In-Reservoir Energy Storage for Flexible Operation of Geothermal Systems

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Keywords

Geothermal, Flexibility, Storage, Deep, EGS, Variable, VRE, Baseload, Load-following

ABSTRACT

Geothermal power plants are almost exclusively operated as "baseload" power, generating at their maximum rated output at all times. However, as variable renewable energy sources see greater deployment in energy markets, baseload is becoming increasingly less competitive relative to flexible, dispatchable generation. Herein, we employ reservoir simulations and optimization modeling to investigate the potential for EGS power plants to adapt to this new market paradigm by providing flexible generation and energy storage services. A novel geothermal system design is considered whereby energy is stored as pressure within an engineered geothermal reservoir, and is used to drive greater production flow than would otherwise be achievable during periods of high electricity demand. Based on multi-physics reservoir simulations, we develop a linear optimization model that captures the transient pressure and flow behaviors within the geothermal reservoir. We use this model to optimize the investment decisions and hourly operations of a first-of-a-kind flexible geothermal plant against a set of historical and modeled future electricity price series. We find that operational flexibility and energy storage can provide significant benefits for a geothermal plant in a market with high electricity price volatility, with revenue improvements of 4%-52% compared to a baseload plant operating on the same price series. Surface generating facilities are oversized by up to 41% in order to take advantage of the greater flow rates provided by reservoir pressurization. Sensitivity analysis assesses the variation in outcomes across a range of subsurface conditions and cost scenarios.

1. Introduction

Conventional geothermal power is a geographically limited resource, confined to a select set of sites at which naturally-occurring hydrothermal reservoirs may be exploited for energy extraction. Enhanced (or Engineered) Geothermal Systems (EGS), which can be deployed in subsurface formations lacking natural permeability, have been proposed as a solution to the problem of limited geothermal resource availability (INL, 2006). Relatively shallow EGS resources underlie much of the western United States, and successful development of EGS technology could unlock hundreds to thousands of gigawatts of geothermal resource potential nationwide, with up to 120 GW deployable by 2050 (Williams et al., 2008, Augustine, 2017, DOE, 2019). In such a scenario, geothermal power would be a major contributor to the nation's energy supply.

Even with such significant resource and deployment potential, the economic outlook for geothermal power is unclear in a rapidly evolving electricity market. Geothermal plants typically operate as "baseload" power, generating at their maximum rated capacity at all times (Matek, 2015). This has historically been a viable operating strategy, but shifting electricity market conditions are eroding the economic value of baseload power relative to more flexible alternatives. As electricity systems move toward complete decarbonization, it is generally accepted that variable renewable energy sources (VREs) will supply an increasingly significant share of total generation (Jafari et al., 2020, Larson et al., 2020, Williams et al., 2021). However, increased VRE penetration in electricity markets drives greater volatility in net load and electricity prices (Denholm et al., 2015), can lead to overgeneration (Jafari et al., 2020), and has been associated with negative pricing episodes of increased length and severity (Mills et al., 2020). Under such conditions, increased system flexibility is necessary in order to maintain supply-demand balance in the grid, limiting the system value inflexible baseload resources (Lund et al., 2015, Denholm and Hand, 2011, Kondziella and Bruckner, 2016, Mai et al., 2014, Palmintier and Webster, 2016, Jones, 2017, Bloom et al., 2016, Jenkins et al., 2018). From an economic perspective, fast-ramping generators with low fixed costs, which can save money by only generating when electricity prices are high, and energy storage devices that can shift energy to valuable periods can have a competitive advantage over baseload generators in a grid with significant VRE penetration.

While many geothermal plants are capable of operating with a high degree of flexibility, their high fixed operating costs and near-zero variable costs limit the economic value of flexible operations. Plants designed with flexibility in mind, particularly binary-cycle plants, can ramp efficiently between 10% and 100% output at rates of up to 30% nominal power per minute (Linvill et al., 2013), Some binary plants today take advantage of this high degree of flexibility to provide ancillary services to the grid (Matek, 2015), but the economic benefits are limited because reducing production does not reduce operating costs for geothermal facilities (as it does for fossil fueled power plants) and because demand for ancillary services is limited and can quickly saturate. Another strategy through which geothermal plants can take advantage of flexibility is to ramp down production during periods of negative electricity prices, thereby avoiding losses. Millstein et al. (2020) optimized geothermal plant operations against historical real-time electricity price series and found that binary-cycle plants in the U.S. could improve their energy value (measured as the average price of electricity per unit geothermal generation) by an average of 5.5% by operating in this manner. Beyond simple curtailment, Goyal (2002) found that flash steam plants could experience short periods of flush production after shut-in events, but that these "puffs" only recovered around 15% of curtailed production.

While conventional geothermal plants are therefore limited in their ability to extract additional value from flexible operations, appropriately designed binary-cycle EGS plants have the potential to derive much greater benefits. Unlike hydrothermal reservoirs, which are open systems allowing relatively free flow of geofluid, EGS reservoirs created in low permeability formations are characterized first and foremost by their confined nature (Brown et al., 2012). The rock matrix surrounding an EGS reservoir has much lower permeability than the engineered reservoir itself, limiting the flow of fluid into and out of the system. Experiments at the Fenton Hill EGS test site in 1993 and 1995 revealed that this property could be exploited to enable a novel form of in-reservoir energy storage. By reducing flow rate from the production well while maintaining injection rate, operators were able to boost the pressure in the reservoir, which could subsequently be used to drive elevated production flow for an extended period (Brown et al., 2012). These “load-following” experiments were the first to demonstrate the potential for enhanced geothermal to store energy, efficiently shifting its output from one time to another.

In this work, we employ reservoir simulations and plant-level optimization modeling to assess the impact of this mode of in-reservoir energy storage on the economic value of a single EGS power plant. We present a linear optimization model capturing the transient pressure and flow behaviors within an EGS reservoir, and use this model to co-optimize plant investments and operations against both historical and modeled future electricity price series. We further characterize the revenue enhancement potential of a flexible geothermal power plant and assess the sensitivity of results to variations in critical uncertain parameters.

2. Methods

2.1. Representative Plant Design

EGS is an emerging technology, and most proposed plans for its commercialization hinge on using early “near-field” projects to accelerate technological learning (DOE, 2019). These projects would target the hot but low-permeability formations surrounding known hydrothermal sites, where minimal exploration and drilling is necessary for development. Sufficient cost reductions in these early phases could enable the economical development of “deep EGS” resources, those at depths of 3 km or more located in low-permeability formations (Latimer and Meier, 2017). It is this deep resource that represents the vast majority of geothermal potential worldwide (DOE, 2019). In this work we focus on the transitional point in this approach, considering an EGS plant mining a 218 $^{\circ}$C low-permeability geothermal resource at a depth of 3 km. We use this representative case to analyze the impact of flexibility and energy storage on the economics of early EGS projects.

In this work we consider a triplet well design similar to those discussed in Gringarten et al. (1975), Olson et al. (2015), Li et al. (2016), and others. An injection well is drilled to the target depth and deviated to produce a 1.5 km horizontal section. Hydraulic stimulation is used to create regularly-spaced vertical fractures along this interval, and two production wells are drilled in parallel and at opposite orientation to the injection well, intersecting these fractures and creating a long horizontal reservoir. The configuration assessed in this paper is designed to produce 10.1 MW of electric power per well triplet. In the base case, we model 100 vertical fractures with an individual fracture conductivity of 4.5×10^{-12} m^3. The rock matrix surrounding the engineered reservoir is assumed to have a permeability of 9.9×10^{-19} m^2, representative of the hot, low-permeability formations that make up the majority of developable EGS resources worldwide. Recognizing the significant locational variation in subsurface characteristics across potential EGS sites worldwide, as well as uncertainties in technology costs and performance, we include a set of sensitivity cases covering the likely ranges of these parameters.

In the configuration described above, reservoir pressure alone is used to drive geofluid flow in the production wells. Produced fluid is run through a binary-cycle surface plant before being re-injected into the reservoir. The use of a binary-cycle surface plant allows for highly-flexible generation with no additional operational and maintenance costs (Matek, 2015). Under baseline financial assumptions, the cost of the surface plant is $1950/kW net, a figure which does not include the cost of production pumps (Adams and Schadle, 2020, Adams et al., 2021). The field gathering system is assigned a cost of $100/kW, and it is assumed that surface plant oversizing has a specific cost equal to 80% that of the base plant. We assume that interest equal to 6% of plant CAPEX is accumulated during a yearlong construction period, and that the plant has a weighted average cost of capital (WACC) of 5.5% over a 30-year lifetime. Additional O&M costs from oversizing are set at 1.8% of plant CAPEX, and taxes and insurance at 0.75% of plant CAPEX. Both of these figures are taken from the GETEM geothermal development simulator produced by NREL (Mines, 2016). The capital cost of geothermal interconnection is set at $130/kW, with a capital recovery period of 60 years and a WACC of 6.9%, as reported in Gorman et al. (2019). All financial information used in this paper is presented in 2019 $USD.

2.2. Modeling Approach

We employ a bottom-up approach to modeling the performance of a flexible geothermal plant, using multi-physics reservoir simulations to develop a linear optimization model, which is used to evaluate the economics of flexible operations. Reservoir simulations are done in ResFrac, a fully-coupled fluid flow, heat transfer, and geomechanics simulator that includes detailed calculations such as wellbore friction, perforation friction, fracture deformation and pressure response, fluid leakoff, and heat transfer (McClure and Kang, 2017). These simulations provide all of the information necessary for evaluation of reservoir performance under different operating conditions and strategies.

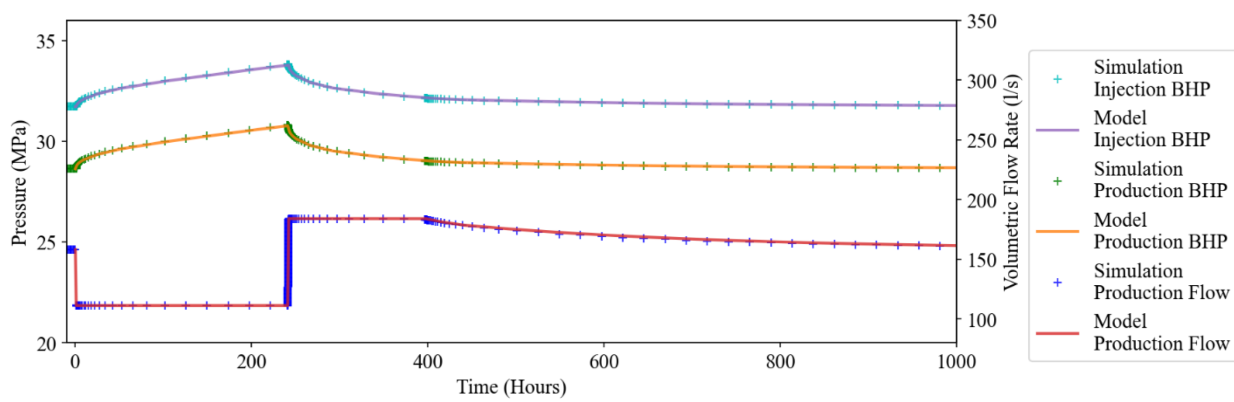

Figure 1: The numerical simulation and the LP optimization model executing an identical sequence of operational decisions. Injection rate is held constant, while production flow is partially shut in for a period of 240 hours, causing the injection and production well bottomhole pressures to rise. The production well is subsequently opened to allow up to a specified maximum flow rate, and both pressures and flow decline back to their steady-state values. Simulation results are shown as point data, while model results are shown as continuous data.

To allow for techno-economic optimization of plant investments and operations, we develop a secondary linear optimization model based on simulation results. We use numerical simulations to assess the transient pressure response at the injection and production well bottomholes to stepwise changes in injection and production rates. Piecewise linearization and subsequent linear superposition of this pressure response function allow us to capture the time-varying reservoir pressure response to variable pumping rates within a linear programming (LP) framework. The LP model also considers the dependence of production rate on reservoir pressure and variable parasitic load due to injection pumping. Fig. 1 illustrates the tight agreement between the simplified LP model and the multi-physics numerical simulation results, even during periods of variable flow rate.

2.3. Techno-Economic Optimization

The LP model introduced in Section 2.2 captures the effects of changes to production and injection rates at hourly timesteps. These two flow rates are the model's operational decision variables. Reductions to production rate (or increases to injection) lead to increased reservoir pressure. The production well bottomhole pressure (BHP) determines the maximum achievable production flow rate at each model timestep. The maximum usable production flow rate is further constrained by the generating capacity of the surface plant, and the size of the plant's grid interconnection. It is assumed for the purposes of this work that the binary organic Rankine cycle (ORC) surface plant can handle geofluid flow rates up to 10% above its design point with minimal loss of efficiency (Hu et al., 2015). Beyond this point, the surface facilities must be oversized (with respect to a plant designed for constant flow from the same reservoir) to take advantage of increased production flow. Surface plant and grid interconnection oversizing are the model's primary investment decisions, and are penalized in the objective function to reflect increased construction, maintenance and insurance costs. Due to the very high flexibility of ORC units, the model does not impose any hourly ramping or minimum generation constraints.

The optimization model takes an hourly electricity price series as input, and co-optimizes investment and hourly operational decisions to maximize plant revenue over a single weather year. Only investment costs corresponding to surface facilities oversizing are considered, and all costs associated with the reservoir, well field, and conventional surface facilities are considered sunk. The model thereby assesses only the relative costs and benefits associated with flexibility and energy storage, independent of the economics of the underlying plant. The use of a fixed electricity price series in this work assumes that the flexible geothermal plant in question operates as a price-taker, i.e. that it does not have enough market power to influence the price of electricity through its operational decisions. This is a good approximation of the conditions that would be experienced by the first flexible EGS plants to enter a regional electricity market.

In this work we optimize flexible geothermal investments and operations against eight historical and eight modeled future electricity price series. The historical series consist of real-time locational marginal price data for the year 2019 taken from seven grid nodes in the Western Interconnection and one in the Texas Interconnection, sourced from the CAISO OASIS tool (CAISO, 2021) and ERCOT's online market prices database, (ERCOT, 2021) respectively. The nodes in the Western Interconnection are located in states and regions with identified geothermal resources, and are intended to represent the range of possible electricity market conditions that might be encountered by an early flexible geothermal plant. The node from Texas is not located in an area with significant geothermal potential but is instead selected to represent an electricity market with high wind power penetration.

In addition to these historical price series, we also consider synthetic national price series for the year 2030 created using the GenX electricity system optimization model (Jenkins and Sepulveda, 2017). We consider 2030 as a target year for full commercial deployment of flexible EGS, and create eight price series for this year in GenX to reflect different potential market scenarios. These include a set of four series assuming various technology deployment and load scenarios but no policy changes, and an additional four considering the same scenarios under a national $60/ton carbon tax. Each set of four includes one baseline scenario, which represents the results of a simple capacity expansion optimization with no changes to base system inputs. The second scenario uses an alternate load profile peaking in winter, which is more representative of northeastern states under increased electrification. The third and fourth scenarios alter wind and solar input parameters to prioritize deployment of one of these resources over the other. Though these modeled price series are spatially unresolved, and do not capture the same level of volatility seen in real electricity markets, they allow us to evaluate the performance of flexible geothermal in systems with significantly higher VRE penetration than exists in most markets today. For example, the “high solar" and “high wind" carbon tax scenarios each see VREs making up just under 50% of installed generating capacity nationwide.

3. Results and Discussion

3.1. Base Case Results

Optimization results under baseline reservoir performance and plant costing assumptions for historical and modeled future price series are given in Table 1. All revenue and component-sizing results are presented with respect to the corresponding values for a baseload geothermal plant. The average hourly revenue per MW of net generating capacity for such a plant is equal to the average hourly price of electricity for each series. Relative improvement over this “baseload” average revenue from a curtailment-only operating strategy similar to that discussed in Millstein et al. (2020) is given for both sets of price series. This value represents the degree to which revenue could be improved if the plant completely curtailed generation during negative pricing episodes but did not store the lost energy. Revenue improvement from full flexibility represents the average hourly revenue earned by the same plant under flexible operations with in-reservoir energy storage, after subtracting the cost of any oversizing of surface facilities to accommodate flush production. The optimal degree of plant and interconnection oversizing for a fully flexible plant is given with respect to the sizes of these components in an inflexible baseload plant.

Optimization results for historical price series indicate that flexible operation and energy storage produce greater revenue than baseload operation in all cases, with a minimum relative revenue improvement of 7% and a maximum of 52%. The greatest level of improvement occurs at the southern California node, which represents an electricity market with the highest level of solar penetration in the United States (EIA, 2021). Significant improvement is also observed at the Arizona and Nevada nodes, as well as at the wind-heavy Texas node. In these markets, high VRE penetration drives greater electricity price variability, increasing flexible geothermal’s relative advantage over baseload by providing more opportunities for arbitrage via energy storage. Conversely, benefits from flexibility and energy storage are greatly reduced in locations with more stable electricity prices. The northern California node, for example, is located near The Geysers geothermal installation, where steady supply of baseload power leads to relatively stable electricity prices and reduces benefits from flexibility. Though simple curtailment can occasionally provide appreciable revenue improvements, improvements from full flexibility are at least 2.5 times as large in all cases, even taking into account the extra costs associated with surface facilities oversizing.

Results for modeled future price series indicate similar trends to those observed for historical price series. Flexibility and energy storage offer greater relative benefits in a market with a large carbon tax, which results in greater VRE deployment and higher marginal prices during periods of low VRE output. In cases without a carbon tax, revenue improvements are relatively consistent across the baseline, high solar and high wind cases. The high-VRE cases see a much larger relative improvement over the baseline when a carbon tax is also in place. With and without a carbon tax, revenue improvements are greater for the high wind case than for the high solar case. The “winter peaking” case sees very reduced benefits under both policy scenarios, but this case is also not very representative of the areas in the US with significant geothermal potential (DOE, 2019). Because the modeled price series used in this work reflect a perfectly-planned and operated system with minimal volatility, the relative benefits of flexibility in similar real-life systems are likely to be greater than those reported here.

Across all price series, optimal plant oversizing ranges from 0-41% of baseload plant capacity. The greatest levels of oversizing are observed for the historical Texas series and the future carbon tax scenarios. For the Texas series, oversizing allows for increased generation during short periods of extremely high prices. In the future carbon tax scenarios, it is likely that higher average electricity prices decrease the cost of plant oversizing relative to the benefits that can be extracted. Interconnection oversizing is more significant and consistent across all price series, due to much lower capital costs. Even if the surface plant itself is not expanded, oversizing the interconnection allows the installation to deliver more net power at certain times by reducing parasitic load from pumping. Given the variance in optimal component sizing across different electricity market conditions, geothermal developers should make efforts to forecast the evolution of a local electricity market over a flexible plant’s operational lifetime before beginning surface facilities construction. Doing so will minimize the risk of suboptimal plant and interconnection sizing. It is possible that in the case of an undersized plant, extra “peaking” turbines could be added later in its lifetime to enable greater flexibility.

Fig. 2 provides an example of optimal flexible geothermal plant operations in response to a variable electricity price series. As might be expected, the plant will tend to reduce output and increase injection pumping during times of very low electricity prices. These actions will cause reservoir pressure to rise. This pressure is then used to drive flush production during periods of high electricity prices, while the plant reduces its injection rate to further maximize net generation.

Table 1: Revenue and optimal investment results for historical and modeled future price series in the base case model

Price Series	Baseload Revenue ($/MWh Avg.)	Revenue Improvement, Curtailment Only (% of Baseload)	Revenue Improvement, Full Flexibility (% of Baseload)	Optimal Plant Oversizing (% of Baseload Plant Capacity)	Optimal Interconnection Oversizing (% of Baseload Interconnection Capacity)
2019 AZ	31.3	5	23	10	33
2019 N-CA	34.8	0	10	1	21
2019 S-CA	25.9	19	52	11	34
2019 ID	29.6	0	9	0	21
2019 NV	30.5	6	23	2	23
2019 OR	27.3	0	7	0	19
2019 TX	34.6	0	18	41	69
2019 UT	27.8	2	13	0	21
2030 BAU Baseline	29.6	2	17	5	24
2030 BAU Winter Peaking	29.4	0	4	0	17
2030 BAU High Solar	28.9	0	13	3	23
2030 BAU High Wind	32.2	1	18	6	27
2030 CO_2 Tax Baseline	49.3	0	16	16	39
2030 CO_2 Tax Winter Peaking	51.1	0	13	7	28
2030 CO_2 Tax High Solar	46.6	0	25	27	52
2030 CO_2 Tax High Wind	46.5	0	28	26	51

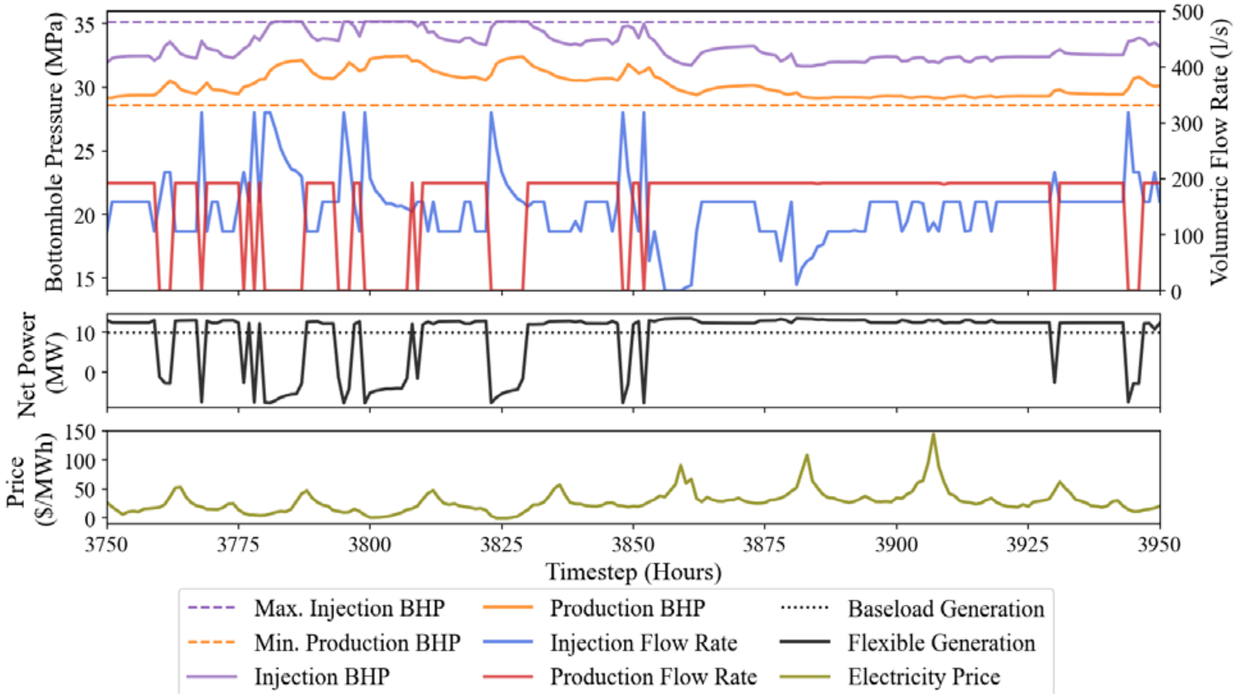

Figure 2: Optimal operational strategy during a selected period of 200 hours for the southern California historical price series in the base case model. The upper plot gives injection and production well BHPs and injection and production flow rates at hourly timesteps during this period. The middle plot gives net electricity generation, and the lower plot gives hourly electricity prices.

3.2 Sensitivity Analysis

In addition to the base case, we also investigate 14 sensitivity cases designed to cover the range of parametric variation that might occur across different locational, regulatory, and technology advancement scenarios. Individual sensitivity cases adjust a single parameter value relative to the base case, allowing us to evaluate the sensitivity of the results outlined in Section 3.1 to variations in each of these parameters. Sensitivity parameters include the cost of surface plant oversizing C_{plant} , the maximum allowable pressure increase in the reservoir ΔP_{max}, fracture conductivity K_f, number of fractures N_f, and rock matrix permeability k_m. We include high and low bounding cases for each parameter, as well as mid-high and mid-low cases for both K_f and k_m. The parameter variations associated with each sensitivity case are outlined in Table 2. Flexible operations and investments are optimized for each sensitivity case against all 16 historical and modeled future electricity price series. Fig. 3 presents the relative average revenue improvement from full flexibility for each of the 240 total cases analyzed.

Results indicate that a reduction in surface plant cost generally improves the value of flexible operations, especially for price series with a high level of optimal plant oversizing. Reduced plant cost allows for greater surface oversizing, which in turn enables greater generation during peak-price periods. Increasing surface plant cost has the opposite effect, though often to a lesser extent.

Anticipating that excessive reservoir pressurization could produce deleterious effects, including induced seismicity (Majer et al., 2007), we limit ΔPmax to 3.5 MPa in the base case model. We find that increasing this value by 1.5 MPa does not produce major benefits in any scenario. Reducing ΔPmax by the same amount limits the benefits of flexibility in some cases. Overall, it seems that the 3.5 MPa pressurization limit used in this paper unlocks most of the benefits of flexibility. The seismic risk associated with this level of pressurization should be further characterized through field testing.

Table 2: Sensitivity case names and parametric variations

Scenario	Description
C_{plant}^{-}	Surface plant capital cost reduced by 33%
C_{plant}^{+}	Surface plant capital cost increased by 50%
ΔP_{max}^{-}	Maximum allowable reservoir pressure reduced by 1.5 MPa
ΔP_{max}^{+}	Maximum allowable reservoir pressure increased by 1.5 MPa
k_m^{--}	Matrix permeability reduced to 1/100 of base case value
k_m^{-}	Matrix permeability reduced to 1/10 of base case value
k_m^{+}	Matrix permeability increased to 10x base case value
k_m^{++}	Matrix permeability increased to 100x base case value
K_f^{--}	Fracture conductivity reduced to 1.1×10^{-12} m^3
K_f^{-}	Fracture conductivity reduced to 2.3×10^{-12} m^3
K_f^{+}	Fracture conductivity increased to 1.2×10^{-11} m^3
K_f^{++}	Fracture conductivity increased to 3.2×10^{-11} m^3
N_f^{-}	Number of fractures reduced to 50
N_f^{+}	Number of fractures increased to 150

We find that reduced matrix permeability has the most significant effect on flexible operations, cutting relative benefits by up to a quarter in the lowest-permeability case. Reduced matrix permeability limits the migration of geofluid between the fractures and the matrix, leading to pressure responses of greater magnitude in response to pumping. This increased pressure response causes the reservoir to reach its pressure cap much more quickly, effectively reducing the energy storage capacity of the system. Increased matrix permeability, on the other hand, does not appreciably improve the relative benefits of flexible operation over baseload. These results suggest that it will be necessary to fully characterize the subsurface properties of a potential EGS site in order to accurately assess the economic potential of flexible operation and in-reservoir energy storage.

Changes to the fracture conductivity K_f primarily affect the injection wellhead pressure required to maintain a given pumping rate. Reduced conductivity results in increased injection pressure requirements, and therefore increased injection load. Relative revenue improvements from flexibility are greater in cases with lower fracture conductivity, as the shifting of injection loads to times with lower electricity prices has a greater relative impact in these cases. Conversely, relative benefits due to flexibility are somewhat lower in cases with high fracture conductivity and low pumping load.

Increasing or reducing the number of fractures present in the engineered reservoir has several effects. A smaller number of fractures will reduce the overall transmissivity of the reservoir, leading to higher parasitic load from injection pumping. It will also reduce the surface area over which the fracture system interacts with the rock matrix, somewhat limiting the exchange of fluid and therefor increasing the pressure response to pumping. The effect of the number of fractures on the relative benefit of flexibility is unpredictable, but is generally fairly small.

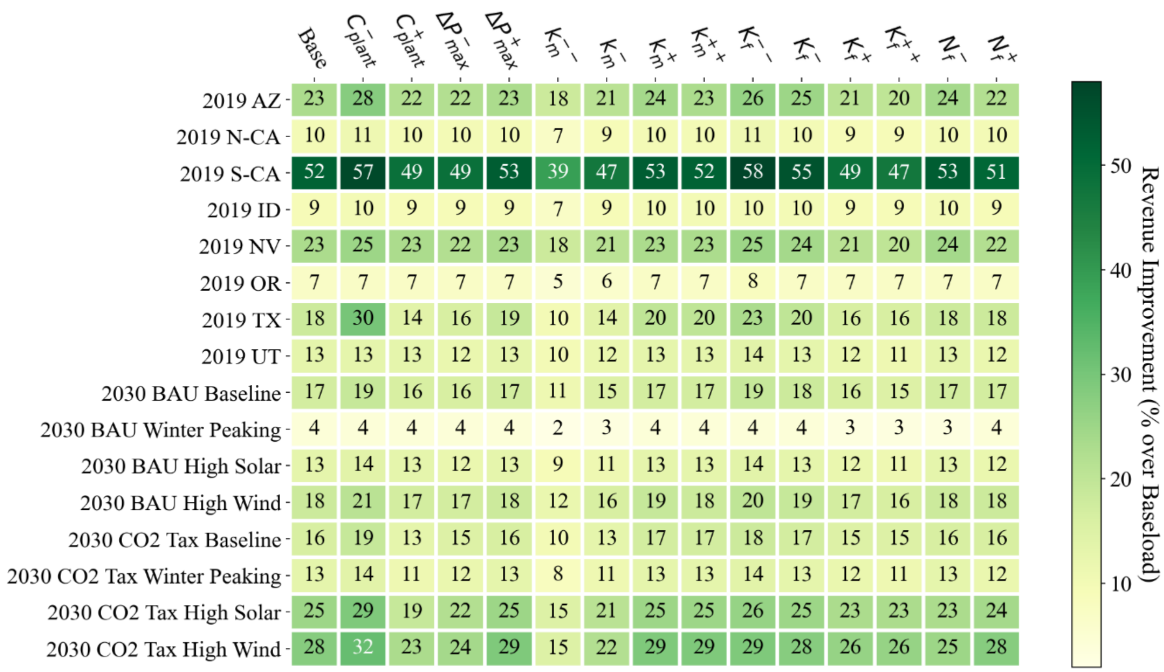

Figure 3: Relative revenue improvement over baseload for a fully flexible geothermal plant across 15 sensitivity cases and 16 electricity price series.

4. Conclusion

Enhanced geothermal power has significant potential to contribute to a zero-carbon electricity grid, but geothermal's traditionally inflexible generation profile limits its usefulness and economic appeal in systems with high VRE penetration. In this work we investigate the potential for EGS power plants to overcome this limitation, providing flexible generation and energy storage services. We develop a novel modeling framework which accurately represents pressure and flow behaviors within an EGS reservoir and optimizes operations and investments to maximize the revenue of a geothermal power plant. We demonstrate that by exploiting the natural properties of a hot dry rock reservoir, an EGS power plant can provide flexible generation and energy storage services that significantly enhance its economic value. If this additional value can be translated into plant revenues via well-constructed energy and capacity markets or power-purchase agreements, flexible operations and energy storage can effectively raise the price point at which EGS power can compete as an energy source. This extra financial breathing room could be crucial to the economic success of early EGS projects, which represent an important step on the path toward development of much more significant “deep EGS” resources.

We find that flexibility and energy storage are more valuable in electricity markets with high VRE penetration, where large fluctuations in electricity prices provide opportunities for arbitrage. Furthermore, the degree of value added by full flexibility is fairly insensitive to variation in most subsurface parameters and surface plant costs. The greatest impact is observed in the very low matrix permeability case, which significantly reduces the energy storage capacity of the reservoir and the revenue improvements that can be achieved through flexible operation. These results indicate that flexible operations and energy storage can improve the value of EGS projects across a wide range of subsurface conditions, but that these conditions will need to be well-characterized in order to accurately assess a site’s flexible potential.

This work is designed to assess the value of flexible operations and energy storage for early EGS projects, and does not focus on electricity systems under deep decarbonization. Moving toward entirely carbon-free electricity would almost certainly drive greater deployment of VREs (Jafari et al., 2020, Larson et al., 2020, Williams et al., 2021), which would lead to even greater benefits from geothermal storage and flexibility. However, it is likely that any successfully deployed early EGS projects will have entered the market well before this level of decarbonization is achieved. Because the fixed price series analysis used in this work assumes very low levels of flexible EGS market penetration, it is of limited use in quantifying the long-term value and deployment potential of flexible geothermal power under such scenarios. An accurate analysis of this long-term potential must capture the ability of flexible geothermal plants deployed at scale to influence the price of electricity through their operational decisions, as well as the diminishing marginal returns associated with increasing deployment of a specific energy technology, which apply especially strongly to energy storage technologies (Mallapragada et al., 2020). To this end, the optimization model developed for this paper is designed in such a way that it can be incorporated, with some reductions in complexity, into a larger long-term electricity system capacity expansion model. The use of capacity expansion modeling to analyze the long-term value and deployment potential of flexible geothermal power with energy storage will be the primary focus of future work on this subject.

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