PROCEEDINGS, 50th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 10-12, 2025
SGP-TR-229

Sub-surface Analysis for Geothermal Hot Water System for Morgantown, West Virginia

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Keywords: deep direct use, dry hot rock, reservoir modeling, deep closed loop single well, enhanced geothermal systems, geomechanical model

ABSTRACT

The project aims to conduct a techno-feasibility analysis for transitioning the University's campus from a steam-based to a geothermal hot water system. This assessment is crucial for optimizing water injection and production processes. in 2023, the drilling of the MIP 1S well provided essential data, including logs, sidewall cores, and drilling records. These served as the foundation for constructing a comprehensive 3D reservoir model for the deep direct geothermal well located at the University. Utilizing offset data from neighboring wells, this model was expanded into three dimensions, incorporating crucial rock properties and data from formation injection and diagnostic fracture injection tests for precise calibration of the geomechanical model and history matching of injection pressure.

Our focus included an in-depth examination of the Utica formation's potential as a heat reservoir, alongside exploration of various geothermal system configurations. Complex heat and fluid flow dynamics within highly fractured systems, including exchange with the matrix, were simulated using multi-continua approaches. The CMG-STARS 3D reservoir model has been instrumental in identifying the most suitable configuration for deploying geothermal systems in drilling deep direct-use geothermal wells within the Appalachian basin. Evaluation of configurations, including the Deep Closed Loop Single Well and Enhanced Geothermal Systems, facilitated thorough comparison and sensitivity analyses. This research not only advances our understanding of geothermal energy utilization but also provides valuable guidance for optimizing geothermal system configurations in similar geological settings.

1. INTRODUCTION

WVU stands out as an optimal site for a geothermal district heating and cooling (GDHC) system as it benefits from elevated heat flows, as affirmed by the Marcellus Shale and Environmental Laboratory (MSEEL), project data and favorable geological conditions. GDHC aligns with WVU's sustainability goals, reducing greenhouse gas emissions and fostering an eco-friendly campus, in line with climate change mitigation efforts. Currently, most U.S. geothermal power plants and direct-use applications are installed in California, Nevada, and Idaho where there exists high geothermal temperature gradients and relatively shallow fracture networks in the subsurface (T. Reinhardt, 2013). However, recent studies from Southern Methodist University (SMU), as a part of their project to update the geothermal heat flow map (Figure 1) of North America (D. Blackwell et al., 2011), discovered temperatures beneath the state of West Virginia are significantly higher than those previously estimated in Massachusetts Institute of Technology (MIT) "The future of Geothermal Energy" report (Tester, 2006). This high temperature region extends from north-central West Virginia (Monongalia County) to southeastern West Virginia (Greenbrier County) (D. Blackwell et al., 2011). Based on the Low-temperature Geothermal Play Fairway Analysis in Appalachian region, the elevated temperatures under Morgantown are sufficiently hot enough and capable of supporting commercial geothermal systems for direct-use applications (T.E. Joran et al.,). The proposed GDHC system, utilizing the Utica as heat reservoir, promises exceptional energy efficiency, with estimates indicating temperatures conducive to district heating at reasonable drilling depths of 13,484 ft. Shifting from the current gas-fired facility to GDHC significantly lowers WVU's carbon footprint.

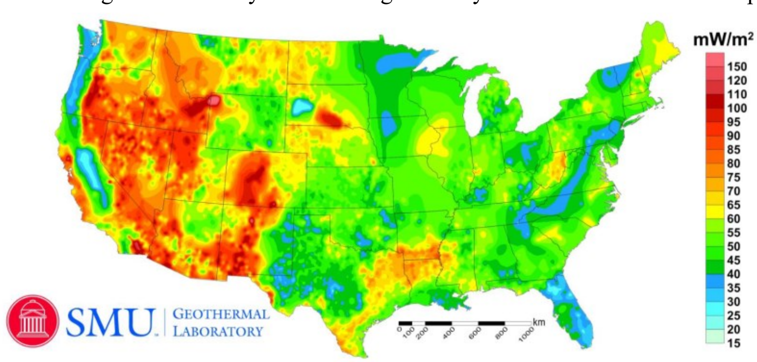

Figure 1: The updated heat flow map of the conterminous United States, the circle represents West Virginia (D. Blackwell et al., 2011)

2. GEOTHERMAL SITE LOCATION

The proposed project is situated at WVU in Morgantown, a public land-grant university in Northern West Virginia, established in 1867 and serving as the state's flagship institute. The Morgantown campus spans 1,892 acres and encompasses approximately 245 buildings. WVU's three main campuses—Downtown, Health Sciences, and Evansdale**.** The current DHC system at WVU is steam-based. The current system uses steam to heat the water, and the hot water is circulated throughout the buildings for heating and domestic usage.

The proposed Geothermal District Heating and Cooling (GDHC) system will utilize a secondary water system to exchange heat with geothermal water and subsequently heat the connected buildings. The project aims to leverage the facilities of the Morgantown Industrial Park (Figure 2) well pad and infrastructure in collaboration with Northeast Natural Energy L.L.C. and the Marcellus Shale Energy and Environment Laboratory (MSEEL). This collaboration includes the continued use of the collaborative laboratory facility for science well and geologic sample collection. The MSEEL site is equipped for surface emissions monitoring, water production, and sample collection.

Figure 2. WVU Industrial Park

3. NUMERICAL RESERVOIR SIMULATIONS

The MIP 1S well was drilled and Logs, sidewall cores, and other drilling data were acquired during drilling the intermediate depths of the MIP 1S well. Figure 3. showcases the MIP 1S vertical geothermal science well located on the MIP pad in Morgantown Industrial Park. Figure 4 shows the MIP 1S well gamma ray, density and dipole sonic logs. Based on the analysis of lithology and digital temperature data from nearby deep well drilled in the Appalachian basin to the point pleasant – Utica the temperature at depth is sufficient for DDU geothermal use at WVU. As shown in Figure 5 multiple temperature log has been obtained from MIP1S to make sure the reservoir temperature has reached to the equilibrium (Carr et al., 2024). The temperature log is then extrapolated to the target depth and compared with previous estimation reported by D. Blackwell et al., 2011. We developed and applied numerical models to study closed loop geothermal systems and enhanced geothermal systems using CMG STARS commercial reservoir simulation. The closed loop geothermal systems rely on circulation of water in a closed- loop design without penetrating the reservoir to extract subsurface heat and bring it to the surface. Enhanced geothermal systems (EGS) utilize horizontal drilling and hydraulic fracturing techniques to extract heat from subsurface formations with low natural permeability. By creating artificial fractures and connecting them to production wells, EGS enables efficient heat transfer from the hot rock to a circulating fluid. This approach has the potential to expand geothermal energy production beyond traditional hydrothermal systems, offering significant opportunities for renewable energy generation.

We used CMG STARS to conduct fluid and heat transport simulations within a hydraulically fractured geothermal system. Multi-continua approaches were utilized to model heat and fluid flow through highly fractured systems, including heat and fluid exchanges with the matrix. The base fine grid model was developed to encompass formations like Utica Shale, Upper- and Lower-Point Pleasant, Lexington, and Trenton. This model was then extended to the surface using a coarse grid constructed from gamma and density logs. The temperature gradient obtained was implemented, incorporating a dynamic temperature gradient as a function of formation lithology to estimate downhole temperature.

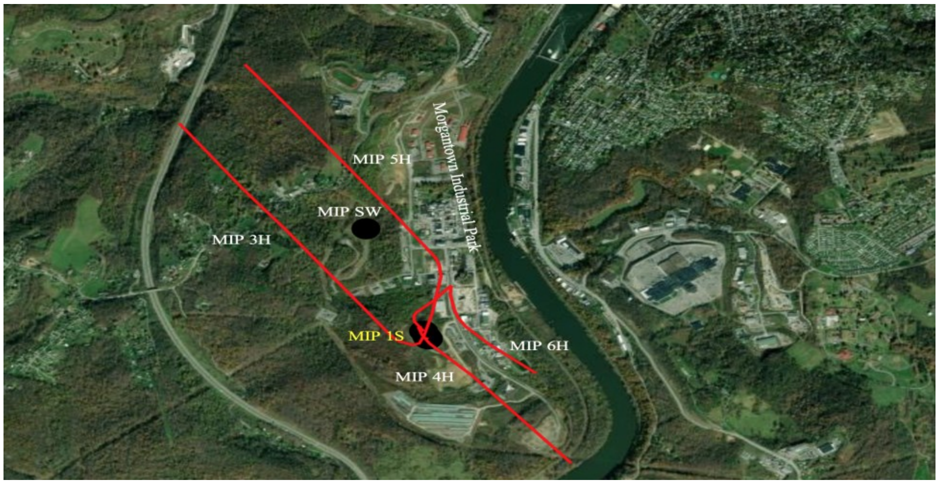

Figure 3: MIP Pad and 6 wells drilled and completed including MIP1S geothermal science well along with MIP 3H, 4H, 5H, 6H and SW. (Fathi et al 2024)

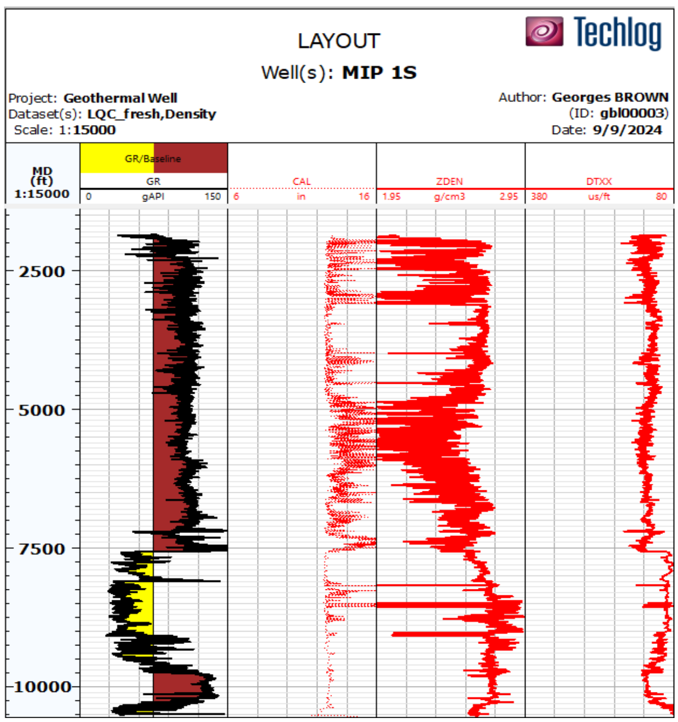

Figure 4: MIP1S logs (Fathi et al 2024)

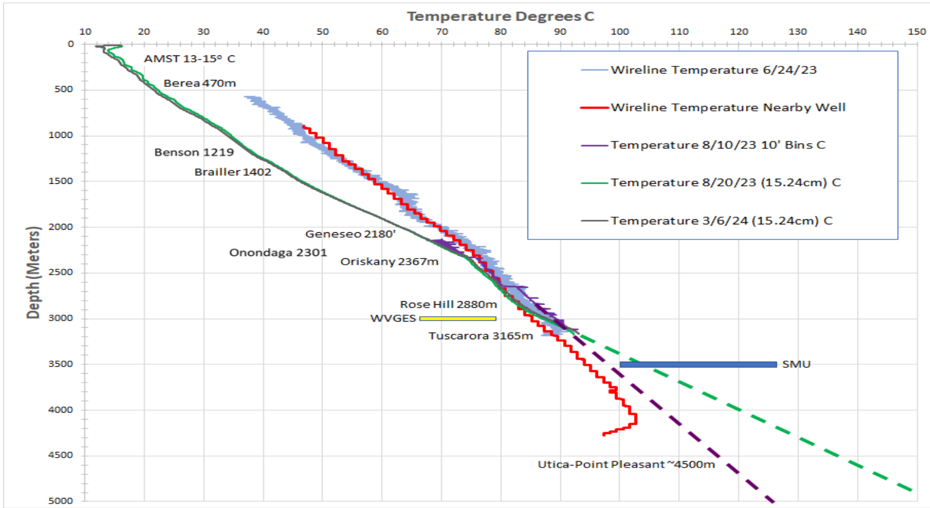

Figure 5: Temperature logs for different days after the MIP 1S reached total depth showing temperature versus depth in the MIP 1S, and from nearby deep well. (Carr et al 2024, International Meeting for Applied Geoscience and Energy)

3.1. Results

Single closed loop system

In Figure 6, the water temperature profiles for both casing and tubing are shown over 30 years of water injection and production. Cold water, injected through the casing at 62°F, flows into the annulus and is produced through the tubing. At a downhole depth of 13,484 ft, the maximum water temperature initially rises to 240°F during the first year of injection, while the reservoir temperature stands at 255°F. Over time, the temperature gradient decreases as the reservoir cools. After 30 years, the bottomhole temperature drops to 190°F. Similarly, the produced water temperature starts at 185°F in the first year (depicted in red) and declines to 146°F by the final timestep (depicted in grey). This gradual reduction reflects the depletion of thermal energy within the formation, resulting in less efficient heat transfer to the produced water. Figure 7 illustrates the change in produced water temperature within the tubing over the 30-year injection period. During the first 10 years, a significant temperature drop is observed: the bottomhole temperature decreases from 240°F to 196°F, leading to a corresponding surface temperature decline from 185°F to 156°F. Over the subsequent 20 years, the temperature change stabilizes, with an approximate 6°F reduction at both the bottomhole and surface levels. Figure 8 presents a map of temperature change around the wellbore at the true vertical depth (TVD), highlighting the growth of the heat extraction radius over the 30-year injection and production period. Initially, the radius of heat extraction is limited, but it gradually expands as heat is continuously extracted from the formation, ultimately reaching a maximum radius of 140 ft by the end of the 30 years. This expansion reflects the progressive depletion of thermal energy in the surrounding rock and indicates the spatial extent of the reservoir's thermal response to sustained water injection and production. However, the analysis also reveals a constrained heat drainage area, which limits the application potential of single-well closed-loop systems.

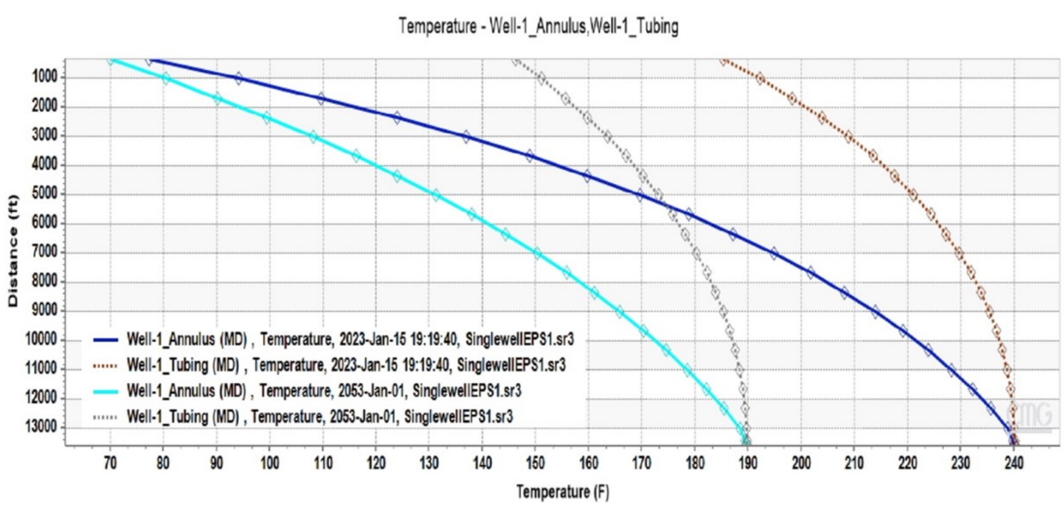

Figure 6: Temperature profiles of casing and tubing over 30 years of water injection and production, showing the progressive decline in thermal energy at a depth of 13,484 ft.

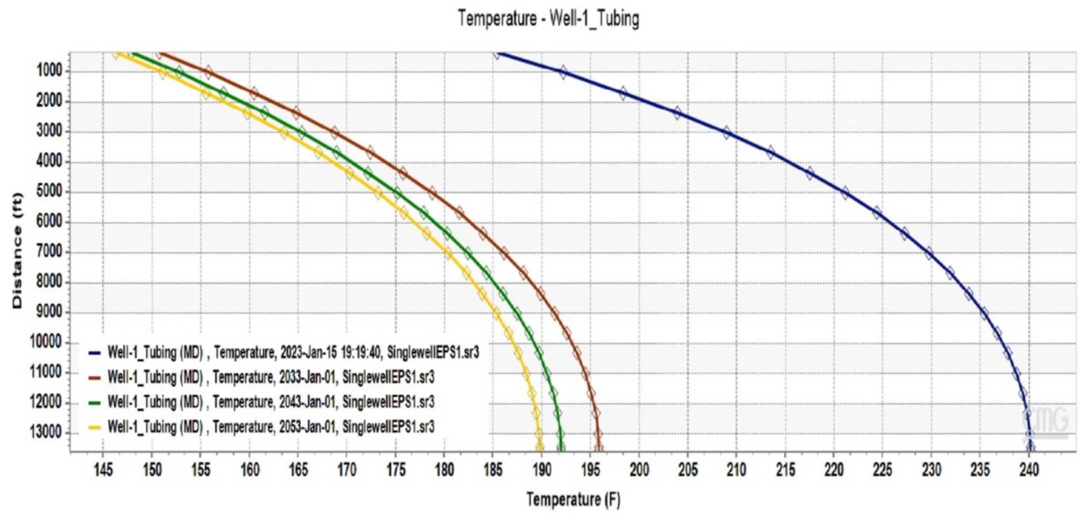

Figure 7: Produced water temperature changes in tubing over 30 years of injection, highlighting significant drops in the first 10 years and stabilization in the subsequent period

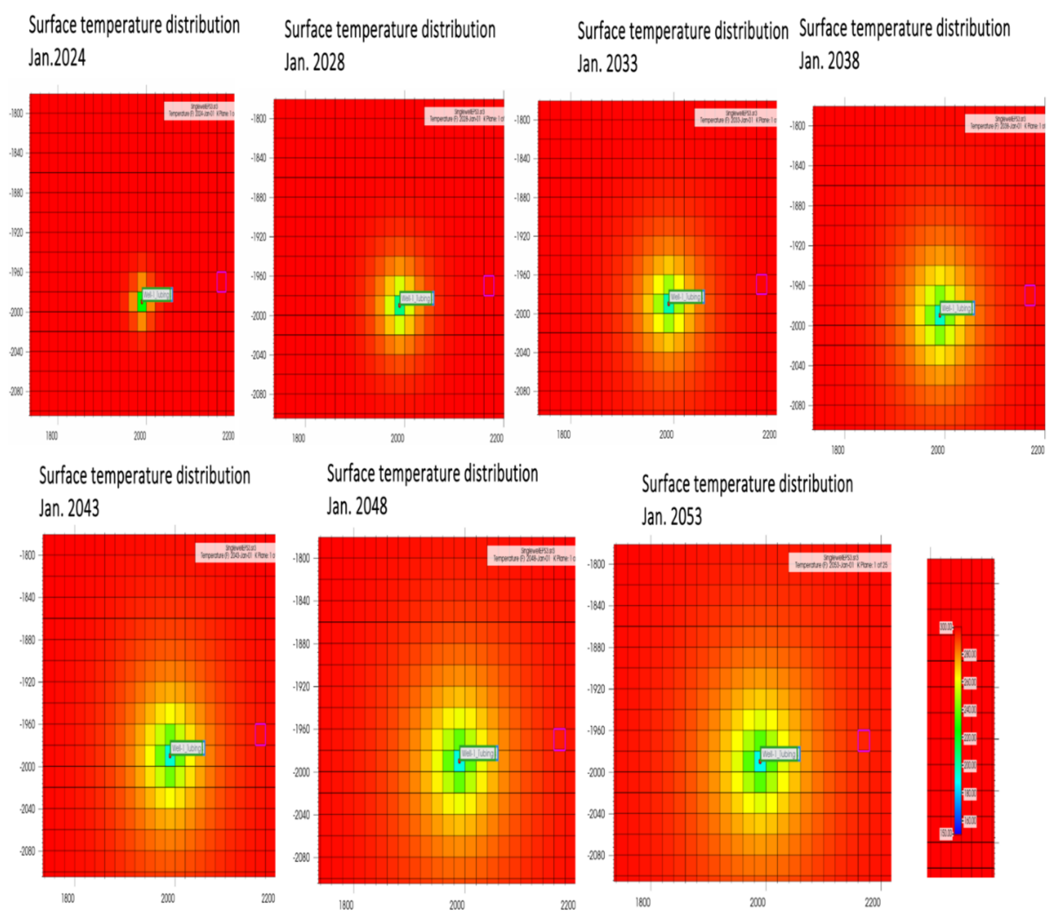

Figure 8: Map of temperature change around the wellbore at true vertical depth (TVD), illustrating the growth of the heat extraction radius and its limitations for single-well closed-loop systems.

The thermal properties of the rock and the fluids need to be precisely defined as they indeed, affect the simulation output. From (Nalla et al. 2005), the volumetric heat capacity used for the case described was 27.97 Btu/(ft^3·°F), with a formation thermal conductivity of 5.67 Btu/(ft·day·°F) and a working fluid volumetric heat capacity of 62.43 Btu/(ft^3·°F). Since the MIP 1S well has not yet been completed to the target depth and core samples have not been obtained, we used the typical heat capacity and thermal conductivity values for the Utica and Point Pleasant formations (shale), as well as the Trenton and Lexington formations (limestone), in our base simulation. To account for uncertainty in these key parameters, we conducted a sensitivity analysis by simulating two additional scenarios—middle and high limits—based on the upper, middle and lower bounds of shale and limestone heat capacity and thermal conductivity. These scenarios help assess the impact of parameter variability on the system's thermal performance. Table 1 summarizes the temperature dynamics in the tubing (production line) over the 30-year simulation period, highlighting how different thermal properties influence the efficiency of heat extraction and temperature behavior over time.

Table 1: Temperature dynamics in tubing over 30 years, highlighting the impact of thermal properties.

Scenario	Years	Temperature (Tubing)ºF
LOW	2023	185
	2053	156
MIDDLE	2023	196
	2053	161
HIGH	2023	207
	2053	173

Enhanced Geothermal System

In this study, two horizontal wells are modeled and completed in the Utica Shale at a depth of 13,484 ft true vertical depth (TVD). Each well has a lateral length of 6,756 ft, divided into two stages with five clusters geometrically designed for hydraulic fracturing. The lateral spacing between the two wells is 1,000 ft. A larger fracturing job is performed on the injection well, assuming a fracture half-length of 700 ft, while a smaller fracturing job is applied to the production well with a fracture half-length of 300 ft to ensure effective communication between the two wells.

Slickwater fracturing with 100 mesh proppant is used to seal natural fractures and minimize fluid leak-off. The numerical simulation domain consists of a Cartesian grid with a total of 54,000 grid blocks: 180 in the I direction, 60 in the J direction, and 5 in the K direction and grid refinement is used around hydraulic fractures for better accuracy and resolution. Based on a fracture gradient of 1.18 psi/ft obtained from an adjacent well, a maximum bottomhole pressure of 16,000 psi is applied to the injection well, while the production well operates at a minimum bottomhole pressure equal to the hydrostatic pressure of 5,806 psi.

Simulations are conducted over a 30-year injection and production period. Key parameters monitored include bottomhole and surface produced water temperatures, injection well pressures, and production rates. The reservoir temperature around the hydraulic fractures is also tracked throughout the simulation period. Sensitivity analyses are performed to examine the effects of varying injection rates of 3,000, 6,000, and 9,000 barrels per day (bbls/day) on reservoir performance, injection efficiency, and production outcomes. These rates are still far below the required rates however will be used as our base case for completion optimization.

Figure 9 presents a 3D model of the reservoir with two wells drilled and completed in the Utica Shale formation. The model incorporates multiple stratigraphic layers, including the Utica, Point Pleasant, Lower Point Pleasant, Lexington, and Trenton formations, with respective true vertical depths (TVD) of 13,474.5 ft, 13,674.4 ft, 13,720 ft, 13,753 ft, and 13,789 ft.

Figure 10 illustrates the bottomhole temperature dynamics of produced water over 30 years of operation under three different water injection rates: 3,000 bbls/day, 6,000 bbls/day, and 9,000 bbls/day. Initially, the bottomhole temperature increases due to heat conduction from the surrounding formation. In the case of high injection rates (9,000 bbls/day), the temperature rises for the first three years before declining significantly as the reservoir's thermal energy depletes. For 6,000 bbls/day, the temperature increases over the first four years and then experiences a similar decline. However, for the low injection rate of 3,000 bbls/day, the temperature rises steadily over the first 11 years before a gradual and more moderate decline. This trend highlights the relationship between injection rate and reservoir thermal response, with higher rates leading to faster depletion of thermal energy. Figure 11 depicts the changes in reservoir temperature over the 30-year injection period for the three injection scenarios. The hydraulic fractures act as heat sinks due to the injection of cold water, inducing heat conduction from deeper formations with higher temperature gradients. For the 3,000 bbls/day injection rate, the process of heating the reservoir is more sustainable, with the thermal stabilization continuing throughout the injection period. In contrast, higher injection rates (6,000 bbls/day and 9,000 bbls/day) result in accelerated thermal depletion and reduced efficiency over time.

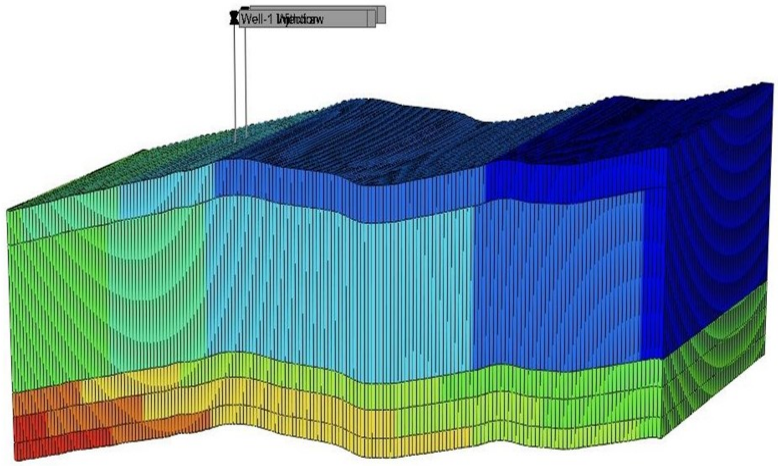

Figure 9: 3D reservoir model illustrating the geological layers (Utica, Point Pleasant, Lower Point Pleasant, Lexington, and Trenton) and the placement of two horizontal wells completed in the Utica Shale formation.

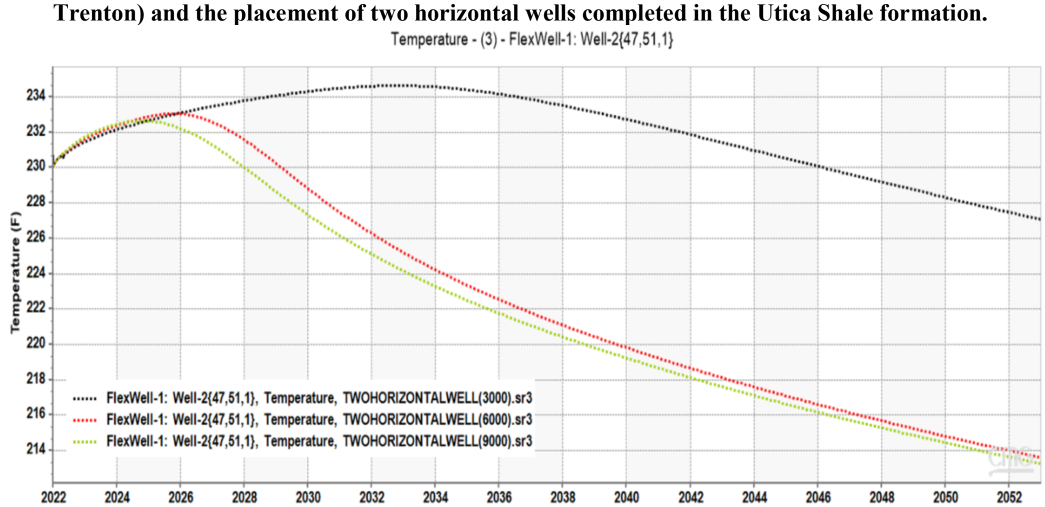

Figure 10: Bottomhole temperature dynamics of produced water over 30 years for Enhanced Geothermal Systems (EGS) under three injection rates: 3,000 bbls/day, 6,000 bbls/day, and 9,000 bbls/day, showing the thermal response of the reservoir.

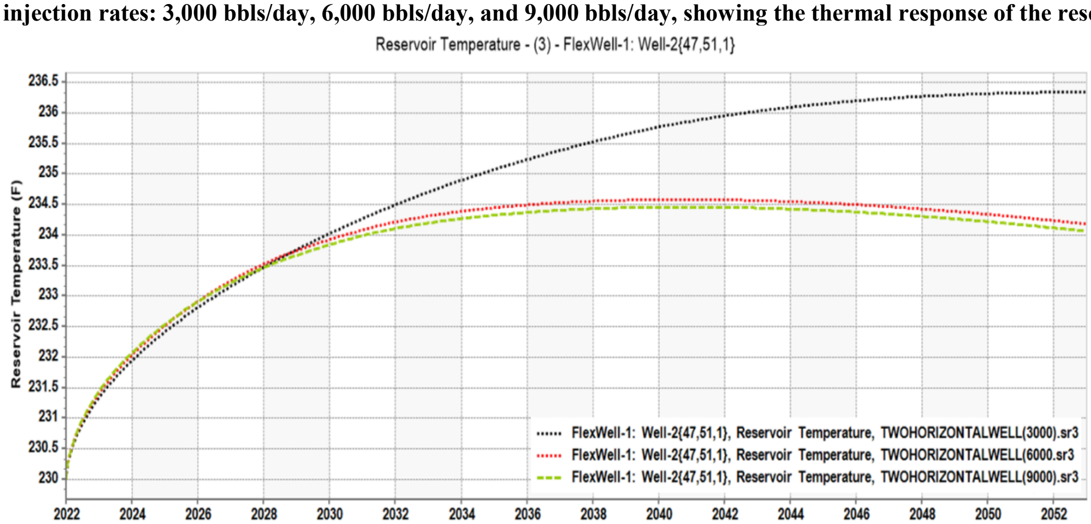

Figure 11: Reservoir temperature changes during 30 years of operation for EGS under different injection rates, highlighting the thermal stabilization process at lower injection rates.

Figures 10 and 7, provide valuable insights into bottomhole temperature dynamics during the 30-year operational period for Enhanced Geothermal Systems (EGS) and closed-loop systems, respectively. In the closed-loop system (Figure 7), the bottomhole temperature steadily decreases over time due to the absence of replenished heat from external sources, reflecting a more constrained thermal footprint. Conversely, in the EGS scenario (Figure 10), the bottomhole temperature initially rises due to the thermal contribution from surrounding formations, especially at lower injection rates. The comparison underscores the advantage of EGS in leveraging conductive heat transfer from adjacent formations, which mitigates thermal depletion compared to closed-loop systems. However, higher injection rates in EGS systems can accelerate thermal energy depletion, leading to a performance decline similar to closed-loop systems in later years. Figure 12 shows the dynamics of reservoir temperature change around the hydraulic fractures connecting injection and production at initial condition (top) after 10 years of operation (middle) and after 30 years of operations at the bottom.

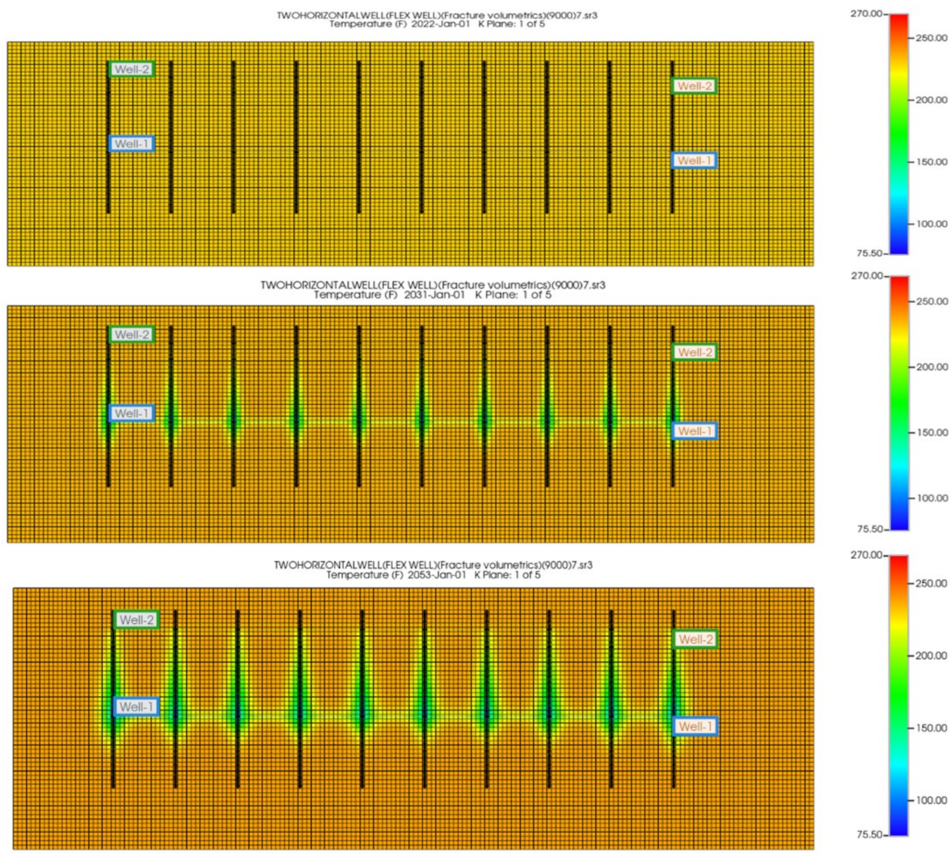

Figure 12: Reservoir temperature changes around hydraulic fractures and within the reservoir during 30 years of operation for EGS under 9000 bbls/day of water injection.

CONCLUSION

The comprehensive study to evaluate the transition of WVU's campus from a steam-based system to a geothermal hot water system has demonstrated the feasibility and potential advantages of geothermal energy deployment in the Appalachian region, particularly using the Utica Shale formation as a heat reservoir. The analysis utilized a detailed 3D reservoir model, incorporating data from the MIP 1S well, geological logs, and diagnostic fracture injection tests, to simulate both single closed-loop and enhanced geothermal systems (EGS).

In the single closed-loop system, cold water was injected at 62°F through the casing and produced through the tubing, with the bottomhole temperature initially reaching 240°F during the first year and gradually declining to 190°F over 30 years. The produced water temperature followed a similar trend, dropping from 185°F to 146°F over the same period. The results revealed a constrained heat drainage area, with a maximum heat extraction radius of 140 ft after 30 years, reflecting the limitations of closed-loop systems in sustaining efficient heat transfer due to the absence of replenished thermal energy.

In the enhanced geothermal system, two horizontal wells were modeled at a true vertical depth of 13,484 ft, with lateral lengths of 6,756 ft and hydraulically fractured zones for effective heat extraction. Sensitivity analyses of injection rates (3,000, 6,000, and 9,000 bbl/day) revealed that lower rates achieved better thermal stabilization, while higher rates accelerated thermal depletion. The bottomhole temperature dynamics showed initial increases due to heat conduction, with sustained temperature profiles over 30 years at lower injection rates. Reservoir temperature mapping indicated effective heat transfer around hydraulic fractures, showcasing EGS's superior capability to leverage conductive heat from surrounding formations compared to closed-loop systems.

The proposed Geothermal District Heating and Cooling (GDHC) system aligns with WVU's sustainability goals, reducing carbon emissions, enhancing energy efficiency, and offering long-term cost savings. This research not only establishes WVU as a benchmark for geothermal energy utilization in regions with moderate temperature gradients but also provides critical insights into optimizing geothermal configurations to support broader renewable energy adoption globally.

ACKNOWLEDGMENTS

"Work was funded by Analysis of Geothermal Deep Direct-Use Combined with Reservoir Thermal Energy Storage on the West Virginia University Campus – Morgantown, WV under DOE EERE, United States of America Geothermal Technologies Program Award Number: DE-EE0009597. Northeast Natural Energy, LLC is an integral and critical participant providing data access and guidance."

"Maya Dziver from Computer Modelling Group provided advice on the use of CMG STARS."

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