Optimization of Enhanced Geothermal Systems under Geological and Reservoir Stimulation Uncertainty

Ahinoam Pollack, Tapan Mukerji

Energy Resources Engineering Department, Stanford University, Stanford, CA, USA

Keywords

Enhanced Geothermal Systems, EGS, hydraulic fracturing, Monte Carlo, Optimization, Uncertainty

ABSTRACT

There are many uncertain parameters when creating an Enhanced Geothermal System (EGS). Uncertain geological parameters include the stress field, location and orientation of pre-existing fractures, rock toughness, and temperature and pressure distribution. In addition, the physical mechanisms governing fracture creation are still being researched. Due to these uncertainties, the reservoir's response to stimulation and operation cannot be predicted with certainty using numerical simulators. With an uncertain reservoir response, it is challenging to make engineering optimization decisions that will greatly improve the profitability of an EGS.

This paper explores the optimization of an EGS under geological and reservoir stimulation uncertainty. A base case EGS model is created, using available data for a candidate EGS site in the West Flank of Coso, California. The EGS base case is a horizontal injector well flanked by two producer wells. The injector well is hydraulically fractured to create tensile fractures and open pre-existing natural fractures. Using Monte Carlo simulation, 119 models were generated varying the uncertain earth parameters within ranges reported for the West Flank of Coso site. For each model, fracture stimulation parameters such as mean fracture length, and mean fracture aperture, were randomly selected according to prior uncertainty.

Monte Carlo Optimization (exhaustive brute force sampling) was used on these models to optimize four engineering decisions: the well head pressure on the injection well, the pump power on the production wells, the distance between the injector and producers, as well as the spacing between fractures. The engineering decisions were optimized to maximize the present value of the EGS, accounting for the cash flow discount rate and the cost of pumping.

Our analysis shows that for the prior uncertainty and conditions used in our model, a fracture spacing of 10 m and a distance between the injector and producers that is less than the mean hydraulic fracture length, increase the present value of the EGS.
1. Introduction

Currently, geothermal energy provides only 0.37% of the total U.S. electricity generation (U.S. Energy Information Administration, 2018). Research suggests that EGS technology could increase U.S. geothermal energy generation by 100 GWe, or 10% of total electric capacity (Tester et al., 2006). After decades of research, however, EGS is still not commercially feasible. EGS experiments have not been able to sustain fluid flow rates and fluid temperature at commercial levels.

This study investigates the optimization of a new EGS design that has been mentioned in literature (Hu, Tutuncu, Eustes, & Augustine, 2016; Li, Shiozawa, & McClure, 2016) but not yet been tested in a field site. The EGS design considered is a horizontal injector well flanked by two horizontal producer wells. The injector well is hydraulically fractured to create tensile fractures and open pre-existing natural fractures. Cold water is then injected into the injector well, flows through the stimulated fractures, and hot water is produced via the two flanking production wells, (Figure 1). A major difference between this design and previous EGS designs is the focus on the stimulation of both tensile and shear fractures, with the stimulation therefore done via perforations in a cased well. The cased well allows for the stimulation of multiple zones along the wellbore, instead of only shearing preexisting natural fractures. This well configuration and mix of hydraulic fracturing and shear stimulation is similar to operations for the production of shale gas in the oil industry.

This paper explores the optimization of four engineering decisions: the pumping power on the production wells, injector well head pressure, distance between the injector and producer, and fracture spacing. These decisions are optimized given the uncertainty of the earth parameters and stimulation results, using a Monte Carlo Optimization.

Figure 1: (a-Left) Schematic of an EGS site: cold water injected via an injector well (blue arrow) heats up as it travels through stimulated hydraulic fractures (colorful circles) and opened natural faults (green mesh) from the injector to the two producers (red arrows). The hot fluid is used to generate electricity. (b-Right) A numerical model representation of an EGS site, with the color indicating temperature (blue-cold; red-hot).
1.1 Previous Research on Optimizing EGS

Li (Li et al., 2016) performed an optimization and sensitivity analysis of a similar EGS design with a single horizontal well injector and a single horizontal well producer. Li found that increasing the number of fractures increases the possible flow rate through the system, since the effective permeability in the system increases linearly with the number of fractures. With larger flow rates, the wellbore friction loss was the limiting factor of the system. Li assumed a constant fracture aperture in each of the stimulated faults. Doe (Doe, McLaren, & Dershowitz, 2014), on the other hand, discussed more realistic scenarios with variable fracture aperture and how that variability affects EGS performance. Doe showed that variability in fracture aperture leads to preferential flow paths: injected water flows mainly through fractures with anomalously high apertures. High flow rate in few fractures causes rapid cooling of the fractures and in turn production of cold water (early thermal breakthrough) and lower electricity generation.

Hu (Hu et al., 2016) and Hofmann (Hofmann, Babadagli, & Zimmermann, 2014) focused more on examining the sensitivities relating to the hydraulic fracturing process. Hu found that stress anisotropy, high fluid viscosity, high proppant concentration, large pump volume, and pump rate tend to create large planar fractures that are not complex and variable, which leads to higher EGS viability. Natural fractures perpendicular to the maximum principal stress and to the hydraulic fractures tend to arrest the propagation of the natural fractures or minimize their extent due to friction losses. Fewer natural fractures and fractures parallel to the principal horizontal stress lead to more planar fractures. Hoffman arrived at similar conclusions to Hu, except for finding that complex fracture networks created by stimulation and pre-existing fracture networks are more favorable to an EGS than planar systems since they create a larger stimulated zone and are less prone to thermal breakthrough.

2. Methodology

The Monte Carlo Optimization workflow is as follows:

I. Sample values from the distributions of uncertain earth parameters and engineering decisions, given in Table 1, Table 2, and Table 3. The mean fracture half-length distribution, an example of a distribution of a sampled parameter, is shown in the histogram of Figure 2a.

II. Build a flow simulation model based on each of the uncertain parameters and simulate the hydro-thermal flow and energy production for twenty years. An example of the results of multiple hydro-thermal flow simulations is shown in the plots of Figure 2b,c, and d.

III. Calculate the PV for each EGS simulation. Examine the conditional probability distribution functions of PV values given the different engineering decisions to gain an understanding of optimal engineering parameter ranges.
2.1 Base Earth Model

The model for this sensitivity analysis was based on the West Flank of the Coso geothermal site in California. The main Coso Geothermal Field has a mean capacity of 300 MW of electricity. The West Flank of Coso, however, was shown to have low permeability and a lack of fluid convection and therefore was deemed not viable for geothermal fluid production. This assessment was based mainly on an exploration well (83-11) drilled to a depth of 2,500 m, which had both injection tests and temperature logs showing low permeability (Blankenship et al., 2016). Temperature logs of well 83-11 also showed temperatures reaching 250 °C. This site has EGS characteristics of both high temperature and low permeability. Hydraulic stimulation could increase the rock permeability and allow for extracting the thermal energy in the hot formation.

A 3D model from Blankenship et al. (2016) in Figure 3a shows the main natural faults in the area as well as exploration well 83-11. The temperature logs for well 83-11 and two other nearby shallower explorations wells are shown in Figure 3b. The bottom of well 83-11 shows a deviation from its conduction profile and higher temperature, indicating it is nearing a high temperature zone. In the 3D model, the bottom of the well is showed as nearing a natural fault. For this paper, we hypothesize that the natural fault may be an active source of hydrothermal upflow or a location with remnant heat from past hydrothermal flow up the fault. It is assumed the hot zone intersected by well 83-11 surrounds the fault, and the elevated temperatures extend for some distance around the fault. The numerical EGS model used in this study covers a study depth of 2,000 to 2,850 m, and the study area is indicated by a green dotted box in both images of Figure 3.

A 3D rendition of an EGS model placed in the study area is shown in Figure 1a and includes a natural fault cutting the system (green mesh lines) and hydraulic fractures extending from an injection well to the production wells. The hydraulic fractures are aligned North-South. The orientation of the hydraulic fractures was determined from the stress direction. In the region’s strike slip faulting regime, hydraulic fractures extend parallel to the maximum horizontal stress. The measured maximum horizontal stress in the area extends NNW-SSE (tilted 8° to the West) (Blake & Davatzes, 2011), and thus the N-S fracture orientation in the model is a close approximation.
A numerical representation of the EGS model is shown in Figure 1b. The model includes an injector flanked by two producers on either side. The injector is hydraulically fractured, and the hydraulic fractures extend towards the producer. The black lines between the injector and producer are hydraulic fractures, which in real field cases would be identified via micro seismic monitoring. A natural fault is included in the model, crossing the wells.

![Figure 3: (a-Left) A 3D view of the study area. The numerical EGS model is based on the area marked by the green dotted rectangle. A deep well (83-11) reaches temperatures of 250 °C at a depth of 2,500 m. The high temperatures are near a natural fault that is mapped based on seismic and geologic mapping data (Blankenship et al., 2016). (b-Right) Temperature logs of three wells near the study area. The green rectangle marks the depths of the EGS model, from 2,000 to 2,850 m depth. From the two shallower wells, the background geothermal gradient is assessed to be approximately 55 °C/km. Well 83-11 heats up quickly at the bottom of the well, perhaps nearing a heat source. It is hypothesized that the nearby fault is the conduit of elevated temperature.]

2.2 Uncertain Fracture Parameters and Their Prior Distribution

The uncertain parameters can be divided into two: fracture related parameters (see Table 1) and matrix parameters (Table 2). These parameters are varied in the optimization analysis, such that the optimal engineering decisions will be effective no matter the true state of the earth or the results of the stimulation.

The fracture parameters indicate the characteristics of the hydraulic fractures created by the hydraulic fracturing stimulation. The hydraulic fractures stimulation was not numerically simulated, and therefore the hydraulic fracture properties were assigned stochastically with a given mean and standard deviation. Every model has a mean fracture half-length and mean fracture aperture. The individual fracture properties in each model vary around the mean value according to the assigned standard deviation of the property for that model.

There is little field test precedence in the literature to guide an estimation of the mean hydraulic fracture half-length and aperture for hydraulic fracturing with proppant from horizontal cased wells in crystalline rock. Therefore, the values for these parameters were mainly taken from work by Reinicke, (2009) and Hofmann et al., (2014) from simulations of hydraulic fracturing...
and a compilation of hydraulic fracture characteristics from the oil and gas industry. The mean and standard deviation of the fracture parameters vary across the EGS models, and are obtained by sampling from a uniform ($U$) distribution between a minimum and maximum value indicated in Table 1.

The igneous rock at reservoir depth in Coso is not layered and, for this study, is considered to be approximately isotropic, producing penny shaped circular hydraulic fractures, where the height of the fracture approximately equals its length. Nonetheless, an aspect ratio parameter, of the ratio of the fracture height to fracture width, was added to the simulations to allow for the possibility of high toughness layers ending fracture extension upwards. In addition, the ratio of the fracture vertical extent downwards relative to vertical extent upwards was added to the simulations to account for the possibility that the minimum horizontal stress above the fracturing zone is less than the minimum horizontal stress below the fracturing zone, and therefore the fractures would extend further upwards relative to downwards.

Besides hydraulic fractures, the model also includes a single large natural fracture that was mapped through geologic map data as well as a cloud of microseismicity occurring throughout 1996-2012 (Blankenship et al., 2016). The fault was mapped with a throw of fifty meters, which could indicate a fault thickness of anywhere from 1 cm to 10 m (Manzocchi, Walsh, Nell, & Yielding, 1999). In this model, the fault was mapped as 5 cm wide and allowed to have its permeability vary, such that the fault conductivity was between 0 and 200 md-m.

### Table 1. Uncertain fracture related parameters.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Distribution</th>
<th>Source of information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulic fracture half length (m)</td>
<td>$\mu \rightarrow U[100, 300]$  $\sigma \rightarrow U[0, 70]$</td>
<td>Ideally, this value would be taken from experiments at similar sites or rigorous simulations based on the measurements of the stress state. For now, values are guided by Reinicke (2009) and Hofmann et al. (2014).</td>
</tr>
<tr>
<td>Fracture aperture (m)</td>
<td>$\mu \rightarrow U[0.0005, 0.0018]$  $\sigma \rightarrow U[0, 0.0007]$</td>
<td>Ranges are guided by Reinicke (2009) and Hofmann et al. (2014).</td>
</tr>
<tr>
<td>Aspect ratio (mean fracture height/mean fracture length)</td>
<td>$\mu \rightarrow U[0.7, 1]$</td>
<td>Ranges are guided by Reinicke (2009) and Hofmann et al. (2014).</td>
</tr>
<tr>
<td>Ratio of fracture vertical extent downwards relative to vertical extent upwards.</td>
<td>$\mu \rightarrow U[0.8, 1]$</td>
<td>Ranges are guided by Reinicke (2009) and Hofmann et al. (2014).</td>
</tr>
</tbody>
</table>
2.3 Uncertain Matrix and Geological Parameters and Their Prior Distribution

The ranges of the matrix parameters were obtained mainly by using common properties of the rocks found in lithology logs of wells drilled in the West Flank. The matrix permeability was estimated to be significantly less than 0.1 md based on the conductive signature of the temperature log of well 83-11 (Blankenship et al., 2016). The temperature field was based on three temperature logs in the area of interest. Two of the logs showed a background geothermal gradient of 55 °C/km, while well 83-11 showed temperatures of 250 °C at a depth of 2,500 m, near a fault. It is assumed that the fault is the source of elevated temperature. The temperature field is modelled as heat diffusion away from the fault towards the background geothermal gradient, with a variable for width of the hot temperature zone around the fault, visualized in Figure 4 and listed in Table 2. Another uncertain geological variable is the boundary condition of the model. We set two possible conditions: an open boundary modelled by a constant pressure boundary, and a closed boundary given by no-flow boundary.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Distribution</th>
<th>Source of information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Matrix permeability (md)</td>
<td>$\log_{10}(perm) \rightarrow U[-1, -5]$</td>
<td>Analysis in (Blankenship et al., 2016).</td>
</tr>
<tr>
<td>Reservoir temperature (°C)</td>
<td>Background geothermal gradient of 55 °C/km.</td>
<td>Temperature logs.</td>
</tr>
<tr>
<td>Model Boundary Condition</td>
<td>(no flow; constant pressure).</td>
<td>Ideally, hydrogeology analysis would yield more insight into prior uncertainties.</td>
</tr>
<tr>
<td>Width of Hot Zone Around Fault (m)</td>
<td>$U[100, 500]$</td>
<td>Ideally, natural state modeling would be done to ascertain the range of uncertainty of the temperature distribution around the fault. The temperature distribution would depend on the hydrothermal history of the fault as well as the permeability evolution due to seismicity along the fault (McKenna &amp; Blackwell, 2004)</td>
</tr>
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</table>
Figure 4: (a-Left) A cross section through part of the numerical model. The natural fault is shown by a thick black line. We hypothesize that the fault carries high temperature fluid, and that the temperature field (color bar in Celsius on the right) dissipates with distance away from the fault. Since this diffusion distance is unknown, this "width of the hot zone around the fault" is one of the study's uncertain parameters. (b-Right) A map view of the same fault intersection the injection and production wells.

2.3 Engineering Decisions

The four engineering parameters that are optimized in this study are: the maximum well head pressure of the injection well, the pumping power of the production wells, the distance between the injection and production wells, and fracture spacing. The pumping power and well head pressure need to be optimized since the amount of pumping increases flow rates, and therefore, electricity generation. Yet, on the other hand, high injection pressures and pumping rates also increase parasitic losses to power the pumps. The utility of pumping therefore needs to be investigated.

Similarly, the fracture spacing also comes at a trade-off price. Increasing the amount of fractures, increases the system permeability, but also increases the cost of stimulation. The distance between the injection well and production well is relative to the mean hydraulic fracture half length. It is assumed, that after stimulation, microseismic analysis will be used to determine the mean fracture length, and then the producer will be placed at a specific distance from the injector based on the length of the fractures. It is possible that it is better to put the production wells closer to the injection well to ensure connectivity. However, better connectivity may result in insufficient fluid residence time and lower production temperatures. This parameter is illustrated in Figure 5.
### Table 3. Engineering decisions.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Distribution</th>
<th>Source of information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum well head pressure at the injection well (kPa)</td>
<td>( \mu \rightarrow U[1000, 15000] )</td>
<td></td>
</tr>
<tr>
<td>Pump power at the production wells (kW)</td>
<td>( \mu \rightarrow U[500, 1500] )</td>
<td>Baker Hughes lists geothermal pump as reaching 2000 HP (1491 kw) (Baker Hughes, n.d.)</td>
</tr>
<tr>
<td>The distance to the producer relative to the mean fracture length (unitless)</td>
<td>( \mu \rightarrow U[0.5, 1.2] )</td>
<td></td>
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<tr>
<td>Fracture spacing (m)</td>
<td>U[10;15;20; 25]</td>
<td></td>
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**Figure 5:** A map view of two sample EGS models. (a-Left) An EGS model with a ratio of 0.5 of the separation distance of injector and producer relative to the mean fracture half length. This model has a mean fracture half length of 300 m and the production wells are at a distance of 150 m from the injection well. (b-Right) An EGS model with a ratio of 1 of the separation distance of injector and producer relative to the mean fracture half length. This model has a mean fracture half length of 175 m and the production wells are 175 m from the injection well.
2.4 Financial Model for Calculating Present Value

The Present Value (PV) for each model is calculated by taking into account the revenue from electricity generation, the parasitic losses of electricity to pumping, as well as the discount rate applied to the cash flows. Overall the PV is calculated as follows:

\[ PV = \sum_{n=1}^{20} \frac{Net\ Electricity\ Sales}{(1 + Interest\ Rate)^n} \]

where \( n \) is the number of elapsed years since the start of the project. The overall life of the project for this study is twenty years. The electricity generation is calculated as follows:

\[ Sales_e (\$) = Electricity_{net} (kWhr) \times Price_{kWhr} \quad (1) \]

\[ Electricity_{net} (kWhr) = Electricity_{gross} (kWhr) - Electricity_{power\ pumps} (kWhr) \quad (2) \]

\[ Electricity_{gross} (kWhr) = Flow\ Rate \left(\frac{kg}{s}\right) \times (h_{inlet} - h_{outlet}) \times \eta_{plant} \times Hours \quad (3) \]

where \( h_{inlet} \) and \( h_{outlet} \) are fluid enthalpy at the production wells and turbine outlet, respectively, and \( \eta_{plant} \) is the efficiency of the plant. In this equation, the main varying parameters are the fluid flow rate and the fluid temperature produced from the subsurface, which are taken from the hydro-thermal flow simulations. The plant efficiency declines with lowering temperatures, as shown in Figure 6. The efficiency is initially around 0.12 and declines rapidly below 140 °C. The reinjection temperature is 76.5 °C.

![Plant Efficiency vs. Temperature (C)](image)

Figure 6: Plant efficiency as a function of temperature. This plot is based on (Lukawski, Dipippo, & Tester, 2018).
The overall financial parameters for this model are shown in Table 4 below:

### Table 4. Financial parameters

<table>
<thead>
<tr>
<th>Item</th>
<th>value</th>
<th>Source of information</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sale price per kWhr ($)</td>
<td>0.076</td>
<td>This is the average price of electricity in recent geothermal PPA agreements (Hernandez, Richard, &amp; Nathwani, 2016).</td>
</tr>
<tr>
<td>Discount rate</td>
<td>0.15 for first two years and 0.07 for further years</td>
<td>Assumes a lower rate of interest after the plant is stable and operating.</td>
</tr>
</tbody>
</table>

3. Results

The optimization analysis was done using Monte Carlo Optimization. For the Monte Carlo optimization, 119 uncertain parameter combinations were sampled and used to build numerical models. The models’ hydro-thermal flow and energy production was then simulated using the commercial simulator CMG STARS. The temperature and flow rate of the produced water was then used in the financial model described above to calculate the PV. The histogram of PV values of all the models is shown in Figure 7. The histogram shows a gaussian-like distribution with a median of $19M. However, there are several models with PV values in the negative domain, meaning the costs of pumping are higher than the generated electricity. The histogram highlights the risk associated with EGS projects. The range of PV values, though, can be reduced by both reducing the uncertainty of the geological model through data collection and deciding on engineering parameters that lower the PV variance.

![Histogram of the Models' Present Values](image)

Figure 7: Histogram of the PV values of all the stochastically generated EGS models.
The PVs for the models were used to construct probability distribution functions (PDF) of PV conditioned on the different engineering decisions to assess the optimal decisions. Figure 8a shows the PDF of PVs separated into the models with fracture spacing of 10, 15, 20 and 25 m. The vertical lines on the bottom of the graph show the median PV values for each group, indicated by matching colors. The PDFs of fracture spacing of 15 and 20 m show similar structures with a low median PV. The PDF of models with a fracture spacing of 25 m has a larger median PV, but also a larger variance. The PDF of models with a fracture spacing of 10 has the highest median PV and also has less variance. A lower fracture spacing increases the number of fractures and the system permeability, resulting in higher flow rates and electricity generation for a given pressure drop.

Figure 8b shows the PDFs of PVs separated into three levels of injector well head pressure (WHP). All of the injector WHP have similar medians. The higher injector WHP (the green line in Figure 8b) shows a slightly lower PV, indicating that the high injection rates are not compensated with sufficient increase in electricity generation. Similarly, the pumping power on the production wells also does not show a clear impact on the PV. The PDFs of the PV separated into three levels of production well pumping power are shown in Figure 9a. The pumping power adds a parasitic loss to the EGS. The additional flow rate from pumping just compensates for the additional pumping cost without adding any value. This study stopped at a limit of a 1.5 MW pump, equivalent to a 2000 horse power, advertised by Baker Hughes (Baker Hughes, n.d.).

Figure 8: (a-Left) The histogram of PVs of the stochastically generated EGS models separated into different levels of fracture spacing. The vertical lines on the bottom axis indicate the median PV of each group, matching the colors in the legend. A fracture spacing of 10 has the highest median. (b-Right) The histogram of PV values separated into different levels of well head pressure. All PDFs separated into the different well head pressure are approximately the same.

Figure 9b shows the PDFs of PVs of the producer location relative to the mean hydraulic fracture half-length. While models with producer location ratios between 0.5 to 0.97 have higher medians, models where the production wells are located more than the mean fracture half-length away from the injection wells show a lower median PV. Production wells at too great a distance
from the injection well risk the chance of intersecting only few of the stimulated fractures and having limited system connectivity, and thus low system flow rates.

A Distance Based Generalized Sensitivity Analysis (Fenwick, Scheidt, & Caers, 2014; Grujic, 2016) was performed to calculate the relative influence of the four optimization parameters on the EGS PV. The pareto plot in Figure 10 shows that well separation and fracture spacing are the most important optimization parameters.

Figure 9: (a-Left) The histogram of PVs of the stochastically generated EGS models separated into different levels of pump power. The vertical lines on the bottom axis indicate the median PV of each group, matching the colors in the legend. High pump power does not show any marked increase in PV. (b-Right) The histogram of PV values separated into different levels of the producer separation distance from the injector relative to the mean fracture length. Placing the production wells at a distance greater than the mean fracture length has a clear negative impact on the EGS PV.

Figure 10. Relative importance of the four optimization parameters.
Specifically, the results indicate that a fracture spacing of 10 m and a producer that is located less than the mean hydraulic fracture length away from the injection length will yield higher PV. Figure 11 below shows the PDF of PVs of all models in blue and the PDF of PVs of optimized models (models with 10 m spacing and a well separation ratio less than one) in red. There is a 10 million dollar difference in the median PV value between the models with the optimized engineering decisions versus the prior models.

![Prior PV PDF vs. Optimized PV PDF](image)

**Figure 11: Histogram of the PV values of all the stochastically generated EGS models.**

4. Conclusions and Future Work

This study found that EGS PV is highly variable when taking into account all the unknown geological and stimulation parameters tested in this study. It was found that placing the production wells closer to the injection wells, and a fracture spacing of 10 m can significantly increase the PV of an EGS. This study did not take into account the initial investment cost of the drilling and stimulation, as well as operational costs. These costs will need to be below the PV of the EGS.

In future work, we will study a more complete cost model and calculate the net present value. In addition, we will numerically simulate the stimulation phase.

5. Acknowledgements

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