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Implications of Drilling Technology Improvements on the Availability of Exploitable EGS Resources

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ABSTRACT

This study uses an inverse modeling approach to quantify how improvements in technologies that reduce well drilling costs can increase the national occurrence of economically viable EGS sites. To provide context to the potential technology improvements, we group well costs into four general categories; 1) drilling costs, 2) non-drilling costs, 3) trouble time, and 4) additional time. Results from the DOE's GeoVision study has produced four cost curves for geothermal well drilling that describe the drilling cost as a function of depth with each curve representing a different level of technology that helps reduce drilling costs. This study examines how those advances in drilling technology can change the spatial area where EGS can be economically exploitable.

To do this, we simulate a hypothetical 50 MW EGS system with an initial reservoir temperature of 200 ^{o}C and then calculate the drilling costs required to achieve LCOE's of 8, 10, 12, 14, and 16 ¢/kW-hr. The costs curves are used to calculate the attainable depth for each required cost. The attainable depths are then cross-referenced against the SMU temperature-at-depth maps to determine the economically exploitable area for each cost curve and LCOE. Results show that LCOE's of 8 and 10 ¢/kW-hr are nearly unattainable without other cost reductions; however 10 ¢/kW-hr is attainable for the Ideal case for depths of 3400 m. At higher LCOE's, the exploitable area increases exponentially above a threshold as a function of the decrease in drilling costs.

1. INTRODUCTION

With few exceptions, the quality of a geothermal energy source increases with depth as one drills deeper to access higher temperature environments. This is especially true for enhanced geothermal systems (EGS). However drilling costs also increase with depth, creating a tradeoff between the cost of accessing the energy and the production capacity of the source. This dynamic is unique to geothermal energy and creates a condition where the levelized cost of electricity (LCOE) is not only a reflection of the economic viability of a project but also of the tradeoff designers and engineers must make between source temperature and drilling costs. Without the advent of new drilling technologies, the only method we have to reduce drilling costs is to drill as shallow as possible, which limits the locations where suitable temperatures can be found.

The Department of Energy (DOE) Geothermal Vision (GeoVision) Study has been established to identify the challenges and necessary actions to increase the opportunities for U.S. geothermal energy production. Within that broad objective, emphasis is being placed on assessing the history of geothermal development, quantifying the ranges of performance, costs, benefits, and impacts, and developing credible analyses of future growth to identify the opportunities and hurdles. The GeoVision Study has been broken into seven distinct tasks that are being led and implemented by the National Laboratories with considerable input from private interests, academia, and other subject matter experts. One of those tasks is the Reservoir Maintenance and Development (Reservoir M&D) task being led by Sandia National Laboratories who are investigating the technologies and practices that establish and affect the below-ground thermal, hydraulic, and economic performance of a geothermal system (Lowry et al, 2016). Included in the Reservoir M&D investigation is an update to the drilling cost curves used in the Geothermal Energy Technologies Evaluation Model (GETEM) (Entingh et al., 2006) to better reflect the current state of drilling technologies and material costs and to establish scenarios that reflect different levels of technological advancements.

Here, we use an inverse approach to examine how the spatial area of exploitable resource changes as a function of increases in drilling technology for developing EGS.

2. DRILLING COST CURVES

By necessity, the cost curves developed for the GeoVision study condense the complexity in drilling performance into a tractable set of scenarios such that the final results highlight the more significant aspects of well drilling that can drive the costs. The curves are not intended to reflect the absolute cost of drilling a particular well but rather reflect the sensitivity of the total well cost to improvements in major aspects of the drilling and completion effort. To create the curves, costs were grouped into four categories:

1. Drilling
2. Flat time
3. Trouble time
4. Additional

Activities grouped into the drilling category are limited to those strictly related to extending the hole: rotating on the bottom, tripping drill pipe, and handling the BHA to replace damaged bits. Included in the drilling cost category is the cost of drill bits and BHA components, including directional equipment and related labor. Flat time includes all planned activities and associated costs that do not directly contribute to extending the hole, such as running casing, cementing, and wireline logging. Trouble time incorporates any activity and associated costs that arise from adverse hole conditions or unexpected failures. Among the most prevalent of these is lost circulation. Addition costs include mobilization/demobilization, site preparation, pre-spud engineering, and wellhead equipment. For the sake of developing the cost curves, additional costs are not varied due to the fact that they are relatively small when compared to the other costs and that there is relatively little that better technologies can do to reduce them.

Several sets of cost curves were created but for this study, the set corresponding to large diameter, vertical designs was used. To reflect advances in technology, changes were made to the rate of penetration (ROP), bit life, the number of casing intervals, mud costs, wireline logging, and contingency costs. Contingency costs represent the trouble costs. Table 1 lists the values used for each scenario.

Table 1 - Assumed technology advances for reducing drilling costs.

Scenario	ROP [ft/hr]	Bit Life [hr]	# of Intervals	Mud Costs	Wireline Logging	Contingency
Base Case	25	50	3-5*	Standard*	All intervals	15%
Intermediate 1	50	100	Base Case - 1	Half depth with air, half depth with mud	Only production interval	10%
Intermediate 2	75	150	Base Case - 2	Half depth with air, half depth with mud	Only production interval	5%
Ideal	100	200	1	Full depth with air	Log while drilling	0%

*Based on depth using default values from the GETEM model

The costs for each scenario were calculated for depths ranging from 500 to 7000 m at 500 m intervals using the proprietary Sandia code, Well Cost Simplified (WCS). To maintain consistency with some of the other tasks in the GeoVision study, GETEM's default design criteria were used. The cost curves are shown in Figure 1.

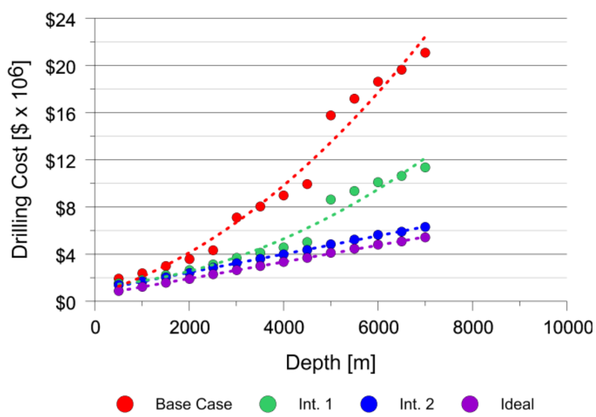

Figure 1 - Cost curves for four the different technology scenarios.

3. MODEL SETUP

The analysis assumes a 50 MW EGS system with a reservoir temperature of 200 °C. The total number of wells is based on the required geothermal fluid mass flow rate to achieve 50 MW divided by a user defined maximum flow rate of 40 kg/s (GETEM default). The project is set to have one injection well per 2 producers, which in most scenarios resulted in 18 production wells and 9 injection wells. The injection wells are stimulated at a cost of $1,250,000 per well. Power conversion assumes a binary power plant using isopentane as the working fluid, a pinch point difference of 4.0 °C, an evaporator pressure of 1 MPa, and a cooling condenser temperature of 40 °C. Injection wells are assumed to be pumped and production wells are only pumped if the injection pumping is not enough to maintain the required pressure at the inlet to the power plant.

Thermal drawdown is calculated using the Gringarten method (Gringarten et al., 1975) that assumes 500 m spacing between the injection and production wells, a reservoir cross-sectional area of 375,000 m^2, and 12 flowing fractures with an aperture of 0.15 mm. This configuration results in a reservoir permeability of 9×10^{-15} m^2 and produces a thermal drawdown of approximately 5-7 °C over the 30 year simulation period. The entire system is simulated using the geothermal systems assessment model, GT-Mod (Lowry et al., 2010).

Within the model, the drilling cost is calculated from each of the cost curves as a function of the resource depth. The simulations are run by assuming a target LCOE value and then adjusting the depth of the resource (and hence the drilling cost) until target LCOE's of 8, 10, 12, 14, and 16 ¢/kW-hr are achieved. Because each cost curve assumes a different number of casing strings, which is also dependent on the depth, each simulation is run multiple times to insure that the casing design is consistent with the depth of the resource and the technology in place.

The final step is to cross reference the depths with the SMU depth to temperature maps (SMU, 2017) to determine the area at each depth where the temperature is 200 ^oC or greater (Table 2). The shallowest map is at 3500 m depth so for depths less than 3500 m, a linear interpolation was used from 0 km^2 at 0 m depth to 132 km^2 at 3500 m depth. A second order polynomial was used for depths > 3500 m.

Table 2 – Summary of the area in km^2 of given temperature at depth (SMU, 2017).

Temperature [^oC]	Depth [m]			
	3500	4500	5500	6500
50	959,748	57,343	84	0
75	3,463,269	2,118,408	475,820	34,149
100	1,474,285	2,467,154	2,777,864	1,309,683
125	1,319,183	1,091,751	1,571,730	2,556,464
150	125,161	1,248,734	872,892	1,071,523
175	3,847	346,121	1,075,472	729,618
≥ 200	132	16,283	571,723	1,644,157

3. RESULTS AND DISCUSSION

For the Base Case, Intermediate 1, and Intermediate 2 scenarios, an LCOE of 8 ¢/kW-hr was unattainable at any depth and for the Ideal case was only attainable at a depth less than 500 m. For that reason, the 8 ¢/kW-hr case was re-simulated by assuming a 500 m depth and then calculating the resulting LCOE. This is reflected in the second column of Table 3 where 500 m is listed as the criteria as opposed to a target LCOE. The LCOE values under the 500 m column are those calculated with the drilling cost for a 500 m depth.

Table 3 - Results of simulation analysis reflecting the required depth and the cost per well to reach the criteria LCOE.

Scenario	Criteria				
	500 m	10 ¢/kW-hr	12 ¢/kW-hr	14 ¢/kW-hr	16 ¢/kW-hr
Base Case	9.29 ¢/kW-hr $2,000,857	1233.91 m $2,762,272	2604.96 m $4,680,792	2970.53 m $6,411,590	3642.01 m $8,206,606
Intermediate 1	8.73 ¢/kW-hr $1,520,569	2214.69 m $2,904,762	3545.67 m $4,746,433	4576.08 m $6,632,729	5239.12 m $8,059,025
Intermediate 2	8.52 ¢/kW-hr $1,355,310	2534.58 m $2,995,765	5283.84 m $5,212,461	7092.19 m $6,670,506	8827.55 m $8,069,712
Ideal Case	8.13 ¢/kW-hr $915,792	3404.13 m $3,050,204	6085.34 m $5,050,781	8076.08 m $6,483,891	9160.76 m $7,281,091

While it might be expected that the drilling costs should be the same for identical LCOE values, the results show that that is not the case. Several factors contribute to this. First is that the pumping requirements change with depth. At shallower depths, more pumping power is required because the difference in hydrostatic bottom hole pressure between the injection and production well is less (Figure 2). Secondly is that for deeper wells, the production temperature at the plant is less than at shallower depths due to a higher degree of cooling as the geofluid moves up the production well. For a reservoir temperature of 200 ^oC at 500 m, the geofluid cools approximately 1.15 ^oC while at 7000 m, it will cool 15.25 ^oC. Cooler production temperatures also require a higher mass flow rate to produce the same amount of power, further differentiating each scenario.

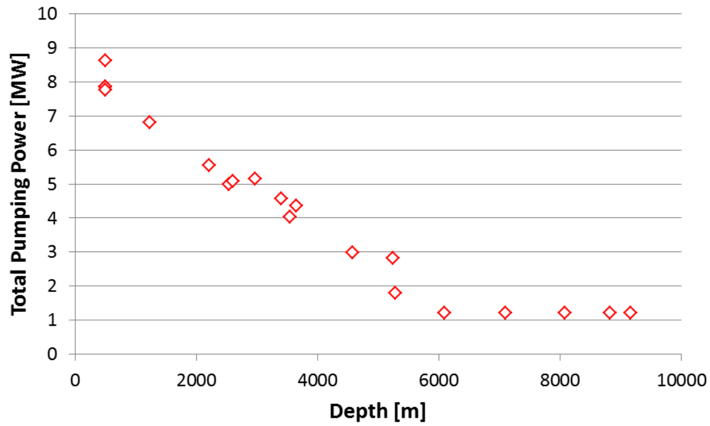

Figure 2 - Pumping power as a function of depth. The pumping power includes both plant and well pumping requirements.

The left plot of Figure 3 is a plot of the LCOE as a function of drilling cost and shows that for every half-million dollar decrease in drilling cost there is a 55 cent decrease in the LCOE. Conversely, the right plot of Figure 3 is a plot of the exploitable area as a function of the drilling cost indicating that the amount of exploitable area for every dollar increase in drilling cost grows exponentially faster by a factor of 2.25 for the Ideal case versus the Base case. This results in 14, 800, and 45,000 times more area for the Ideal case over the Base case for wells costing $2,500,000, $5,000,000, and $7,500,000, respectively.

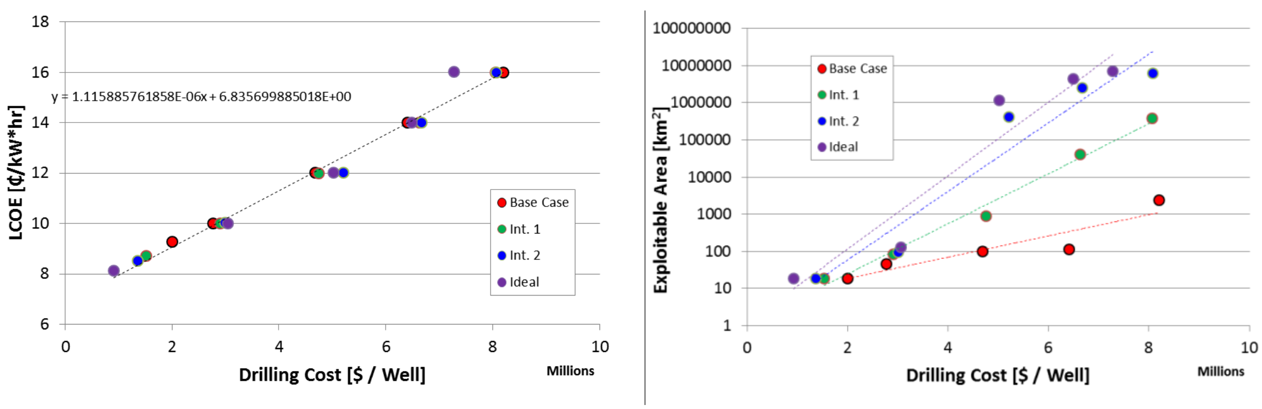

Figure 3 - Plot of the LCOE (left) and exploitable area (right) as a function of drilling costs.

4. SUMMARY

This study has looked at the practical consequences of drilling technology advancements in terms of resource availability. Target LCOE values of 8, 10, 12, 14, and 16 ¢/kW-hr were met by adjusting the drilling cost of a hypothetical EGS system using well designs stipulated by the technology. Results show that for the highest drilling technology advancements (the Ideal case), the available exploitable area increases exponentially over the Base case by a factor of 2.25, which results in 45,000 times more area when drilling a $7,500,000 well. Increases in the exploitable area means that other factors such as leasing costs, ease of access, grid connectivity and the like can come into play. This may allow for further reductions in the LCOE as cost factors not associated with drilling are taken into account.

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