2022 GETEM Geothermal Drilling Cost Curve Update

Preprint

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2 CGG

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2022 GETEM Geothermal Drilling Cost Curve Update

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Keywords

Geothermal, drilling, GETEM, GeoVision, cost curve, API, oil and gas, FORGE

ABSTRACT

The Geothermal Electricity Technology Evaluation Model (GETEM) is an essential tool for the U.S. Department of Energy's (DOE) Geothermal Technologies Office (GTO) to understand the performance and cost of technologies it is seeking to improve. This detailed model is used for supply curve analyses, assessing the current economic feasibility and levelized cost of energy (LCOE) of hydrothermal geothermal systems and enhanced geothermal systems (EGS), and evaluating the potential impact of advanced geothermal technologies. GETEM can be used to estimate the performance and costs of currently available U.S. geothermal power systems. It is also used to estimate the costs of technologies 5 to 20 years in the future, given the direction of potential research, development, and demonstration (RD&D) projects. The model is intended to help GTO determine which proposed RD&D programs and projects might offer the most efficient improvement when using taxpayer funding. The model requires annual updates as well as revisions to reflect the current state of the art.

Drilling costs are a significant portion of total geothermal development costs. The current GETEM drilling cost inputs rely on drilling data from 2009 and require an updated analysis of more recent data to ensure they remain representative of current technologies. An updated, more accurate understanding of costs could help the geothermal industry secure project development financing and investment funding and better allow the oil and gas (O&G) industry (both operators and service companies) to weigh potential geothermal market participation and customization.

This report details recent drilling improvements from the Utah Frontier Observatory for Research in Geothermal Energy (FORGE) and the O&G sector, comparing drilling performance and costs with values in GETEM, particularly the baseline drilling cost curves. Although drilling performance at FORGE has improved significantly, we did not find associated cost decreases that would justify lowering the GETEM baseline cost curves at this time.

1. Introduction

Drilling costs can account for up to 50% of the capital cost of developing a representative 50-megawatt (MW) geothermal plant (Tester 2006). In addition, it is thought that drilling costs could exceed 75% of the total project cost of EGS developments (Petty et al. 2009). Indeed, drilling costs are a significant fraction of any geothermal development's total cost and ensuring they are accurate is vital to the planning and development of geothermal projects.

The most recent geothermal cost analysis was conducted in 2017 as part of the landmark U.S. Department of Energy (DOE) *GeoVision* study (*GeoVision* 2019). In "GeoVision Analysis Support Task Force Report: Reservoir Maintenance and Development," Lowry et al. applied the lessons and data from numerous previous geothermal drilling studies (e.g., Tester et al. 2006; Polsky et al. 2008; Bush and Siega 2010; Finger and Blankenship 2010; Sanyal and Morrow 2012; Lukawski et al. 2014; Yost et al. 2015; DOE 2016; Lukawski et al. 2016) to create up-to-date geothermal cost curves using the Well Cost Simplified (WCS) model (Lowry et al. 2017). These studies relied on drilling data from oil and gas (O&G) wells through 2009 and geothermal wells through 2013. However, the drilling sector in both industries has continued to make efficiency and technology advancements throughout the past decade. This report examines drilling data from the American Petroleum Industry (API) Joint Association Survey (JAS) on 2019 drilling costs and data from Utah FORGE to compare with and potentially update the baseline drilling cost curves used in GETEM.

2. Oil and Gas Drilling Costs

Geothermal drilling costs are frequently compared to those from O&G. Though there are many similarities between the industries, the comparison is somewhat limited because geothermal wells typically contain challenges that O&G wells do not, such as:

1. Harsh downhole environments, including high temperatures, hard and abrasive rock, and/or corrosive groundwater chemistry.
2. Large diameter boreholes to accommodate the higher flow rates necessary for geothermal electricity or heat production.
3. Lack of similarity from well to well, making the learning curve less useful (Finger and Blankenship 2010).

Later analyses agree that a direct comparison between O&G and geothermal drilling costs cannot be made (Lukawski et al. 2014, Lowry et al. 2017). In addition, previous work has attempted to create cost indexes to link geothermal drilling costs to O&G costs as a function of depth with limited success (e.g., Augustine et al. 2006; Mansure et al. 2006; Tester et al. 2006; Polsky et al. 2008; Sanyal and Morrow 2012; Mansure and Blankenship 2013). However, because the O&G industry drills several orders of magnitude more wells in the United States every year (>21,000 in O&G vs. <20 in geothermal in 2019), there are more data available and it must be considered (API 2020, Robertson-Tait et al. 2020).

Mansure and Blankenship (2006, 2013) found that the Bureau of Labor Statistics Producer Price Index (PPI) for drilling O&G wells is most appropriate for trackin drilling costs. This PPI updates monthly and accounts for all well construction costs, including rig rates, labor, casing, cementing, and rentals costs. As seen in Figure 1, the PPI has varied greatly over the past 20 years due to oil prices, global economic events, and Covid-19. For reference, the Consumer Price Index and West Texas Intermediate price of oil in Cushing, Oklahoma, are also shown on Figure 1.

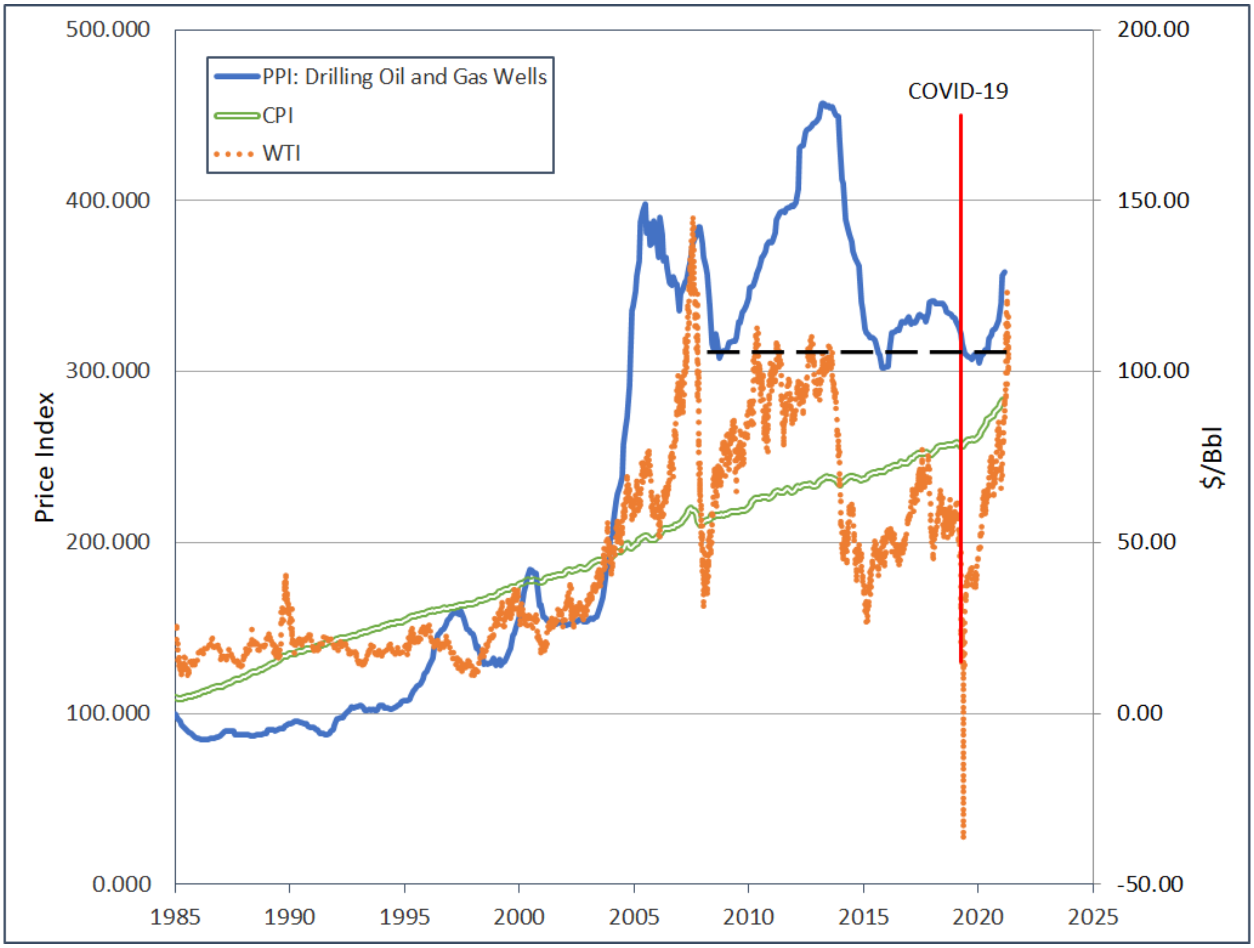


Figure 1: Bureau of Labor Statistics Production Price Index (PPI) for drilling O&G wells versus the consumer price index (CPI) versus the West Texas Intermediate (WTI) price of oil. The dotted line indicates the PPI level in 2009. Figure is updated from Lowry et al. (2017). Source: Federal Reserve Bank of St. Louis.

The Covid-19 pandemic upended the global economy, causing unprecedented changes in markets, industry, and the demand for oil. The most extreme result of this can be seen in April of 2020 when lockdowns brought travel and many industries to a halt and the price of oil briefly fell to nearly $0 per barrel. The subsequent years of the pandemic have seen drastic increases in inflation and the price of oil, leading to sharp upward trends in all data displayed in Figure 1. Because of the extraordinary conditions surrounding the post-Covid data, they were not considered in this analysis.

The pre-Covid data, however, are relevant to this analysis. The PPI indicates that the pre-Covid O&G drilling costs in 2019 were similar to the costs in 2009, which were partly used to build current GETEM drilling cost curves. Additionally, there is no clear trend in O&G drilling costs that can be used for future drilling cost predictions.

Perhaps the most comprehensive source of O&G drilling costs in the United States is the JAS, published annually by the API. It organizes wells drilled in the United States in any given year by geographic location (onshore, offshore), state, well type (shale, exploratory, development, sidetrack) and well class (oil, gas, dry). The well costs are further split into 11 total measured depth footage intervals. Unfortunately, the JAS does not differentiate between vertical, directional, and horizontal wells. The JAS data have been employed by several influential geothermal drilling-cost analyses. In particular, Lukawski et al. (2014) used the 2009 JAS data to create the Cornell Energy Institute well cost index, which is frequently referenced in geothermal literature.

Conventional wisdom asserts that the state of O&G drilling has changed significantly in the past decade. Operators in the most active areas, such as the Permian Basin, tout faster drilling times and lower costs (Hunn 2017, Dittrick 2019). However, the JAS data do not reflect this trend. Figure 2 shows the average drilling costs for all onshore wells drilled in the United States from 2010 to 2019. When normalized for drilling activity and adjusted for inflation, it shows that drilling costs have remained relatively static.

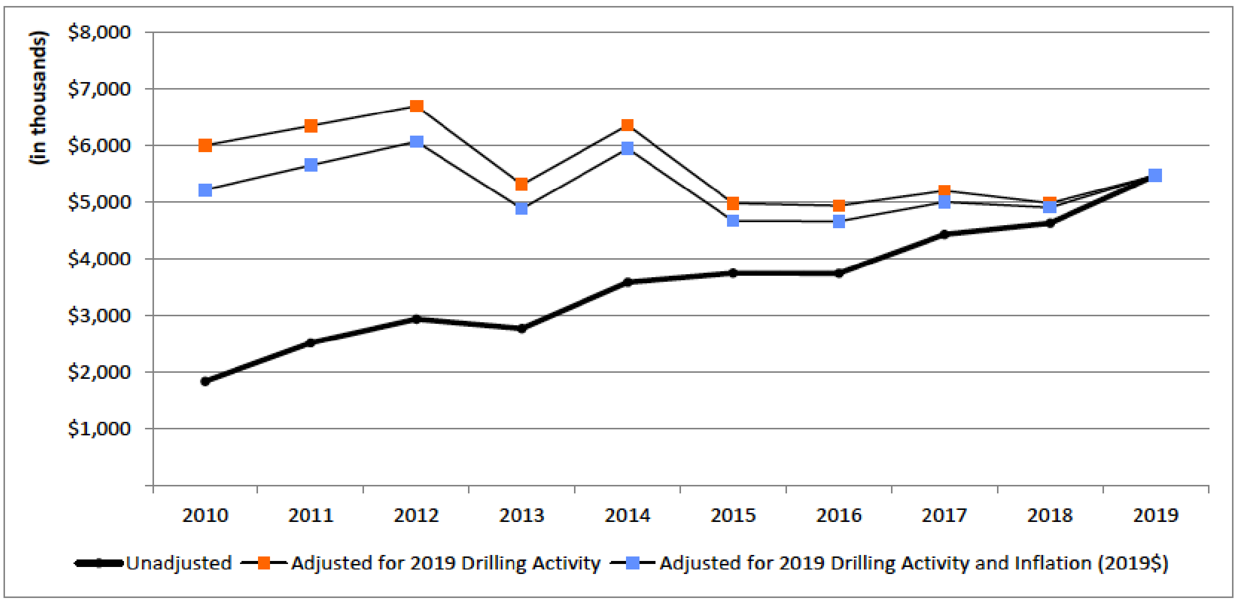


Figure 2: Average drilling cost per well for onshore wells from 2010 to 2019. Source: JAS 2020

Indeed, when focusing on shale wells, which feature the most repeatability and should see the steepest learning curve, the results are essentially the same. Figure 3 shows the average cost per foot of U.S. shale wells from 2015 through 2019. This is a relatively short time period, but as it encompasses the bulk of the drilling boom in most U.S. shale basins, we would expect to see drilling costs steadily decline. However, like in the previous data set, the cost per foot of shale wells remains relatively stable during this time.

The JAS data predate any Covid-19 effects, which began affecting oil demand in March 2020. This is advantageous for this analysis, as the anomalous effects of the pandemic are not representative of general cost trends.

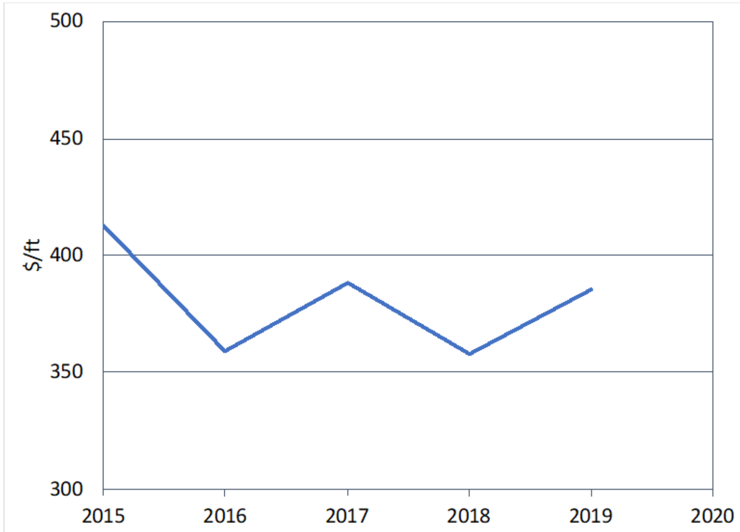


Figure 3: Average drilling cost per foot of U.S. shale wells. Source: API 2020

Although we asserted earlier that there is not a direct correlation between geothermal and O&G drilling costs, it does seem likely that they would follow similar trends. In this instance, O&G drilling costs remained relatively flat from 2009 through 2019. The PPI index indicates that the cost decreases seen at the beginning of Covid-19 are somewhat modest and quickly faded as oil demand and prices increased. Nothing in this examination of O&G drilling costs suggests that the geothermal drilling curves created by the *GeoVision* Reservoir Maintenance Task Force warrant significant revision.

3. FORGE Drilling Performance and Costs

An ongoing challenge for evaluating geothermal drilling costs and performance is the lack of public data. Lowry et al. (2017) used seven deep geothermal wells drilled in Australia from 2003 to 2010 to calculate the rate of penetration (ROP) and bit life inputs for the WCS model used to create the GETEM drilling curves used in *GeoVision*. Ideally, the GETEM cost curves would be updated with more current drilling results. One source of recent public data is the DOE-funded FORGE project, which has drilled multiple wells near Fallon, Nevada, and Milford, Utah.

Hackett et al. (2020) compared the performance of the polycrystalline diamond compact (PDC) bits used to drill the FORGE 21-31 well to the tri-cone bits used to drill the nearby Fallon 82-36 well. PDC bits are widely used in the O&G industry for drilling all manner of wells, but historically have been rarely used in the geothermal industry due to low reliability and high cost. Tri-cone bits are more prevalent in geothermal wells and were used in the Australian wells examined in Lowry et. al (2017). Hackett et al. found that when correctly applied, however, PDC bits can deliver faster ROPs that more than offset their higher cost.

Over the course of the Utah FORGE project, the operators drilled a variety of test wells, experimenting with different PDC bit designs, drilling efficiency parameters, and well types. The three most recent wells drilled at FORGE demonstrated the culmination of these efforts with greatly increased ROPs (Winkler et al. 2021, Samuel et al. 2022). Drilling performance and cost data from these wells were compared against the values currently used in the *GeoVision* baseline cost curves.

WCS uses average ROP and bit life values in its well cost calculations. To better compare the FORGE results to the baseline cost curves, we needed to determine which numbers to use. Table 1 shows the average ROPs for each interval in the three most recent wells drilled at Utah FORGE. Well 16A(78)-32 is particularly interesting because it includes a long (3,566') tangential section at a 65° incline, a first in a geothermal well. The following wells, 56-32 and 78B-32 showed continued ROP improvement indicating advancement along the learning curve. ROPs were calculated using on-bottom hours and hole depths. We did not include experimental bit runs, clean out runs, or coring runs in these averages.

Table 1: Depths and average ROPs for each well interval of the three most recent wells drilled at Utah FORGE.

Direction	Region	Depth in (ft)	Depth out (ft)	Diameter (in)	Average ROP (ft/hr)	Well
Vertical	Surface	28	1,629	17.5	134	16A(78)-32
Vertical	Surface	134	381	17.5	206	56-32
Vertical	Surface	128	421	22	84	78B-32
Vertical	Intermediate	1,629	5,113	12.25	32	16A(78)-32
Vertical	Intermediate	381	3,500	12.25	251	56-32
Vertical	Intermediate	360	3,009	14.75	92	78B-32
Vertical	Hard rock	5,113	5,892	8.75	17	16A(78)-32
Curve	Hard rock	5,892	7,389	8.75	31	16A(78)-32
Tangent	Hard rock	7,389	10,955	8.75	42	16A(78)-32
Vertical	Hard rock	3,500	9,145	8.75	31	56-32
Vertical	Hard rock	3,009	8,545	10.65	62	78B-32
Vertical	Hard rock	8,545	9,500	5.75	100.5	78B-32

For the three FORGE wells, nearly all of the bits were PDCs, and the majority were pulled due to drilling tool failures, core points, or hole section total depths (TDs) and not bit wear. Two 8.75" bits in well 56-32 were pulled because of slow ROP due to bit wear. These bits drilled 1,209' and 1,234' and were on bottom for 52 and 37 hours, resulting in an average bit life of 45 hours. One 10.625" bit in the 78B-32 well drilled a record 2,110' in only 32 hours. However, this bit life value was not factored into the average, as the very high ROP led to a low bit life value, which would have degraded our cost calculations.

Currently, the WCS model uses a single average ROP and bit life value across the entire well. This may be updated in the future, but to stay consistent with this convention, average ROP values were calculated for each well. These are shown in Table 2.

Table 2: Average ROP values for the 3 most recent FORGE wells.

Production Diameter (in)	8.75	10.625	8.75	8.75
Well Type	Vertical	Vertical	Horizontal	Horizontal
Average ROP (ft/hr)	46	72	36	43
Bit Life (hrs)	45	-	-	-
FORGE Well	56-32	78B-32	16A(78)-32	Combined[1]

The planned modifications to the baseline *GeoVision* WCS model are shown in Table 3. The average ROPs from FORGE are significantly higher than those used to create the baseline cost curves. The ROP values we used are conservatively based on FORGE results. Though FORGE bit life data are limited, it is similar to the values used in the *GeoVision* WCS runs (45 vs. 50 hours) and does not justify a change. As ROPs increase, the WCS reliance on bit life for cost calculations may need to be updated.

Table 3: Possible revised single-well values for WCS, along with the values currently used in *GeoVision*.

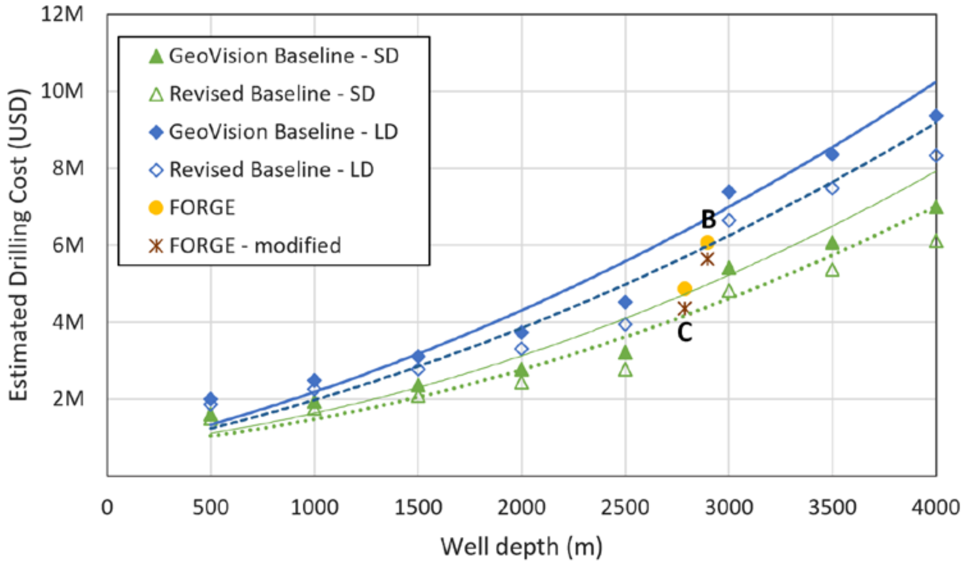
	Vertical		Horizontal	
	GeoVision	Revised	*GeoVision*	Revised
Average ROP (ft/hr)	25	45	25	40
Bit Life (hrs)	50	50	50	50

Figure 4 shows the original *GeoVision* baseline curves and revised well cost curves from this analysis. As seen in the figure, inputting our results into WCS decreased the baseline curves by approximately 10% for all four *GeoVision* baseline cases (vertical and horizontal liner production sections, each with "small diameter" and "large diameter" versions). The production zones in the "large diameter" and "small diameter" wells are 12.25" and 8.5", respectively. The Utah FORGE wells have production zone diameters of 8.75" [2], so they should be compared to the "small diameter" curves. Though well 16(A)-78 is not horizontal as modeled in *GeoVision*, it contains a long tangential section which is likely closer to what the industry will adopt for EGS wells.

Figure 4 also includes the actual costs of the three Utah FORGE wells. The "FORGE" costs include all reported well costs, whereas the "FORGE—modified" costs exclude costs and drill time associated with science that would not be conducted at a development well, such as coring and experimental equipment testing.

[1] The vertical section of well 16A(78)-32 included some experimentation and monitoring, so it was drilled comparatively slow. This section was replaced with the vertical section of 56-32, drilled at the same diameter, for a "combined" average ROP.

[2] Well 78B-32 has a diameter of 10.625" until the last 1,000' which is 5.75". This is closer to the small diameter case than the large.



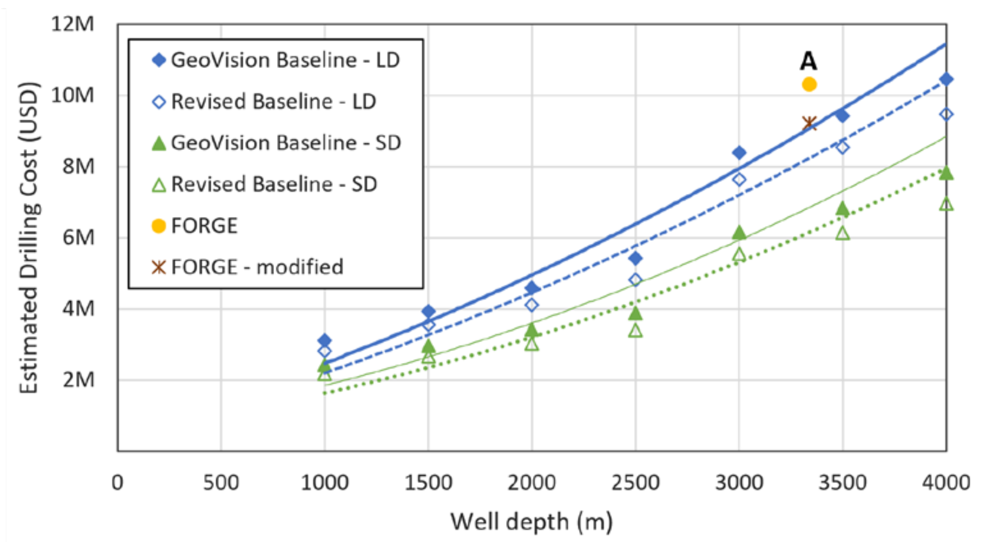


Figure 4: GeoVision WCS original and modified baseline cost points and associated polynomial fit curves for vertical (top) and horizontal liner (bottom) large diameter (LD) and small diameter (SD) wells. Well costs from Utah FORGE wells are overlayed for wells 16(A)-78 [A], 56-32 [B], and 78B-32 [C].

Utah FORGE wells demonstrate a significant improvement in both drilling speed and well cost over the current state of the art. However, when examining the comparison between the *GeoVision* curves and actual FORGE costs in Figure 4, a decrease in the *GeoVision* baseline curves does not appear to be justified. Despite the imperfect comparison, the original small diameter baseline curve matches the actual modified FORGE costs in the vertical case with surprising accuracy. The horizontal case is a less apt comparison due the long tangential section in well 16(A)-78. Nonetheless, a 65° well is likely to be less costly than a horizontal well, and the 16(A)-78 was significantly more costly to drill than the baseline curve predicted.

4. Conclusions

Ensuring that the cost curves used in GETEM accurately reflect the current geothermal industry is essential for GTO, industry stakeholders, and other decision makers in geothermal. Due to the sparsity of publicly available data, these cost curves were based on broad literature reviews of geothermal and O&G data prior to 2013 (Lowry et al. 2017). In this report, the GETEM cost curves have been revisited and compared with more recent O&G data and new geothermal drilling results from the Utah FORGE site. The key insights from these sources of well cost data are:

- Despite advancements in pre-Covid O&G drilling performance over the last 10 years, drilling costs have remained relatively constant.
- Results from the most recent Utah FORGE wells show significant increases in ROP in hard rock with the use of PDC bits and drilling efficiency measures. Well average ROPs are double the values used in the creation of the baseline *GeoVision* cost curves used in GETEM. Increasing the ROPs in the *GeoVision* WCS runs to match the FORGE ROPs decreases the cost curves by approximately 10%. However, FORGE well costs, even when adjusted to be more representative of development wells, align more accurately with the unrevised baseline cost curves.

Overall, the last decade has seen relatively constant drilling costs in O&G but noted improvements in drilling performance in geothermal wells as industry stakeholder adopt new tools and techniques. However, these improvements have not yet translated to costs lower than the baseline curves. Total well costs are also dependent on site, rig costs, and many other factors besides ROP. To justify a baseline cost curve update, a larger sample of final well costs from FORGE and the geothermal industry must be examined and demonstrate total well costs below the current baseline curve. Accordingly, we do not recommend a decrease to the GETEM baseline cost curves at this time.

Our analysis of well costs also shows the limited impact of ROP on total geothermal well costs. Though higher ROPs decrease drilling time and associated costs, it has no effect on other costs such as the time and material costs associated with casing and cementing. To further reduce geothermal costs, these costs must also be decreased. As more geothermal is deployed and recent improvements are embraced by industry, the GETEM curves should be reexamined.

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