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EGS Well Test Analysis from the Perspective of Conventional Geothermal Reservoir Engineering

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ABSTRACT

The U.S. Department of Energy (DOE) Geothermal Technologies Office (GTO) Frontier Observatory for Research in Geothermal Energy (FORGE) initiative is a dedicated field site in Milford, Utah, where scientists and engineers are developing and testing enhanced geothermal systems (EGS) technologies and techniques (Moore, 2019). All data from FORGE are made publicly available in an online repository. In August 2024, a nominal 28-day flow test (circulation test) was conducted on the fractured EGS well doublet at FORGE. Prior the test, both wells had been hydraulically fractured with many stages employing different techniques, procedures, and materials for perforations, fracturing, and proppants. This paper presents analyses and discusses some of the implications of the flow test from the perspective of conventional geothermal reservoir engineering. FORGE achieved impressive technical successes in fracturing the wells and ultimately demonstrating commercial levels of injection, production, and temperature. Using an analysis approach from conventional geothermal reservoir engineering, the FORGE doublet (as-is) was found to have a potential generation capacity 1.7 Mwe,net. Again, for the FORGE doublet (as-is), Monte Carlo analysis provided an estimate of a P90 reserves of 0.9 Mwe,net for a 10-year project life. While FORGE is continuing its mission, it has provided enough data for private industry to make informed techno-economic assessments of the commercial implementation of EGS.

1. INTRODUCTION

The past few years have been a time of unprecedented activity, advancement, and investment (both public and private) in non-conventional and novel geothermal technologies. The most promising EGS technology, thus far, is the application horizontal (or highly deviated) wells which are hydraulically fractured with proppants injected. The FORGE project has drilled, completed, fractured, and flow tested a well doublet consisting of directionally drilled wells at around 8000 feet depth below the surface. The doublet is completed in a large volume of hot 392 °F (200 °C) crystalline granite. The doublet's production well is drilled nearly parallel to the injection well with the production well approximately 300 ft. (91 m.) above the injection well (see Figure 1).

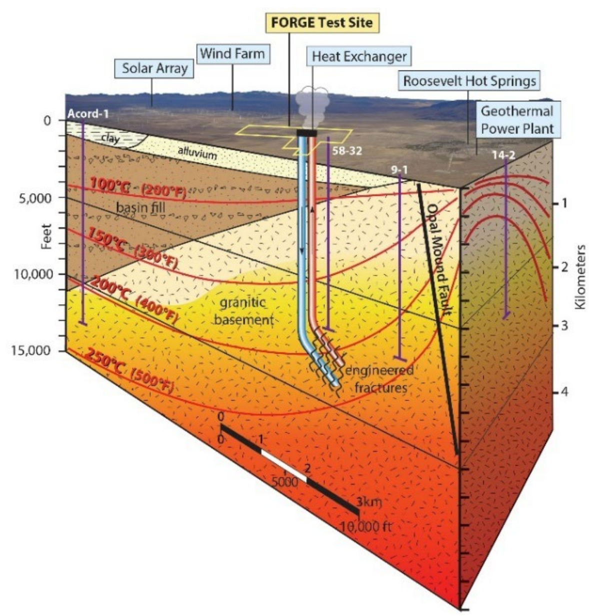

Figure 1: Overview of the Utah FORGE site, showing conceptual model, subsurface temperature contours, and the well doublet, the Utah FORGE research team is led by the University of Utah's Energy and Geoscience Institute (EGI), (graphic taken from the Geothermal Data Repository (GDR).

2. WELL DOUBLET GEOMETRY

Figure 2 shows the geometry of the drilled doublet in a plane parallel to the drilled direction which is to the southeast. Well 16A(78)-32 (the injection well) was spud on October 30, 2020, and it was drilled vertically to a kickoff point at 5900 ft MD from which it was directionally drilled at an azimuth of 105 degrees to 10,987 ft MD (8,559 ft TVD). Well 16B(78)-32 (the production well) was spud on April 26th, 2023, and it was drilled vertically to a kickoff point at 5500 ft MD from which it was directionally drilled parallel to and approximately 300 ft above well 16A(78)-32 to depth of 10,947 ft MD (8,262 ft TVD). Each well has approximately 3500 ft of deviated section. Well 16A(78)-32 has 10 stages of stimulation spanning the lower 1500 feet of the well. Well 16B(78)-32 has 5 stages of stimulation spanning the central 800 feet of the well.

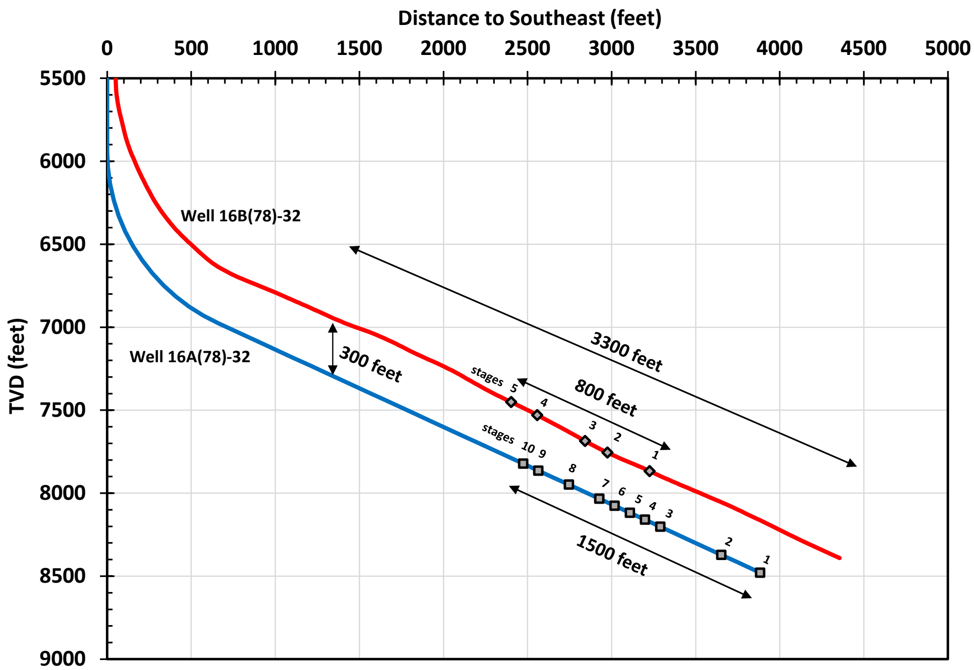

Figure 2: FORGE Utah wells 16A(78)-32 and 16B(78)-32 showing as-drilled geometry with the locations of stimulation stages, which represent various types of stimulations done to compare effectiveness, no vertical exaggeration.

3. AUGUST 2024 CIRCULATON TEST: FLOW DATA

An extended circulation test was conducted during the 28 days from August 8, 2024, to September 4, 2024 (England, et al 2024), Figure 3 shows a diagram of the layout. Ambient temperature water from the 125,000 bbl water pit was used to supply a high-pressure injection pump to inject into well 16A(78)-32. Well 16B(78)-32 was produced by artesian pressure (due to the reservoir being pressurized by injection into 16A(78)-32). The production flow from 16B(78)-32 was piped into an atmospheric flash tank to vent the steam, and the post-flash liquid was flowed into the 16A/B-32 sump. The produced fluid was then flowed into the 125,000 bbl water pit by transfer pump (see Figure 3). Due to mass loss from steam flash, evaporation, and into the formation (less than 100% fluid recovery), there was a need for make-up water, particularly at the start of the test when the injection was pressuring up the reservoir and production rate was ramping up. This make-up water was supplied by using well 58B-32 (a shallow water supply well) to recharge the 125,000 bbl water pit. The test included extensive metering and sampling the discussion of which are beyond the scope of this paper.

As shown in Figure 4, injection into well 16A(78)-32 was held at a constant rate of 10 bpm (420 gpm) after increasing in steps over the first three days. Well 16A(78)-32's injection pressure varied from 2800 to 3000 psi during the test. Figure 5 shows production data from well 16B(78)-32. The figure includes 16B(78)-32's production wellhead pressure, production fluid temperature (which was single phase liquid at the wellhead), flow rate outflowing from the atmospheric flash tank, and total production flow on a pre-flash basis. For the case of pre-flash flow, this was calculated from the flash tank flow and the production temperature. The flow rate data show in Figures 4 and 5 were independently processed and calculated from raw FORGE data which were in gpm. The raw flow rate data included metering of the flow rate (in gpm) from the 16B(78)-32 wellhead with two meters, and metering of both of two outlets from the atmospheric flash tank. The flow meters on the 16B(78)-32 wellhead discharge were intermitted during the test and were disregarded. The flow meters on the outflow from the flash tank were provided a continuous record, and their data were used instead.

Figure 6 shows the flash-corrected mass flow rate from production well 16B(78)-32 compared to the mass flow rate of 16A(78)-32 injection. During the first half of the test 16B(78)-32 was flowing at wellhead pressure of 260-270 psi with single phase liquid production at 370 ºF (188 ºC) while flash-corrected production mass flow was steady at 20 kg/s. At this time the injection mass rate was steady at 26.5 kg/s, indicating a fluid recovery factor of 20/26.5=0.75.

Later in the test, 16B(78)-32's wellhead pressure was steady at 250 psi, while flash-corrected production mass flow increased and was steady at 23.5 kg/s, while production temperature also increased to 380 ºF (193 ºC). During this period of the test the fluid recovery factor also increased to 23.5/26.5=0.90. The fluid recovery factor is a very important aspect of this test (assuming there is no abundant source of make-up water that can be permitted and allocated to the project during commercial operation). For example, a commercial project designed for 10,000 gpm of total production would need a continuous 1,000-2,500 gpm of makeup water depending on whether the fluid recovery factor was 0.90 or 0.75.

A circulation test of this type would go further to proving commercial or technical success by finding operating conditions that demonstrate 100% mass recovery or accepting that the development plan requires continuous makeup water which has been sourced and accounted for financially. It may be possible to achieve 100% mass recovery by having, for example, a few more production wells than injection wells, the quantification of which could be aided by reservoir simulation.

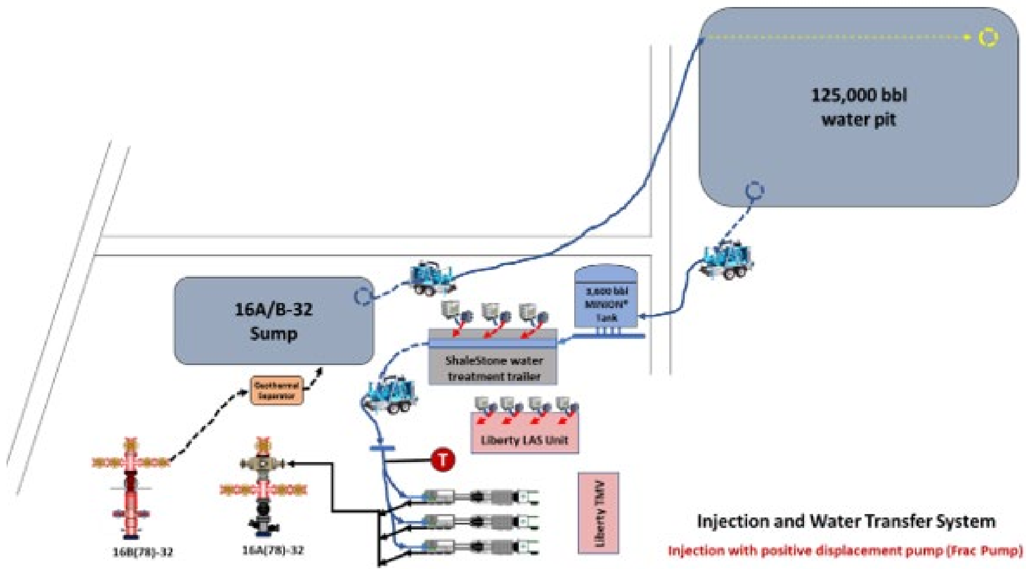

Figure 3: Schematic layout of extended circulation test August 2024 (England, et al 2024)

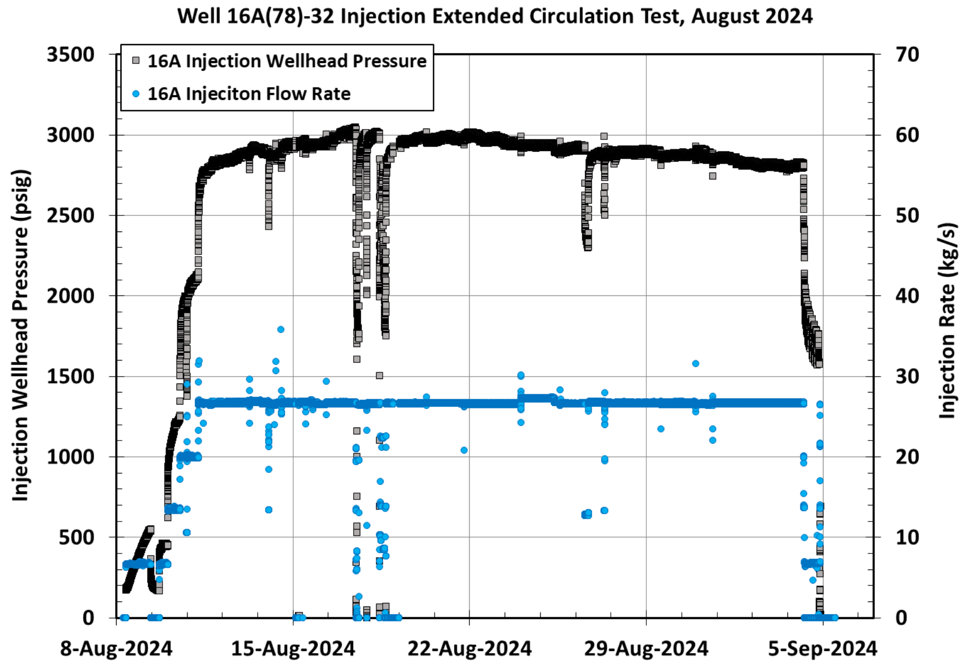

Figure 4: Well 16A Injection pressure and rate during the 28-day circulation test in August 2024.

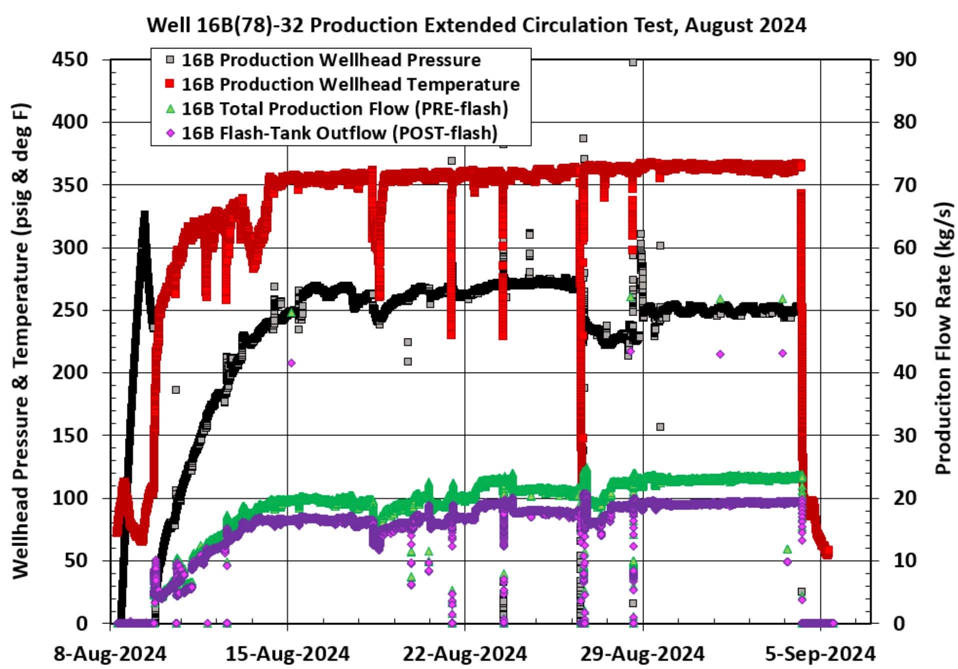

Figure 5: Well 16B(78)-32 production wellhead pressure and flowing temperature during the 28-day circulation test conducted in August 2024.

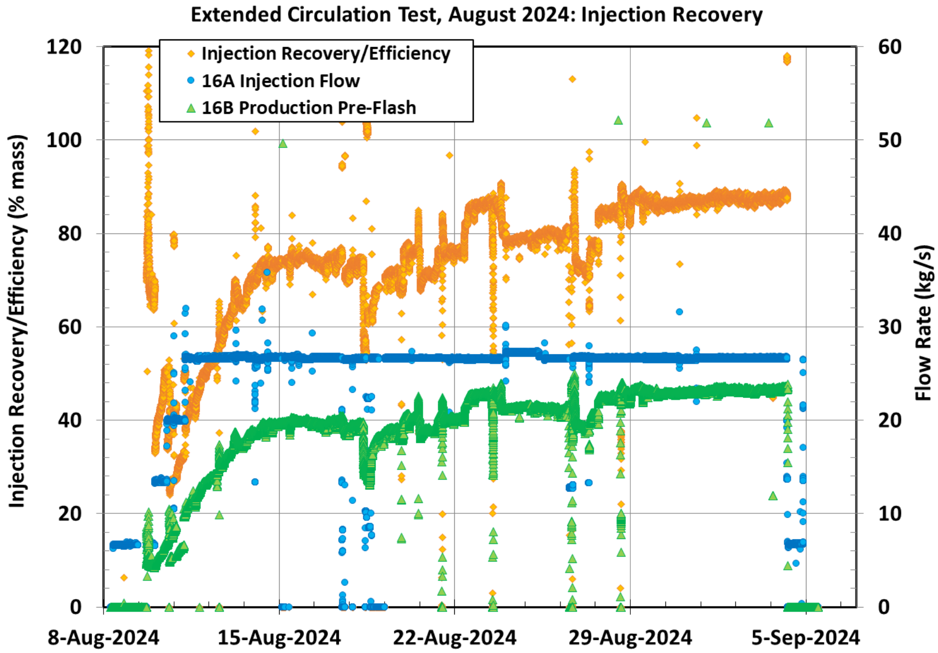

Figure 6: Flash-correct production mass flow compared to injection mass flow showing a 75% fluid recovery in the beginning of the test which increased to 90% toward the end.

4. POWER GENERATION POTENTIAL

During the extended circulation test, dynamic spinner surveys were conducted to quantify the injection and production flow allocations among the stages in 16A(78)-32 and 16B(78)-32, respectively. These allocations are shown as the percentages in Figure 7. As mentioned above, there was a range of variation in how the stages were conducted, materials used, and other parameters. This was done as part of experimentation aimed at optimizing the effectiveness of the stimulations. It is anticipated that with was learned from these experiments, that future stimulation programs will be able to deliver more evenly distributed allocations. As can be seen, the effective stages were highly effective, and the flow is fairly evenly distributed among the effective stages.

As noted above, because the circulation test didn't achieve 100% mass recovery, nor was a plan for makeup water either outlined or simulated, there remains some uncertainty as how this issue will be handled on a project development level. The latter part of the circulation test showed 23.5 kg/s of production at 380 °F (193 °C) accomplished with 26.5 kg/s of injection. The net electrical power generation from this heat flow (23.5 kg/s at 193 °C) can be estimated from equation (1), adapted from (Dipippo, 2016):

$$W_{e,net} = \eta_t \, M_{tot}\left(H_{in} - H_{ref}\right) \tag{1}$$

In equation (1), $W_{e,net}$ (watts) = net power generation including estimated parasitics, η_t $(ratio)$=overall (net) thermal-to-electrical efficiency of the plant (assumed to be binary due to temperature of the resource), M_{tot} (kg/s)= mass flow rate into plant, Hin(kJ/kg)= fluid enthalpy entering plant, and H_{ref} (kJ/kg)= fluid enthalpy at reference temperature equivalent to the plant outflow temperature (Grant, 2018). For the production flow from the August 2024 circulation test, Farrouk and Moon (2014), provides a framework to estimate η_t, for a wide range of conditions. For a binary plant supplied by 193 °C single-phase liquid, η_t has a basic expectation of 0.07-0.09, which is the upper end of the correlation suggested by Dickson and Fanelli (2003), for a resource temperature of 193 °C. To allow for the possibility of advanced cycles and new technologies, a value of 0,11 was used for η_t.The other parameters used were H_{in}=821 kJ/kg (for 193 °C, production), H_{ref}=167 kJ/kg (based on 40 °C plant outlet), the mass flow for 16B(78)-32 M_{tot} = 23.5 kg/s.

This calculates to 1.7 Mwe,net for the production flow of 16B(78)-32 (23.5 kg/s at 193 °C) during the later part of the extended circulation test which showed stable flow, temperature, pressure, and 90% mass recovery between the injection well and the production well. It is understood that FORGE is a research project, and various fracking techniques were applied with various effectiveness, with the most effective stages of fracking being quite effective, likely beyond which was considered not possible in the very near past. Therefore, the 1.7 Mwe,net is not proffered as the maximum potential. With the make-up water issue solved (getting to 100% mass recovery) the potential startup generation would be higher for this doublet and replicated to full project development size.

It appears plausible that if 16A(78)-32 and 16B(78)-32 were fractured with stages along their entire deviated lengths, that the flow rate could be tripled from the tested rates in the circulation test. This doublet would potentially produce sufficient fluid for 5.1 Mwe,net electricity generation. (3x1.7 Mwe,net). Beyond this, there is possible additional upside by drilling longer laterals, allowing more stages and more flow rate.

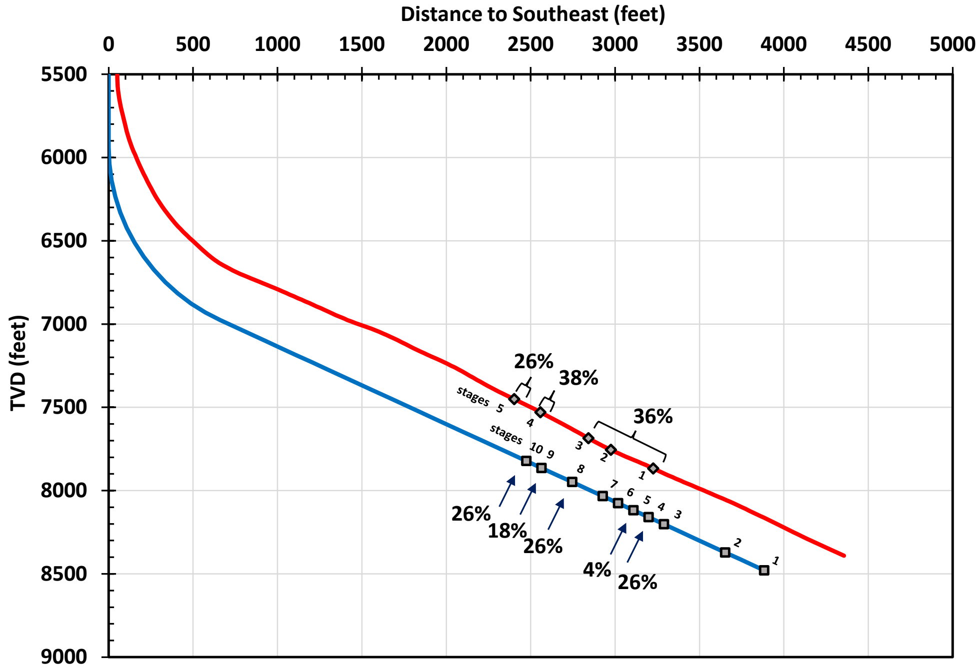

Figure 7: Flow contributions of each stage as derived from dynamic production logging during the August 2024 extended circulation test.

6. RESERVES

The above calculations only address the project startup generation and not the longevity of the production enthalpy. From experience in conventional geothermal, a greenfield project based on 300ft (91m) spacing between the injection and production wells would not meet the target of 30 years of reserves. The spacing between injection and production wells at FORGE being 300 feet (91m), which is much less than what is used in conventional geothermal which is generally 980 ft (300m) to 3280 ft (1000m), or more. The longevity of reserves could be counteracted by reducing each doublet's flow rate significantly to delay thermal breakthrough. Alternatively, the doublets could be operated at their maximum with the expectation of an aggressive make-up drilling program to add doublets as they deplete heat reserves.

Figure 8 shows the dimensions of a postulated fracture network for the as-is FORGE EGS reservoir as of the August 2024 extended circulation test. It should be noted that volume is based on approximations and not based on simulation. However, it is believed that some reasonable approximations can be made. For length, a value of 1500ft is used, which is based on a contiguous length that extends approximately 300 feet beyond the stages in 16B(78)-32 in both directions. For the cross-sectional area, a circular diameter of 1330ft was used which is based on the cross-sectional area described by Fercho, et al. (2023), which had a rectangular cross-sectional area. Note that the use of a circular cross-sectional area here is merely a convenience and no implications are made here to the actual shape.

In a literature review, it was found that many (not all) EGS reserves calculations or forward simulation forecasts were based on a 10-year project life. In this work, a 10-year project life is used as opposed to the typical 30-year project life used in conventional geothermal, which is a significant difference. However, with an injector to production well spacing of 300ft (91m), as in FORGE, that reserves for a 30-year project life would be at a very low flow rate. Alternatively, if EGS wells were developed with a much larger spacing, for example 980 ft (300m) to 3280 ft (1000m) as in conventional geothermal, it is likely that the flow rate for each doublet would be much lower, but with the benefit of a longer time to thermal breakthrough and depletion. In either case, large numbers of wells may ultimately be needed if a 30-year project life is targeted. For close spacing, the project will have higher initial flow rates but will need many make-up wells as thermal depletion manifests quicker. For large spacing, because the initial flow rates are lower, a larger number of doublets will be needed for a given level of development.

To make a first, order simplified estimation of the reserves in the as-is FORGE ESG reservoir (as it existed August 2024), the Monte Carlo volumetric heat-in-place was used. The technique used is consistent with USGS Circular 790 (Muffler 1979), with modifications made to be consistent with more recent research which suggest modification to the reference temperature Garg used and range of heat sweep recovery factors from Garg (2011), Williams (2007), and Grant, (2018). Figure 9 shows the input parameters to the heat-in-place calculation, and Figure 10 shows the output range of electrical reserves. The calculation shows for a 10-year project life that P90 reserves are estimated to be 0.9 Mwe, with the P50 reserves estimated at 1.7 Mwe. It is concluded that it is a reasonable expectation that the FORGE EGS reservoir as it exists in August 2024, could generate 1.0 to 1.7 Mwe for 5 to 10 years.

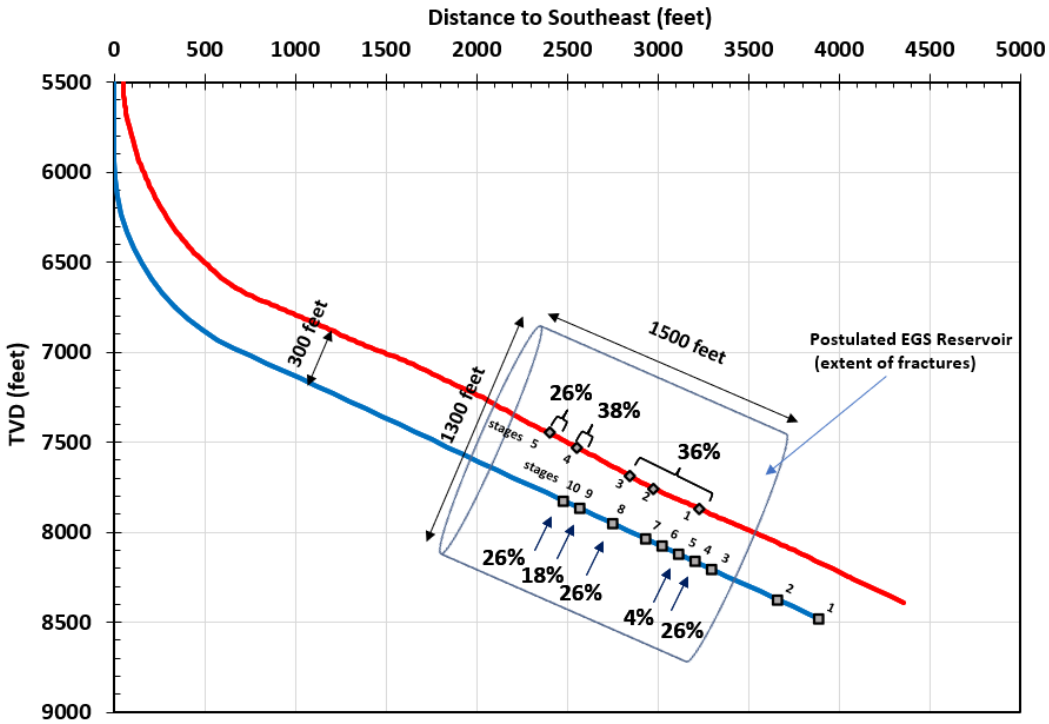

Figure 8: Postulated extent of induced fractures comprising the created EGS reservoir for the purpose of a heat-in-place reserves calculation (the diameter of the zone was specified to make the cross-sectional area consistent that reported by Fercho, et al. (2023).

Metric Units					
Parameters	**Best Guess (Mode)**	**Units**	**Probability Distribution (Type)**	**Minimum Value**	**Maximum Value**
Monte Carlo Sampling	*2000*	*NA*	Fixed		
Injection Temperature	40	deg °C	Single Valued		
Total Project Life	10	*Years*	Single Valued		
Plant Capacity Factor	0.98	*fraction*	Single Valued		
Reservoir Area	0.13	kilometers²	Triangular	0.08	0.14
Reservoir Thickness	457	meter	Triangular	400	500
Porosity	0.02	*fraction*	Triangular	0.01	0.03
Reservoir Volumetric Specific Heat	2517.5	KJ/m³ deg °C	Constant	2300	2600
Average Reservoir Temperature	193	deg °C	Triangular	190	210
Fraction of Reservoir Volume Containinga Steam Zone	0	*fraction*	Single Valued		
Average Steam Saturation in the Steam Zone	0	*saturation*	Single Valued		
Heat Recovery Factor	0.3	*fraction*	Constant	0.1	0.4
Utilization Factor	0.55	*NA*	Fixed / BYPASS		

Figure 9: Input parameters for Monte Carlo volumetric heat-in-place

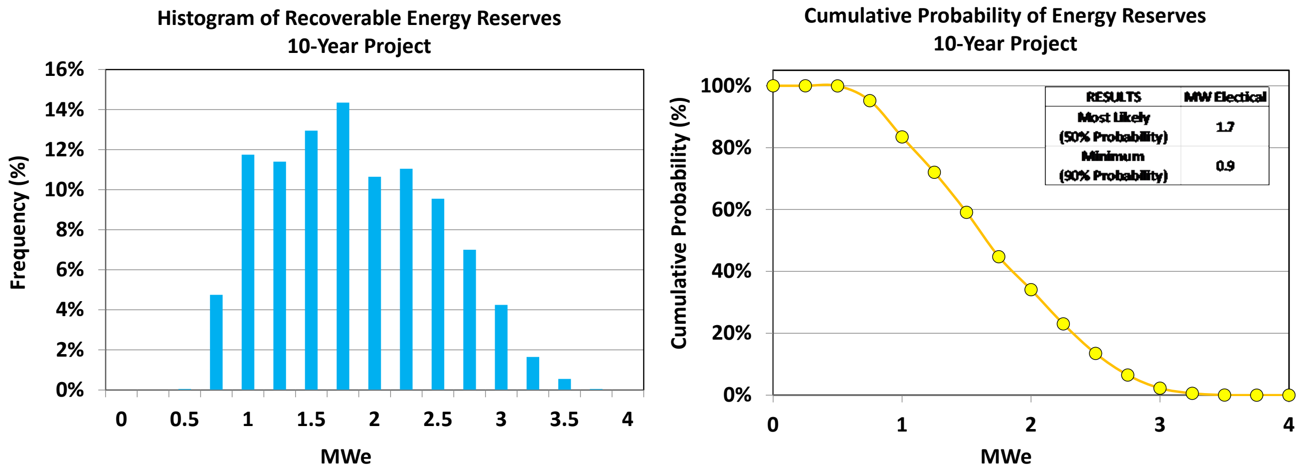

Figure 10: Output parameters for Monte Carlo volumetric heat-in-place of the as-is FORGE EGS fracture network.

7. CONCLUSIONS

The FORGE demonstration project has achieved impressive technical successes in the, now rapidly, advancing development of EGS geothermal. By the range of outcomes in the various stages of fracking, FORGE has shown which techniques and operations deliver better results. While it is understood that FORGE is a research-oriented demonstration project, as opposed to a commercial development project, FORGE has provided enough data for the industry to consider the implications of their findings in extending EGS to large-scale, economically profitable, private sector commercial electricity generation.

It is not known if it is mechanically feasible to re-enter and perform further fracking operations on wells 16A(78)-32 and 16B(78)-32. Hypothetically, however, it appears plausible that if 16A(78)-32 and 16B(78)-32 were fractured with stages along their entire deviated lengths, that the flow rate could be tripled from the tested rates in the circulation test. This doublet would potentially produce sufficient fluid for 5.1 Mwe,net (3x1.7 Mwe,net) electricity generation. Beyond this, there is possible additional upside by drilling longer laterals, allowing more stages and more flow rate. However, it is important to note that these calculations only address a potential project's *startup* generation and not the longevity of the production enthalpy.

In ramping EGS doublets to commercial, economically viable developments, longevity of reserves could be addressed by one of several approaches: (1) develop doublets with close well spacing and operate them at a lower than maximum flow rate, one that delays thermal breakthrough, or reduces it to a tolerable level, (2) develop doublets with close well spacing to deliver higher flow rates, operate them at higher flow rates such that depletes heat before the end of project's power purchase agreement timeline, and plan for makeup wells or drill "extra" wells in advance, (3) develop doublets with larger well spacing enough to provide desired longevity, and operate them at maximum flow rate.

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