the injection well and produced from an offset producer. The fluid heats up as it travels through the formation and the stimulated fracture network [1]. EGS have gained great attention since they promise to deliver the maximum heat extraction efficiency, geographically disperse, carbon-free energy with minimal environmental impact in compared to other geothermal systems.

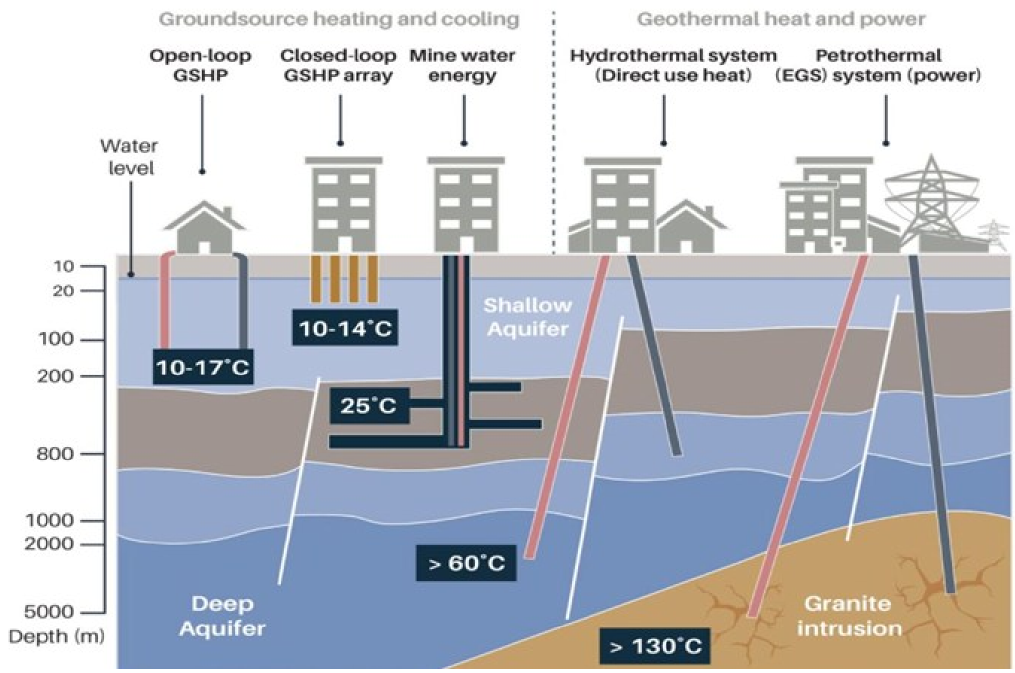

Figure 1: Various types of Geothermal systems

Advanced EGS allows long-term sustainable energy supply with a substantially higher heat extraction rate compared with traditional designs. While hydraulic fracturing creates numerous connection paths between the injector and the producer for heat exchange, it also introduces an uncertain pathway for the fluid to flow from the injector to the producer. The connectivity between the injection-production well pair, as well as the conductivity of the flow path is crucial for the success of EGS. Few data from various diagnostic techniques like micro-seismic, DAS and DTS fiber optic monitoring systems have illustrated that it is almost impossible to create unique fractures along the well and in reality, fractures with significantly varying characteristics will be generated. This data shows uneven flow path via each of fractures due to varied hydraulic conductivity, leads to thermal short-circuiting, which leads to a decrease in the temperature of the received fluid [1]. This topic will be explored further in later section.

It should be mentioned closed loop geothermal systems, which circulate working fluid within a wellbore in a continuous loop with no direct contact between the working fluid and the reservoir fluid and with heat exchange occurring by conduction through the wellbore such Eavor-Loop™ Geretsried project in Germany also have been developed lately with variable degree of heat extraction efficiency and mostly difficult to be economical viable solution.

2. THERMAL SHORT-CIRCUITING IN GEOTHERMAL SYSTEMS

Much like other subsurface energy resources, geothermal systems, ranging from low to high temperature applications, face a number of operational challenges that impact reservoir performance and sustainability. These issues are not unique to geothermal energy but are also well-documented in the oil and gas industry. A particularly critical issue is the imbalance of reservoir flow, referring to uneven or preferential movement of fluid in and out of the geothermal formation. This imbalance often results in several significant complications and challenges include:

1. Thermal breakthrough due to short-circuiting (Flow Channeling): occurs when cooler injected fluid, initially isolated from production zones, prematurely reaches a production well. The timing of breakthrough is governed by factors such as fluid velocity, reservoir thickness, and spacing between wells. This may cause a large portion of the reservoir to be bypassed and significantly reduces residence time for the injected fluid. The development of highly permeable flow paths between injection and production wells leads to poor thermal sweep and reduced heat exchange.

2. Thermal drawdown: refers to the gradual decrease in reservoir temperature resulting from continuous fluid extraction. This decline reduces the overall efficiency and lifespan of the geothermal system as shown in Figure 2.

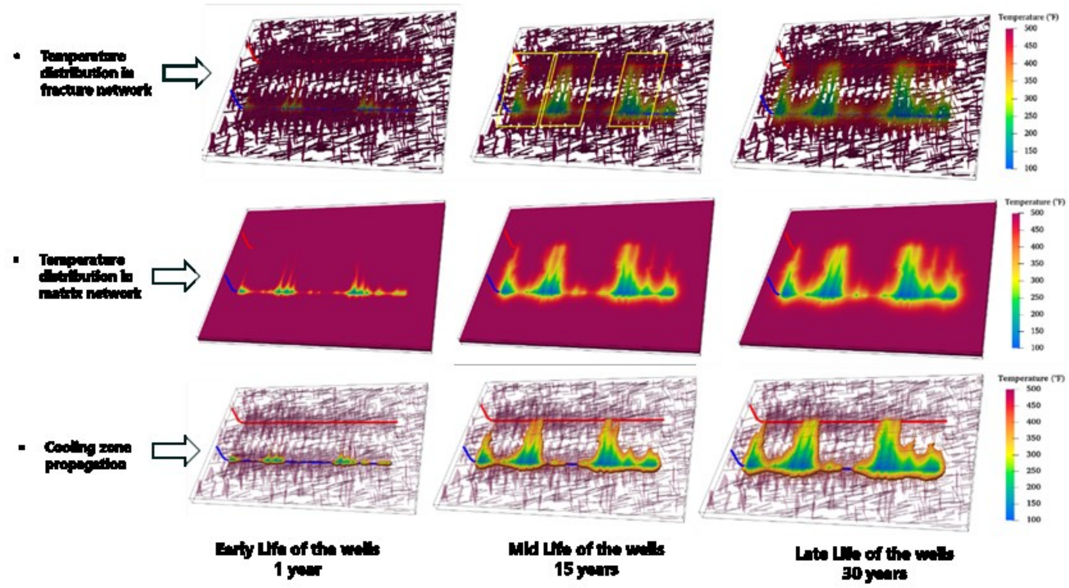

Figure 2: Temperature distribution and cool zone propagation profiles over time [4]

Thermal short-circuiting poses a substantial threat to the effectiveness of geothermal reservoirs [1]. When injected fluids preferentially flow through dominant high permeability section or fractures, they do not adequately interact with the surrounding hot rock matrix, resulting in inefficient heat transfer. Over time, this not only reduces energy output but also accelerates the thermal decline of the reservoir as illustrate in Figure 2. Traditional EGS designs have tended to suffer flow localization, with only a small number of flowing fracture pathways where flow uniformity is a key metric that we can use to evaluate the performance of an EGS. Designs with greater uniformity will have better thermal longevity [5].

For instance, the Soultz project in France encountered a rapid drop in the temperature of produced fluids, indicating possible thermal short-circuiting. This issue was linked to one dominant fracture that conducted around 70% of the injected fluid, even though four fractures were present overall [2]. Similar challenges have been reported in other EGS projects, such as Rosemanowes in the UK. Tracer tests at Rosemanowes showed that one, out of nine fractures, was responsible for carrying over 50% of the injected fluid, resulting in early thermal breakthrough [2].

The latest PLT data from Forge Utah EGS project also shows the dynamic behaviour of such reservoirs in terms flow distribution along the production intervals. For instance, it is mentioned that during the April 2024 flow test, no more than 12% of flow came from any one cluster, with stages 8 and 9 flowing the most as expected. This was in line with expectation since they had the most perforation clusters and injected the largest volume of proppant. However, different results were observed in Aug 2024 testing as stage 8 accepted substantially more flow than stage 9, stage 10 took an unexpectedly high 25.8% of flow from a single perforation cluster, and stages 6 and 7 flowed negligibly due to prior injection issues. Interestingly, the heel-side stage in the production well did not show a similar imbalance. Also, it was noted that April test achieved 8 bbl/min injection with over 90% recovery at 370°F. The August test followed a successful May trial, which reached 70% efficiency with 15 bbl/min injection, 8 bbl/min production, and a 282°F outflow [5].

These recurring issues in field operations highlight the need for further research into methods for mitigating thermal short-circuiting. It is important to recognise that the underlying cause of thermal short-circuiting, thermal breakthrough and thermal drawdown lies in the static and dynamic heterogeneity of the geothermal reservoir including the highly anisotropic permeability distribution plus injection of a cold fluid into hot formation and then production of hotter fluid. Although this is a serious challenge in fractured geothermal systems, this challenge is not limited to EGS projects and expects to occur in both high and low temperature sedimentary geothermal projects.

Various mitigation strategies, including various techniques to optimise hydraulic fracturing, optimising fracture conductivity, maximising the number of fractures, zonal isolation at thief zones and chemical plugging, have been tested. However, these often introduce new challenges, such as induced seismicity or rapid injectivity changes that are difficult to control/justify. Even in highly intense hydraulically stimulated systems, fracture aperture distributions can be highly variable, often resulting in a small number of dominant flow paths. This makes the prediction of flow paths extremely challenging. This is a very well-known challenge in injection wells for oil and gas operators. Advanced well completion is an important aspect of reservoir management nowadays and the utilization of such completions lead to efficient zonal extraction thus increasing productivity and efficacy of the field [7,8&9].

Advanced well completions utilising autonomous downhole flow control technologies present an opportunity to address this complexity in geothermal wells. By providing zone-specific flow regulation without the need for intervention or diagnostics systems, such technologies can adapt in real-time to the evolving reservoir conditions, rebalancing the flow dynamically and improving the thermal contact between injected fluids and rock.

3. DOWNHOLE FLOW CONTROL TECHNOLOGIES

The need for optimized and more environmentally sustainable production in the Oil and Gas industry has advanced the development of horizontal wells. However, increased wellbore lengths have led to various production-related problems, some of which have prompted the development and installation of downhole Flow Control Devices (FCDs) since the early 1990s; providing an effective means of high resolution well control.

Flow control devices in injection wells typically fall into two broad categories: passive and active devices. In the conventional sense, ICVs represent active devices that possess the capability to modify the inflow area, allowing operators to proactively and/or reactively control the well. Despite the cost and complexity associated with ICVs completion, a significant challenge arises from the necessity for real-time knowledge of well and reservoir performance to justify adjusting valve positions. The substantial uncertainties involved in such operations restrict the practical application of these devices. On the other hand, passive devices ICDs are more cost-effective, creating completions with fixed configurations that influence the well's outflow. However, the impact of passive ICDs can be limited if not appropriately designed during well completion, and their effectiveness diminishes in the face of dynamic changes in reservoir properties.

In recent years, with evolution of the devices combined with the deployment of enhanced oil recovery techniques such as water flooding, gas injection, and chemical EOR combined, the oil and gas sector has developed robust strategies to mitigate similar challenges. Latest generation of FCDs, autonomous flow control devices (AFCDs), demonstrated significant benefits for optimized well performance for various implementation in water, CO2, polymer and gas injection wells [7,8&9]; plus in steam assisted gravity drainage [10], where steam breakthrough may present similar issues as water/gas breakthrough in non-thermal applications. By adopting advanced methods and novel technologies found in the Oil and Gas industry, geothermal operations would improve leading to more efficient and cost-effective processes. By adapting these technologies, particularly autonomous flow control technologies, geothermal operators have the potential to significantly enhance fluid distribution both in injection and production sides, manage reservoir static and dynamic uncertainties and optimize long-term thermal recovery.

The utilization of AFCDs in geothermal operations are essentially aimed at promoting an even outflux into reservoir or well known as “injection conformance” and improving the uniformity of produced stream of hot water flow in the reservoir toward the production wells. In other words, in such chemo-thermo-hydro dynamic systems, injection flow control is an effective tool for reservoir management mitigating against thermal and hydraulic related process such the thermal fracture initiation and/or propagation and minimize the impacts of thermal breakthroughs to increase productivity [7].

Autonomous Flow Control Devices

The autonomous outflow control device, FloFuse, has been developed to address such challenges and mitigate disproportionate fluid injections into thief zones that could lead to short-circuiting to production wells [8]. Like other FCDs completion, these devices should be installed in several completion zones in the well by annular flow isolation tools like swell packers to provide independent control to each layer.

This bi-stable active flow control device operates in two conditions: initially, it functions as a normal passive outflow control device, and if the injected flowrate exceeds a predetermined limit, the device automatically shuts off, if required with combination with another type of ICD, the completion could provide a limited partial flow path in such conditions. Figure 3 depicts the cross-section and key elements of the device, which is a spring-loaded, open injection outflow valve designed to limit the flow area to specific zones when a prescribed tripping flow rate is exceeded.

As mentioned before, under normal operating conditions, the device allows injection outflow to pass through a normally operating nozzle and then through sand controls like shrouds or screens, if necessary, as shown in Figure 4. If the pressure built up in the reservoir decreases due to the impacts of thief zones such as inducing, dilating, or propagating fractures, or change in mobility of fluid etc. the injection rate into that zone significantly increases. This results in an elevated pressure drop across the device, countering the return spring until the flow area between the seal face and the nozzle becomes fully restricted. This triggers the valve to the fused (closed) position, restricting outflow into that zone. As a result, the outflow into the 'fused' zone is highly limited, allowing injections to be diverted into other completion zones. This performance enables operators to minimize the impact of thief zones on injected fluid conformance and respond to dynamic changes in reservoir properties, specifically the growth of fractures. Importantly, this technology eliminates the need and cost of running an ILT and the complex well interventions required to open/close integrated sliding sleeves (if available) in traditional completions, enabling optimized well performance autonomously.

The valve is fully reversible, and it will reset if the flow rate becomes sufficiently distributed again. The target normal operating rates, degree of outflow control, and trigger rates can be adjusted based on the application.

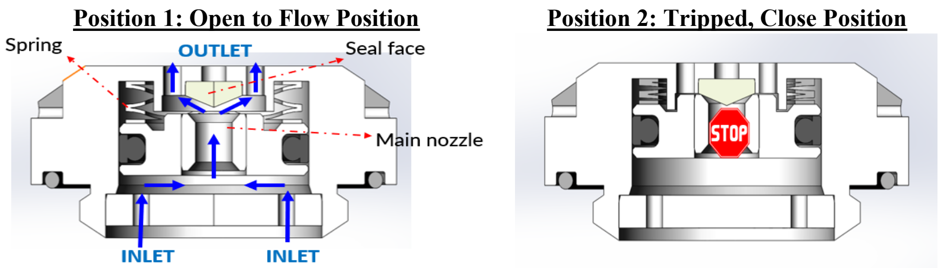

Figure 3: Cross-section of the autonomous Flow control device.

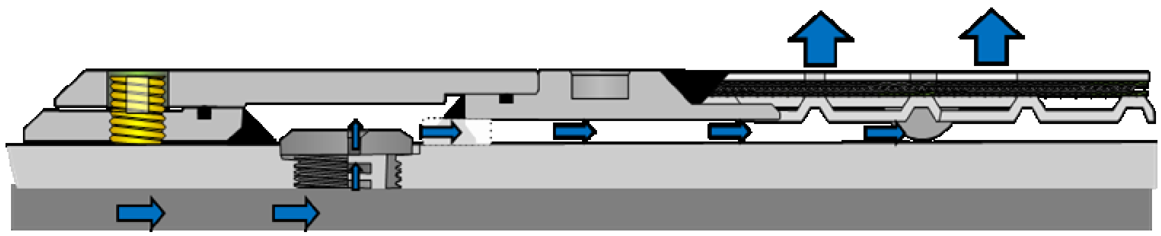

Figure 4: The flow path of injection fluid via screen incorporating the AFCD.

Comprehensive laboratory tests have been conducted to assess the performance of a single valve under various fluid and gas injection conditions. Specifically, a series of water injection experiments were carried out to characterize the valve. The characteristics were delineated, for example, by plotting the curve of differential pressure drop (dP) across the device against the flow rate passing through it. Figure 5 shows an example of such performance curves for a combination of one FloFuse and a bypass ICD device. The Figure shows the combination allows production/injection of up to 145 m3/d of water before autonomous device closes and the flow path would be limited to device only. The reversibility of the device allows returning to open position autonomously if reservoir conditions stabilize or rebalance. The valve can reopen, maintaining dynamic adaptability throughout the well's life. The closure thresholds can be customized based reservoir conditions, providing flexibility for various geothermal applications.

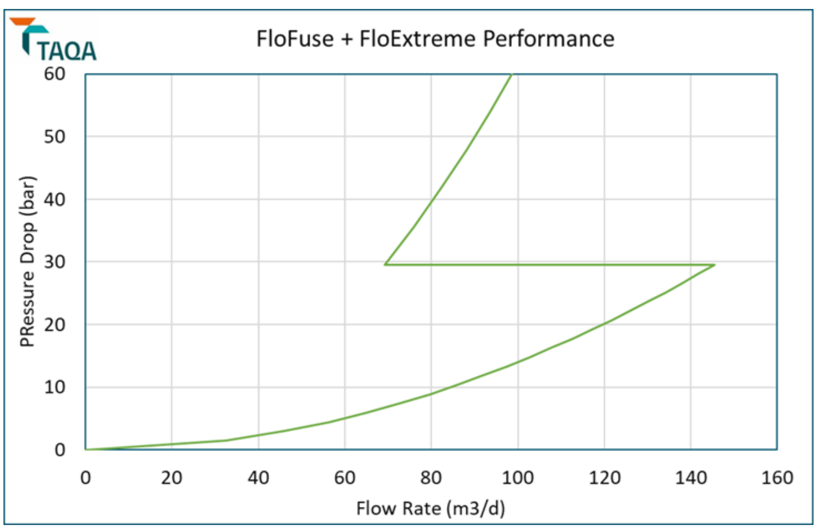

Figure 5: The combined valve performance for water at reservoir conditions

The production version of the device, working under same principal, could also be extremely beneficial to control thief zones from production well side. The questions whether the devices should be used in injection and/or production wells needs to be evaluated for individual cases.

The autonomous flow control device represents a step-change in reservoir flow management in geothermal projects especially in EGS with hydraulic fractures as well as in sedimentary resources where high permeability zones and/or fractures could be initiated or diluted due to thermos-hydro conditions there.

Designed to operate passively and without external intervention, the device autonomously modulates flow based on the local pressure and fluid properties. When deployed along the wellbore or within specific reservoir zones, these devices respond dynamically to shifts in flow rate, selectively increasing resistance to flow in higher-permeability (thief) pathways. This effect forces fluid into lower-permeability regions, thereby increasing the residence time of the fluid within the geothermal reservoir and enhancing thermal exchange.

Like other FCDs completion, these devices should be installed in several completion zones in the well by annular flow isolation tools like swell packers to provide independent control to each layer. Each zone normally comprises both AFCDs and ICDs to deliver optimum performance. When the autonomous valve shuts, the bypass ICDs will still deliver the minimum flowrate desired to the zone. If this is not required, the ICDs could be opted out. The required number of each device and the number of zones depends on the case and should be determined through modelling practice.

The effectiveness of AFCD technology lies in their simplicity and adaptability. Unlike actively controlled ICVs systems, the cost is significantly low, and they require no surface communication or downhole power supply. Their operation is purely driven by local hydro-dynamic forces, making them ideally suited for deep geothermal environments where traditional flow control solutions may be limited in practice.

4. MODELLING STUDY: AFCD'S APPLICATION IN GEOTHERMAL SYSTEMS

Key to modelling geothermal systems are an understanding of critical rock features, reservoir operations, and long-term reservoir performance forecasting. Reservoir simulation is a well-known technique for pre-existing hydrothermal resources including hot water, steam, or multi-phase reservoirs in fractured/porous rocks. Considerable efforts have been made in the domain to build 1D, 2D, and 3D geometric models that use a stochastic fracture network model to estimate the thermal performance of EGS over time [1,2&4].

To evaluate the effectiveness of AFCDs completion, comprising FloFuse devices in EGS environments, a comprehensive numerical modelling workflow was conducted This workflow includes assessing the performance of base case completions and conducting sensitivity analyses to determine the optimal Flow control device completions for the wells. This workflow includes assessing the performance of base case completions and conducting sensitivity analyses to determine the optimal completions for the wells. To effectively deploy the completion for each wellbore, a comprehensive workflow will be initiated, often initiated pre-drilling and swiftly updated with the actual well properties, once the well is drilled, to deliver optimum performance.

A dynamic numerical modelling tool that couples the wellbore and reservoirs is recommended here to comprehend the dynamics between the various alternative phenomena occurring in geothermal system. The simulation utilized a geothermal reservoir model where cold fluid was injected into the reservoir and its migration and heat absorption were tracked as it flowed toward production wells via a relatively low temperature sandstone water aquifer in this paper.

Multiple scenarios were tested for two different reservoirs (cases), including variations in reservoir properties, injection and production rates, reservoir temperature and the flow control device configurations. The model incorporated uncertainty analysis to account for variations in subsurface properties.

4.1. Case 1, An example of Relatively Homogeneous Reservoir

Figure 6 shows the box shaped synthetic reservoir model, used in this study, with 41x80x40 grid blocks in the x, y and z direction respectively. Table 1 lists the model's properties with its layers with permeability profiles is shown in Figure 7. Two vertical wells with similar designs have been placed 700m apart and completed 200m reservoir contact from 1000 mMD to 1200 mMD with permeability profile shown in Figure 7. This is a representative of 1 to 1 pattern in geothermal system that an injection supports a production well directly with injection of 12 kSM3/d (~75.5 mSTB/D) of cold water with temp of 20 ◦C. The production well is also constrained to constant production rate of 12 kSM3/d for 10 years. As the wells are vertical, a gradient was applied on reservoir temperature with an average temperature of 57 ◦C as shown in Figure 6.

Here we made few simplifications in the model to be able to showcase and explain the impacts of AFCD completion in geothermal systems including disregarding the impacts of hydro/thermos/chemo process on rock properties [7], improper well and fracture design, as well as tortuosity of flow path due to heterogeneity far from the wellbore such natural fracture networks, faults and shale layers. Surely, one of the most valuable contributions of AFCD completion lies in its capacity to manage uncertainties, which would be the case for real geothermal projects, associated with the above phenomena.

Table 1: The Model specifications

Parameter	Description (Value)
Reservoir Dimension	41*25 (m) in X, 80*25 (m) in Y, 40*5 (m) in Z
Reservoir Contact length	200 m
Reservoir Pressure	130 bar
Average Porosity	20%
Wellbore	8.5-inch open hole, 6 5/8 inch completion

Injection/Production Rate	12000 SM3/d

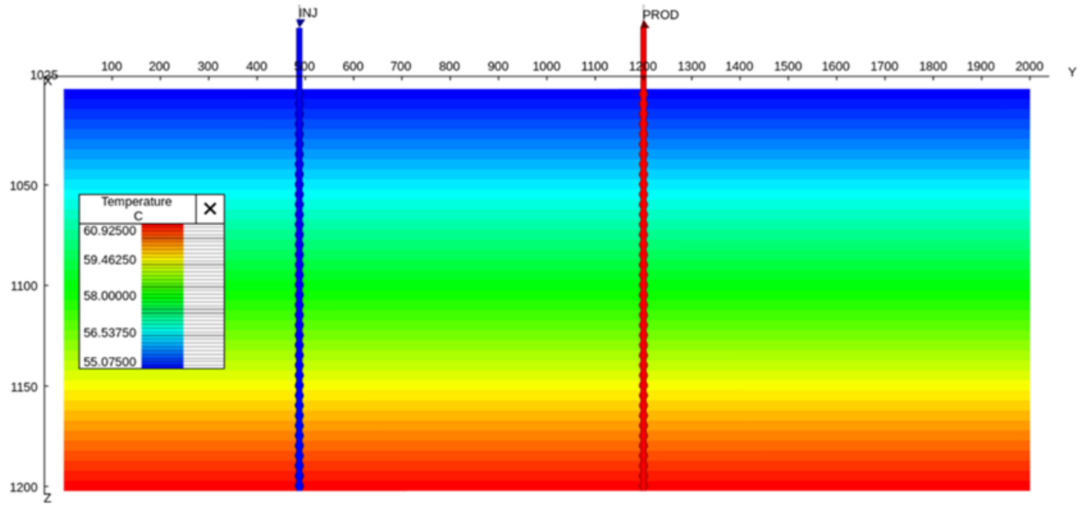

Figure 6: Schematic of the box-shaped simulation model, temperature distribution

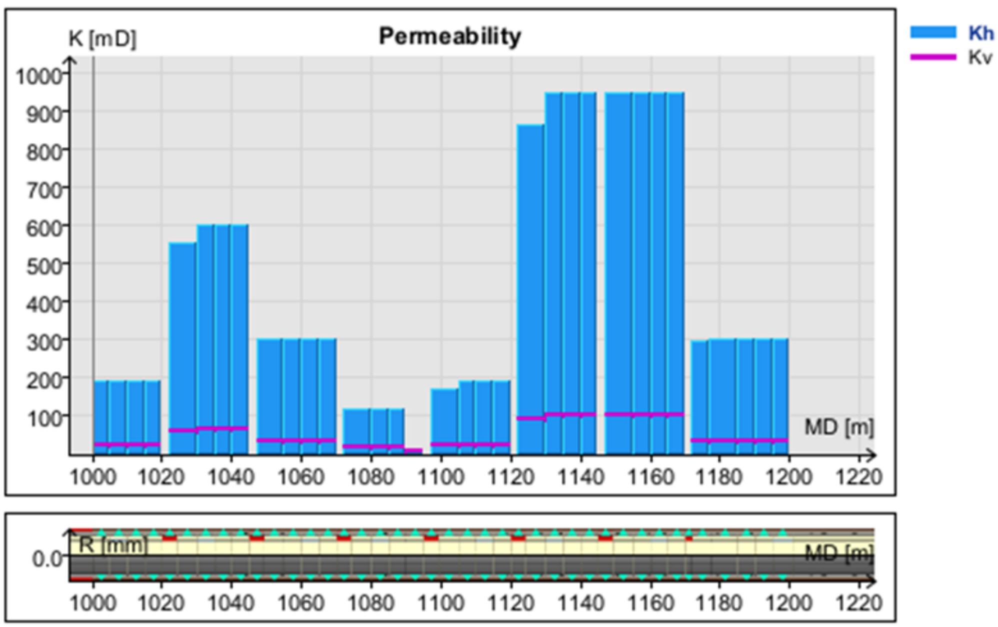

Figure 7: Permeability Profile for Case 1

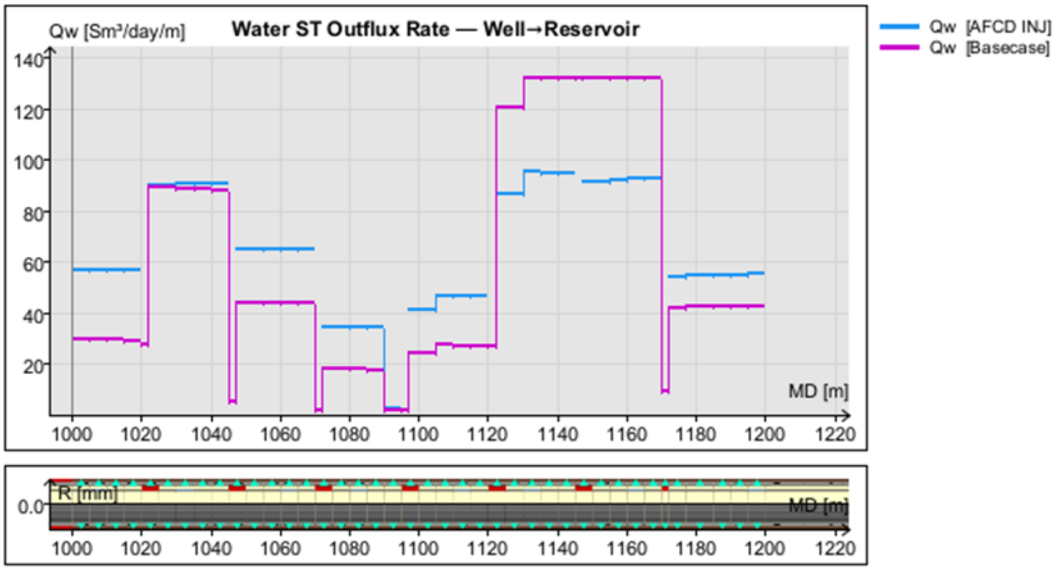

Figure 8: Injection flux distribution along the well for base case and AFCD scenario

Similar to other flow control device completions, these devices should be positioned in multiple completion zones within the well, utilizing annular flow isolation tools such as swell packers to ensure independent control for each layer. Here, the wells are divided into 8 zones with 7 packers and uniform number of FloFuse and ICDs and are included in each zone to achieve optimal performance. In the event of the autonomous valve closure, the bypass ICD will continue delivering the minimum desired flow rate to the zone. Figure 8 shows the uniformization of injection flux for AFCD completion against base case. This illustrates the AFCD completion reduces the outflux at the highest permeability zones and diverts the fluid toward the low injectivity zones. This will enhance the capture of the heat in the water as it flows toward production well. Here, we compared four scenarios of 1) base case, 2) AFCD completion installed at injection well only (AFCD-Inj), 3) AFCD completion installed at production well only (AFCD-Prod) and 4) AFCD completion installed at both wells (AFCD-both). The AFCD wells and reservoir models are coupled using multisegmented wells options and nozzle-type ICD devices are modelled by Equation 1:

$$\Delta \mathrm{P} = \mathrm{C_u} \frac{\rho_{\mathrm{mix}}\, Q^2}{\mathrm{C_d^2} A^2} \tag{1}$$

where ΔP, C_u,, ρ_{mix}, Q, Cd, A are pressure drop through the device, unit of measure constant, fluid mixture density, volumetric fluid flow rate, coefficient of discharge, and cross-sectional area, respectively.

As shown in Figure 9, for base case scenarios without flow control devices in any of the wells, dominant high permeability zones rapidly conveyed injected fluid, leading to early thermal breakthroughs at production wells. This increases over time as shown for three timesteps in Figure 9 for base case scenario. Conversely, the AFCD well scenarios exhibited more balanced flow distribution, delayed thermal breakthrough and improved heat recovery.

The impacts of AFCD completion on the equalisation of outflux from the injector and/or influx toward producers and its impacts on the temperature of produced fluid inside the producer and subsequently at the surface are shown on Figure 10. This Figure shows that 2.5 ◦C increase in temperature of fluid was achieved over time even in a mostly homogeneous, low enthalpy reservoir. It should be noted that homogenous rock properties are not expected due to thermodynamic, hydrodynamic and chemical effects on the rock properties. This is explored in case 2 with higher degree of heterogeneity in reservoir properties. The impact of AFCD completions is expected to be higher for cases with higher degree of static/dynamic heterogeneity especially in EGS.

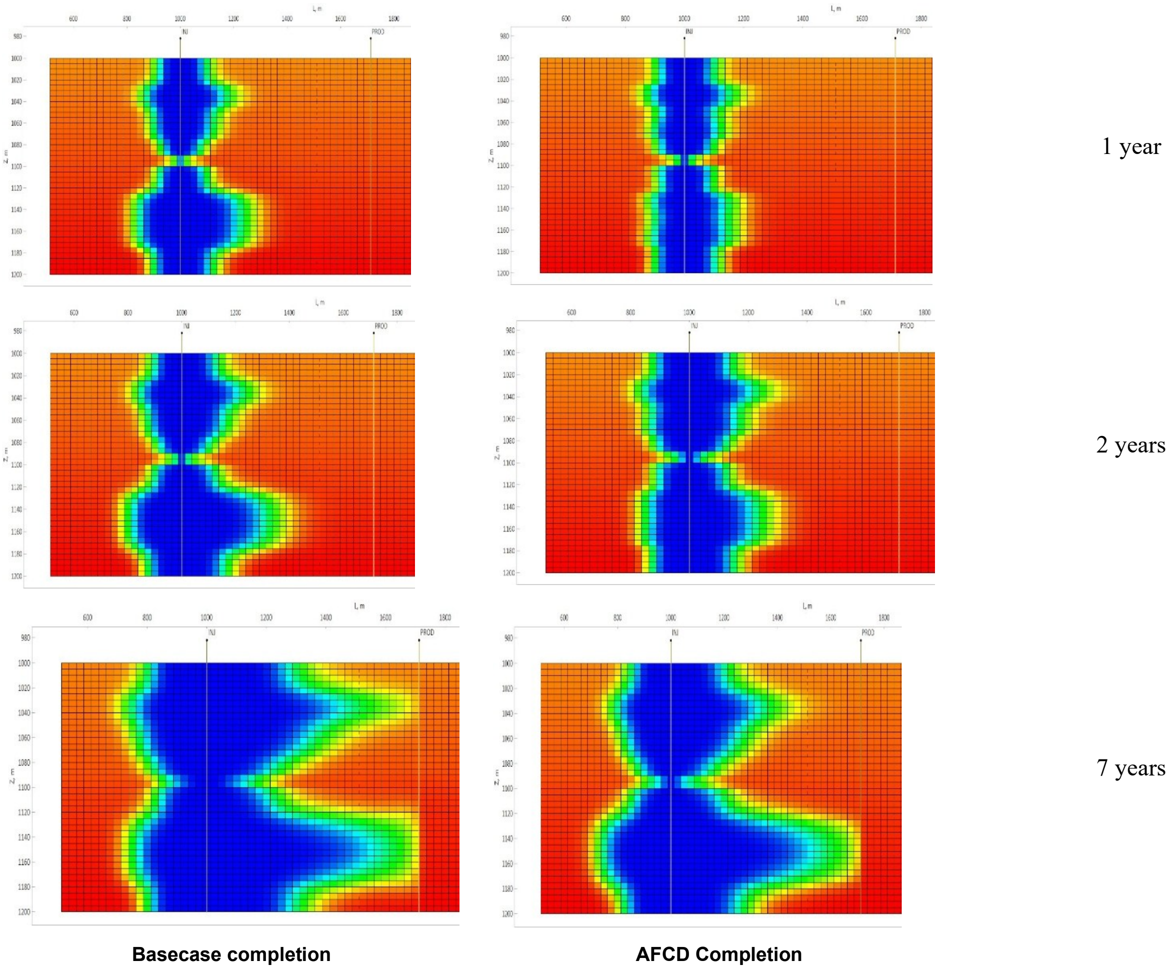

Figure 9: Temperature profile propagation from injector toward producer over time for various completions, case 1

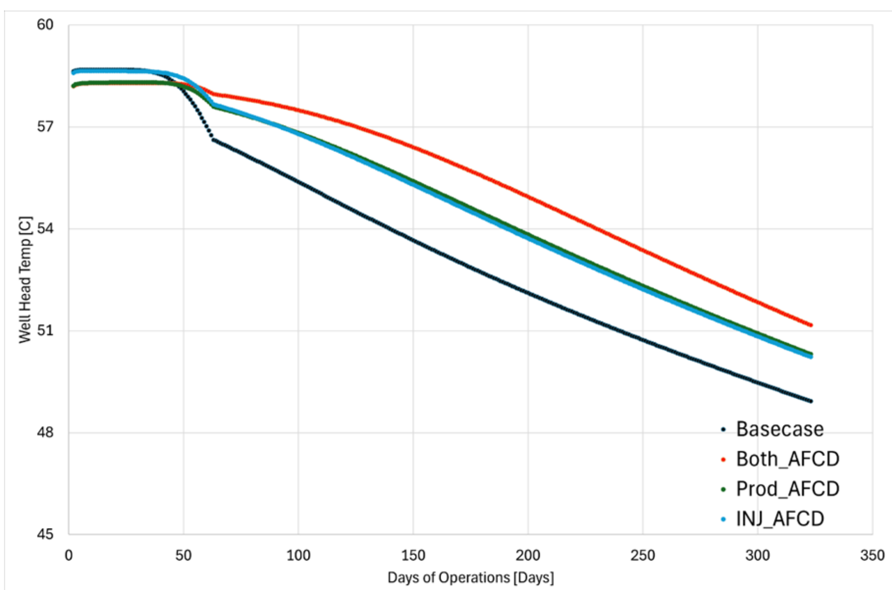

Figure 10: Output fluid temperature at surface over time for various scenarios

Figure 10 shows a slight initial drop in temperature when AFCDs are installed at producers. This is because the high-permeability zones, located at the reservoir's deeper, hotter sections, contribute more to the flow, resulting in a slightly lower average temperature compared to the base case. For alonger term, this is covered by the flux equalisation by use of AFCDs, delivering an extra 2.5°C in temperature output.

4.2. Case 2, an example of Heterogeneous Reservoirs

As already illustrated by several publications, the properties of the reservoir affecting the movement of injection fluids, in particular cold water in hot reservoirs, changes over time [7&9]. In other words, the petrophysical properties are not static and should be considered dynamic. This could be due to geo/thermos impacts on rock strength, fracture initiation and/or dilution, fine displacement, deposition of solids etc.

One of the most valuable contributions of autonomous technology lies in its capacity to manage subsurface uncertainties. Given the inherent complexity and limited visibility in geothermal reservoirs, operational success often hinges on adapting to unknowns such as fracture connectivity and variable permeability over time. The autonomous flow regulation offered by this technology provides a self-adjusting buffer against these uncertainties. By controlling flow rates passively, the devices reduce the impact of unforeseen high-permeability features and contribute to more predictable reservoir behaviour. Here, the permeability profile of reservoir has changed, as shown in Figure 11, to represent such a higher degree of dynamic heterogeneity in reservoir properties.

Figure 12 shows cross-sections of the reservoir between the injection and production wells at several times: 1 year, 2 year and 5 years for both the base case and AFCD completion scenarios for case 2. As expected, the degree of heterogeneity in temperature profile increased significantly due to new injectivity/permeability in place for base case. This was controlled however by AFCD completion where in the highest injective zone, the autonomous devices automatically shut off and only a minimum desired flow rate would be allowed via that section. Figure 12 shows that AFCD completion was capable to control such thief zones and maintaining the uniformity of fluid injection and production profiles over time. This resulted in a significant change in the outcome of the system as shown in Figure 13. This has resulted in four years delay for the cold front to reach the production wells and an increase of up to 7.8°C in the temperature of produced fluid at surface compared to base case completion scenario. This would mean an increase of up to 16% in heat extraction efficiency of such systems.

At the end, the added value of such technologies should be evaluated based on more realistic reservoir and well-bore conditions for such projects. Here, the results from a simple box model, disregarding few complicated but important phenomena, are presented to showcase the benefit of such technologies in maximising the heat extraction efficiency in this model and not the full potential of these technologies in geothermal projects.

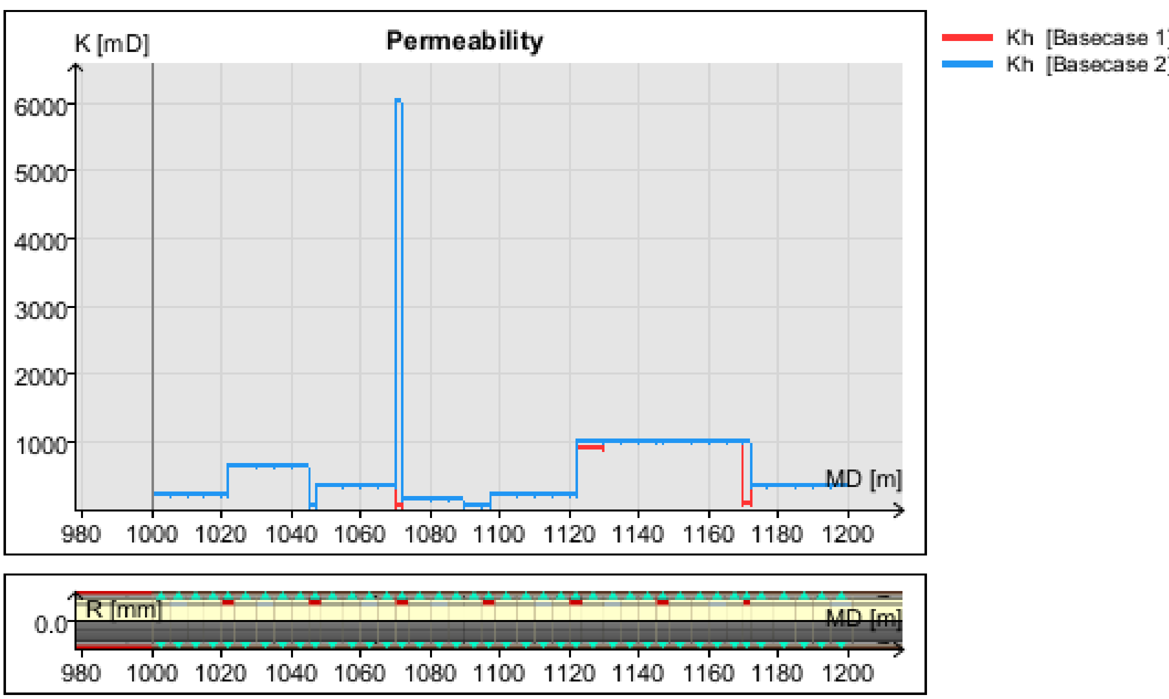

Figure 11: Peremability Profile for Case 2 compared to case 1

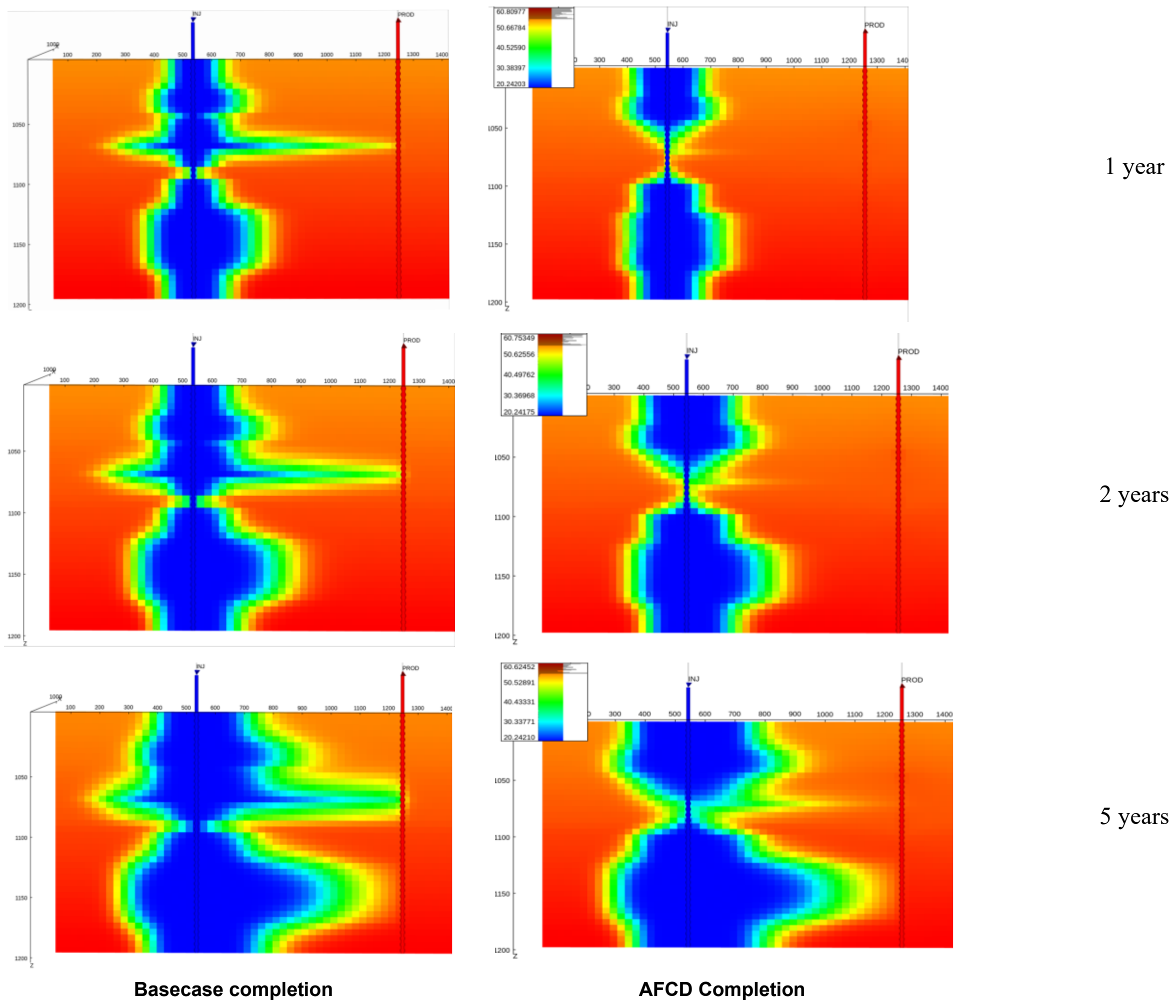

Figure 12: Temperature profile propagation from injector toward producer over time for various completions, case 2

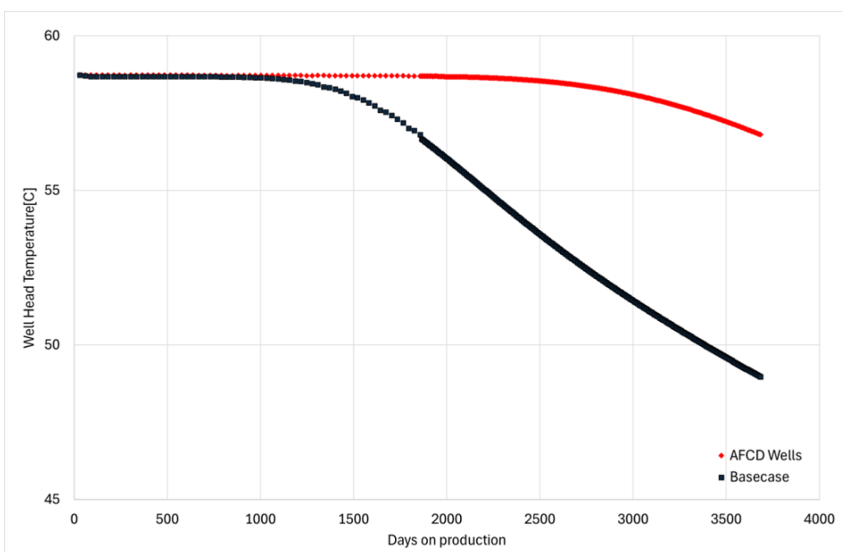

Figure 13: Output fluid temperature at surface over time for various scenarios-case 2

6. OUTLOOK AND FIELD IMPLEMENTATION

Building upon laboratory, oil and gas field successes of autonomous outflow control technology and modelling justifications, field trials are the next logical step in validating such technology. Pilot projects in established EGS sites are currently being proposed, with an emphasis on monitoring real-time reservoir responses and long-term performance metrics. As global policies continue to incentivize low-carbon technologies, the role of advanced geothermal solutions like FloFuse technology is expected to grow. The integration of these devices into a geothermal risk mitigation strategy also supports investment confidence. With fewer early failures or underperforming wells, stakeholders can expect higher returns on investment and greater resilience to operational risks. Coupling AFCD completion with real-time thermal and pressure monitoring systems could further improve reliability, enabling predictive adjustments to operations that preserve long-term performance.

CONCLUSION

This study explores the potential of autonomous flow control devices technologies in geothermal systems to address thermal short-circuiting and improve reservoir heat management.

These tools, already proven in reservoir management for oil and gas wells, can optimize geothermal system efficiency by distributing fluid flow more uniformly, increasing contact between injected fluids and heated rock and enhancing heat absorption.

Autonomous flow control devices enable dynamic flow regulation, adapting to dynamically changing reservoir conditions in real-time.

This study illustrates that incorporating AFCDs into geothermal systems represents a significant leap in geothermal reservoir management, offering enhanced heat efficiency, improved sustainability, and greater economic viability for geothermal energy projects. The results from study showed two years delay for the cold front breakthrough at production wells and an increase of up to 7.8 ◦C (16% in heat extraction efficiency) in the temperature of produced fluid at surface compared to base case completion scenario.

The findings underscore the importance of leveraging advanced flow control technologies to meet the growing global demand for renewable energy.

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