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Use of the Experience Curve to Understand Economics for At-Scale EGS Projects

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ABSTRACT

A significant advantage of proposed enhanced geothermal systems (EGS) projects is the repeatability of projects in similar geologic conditions in a condensed area. This allows for geologic, technical, and experience learnings to be applied directly from project to project. This paper outlines the impact of those learnings on economics as projects increase in scale.

The experience curve is a well established concept in industry used to estimate future cost and economics. Examples from the geothermal industry and the oil and gas industry were examined to determine a reasonable range of slopes for the experience curve for EGS projects. Furthermore, the cost and performance improvement of the US onshore shale industry was reviewed in depth to determine both the experience curve effects and provide a case study on improvement in at-scale subsurface projects.

Potential projects in Switzerland, the eastern United States and the western United States were evaluated using the range of values generated for the experience curve in the previous investigation. A specific horizontal, multi-stage completion well design was used to generate cost estimates and modeled temperature and flow rate assumptions for each case study. This information was then used to determine an unsubsidized LCOE for each project at different phases of maturity. The results show an initial high cost relative to market prices, but the experience curve shows a clear road map to generating cost competitive EGS projects even without any step change breakthrough in technology.

1. INTRODUCTION

EGS has enormous potential to be a significant part of the energy mix and provide flexible clean energy in numerous environments (INL, 2006). However, investment and research is hindered by a perception that EGS is a high cost resource and will continue to be a high cost resource. For example, the Annual Technology Baseline conducted by NREL stated “Thorough literature review for hydrothermal geothermal technologies or EGS technologies cost reduction has not been conducted” and assumed no cost reduction through 2050 (Cole et al, 2016). Other technologies at similar cost points have enjoyed significant public and private R&D based on an assumption of a declining cost curve. This paper seeks to use benchmarks and industry validated assumptions to show a clear roadmap to a declining cost curve and understand the implications of the cost curve.

EGS has the potential to greatly reduce exploration and development risk and decrease the dry hole rate by reducing reservoir risk. Because EGS can function in reservoirs with wider ranges of porosity, permeability, fracture distribution, and connectivity than conventional hydrothermal reservoirs, the risk profile of exploration and development wells can be thought of as similar to unconventional shale wells in oil and gas. Through hydraulic fracturing and other technology developments, the oil and gas industry has been able to reduce the percentage of dry holes for shale production to a significantly lower amount than historical rates, as shown in Figure 1 from Cochener (2010). This enables shale wells to be planned for in campaigns of hundreds or even thousands of wells at a time with a high degree of repeatability. As a result, unconventional operators have adopted a manufacturing mentality to field development where wells have more opportunity for experience curve effects than previous, conventional projects.

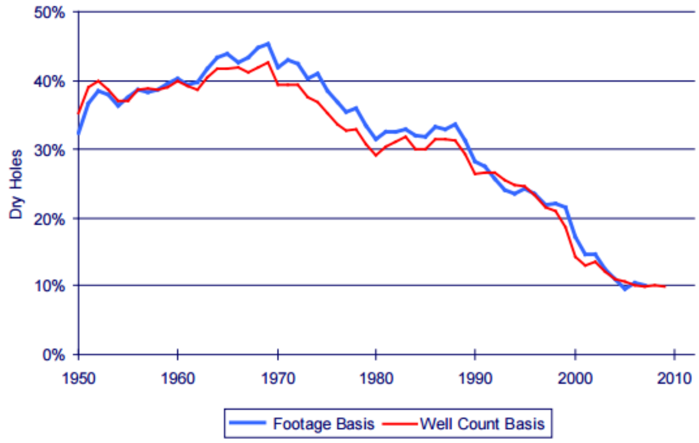


Figure 1: Evolution of dry hole rate over time in US oil and gas wells (Cochener, 2010).

The experience curve is a well established concept in industry for understanding cost projections and is shown in Equation 1 (Boston Consulting Group, 1972 and Lieberman, 1987):

$$c(x) = ax^{-b} \tag{1}$$

where *c(x), a, x, and b* are marginal cost, cost of the first unit, cumulative output, and learning elasticity, respectively.

First developed in 1960s by Bruce Henderson of the Boston Consulting Group, the experience curve has been applied to oil and gas in numerous applications. The dramatic increase in activity associated with the shale boom in the United States and the shift in mentality to a manufacturing mindset provides an excellent case study for the application of the experience curve. Studies of early field development show significant improvement in the first few wells of field development and continued improvement with an increase in volume as predicted by the experience curve (Cochener, 2010). The improvements come from a variety of sources, including reduced geologic uncertainty, crew and engineering familiarity, and incremental technology advancements. Section 3 will present a number of case studies across drilling, completions, and facilities construction that provide evidence of how this cost reduction works in practice.

Using the example of shale oil and gas development and an example of geothermal field development, an estimate and range of acceptable b values was developed. These values were combined with detailed estimates of development costs for a particular EGS project design to calculate LCOE for initial projects and full field projects involving differing numbers of wells. The EGS design used is based on the Haute-Sorne project in development by Geo-Energie Suisse which includes a doublet parallel well system, fully horizontal wellbores, and multistage stimulation with zonal isolation. Estimates were also developed for potential projects in the eastern and western US by scaling the costs to estimates of US based pricing differences and local thermal gradients. For any areas of the project that are not specifically costed out from the Haute-Sorne projects, estimates from the Department of Energy GETEM model were used.

The results present a clear picture of potential cost reduction for EGS fields and for EGS projects as a whole. Under reasonable ranges of assumptions for costs and learning, EGS LCOE approaches and even surpasses the wholesale electricity price in numerous markets after a number of wells have been completed. In some markets and scenarios this can take hundreds of wells to achieve, but in favorable markets there is potential for developing cost competitive EGS in just a few iterations. EGS projects in favorable markets, where the cost of electricity is high, where there is already a significant carbon market in place, or where EGS power can be further monetized through flexible generation, have the potential to be cost competitive today.

2. USE OF THE EXPERIENCE CURVE

The experience curve has a long history of application throughout industrial cost projections. It is used to understand economics over the life of a project or new product and is based on the observation that for many products an efficiency of a certain amount, referred to as the learning rate, is achieved with every doubling of cumulative production. These efficiencies come from many different factors, including learning, specialization, investment, and scale (Boston Consulting Group, 1972). The most important factors for using the experience curve are understanding how and when the curve can be applied and further understanding what range is appropriate for the learning rate. Sections 2.1 and 2.2 will look at the validity of applying the experience curve to EGS by looking for examples of the experience curve in subsurface development and understanding the implications of the manufacturing mentality on use of the experience curve. Section 3 will then use examples from efficiency gains in unconventional oil and gas and EGS projects to determine appropriate ranges for the learning rate in EGS projects.

2.1 Use of the experience curve in subsurface development

There are numerous examples use of the experience curve in subsurface development projects. Kellogg (2011) used experience curves to measure interfirm learning in productivity of oil and gas drilling in Texas from 1991-2005. Formigli et al. (2011) examined the impact of experience effects on development of Brazil's presalt cluster. Covert (2014) used the experience curve to evaluate the performance of hydraulic fracturing in the Bakken shale. The literature shows that the experience curve is an appropriate model to showcase productivity in subsurface projects.

2.2 Manufacturing mentality in EGS and unconventional oil and gas

The mentality and approach to unconventional oil and gas development makes the experience curve a highly suitable tool for cost projections. It is often said operators always knew where the oil and gas from shale was, they just didn't know how to get it out. Unlike conventional formations and exploration projects with significant heterogeneity of resource within a field, shale formations and wells are far more predictable. While there is still in-field heterogeneity, the predictable nature of shale allows operators to plan their drilling programs years in advance and thousands of wells ahead. For example, EOG recently reported that they have 3,200 drilling locations remaining, or >10 years worth of wells at current activity levels (Burgher et al., 2016). This enables operators to plan repeatable projects on a scale unknown in the past. This repeatability has caused a shift in thinking about field development that allows for more scale, longer term thinking, and a lean manufacturing mindset that drives costs and efficiencies. While oil and gas has always been suited to analysis using the experience curve, the new manufacturing mentality of unconventionals makes it particularly applicable.

Similarly, EGS projects have the potential for far greater scale and repeatability than traditional hydrothermal geothermal projects. Because EGS uses stimulation to induce permeability, places horizontal wellbores to increase reservoir contact, and has the potential to create closed loop systems with water recirculation, the criteria for finding a suitable EGS location are broader than conventional projects. This will allow for large exploitation of resources that have the appropriate thermal gradient and suitable reservoir characteristics that will bring a scale and repeatability similar to unconventional oil and gas development. Because of this, in a similar way that the experience curve is particularly applicable to unconventionals, it is also particularly applicable to EGS development.

3. CASE STUDIES OF COST REDUCTIONS

The cost reductions and efficiency gains in unconventional oil and gas are well known. Since the beginning of the growth of unconventionals, completions have grown significantly larger, drill times significantly faster, projects have become more cost effective, and rigs have become more productive (EIA, 2016). In some measures, these cumulative improvements have been dramatic, as shown by the per rig productivity in the Eagle Ford in Figure 2 (EIA, 2017). This figure shows a common measure of productivity, new-well oil production per rig. In the last five years, the value has risen from ~250 bbl/day in 2012 to 1,417 bbl/day in January 2017, a more than five-fold increase in just five years. All other major US unconventional basins have experience similar levels of improvement. Similarly, EGS projects have shown increases in productivity with each iteration. Section 3.1 will explore the cost reductions seen during the development of shale resources. Section 3.2 will examine the evolution of drilling performance of an EGS project to showcase the efficiency gains. Section 3.3 will use these examples to propose some acceptable learning rates.

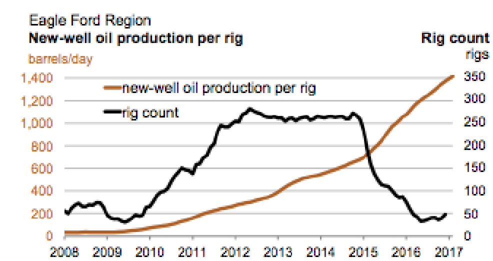


Figure 2: Eagle Ford drilling productivity (EIA, 2017)

3.1 Unconventional oil and gas

Unconventional oil and gas projects both improve dramatically in performance in the very beginning of a campaign as seen in Figure 3 and continue to improve incrementally at large scale as seen in Figure 4. Improvements come from both decrease normalized costs due to scale, innovation, and efficiency and also from increased production performance due to learning and optimized techniques. To illustrate the process of experience and innovation in unconventional development, the following subsections present specific projects that have led to lower costs or increased performance. These case studies provide some examples of how a confluence of numerous incremental improvements can combine to generate the rapid and dramatic improvement in productivity observed in Figure 2.

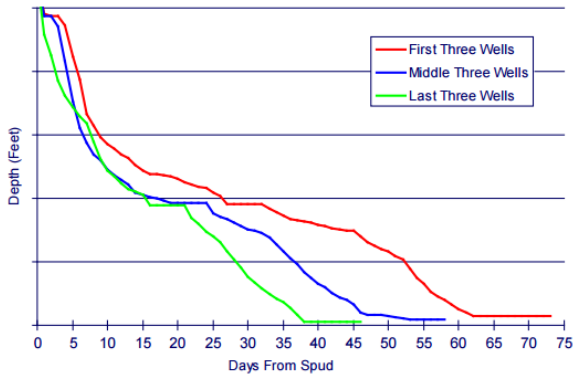


Figure 3: Haynesville drilling days at the start of a new campaign (Cochener, 2010)

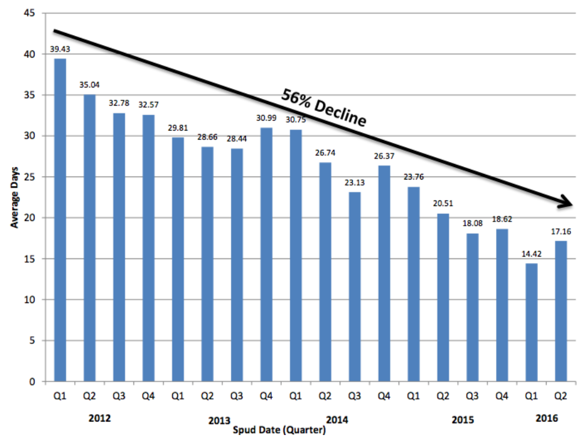


Figure 4: Average drilling days by quarter for the Williston Basin (Whiting Petroleum, 2016)

3.1.1 Drilling cost reductions examples

Drilling costs are a function of the drilling time, the time cost, and the materials consumed. One of the major inputs to drilling cost, and also a substantial area of improvement, is drilling time. Operators gain experience in a field and work with suppliers to develop new solutions and technologies that reduce drilling time. For example, one operator in the Eagle Ford was able to analyze the parameters that impact bit or BHA failure for the intermediate to TD section of the well bore and develop an optimized solution that increased success of one-run wells from 25% to 85% of wells (Walker and Patton, 2016). Another recent improvement in drilling time came from a service company that developed a way to transmit survey results continuously to the surface, saving 4-5 minutes per survey, or 12-24 hours per well (Weatherford, 2016). Another example comes from rig moves, where operators have been able to reduce rig move times by 40% by taking advantage of lean methodologies (Check Six, 2016).

In addition to efficiencies that lead to reduced drilling time, reduction in materials used results in cost savings. For example, one service company developed a fluid additive shielding technology specifically for the Wilcox zone of Eagle Ford drilling wells that provided for hole stability that enables operators to eliminate an intermediate casing string (Bradbury et al., 2016). One company developed a novel process for drying oil-based mud cuttings in a way that allowed the cuttings to be recycled as a road base material, eliminating disposal costs and purchase costs of road base material for new locations (Wynn, 2015).

Innovations like these, especially when combined with increasing crew experience and increasing subsurface knowledge of a particular basin, add up to explain the rapid progress observed in oil and gas unconventional development.

3.1.2 Completions cost reductions examples

Completions costs are also a function of the time, the cost rate, and materials consumed. Numerous innovations since the onset of the unconventional boom have substantially improved both the cost and productivity of unconventional projects. One example is the development and implementation of zipper fracing, a technique where two or more wells are stimulated at once. This decreases the time per well by almost a factor of two and also has an impact on increased production and has become the standard in the industry since it's development in the early 2010s (Jacobs, 2014). Similarly, the growth of recycling flowback water has substantially lowered costs, an EIA (2016) study showed recycling costs $.17/bbl compared $2.00/bbl for disposal. A traditional well will spend several hundred thousand dollars on sourcing and then disposing water, so that represents a significant cost saving. Additionally, early in the days of hydraulic fracturing, screen outs would regularly occur that would require operators to shut down mid operation and flowback a well.

O'Leary (2006) describes screen out rates in directional wells of over 50% in the San Juan basin in 2006. Today, screen outs are virtually non existent, leading to major productivity gains and allowing operator to reduce contingency equipment and personnel from wellsites.

3.1.3 Facilities and other cost reductions examples

Numerous cost reductions and efficiencies have also impacted the delivery of onsite facilities as well. The most impactful innovation was the rise of pad drilling, the ability of multiple wells to be located from one pad. This allows for efficiency gains in drilling and completions but also allows for material reductions in per well pad and facility costs. By placing multiple wells, often 4-6 but sometimes up to 20, on a single location, many economies of scale can be realized. In 2006, fewer than 5% of wells were drilled on multi well pads. By 2013, that percentage had increased to 60% (Thuot, 2014). One operator estimated that pad drilling saved them $.3 million/well compared to single well pads (Bellatrix, 2012).

3.2 Geothermal projects

There is also evidence that geothermal projects receive significant benefits from learning. Figure 5 shows the development of the Unterföhring project in the South German Molasse Basin (Böhm, 2014). The normalized drilling rates decline by approximately a factor of two over the course of the eight wells in the program. INL (2006) proposed a model that incorporates learning for decreased subsurface costs, decreased surface and plant costs, increased exploration success, and increased flow rates. For a parameter such as drilling cost, they proposed a decrease from the base case of 25% by the fifth well.

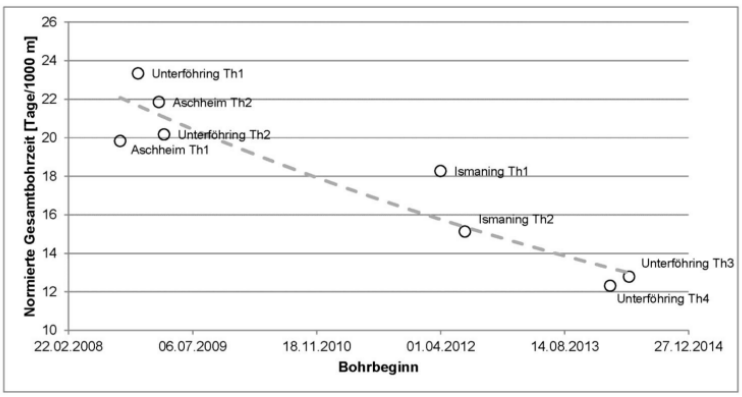


Figure 5: Normalized drill times for the Unterföhring project in Germany (Böhm, 2014)

3.3 Experience curve values

The value or range of values used for the learning rate of the experience curve has a significant impact on the long term cost projections of EGS projects. Rubin et al. (2015) found no examples of learning rates specifically for geothermal in a literature review but estimated a 30% learning rate based on analyzing EIA data from 1980 to 2005. McDonald and Schrattenholzer (2000) analyzed data across numerous parts of the energy sector and determined that the bulk of learning rates for different technologies fell between 18% and 25%. Although the authors did not specifically examine geothermal, the closest analogue, oil extraction, had a learning rate of 25%. Based on this analysis and fits to oil and gas and geothermal data, the learning rates examined in this study range from 18 to 30% for drilling.

4. APPLICATION OF THE EXPERIENCE CURVE TO EGS PROJECTS

4.1 The Haute-Sorne Project

The project used as a case study for the learning curve effects is the Haute-Sorne project in development by Geo-Energie Suisse in Switzerland. Detailed cost analyses have been performed for the first two wells in the program, the Gloverlier-1H (GVL-1H) and Gloverlier-2H (GVL-2H). The wells incorporate a doublet design and will be drilled to a TVD of 4500 meters and have fully horizontal laterals at 1500 meters. Thirty zones will be isolated and stimulated using sliding sleeves and swell packers. Drilling and stimulation costs have been developed and benchmarked from offset wells in the area.

Costs will decline after the first well from a variety of sources. First, as a pilot project, there are a number of aspects of the first well that will not be included on subsequent wells. For example, the current GVL-1H includes coring, a timely and expensive task, that will not be included in subsequent wells. Second, many of the costs allocated to the initial well will benefit from scale as the project expands. For example, the upfront land acquisition costs will decline on a per well basis as more and more wells are drilled in the same area. Similarly, the engineering and risk analysis tasks for the subsequent wells will be much more streamlined as they will be able to benefit from the upfront work done on the first wells. Finally, costs will decline as a result of learning as discussed in this paper.

Figure 6 shows the estimated cost reduction from the first well to the tenth well in the program from these sources. The cost reductions come from a variety of sources. The largest reduction comes from reduced drilling time and associated costs due to learning and removal of some timely phases of the drilling process related to formation evaluation such as logging. Next, reduction in stimulation cost from learning related efficiency gains. Additionally, wellsite construction costs decline on a per well basis because of the ability to use similar features on multiple wells.

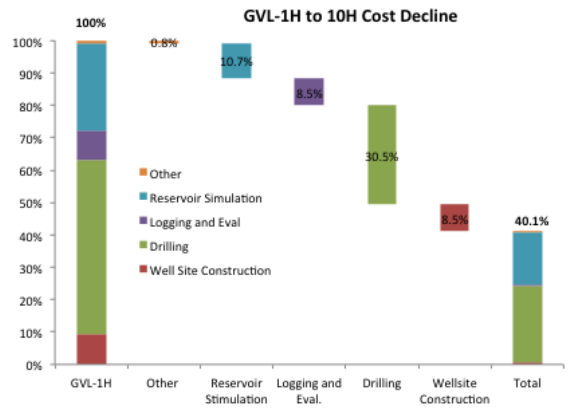


Figure 6: Cost decline from Well 1 to Well 10 for the GVL program.

The cost projections were then combined with estimates of operating costs, output, surface capex costs and other factors to determine the evolution of the LCOE over the development of a large-scale EGS system. Where direct cost estimates for the project were not available, assumptions based on GETEM and local market conditions were made. The results can be seen in Figure 7. High level cost model assumptions can be shown in Table 1. The initial project costs are high, but the combined effect of learning and economies of scale quickly bring the cost down to a competitive rate based on the unsubsidized wholesale cost of electricity. When other revenue and cost factors are considered, such as the renewable energy and carbon offsets, sales of waste heat to industrial partners or district heating systems, and general government financial support, there is an opportunity to finance early stage projects through to a point where they reach the unsubsidized rate.

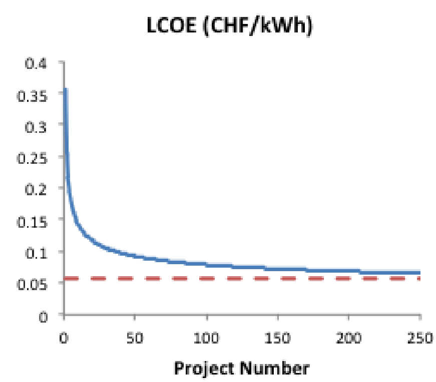


Figure 7: LCOE in CHF/kWh based off assumed learning rate. The red line represents the most recent average price for the wholesale electricity market in Switzerland.

Key Assumptions	Value
Well design	Doublet
Drilling Learning Curve Ratio	76%
Initial Gross Output	5 MW
Initial Net Output	3.5 MW
Decline rate per annum	0.5%
Annual OPEX	1.1m
Output Learning Ratio	105%
Surface Costs Learning Ratio	95%

Table 1: High level assumptions for cost model.

4.2 Eastern and Western US

Next, potential project sites in the Eastern and Western US were evaluated. The cost structure here differs from Switzerland from two main sources. First, because there are different thermal gradients in these markets, the design temperature can be achieved at shallower depths. There may be an opportunity to find an optimized temperature-depth tradeoff that provides for more overall value, but for simplicity it is assumed that the depth is designed to the same temperature. Second, the market in the United States is more favorable to lower costs. This is both because the drilling ecosystem is more established than in Switzerland and because the regulatory and approval process is more established. Figure 8 and Figure 9 show the impact of the better market conditions for developing in the United States and the impact of decreased depth on costs. Costs related to depth are scaled to an assumed depth of 2500 meters for a western US project and 3500 meters for an eastern US project.

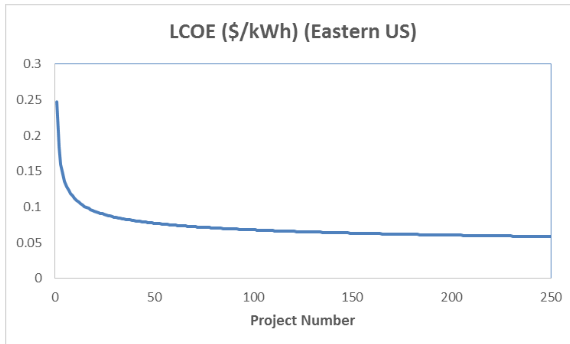


Figure 8: Projected cost curve for Eastern US project based on adjustment from GVL-1H Base Case.

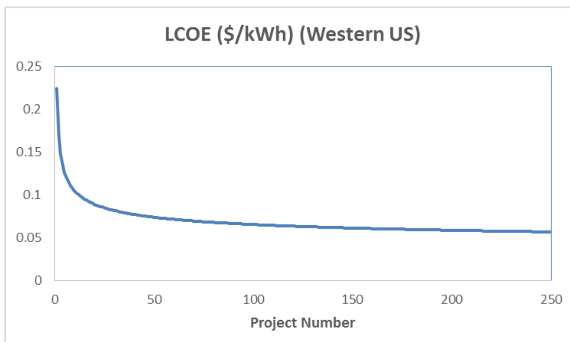
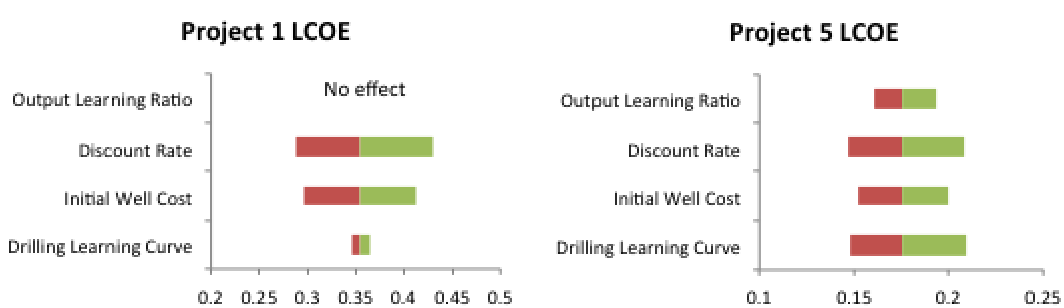


Figure 9: Projected cost curve for Western US project based on adjustment from GVL-1H Base Case.

4.3 Scenarios and Sensitivities

Assumptions related to well cost, output learning ratio, discount rate, and the drilling learning curve can have a significant impact on project economics. Figure 10 presents the impact of each assumption on the LCOE of the base case Haute-Sorne project for four different doublets in the development process, the first, fifth, fiftieth and 250th project. The output learning ratio dictates how much the production is able to be increased through learning over time. The drilling learning curve dictates the subsurface costs. In the early projects, the initial well cost and discount rate are key factors in well costs. As more and more projects are completed, the output learning ratio and the drilling learning curve become the most important factors in LCOE.



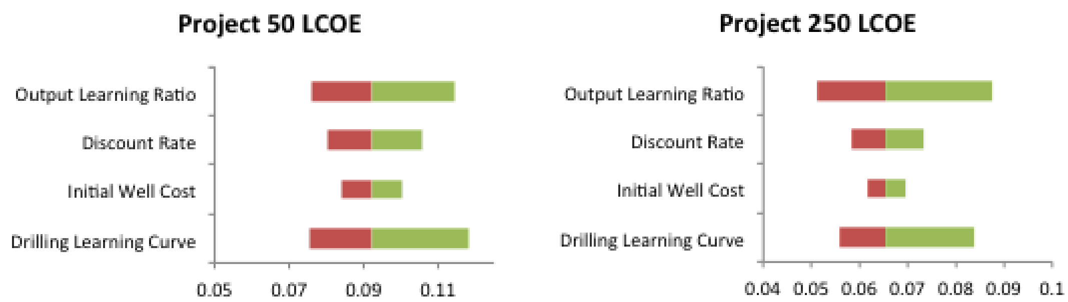


Figure 10: Sensitivities of LCOE on the base case project for key assumptions.

	Low	Base	High
Output Learning Ratio	110%	105%	100%
Discount Rate	3%	5%	7%
Initial Well Cost	80%	100%	120%
Drilling Learning Curve	70%	76%	82%

Table 2: Assumption range for sensitivities.

5. CONCLUSION

- Private investment and public support into geothermal and EGS is hindered by a perception that costs cannot decrease in a reliable manner to be cost competitive with other resources.
- The literature provides few examples of analysis of learning and its impact on cost projections for geothermal and EGS projects which makes it difficult to attract attention of other stakeholders.
- However, the evidence shows that learning curves apply to subsurface projects, including oil and gas and geothermal projects with an estimated range of learning rate between 18% and 30%.
- Moreover, EGS projects are particularly well suited to application of the experience curve due to their potential for reduced exploration risk that enables a manufacturing approach to project development.
- Evaluation of the recent US oil and gas unconventionals boom shows that a confluence of factors related to scale, learning, and innovation lead to dramatic improvements in cost and efficiency of drilling and completions.
- Applying the concept of the experience curve to EGS projects in Switzerland and the United States show a clear roadmap to approaching cost competitive EGS projects at the unsubsidized wholesale rate of electricity under a range of scenarios.
- Early stage research and development resources deployed into pilot projects and development of EGS projects can accelerate the development of commercially viable EGS resources in the near term.

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