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Project Update: Analysis of Two Sequential Near-Field Well Stimulations at Two Operating Geothermal Fields in Nevada

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ABSTRACT

The *goal* of this ongoing Department of Energy (DOE)-funded Ormat-GeothermEx Wells of Opportunity Project is to use stimulation techniques, guided by geomechanical modeling and analytical methods, to sequentially stimulate two existing wells with long open-hole sections at two operating fields in Nevada. These stimulations have the potential generation impact of up to several MWs at each facility. This project is currently in Budget Period 1 (BP1), with an anticipated completion date of August 2025.

Comparative analysis, the results of which will be described during BP2 and BP3, will be used to assess the effectiveness of hydraulic stimulations in different geologic and reservoir management environments, thus a) providing opportunities to adapt and improve methods sequentially from one stimulation to the next, b) providing useful and comprehensive information to the geothermal community about stimulation modeling, methods, costs and results and c) identifying synergies associated with a "stimulation portfolio" approach.

Here we provide an update on BP1 activities and the status of the project team's ongoing efforts to: 1) use all available data to design, forward model, and plan the stimulations; 2) prepare robust designs for stimulation that take advantage of synergies between the 2 proposed wells (for the stimulations to be conducted in BP2); 3) leverage the use of existing technologies, guided by techno-economic analysis (TEA), for stimulation and zonal isolation; and 4) develop geomechanical models and analytical methods to predict and constrain the results of stimulation at a reasonable level of accuracy (as will continue to be vetted and calibrated by hydraulic testing, microseismic and ground deformation data during the stimulations).

The project seeks overall to address some of the remaining barriers to the widespread development of geothermal power from enhanced geothermal systems (EGS) (in this case for existing geothermal wells with long open-hole sections, including improving our understanding of why stimulations succeed or fail in a variety of subsurface conditions and implementing and testing well stimulation techniques and zonal isolation methods), thus increasing the willingness of the geothermal industry to adopt and routinely use EGS well stimulation techniques on a commercial basis.

1. INTRODUCTION

The project plan is to sequentially stimulate two wells at two operating fields in Nevada. These stimulations have the potential generation impact of up to several MWs at each facility. Figure 1 illustrates the project locations in Nevada. Project and well details are summarized as follows:

- Don A. Campbell (DAC) Project, Idle Well 68-1RD (Figure 2). The 30-MWe DAC project (in Mineral County) has been operating since 2013. The target EGS well was initially used for injection, but was shut in soon thereafter because of injection breakthrough. The well was then re-drilled into a deeper section of volcanic rock and encountered an attractive temperature (280°F) but with low permeability. The intention is to stimulate well 68-1RD (current injectivity is 3 gpm/psi), and use it for production. In its current condition, with external swell packers previously installed to isolate the deepest section, this well is ready for below-formation hydrofrac pressure stimulation (i.e., hydroshear).

- Jersey Valley (JV) Project, Injection Well 14-34 (Figure 3). The 8-MWe JV project (in Pershing County) has operated since 2010 with two active production wells and four active injection wells. While the production wells have moderate to high permeability, injection must be placed in low permeability zones to achieve adequate heat sweep. Injection well 14-34 (~260-275°F) is the poorest performer, with an injectivity of less than 1 gpm/psi. With a swell packer already installed to isolate the deepest section, this well is ready for hydroshear stimulation, aiming to connect the well to the range-front fault system to maximize heat sweep in a reservoir with temperatures greater than 300°F, to reduce injection pressures (and the associated parasitic pumping power requirement) and increase power output capacity (the project is injection-limited at present).

Initially, stimulation of a third well (at a third project) was contemplated as part of this project. However, initial techno-economic analysis (TEA) results indicated well readiness and stimulation costs to be higher than first estimated at the time of the project award in 2020. Therefore, the project team has made an informed decision to reduce the scope of the study from three wells to two for stimulation activities.

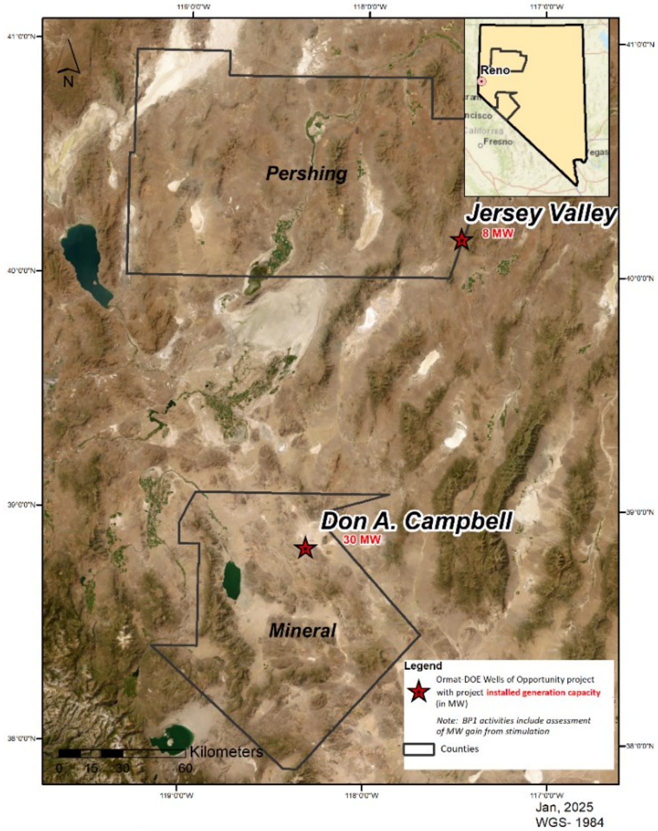

Figure 1: Wells of Opportunity project locations in Nevada (after Ormat and GeothermEx).

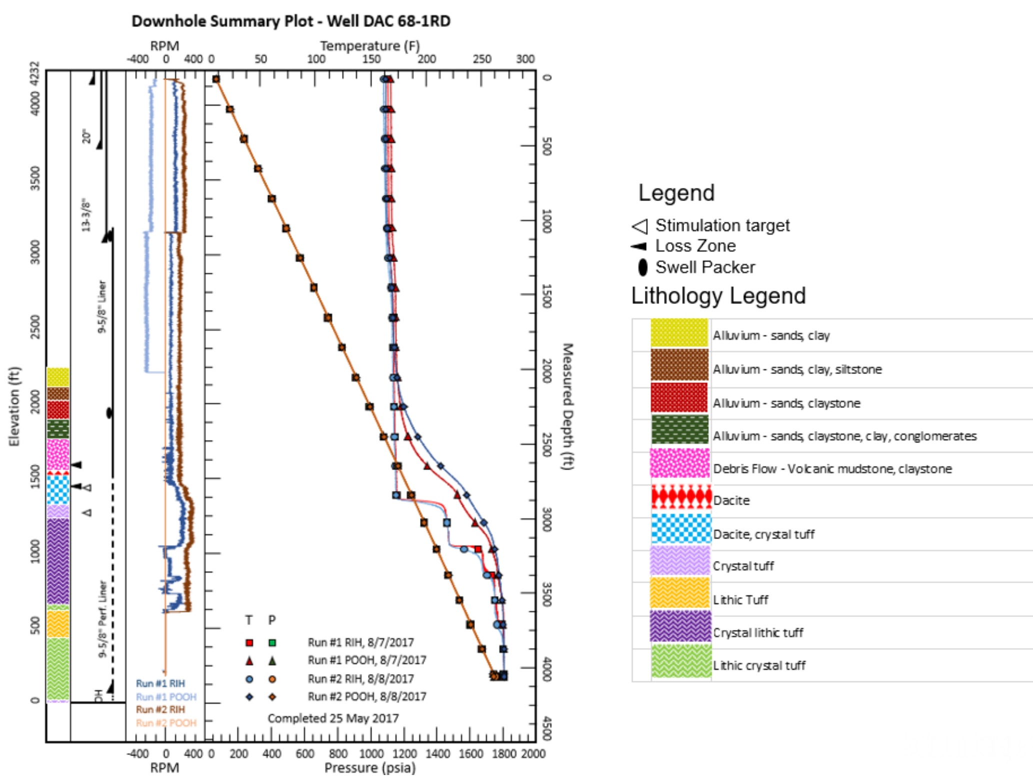

Figure 2: Downhole summary plot for DAC Well 68-1RD, illustrating well completion, pressure-temperature-spinner (PTS) logs, lithologies, and main stimulation targets (after Ormat and GeothermEx).

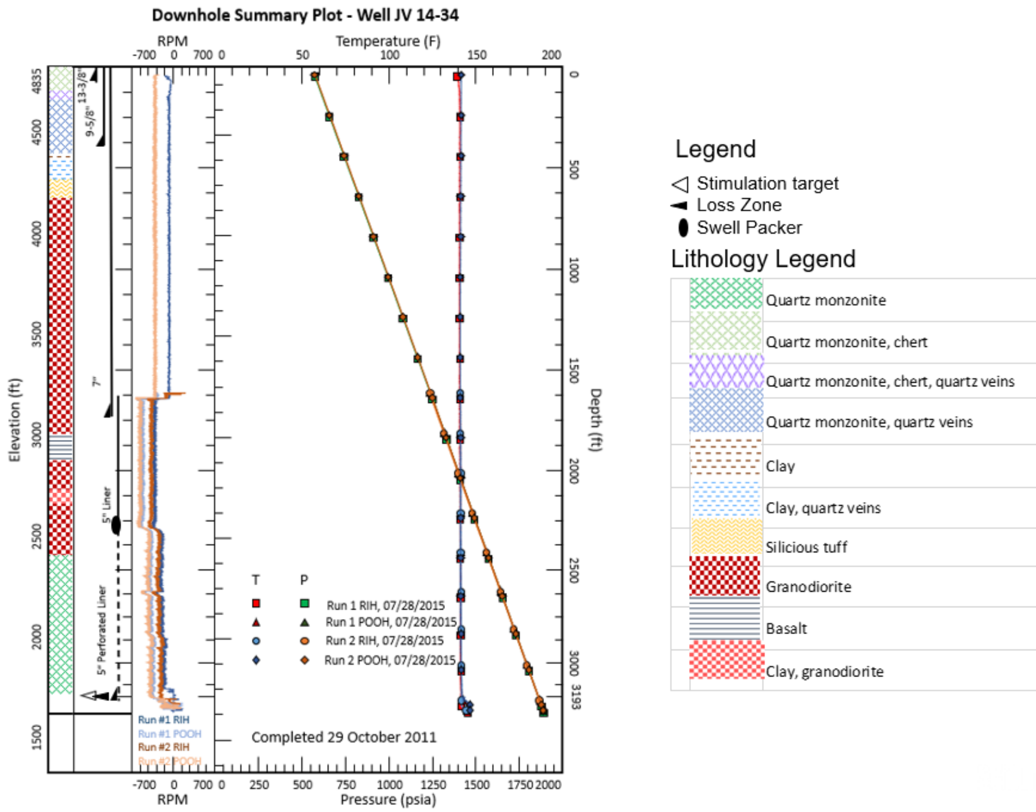

Figure 3: Downhole summary plot for JV Well 14-34, illustrating well completion, PTS logs, lithologies, and main stimulation targets (after Ormat and GeothermEx).

We anticipate that the duration of this project will be approximately three years, though we have identified during Budget Period 1 (BP1) activities that data collection activities, iterative stimulation planning and costing, and logistical coordination have extended the BP1 timeline. The project's critical path is currently: geophysical log data collection, geomechanical and stimulation effectiveness modeling, iterative stimulation planning and costing, and TEA.

2. BUDGET PERIOD 1 ONGOING ACTIVITIES

Gathering existing well data for the DAC 68-1RD and JV 14-34 wells is now complete. Based on the collected data sets, key data gaps have been identified to prepare a geomechanical model for the DAC and JV sites. These data gaps will be filled mainly by collecting selected geophysical logs and PTS logs, and testing existing core and cuttings for rock mechanics parameters and mineralogy. The timing for conducting minifrac/mechanical integrity testing before a proposed hydrofrac stimulation is not yet planned but is anticipated to occur near the beginning of BP2 and in accordance with stimulation activities described below.

The results of high-resolution PTS logs, geophysical logs, laboratory testing of core and cuttings, and their applications to stimulation planning and geomechanical modeling, will be described in upcoming papers authored by the project team.

Modeling platforms and workflows that will be applied to the DAC 68-1RD and JV 14-34 wells for geomechanical modeling have been selected, considering technical limitations/abilities and software compatibilities. Similar applications were recently described in a paper by Khan et al. (2024). During BP1 activities, the geomechanical models are the foundation for hydrofrac stimulation effectiveness modeling; these models will inform the design process to optimize stimulation and zonal isolation methods.

Geomechanical and stimulation effectiveness modeling will be described in upcoming papers authored by the project team.

A TEA to compare hydrofrac versus hydroshear stimulation methods for each well is under development, and will be considered a living document throughout later project stages. Geomechanical modeling results and stimulation costing efforts will inform the TEA. The perceived technical advantages and limitations of each stimulation method will continue to be assessed for each well as data collection and modeling progress and as well-specific risks are evaluated. The TEA will form the basis for the final decision in BP1 about the stimulation method to be used for each well.

The stimulation effectiveness modeling results and TEA that will be presented in BP1, along with the proposed BP2 (stimulation and short-term testing) and BP3 (long-term testing and monitoring) activities, will be described in upcoming papers authored by the project team.

Also described will be the project team's efforts for streamlining the permitting process for stimulation of wells on public lands and preparing induced seismicity mitigation plans (ISMPs) for different projects in a similar seismo-tectonic regime.

Lawrence Berkeley National Laboratory (LBNL) and Sandia National Laboratories (Sandia), with support from Lettis Consultants International Inc. (Lettis), are installing seismic monitoring arrays around the DAC and JV wells, while also preparing the ISMP. Installations at the DAC site are complete, and data collection is ongoing. Installations at the JV site, including permitting and logistical planning, are proceeding.

2. PLANNED STIMULATION ACTIVITIES

2.1 Hydroshearing and/or Hydrofracturing

A hydrofracturing (i.e., hydrofrac) stimulation, as first designed for use in the hydrocarbon industry, involves pumping at rates and pressures high enough to exceed the minimum horizontal principal stress, resulting mainly in tensile failure of the rock and fracture propagation. Sand or particulate matter (i.e., proppant) is typically injected with the fracturing fluid during treatment. When the treatment stops and fracturing pressure transient declines, the fracture closes. The proppant remains in the fractures and facilitates their retaining transmissivity after the pumping. Hydraulic fractures are anticipated to propagate perpendicular to the local minimum principal stress (often horizontal, as is the case for the DAC and JV project areas). Therefore, in highly vertical wells, newly formed fractures will form axially along the wellbore (Shiozawa and McClure, 2014; Khan et al. 2023).

There are multiple previous examples of applying hydrofracturing in vertical geothermal wells initially completed with long open-hole sections (e.g., the Department of Energy [DOE]-funded Desert Peak EGS project; Chabora et al., 2012) and multiple recent examples of applying multi-stage stimulation hydrofracturing techniques in highly-deviated to horizontal wells with cased-and-cemented completions (e.g., Fervo Energy's Project Cape Modern and the DOE-funded Utah FORGE project; Fercho et al., 2024; Xing et al., 2024, respectively).

A hydroshear stimulation is injection-induced shear activation of pre-existing fractures in a reservoir. During hydroshear stimulation, water is injected at a pressure below or close to (but not exceeding) the minimum principal stress in the reservoir (Evans et al., 2005; Cladouhos et al., 2016). Water injection decreases the effective normal stress on the fractures, resulting in the shear-slip of fractures optimally oriented for shear failure in the reservoir. As these critically stressed fractures slip, the fractures open due to the increase in fluid pressure at a constant rate and the self-propping of asperities, which is intended to result in irreversible permeability enhancement of the reservoir. In addition to fracture opening, new tensile wing fractures may be created at the fracture tip, which combines with other pre-existing fractures to propagate a fracture network during reservoir stimulation (Cladouhos et al., 2016). Depending on orientation, cohesive strength (or frictional resistance), and local strength of pre-existing fractures in the reservoir, fracture networks are formed by opening, closing or shearing of pre-existing fractures (Cladouhos et al., 2016).

The project team has previous experience achieving an initial injectivity increase of ~50% while utilizing hydroshear methods, with about 5% improvement per day on average while maintaining constant wellhead pressure (over approximately 10 days of sustained pumping). Elsewhere, though in most cases not conducting sustained injection, case examples are described of hydroshear injectivity improvement (that resulted in ~2x to orders of magnitude injectivity improvements, though starting with exceedingly low injectivities): Tulinius et al. (1996); Zimmerman et al. (2010); Pasikki et al. (2014); Park et al. (2017). This project team also acknowledges that there continues to be limited evidence to support 1) that shear-stimulating natural fractures can be modeled reliably in advance to represent the benefits of this activity, due to the high number of uncertainties with subsurface geology and 2) that hydroshear stimulations themselves yield adequate and sustained reservoir improvement (Norbeck et al., 2018; McClure et al., 2022; McClure, 2024).

Because of significantly different stimulation equipment requirements and job timelines, the project team has identified that each candidate well will be stimulated by either a hydrofrac operation or a hydroshear operation, but would not utilize both stimulation methods, which would have significant cost implications. The perceived benefits of conducting a hydrofrac operation on the DAC 68-1RD well and/or JV 14-34 well are: 1) the support of geomechanical and stimulation effectiveness modeling for job design; 2) the job's shorter number of days (compared to a hydroshear that would include weeks of constant pumping); 3) the "full service" availability of a hydrofrac operation; and 4) the perception that a hydrofrac will yield a more successful outcome, in comparison to a hydroshear (for the reasons described above). However, a hydrofrac operation on an existing well with a long open-hole section, even for a well with installed swell packers, presents an elevated risk of causing cemented casing shoe damage.

In comparison, a perceived benefit of conducting a hydroshear is the ability to implement the stimulation as a bullhead treatment into the DAC 68-1RD and JV 13-34 wells with their existing completions, at lower perceived risk of causing cemented casing shoe damage, although the risk of casing shoe damage is not completely eliminated by electing to perform a hydroshear. A perceived risk of the hydroshear operation is the inability to model stimulation effectiveness with confidence, in advance of the stimulation; this emphasizes a reliance on project analogs and a 'learn as we go' analytical approach and decision logic during the stimulation itself.

2.2 Well Intervention

Potential damage to the cemented casing shoe of these wells, mainly as is perceived to occur as the result of a hydrofrac, is considered a significant risk with implications that may include regulatory requirements for remediation. Monitoring and potentially preventive workover activities are needed to ensure this does not occur. Implications of fracturing at the cemented casing shoe could include:

1. Unintended fracture propagation initiated at the casing shoe.
2. Loss of cement integrity and zonal isolation, allowing fluid migration during injection to shallower formations.

3. Producing geothermal fluids from other formations that are too cool to support project objectives (if the well is used as a producer).
4. Casing shear deformation or bursting.
5. Costly regulatory remediation; environmental and safety risks.

It is presently contemplated that a hydroshear would be bullheaded and would not require well recompletion before stimulation. However, a hydrofrac operation is envisioned to require well recompletion before inducing injection pressures that exceed the fracture gradient below the swell packers in the DAC 68-1RD and/or JV 14-34 wells. Alternatively, a hydrofrac could be attempted in either well without intervention, but the likelihood of short-circuiting through the formation around the swell packers, resulting in exceeding hydrofracturing pressure at the casing shoe, appears high, likely resulting in early shutdown of the stimulation. Figure 4 illustrates the proposed well interventions for the DAC 68-1RD and JV 14-34 wells.

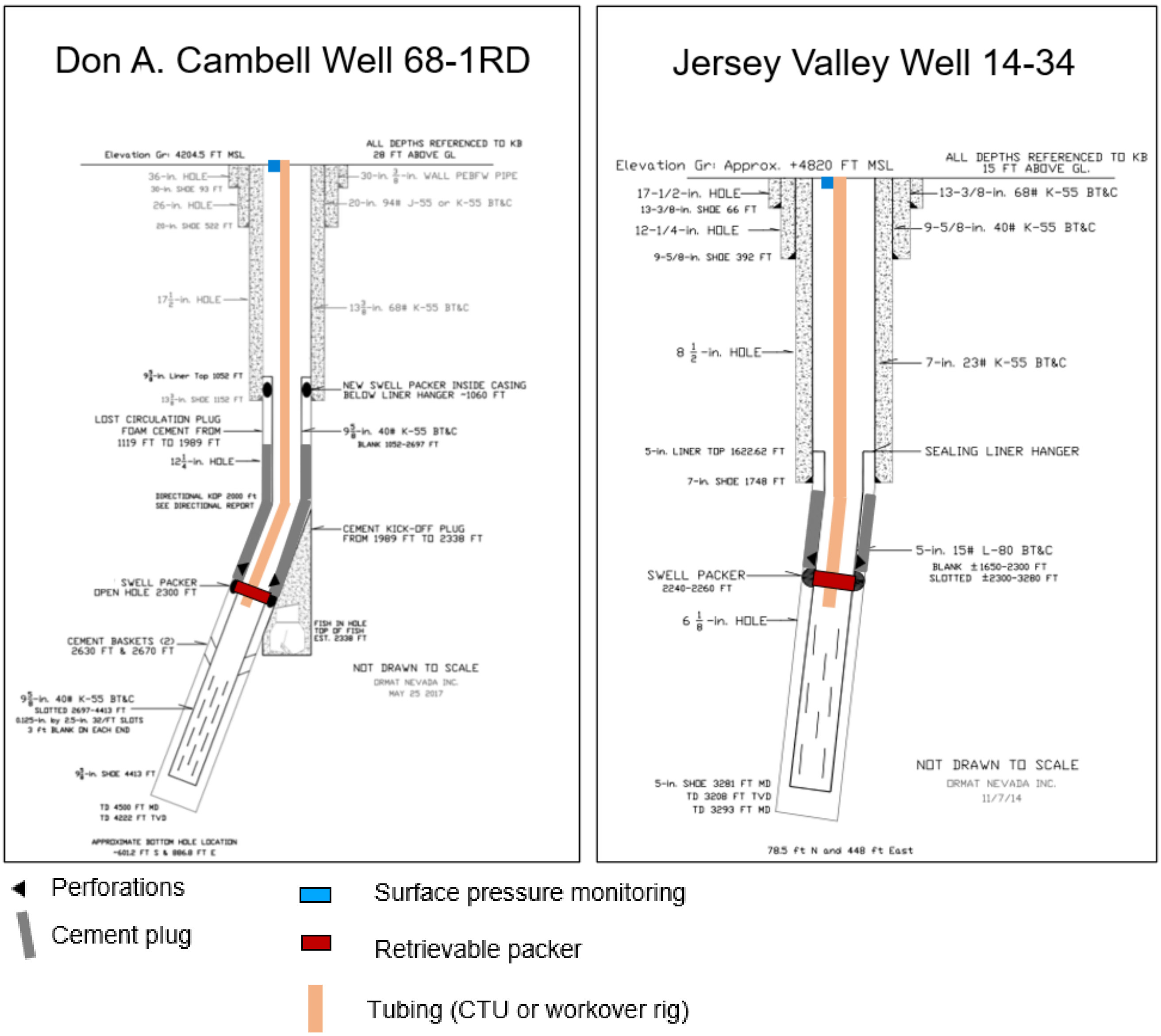

Figure 4: Recompletion concepts for DAC Well 68-1RD and JV Well 14-34 in support of hydrofrac activities (after Ormat and GeothermEx).

The recompletion strategies for the DAC 68-1RD and JV 14-34 wells would be similar and would involve a single intervention with a coil tubing unit (CTU) to perforate above the swell packer. A cement plug would then be placed in the annulus above the existing swell packer. The cement plug would be compatible with the acids that may be pumped during the stimulation. Also, the height of the cement plug, planned for a few hundred feet, should provide a competent barrier to withstand the stimulation pressures. This intervention would be tested by a minifrac. The stimulation treatment would then take place by pumping through the tubing (run through a retrievable packer set at the swell packer's depth) to protect the cemented casing shoe.

2.3 Novel Technologies

This project aims to conduct a detailed evaluation of two to three novel technologies for zonal targeting, stimulation and monitoring. The project team activities during BP1 have identified the following technology opportunities that will be utilized for planning, execution, and monitoring of the stimulations:

- Hydrofrac stimulation effectiveness modeling and optimization using 3D geomechanical modeling software, with workflows as described in Khan et al. (2024) for the Utah FORGE project.

- During hydrofrac or hydroshear treatment, the introduction of SLB's multimodal degradable particulate + fiber diverters through the open-hole liner, to redirect stimulation fluid from a primary stimulation zone to one or more secondary zones, including in support of acidizing. These products are optimized for a wide temperature spectrum by modifying the polymer structure. Diverter materials are degradable and designed to leave behind no wellbore or formation damage after the job. The diverter's degradation rate is largely based on temperature, but fluid composition can also affect the product. These diverters are known to withstand pressures up to 5,600 psi for plugging applications (Alabdulmuhsin et al., 2020).

- Hydrofrac or hydroshear operations are planned to include acidizing, which will be introduced during pumping. The results of mineralogy analysis during BP1 will be used for the acid system formulation and volumetrics design.

- During a hydroshear operation, the project team would consistently carry out PTS logging to evaluate wellbore changes as the hydroshear proceeds. However, during a hydrofrac operation, PTS logging has an apparently greater risk of tool damage or loss. Therefore, to provide wellbore monitoring during a hydrofrac from surface, the usefulness of distributed temperature sensor (DTS) fiber optic line is being considered, which would be suspended in the wellbore for the duration of the hydrofrac activities.

2. STIMULATION OPTIONS

As described above, a hydroshear and/or a hydrofrac of two wells (the DAC 68-1RD and JV 14-34 wells) is being planned. Project limitations will prevent the implementation of both stimulation methods on each well. The contemplated hydrofrac activities for the DAC project are illustrated in Figure 5. This plan assumes a fracture gradient = 0.7 psi/ft and a bullheaded stimulation; program design for a through-tubing application (as described above) is underway.

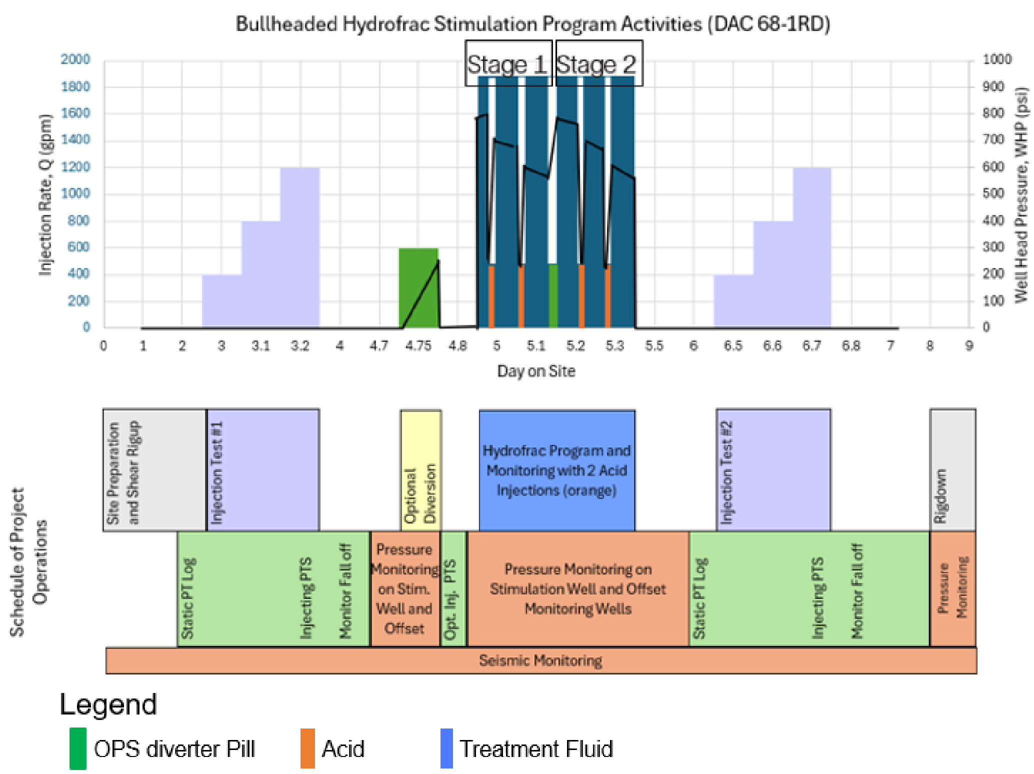

Figure 5: DAC 68-1RD bullheaded hydrofrac schedule (after Ormat and GeothermEx).

An injection test would precede the hydrofrac. The hydrofrac operation will be undertaken with continuous pumping, with the two stages separated by a diverter pill (green boxes in the plot above). Currently, it is not planned to pump proppant since this well is planned for production. Therefore, periodic slugs of acid will be pumped during each stage of the treatment (shown as orange bars in the plot) to dissolve fracture-filling material, and develop open pathways that would remain after the fractures close. The hydrofrac program itself should take only a few hours. When finished, if DTS is not used, a static PTS survey will be run, which will then be followed by a second injection test (using the same injection rates as the first one). After monitoring pressure fall-off for 24 hours, the equipment will be rigged down.

The contemplated hydroshear activities for the DAC project are illustrated on Figure 6 and consist of coordinated monitoring, testing, and hydroshear operations that will result in a sustained 375 psi wellhead pressure for the duration of the hydroshear phase. A fracture gradient range of 0.7-1 psi/ft has been assumed (that a minifrac test will be used to better determine at the start of BP2). A minimum 4-5% average increase per day in well injectivity will be required during the hydroshear shown on Figure 6 to reach the target injectivity of 10 gpm/psi, based on the current injectivity of the well (3 gpm/psi). This hydroshear program is considered logistically complex (in comparison to the use of a “full service” hydrofrac fleet), as it will require sequentially bringing online (and running simultaneously for the duration of the hydroshear) multiple centrifugal and/or positive displacement pumps to achieve and maintain a target final flow rate of 3,600 gpm. The available brine from the DAC and/or JV plants will support the targeted injection rates. During these activities, if the hydroshear shows inadequate progress, project decision logic will indicate that pumping would shut down earlier than indicated by Figure 6.

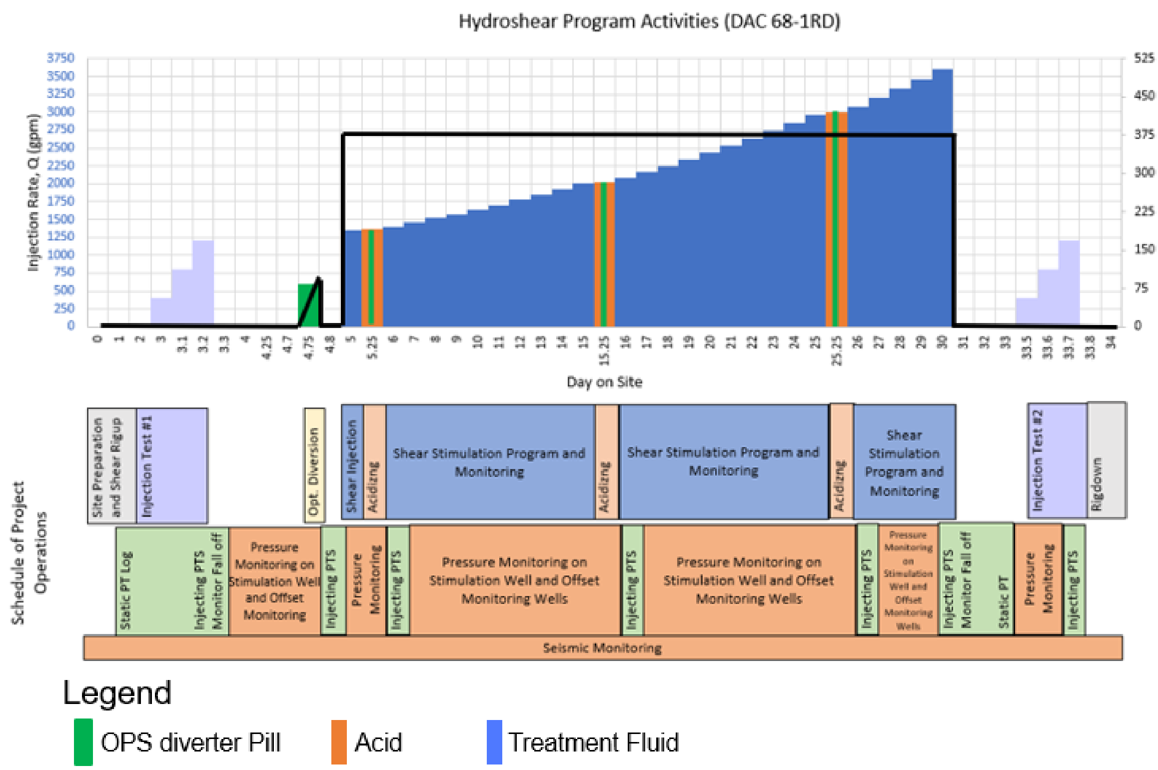

Figure 6: DAC 68-1RD bullheaded hydroshear schedule (after Ormat and GeothermEx).

2. CONCLUSIONS

The goal of this ongoing DOE-funded Ormat-GeothermEx Wells of Opportunity Project is to use stimulation techniques, guided by geomechanical modeling and an analytical approach, to sequentially stimulate two existing wells with long open-hole sections at the Don A. Campbell and Jersey Valley geothermal fields in Nevada. These stimulations have the potential generation impact of up to several MWs at each facility. This project is currently in BP1, with an anticipated completion date of August 2025.

The overall project seeks to address some of the remaining barriers to the widespread development of geothermal power from EGS. In this case for existing geothermal wells with long open-hole sections, including improving our understanding of why stimulations succeed or fail in a variety of subsurface conditions. Additionally, it aims to implement and test sequential well stimulation techniques and zonal isolation methods, thus increasing the willingness of the geothermal industry to adopt and routinely use EGS well stimulation techniques on a commercial basis.

The perceived benefits of conducting a hydrofrac operation on the DAC 68-1RD well and/or JV 14-34 well are: 1) the support of geomechanical and stimulation effectiveness modeling for job design; 2) the job’s shorter duration of days (compared to a hydroshear that is planned to include up to several weeks of constant pumping); 3) the “full service” availability of a hydrofrac operation; and 4) the perception that a hydrofrac will yield a more successful outcome, in comparison to a hydroshear (for the reasons described herein). However, a hydrofrac operation on an existing well with a long open-hole section, even for a well with installed swell packers, presents an elevated risk of causing cemented casing shoe damage. In comparison, a perceived benefit of conducting a hydroshear is the ability to implement the stimulation as a bullhead treatment into the DAC 68-1RD and JV 14-34 wells with their existing completions at a lower perceived risk of causing cemented casing shoe damage, although the risk of casing shoe damage is not completely eliminated by electing to perform a hydroshear. A perceived risk of the hydroshear operation is the inability to model stimulation effectiveness with confidence, in advance of the stimulation, which emphasizes a reliance on project analogs and a 'learn as we go' analytical approach and decision logic during the stimulation itself.

A TEA to compare hydrofrac versus hydroshear stimulation methods for each well is under development and will be considered a living document throughout later project stages. Geomechanical modeling results and stimulation costing efforts will inform the TEA. Each stimulation method's perceived technical advantages and limitations will continue to be assessed for each well as data collection and modeling progress, and well-specific risks are evaluated. The TEA will form the basis for the final decision in BP1 about the stimulation method to be used for each well. The TEA that will be presented in BP1, along with the proposed BP2 (stimulation and short-term testing) and BP3 (long-term testing and monitoring) activities, will be described in upcoming papers authored by the project team.

ACKNOWLEDGMENTS

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