Towards Affordable Geothermal Power: Economic Impacts of Innovation and New Technology

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ABSTRACT

In order to develop a true understanding of the long-term costsof emerging energy technologies, it is important to assess costs on the basis of both the technology's current status as well as a likely future state based on innovations and technology advancements. We are currently conducting such an assessment for geothermal energy technology with particular emphasis on Enhanced Geothermal Systems (EGS). In this paper, we will report our efforts to forecast the implications of innovation and their impact on future cost of power from EGS.

Specifically, we have conducted a detailed assessment of technology advancements and innovations across drilling, well stimulation, and power plants. Leveraging patent data, paper literature, and detailed expert elicitations, we have inventoried a number of innovations and new technologies ranging in maturity from conceptual to commercially proven albeit in complementary industries such as oil and gas. Further, we have developed estimates of improvements along performance and cost metrics for each of these innovations. Finally, we have used a number of analytical models including the U.S. Department of Energy's Geothermal Electric Technologies Evaluation Model (GETEM) to assess the levelized costs of electricity (LCOE) for a series of cases with varying levels of technology improvements.

Preliminary results show that cost reductions range from 20%-50% for drilling, 5%-30% for well construction, 20%-40% for well stimulation, and 10%-38% for power plants. Based on these improvements, the LCOE for an illustrative EGS system can be reduced up to 40% from a reference case. Our paper will report additional details and cases from this on-going work.

Introduction

Enhanced geothermal systems (EGS) have enormous promise but face major roadblocks due to their high costs. This paper deals with the major cost components of EGS and how their cost structure may evolve with continued technological development to make EGS economically more attractive. Some of the technologies mentioned here have a potential to transform the economics of EGS.

Methodology

To develop our understanding of long-term costs of electricity produced from EGS,we carried out a detailed analysis of current status of EGS and the potential technological improvements that are likely to enhance the performance and reduce the cost. Leveragingdata from a comprehensive and on-going expert elicitation program along with articles from peer reviewed journals, patents, and reports we listed a number of innovations and new technologies across drilling, well construction, well stimulation and power plants.

Further we used number of analytical models to develop our own estimates of cost. These centered around the U.S. Department of Energy's Geothermal Electric Technologies Evaluation Model (GETEM). We assessed the levelized costs of electricity for various scenarios considering different levels of technology improvements.

Results and Findings

Our analysis driven byexpert elicitation and in-depth literature review identified several major cost components of EGS plants. Table 1 lists them along with their contribution to total cost.

Some of the technologies presented here are in conceptual form; however preliminary results demonstrate their potential to reduce the cost. The remaining technologies are proven commercially in complementary industries such as oil and gas.

Drilling

For any geothermal project, exploration, production, and injection well drilling are major cost components and account for 30% of the total capital investments even for high-grade geothermal resources. For low-grade resources, it may increase up to 60% or higher. Hence any efforts in the direction of reducing the drilling

Table 1. Key cost components and their distribution in the total cost of EGS plant.

	Cost Component	% of Total Cost	Comments
1	Drilling	40-70	Includes rig rates and operating costs
2	Reservoir development	15-30	Including fracking, stimulation, fluid production
3	Power plant	20-35	Heat exchangers and turbines
4	Risk management	2-5	Surveillance, seismic issues, stakeholder relations
5	Transmission	1-5	Infrastructure and grid integration

cost would greatly reduce the investments and consequently the price of electricity generated.

New drilling technologies focus on improving rate of penetration (ROP) and increasing bit lifetime to reduce the drilling cost substantially. Some representative promising new drilling technologies are discussed here.

Expandable Tubulars

In conventional wellbore construction, casings are arranged in a nested arrangement. With every new drilled interval, a new casing is lowered through the previously drilled and cased interval. So the new casing's outer diameter must be smaller than inner diameter of the previous casing. Continued use of such casings eventually reduces the bottom-hole diameter with increasing depth. Therefore in order to achieve larger bottom-hole diameter, uppermost casing has to be of very large diameter which increases the drilling cost radically.

Expandable tubular[1] is a special technique useful in improving drilling and well construction. In this approach, a radially expandable new casing is lowered through previous casing and then expanded plastically to the same diameter as previous casing. This allows the larger diameter drill bit passage leading to larger diameter wellbore than in the conventional situation.

The major benefit of this process is the ability to drill near-single-diameter wellbores. This is estimated to save as much as 50% on drilling since it eliminates use of multiple casing strings while keeping the bottom-hole diameter large. Use of expandable solid tubulars is also a valuable approach for corrosion problems where a lining of corrosion-resistant material is expanded inside cheap and less corrosion-resistant casing.

This technology was originally developed by Shell and was commercialized by Shell and Halliburton. For the first time Shell and Saudi Aramco demonstrated its usefulness and then it became one of the most quickly accepted technologies in oil & gas industry. It is currently being practiced in North America, Middle East and China.

Spallation

Drilling deep boreholes 10,000 ft or deeper in hard rock is difficult with conventional drilling methods. Low rates of penetration, frequent wearing of drill bit and drill string, number of round trips made for changing damaged bits and drill strings increase the cost of drilling tremendously. Spallation eliminates the majority of these problems.

Spalls are thin flakes and spallation is taking thin flakes off the rock surface. There are various ways of spalling a rock such as gas spallation, combustionflame jet[2], electrical heating, thermo-mechanical, and combination of thermal and mechanical or fluid[3]. In all these methods, rock surface is heated instead of traditional mechanical abrasion to break the rock. On heating certain types of hard rocks do not expand uniformly. Due to this rock surface is stressed enough to flake and break apart. The temperatures used are 500° C or more above the ambient temperature of the rock. Heating quickly is important. This technology, especially spallation using fluid has been commercialized by Potter drilling company.

The combustion flame is useful for air-filled boreholes. While drilling deeper, when the borehole has to be filled with water or mud for mechanical stability, it is difficult to use flame under water column. Further, most flames produced by combustion reactions are very high temperatures, 1800-3000° C or more. This destroys downhole tools and also can melt the rock making it unspallable. In such situations, other types such as gas or fluid spallation help.

This technique eliminates the need for drill string rotation. Further there is no contact between rock and end of the drilling apparatus which eliminates the wear caused by the abrasion at tool-rock interface. It make the process 3-5 times faster and reduces the cost of drilling by 50%.

Some of the challenges involved are spallation suffers from overheating and it is difficult to maintain the thermal flux especially in combustion jet spallation. Some rock types are not spallable. Also it creates a little CO_2 in the process.

Particle Jet Drilling

As the wellbores are drilled deeper, not only the cost of drilling increases exponentially, but also the rate of penetration slows down due to hard rock formations. The drill bit and other downhole equipment get damaged and straight, vertical (directional) drilling becomes a challenge. Particle jet drilling helps alleviate these issues.

This technology was first used in the preliminary form in 1980. However, because of very high pumping pressure requirements, it was ignored for over two decades. This is an advanced hydraulics based drilling system. Slurry containing solid particles mixed with drilling fluid is circulated through a pipe string and is forced through a nozzle to impact and disintegrate the rock[4]. The rock in front of the drill bit gets chipped off, a process called as kerfing. This way the drill bit has to remove less rock and the remaining rock brakes down in relatively larger pieces easily compared to conventional techniques.

Some recent improvements in the technology avoid equipment erosion and use lower surface pumping pressures. The velocity and mass of the solid particles in the slurry play an important role. Larger (higher mass) particles rather than high velocity particles, increase the impulse energy required for cutting.

By adjusting the particle injection rate (by using mass and velocity relationship), one can design rate of penetration for practically any type of rock formation. When tested, PJD bit was found to be universal with the ability to drill all types of rocks with higher rate of penetration.

In this method the non-contact PJD bit is used instead of conventional rotary mechanical drill bit or jet-assisted drill bit. This bit entirely works on action of particle impingement for cutting the rock formation. This eliminates the problems associated with direct-contact drilling techniques including the bit life and also results in straight holes. Up to 20 times greater penetration rates were observed. Using this drilling technique along with production technological breakthrough can provide the ability to have reservoirs that can produce 400,000 – 600,000 bbl/day or more of superheated water[5].

Chemically Enhanced Drilling Method (Drilling by Dissolving)

In conventional drilling, drilling fluid jets are used for sweeping the rock cuttings. To increase the efficiency of cutting, high pressure jets are used. These high pressure high velocity jets, usually with water, also mechanically grind down the rock being drilled. However, this grinding is limited to the soft rock formations and fails for hard rocks such as Granite in EGS drilling.

In oil and gas industry acid is frequently used for well stimulation and to increase the production rate. Acid dissolves constituents of the rock and increases rock permeability, creates fractures in the rock. A combination of this and high pressure jets approach is used in chemically enhanced drilling. Drilling fluid with chemicals dissolves the rock ingredients thus creating a borehole. Acids such as hydrochloric acid, formic acid, acetic acid either alone or in combination are used for the rock formations containing basic minerals such as calcium carbonate[6]. For subterranean formation, hot aqueous hydroxides of alkali metals are used[7].

There are many advantages associated with this method. Because the rock is being dissolved, there is no need to bring the cuttings to the surface. Hence there is no need to use specialized drilling fluids that can suspend the rock cuttings. Settling tanks and solid handling equipment on the surface that remove the cuttings from drilling fluid before recirculation are not required. Since there is no need for all the drilling fluid to return to the surface, no need of plugging to stop leak-off. Some drilling fluid can be lost without damaging the wellbore by moving solid cuttings. Besides this method has a potential to increase rate of penetration to 100-150 ft/hr by using 5% acid.

Some challenges faced by this method are: (1) In conventional drilling method, in order to maintain the control of the hole, it needs to be sealed as soon as drilled. Chemically enhanced drilling is not capable of doing this. (2) Conventional drilling rigs are not compatible with corrosive fluid used in this method.

Power Plants

High efficiency turbines, variable phase turbine and Euler turbine can increase the net power production by 30-50% compared to standard ORC turbines[8].

Variable Phase Turbine

This technique makes use of discrete two-phase nozzles impinging upon an axial impulse rotor. This achieves high constant entropy efficiency while allowing the direct drive of generator without a gearbox. The need for lube oil system is eliminated thus avoiding efficiency loss and reducing the cost. This turbine with a liquid heat exchanger, a pump and a condenser together known as 'variable phase cycle', produces 30-50% more power than a standard ORC (Organic Rankine Cycle) besides reducing the complexity and cost.

Euler Turbine

This is a radial outflow turbine and has several advantages over radial inflow turbine. The standard ORC absorbs heat the form of latent heat and creates a pinch point limiting heat input into the cycle. The ideal thermodynamic cycle (such as when Euler turbine is used) eliminates this boiling pinch point and recovers more heat converting recovered heat into electricity more efficiently. The performance of this turbine has been validated through successful tests where 30-50% more power was generated.[9]

Hybrid Power Plant

A novel approach of coupling biogas power plant and geothermal power plant is being explored in Germany.[10] It is the first worldwide plant using combination of two renewable energies. The excess heat from the cooling cycle and the exhaust fumes from gas engine of biogas plant are fed to the geothermal plant. This additional heat input increases efficiency resulting in more electricity production. An additional advantage would be lower emissions. It is anticipated that this plant would generate ~12% more power while reduce CO_2 emissions by up to 46,000 tons per year.

Well Stimulation

Since natural rock-permeability rarely meets the conditions required for geothermal power production, the rock-permeability could be artificially enhanced. In order to stimulate the reservoirs, large volumes of fluid is introduced under very high pressures into the host rock, the process known as hydrofracking. Due to self-propagation effect of fractures, the permeability increases.

In order to maximize heat transfer in EGS, all the fractures in the hot dry rocks need to be networked optimally. Cold water circulation through reservoir results in rock contraction, thus creating a tensile stress. This leads to the nucleation of new cracks, the effect know as secondary thermal fracture. For reservoir stimulation this mechanism could be explored further.[11]

Chemical Stimulation[12]

This technique involves mineral precipitation/dissolution. For the acid treatment number of factors such as acid solubility of formation, type of formation, formation porosity and permeability, type of mud used, and length of perforated or open hole interval need to be considered.

The steps involved in the process are:

1. Preflush (typically uses 10-15% hydrochloric acid) – removes calcium and carbonates in the formation
2. Mainflush (mixture of 10% hydrochloric acid and 5% hydrofluoric mud acid formulation) – dissolves silicate minerals and most drilling muds. This is injected slowly to allow all the silica to dissolve.
3. Postflush/overflush (dilute, 3% hydrochloric acid or ammonium chloride) followed by fresh water – displaces acids and any precipitation reaction products thus reducing potential corrosion to casing or lining.

This technique has been used over three decades ago[13] and has a potential to improve injection or production capacity of a well by 100%[14]. In another type of chemical stimulation, common chelating agents[15,16] such as EDTA and HEDTA are proved effective in dissolving carbonates at temperatures above 200° C. This technique has been lab tested as well as field demonstrated[17].

Use of Supercritical CO_2 for Heat Extraction

In the 1970s, the Los Alamos National Laboratory was actively involved in field testing and demonstrating the Hot Dry Rock (HDR) geothermal energy concept. Based on this work, heat mining using supercritical carbon dioxide ($SCCO_2$) for both reservoir creation and heat extraction was proposed[18].

This concept of engineered geothermal reservoirs appears to be advantageous over conventional water-based system in following ways:

1. Unlike water, density of CO_2 changes significantly with temperature. This creates a large density difference between cold CO_2 in the injection well (0.96 g/cc) and hot CO_2 in the production well (0.39 g/cc). The resulting thermal siphoning due to large density difference would significantly reduce the circulating pumping power required compared to the water-based system.
2. Water coming out of geothermal well is not chemically toxic but contains lot of minerals, particularly silica and carbonates, which makes it impossible to use the geofluid directly in the turbine, resulting in scaling in the surface piping, surface equipment and heat exchangers. This could be eliminated by use of $SCCO_2$ since CO_2 does not dissolve minerals from the reservoir.
3. Thermodynamic efficiency can be increased since reservoirs above 374° C (critical temperature for water) could be developed without problems such as silica dissolution in water.
4. Ancillary benefit – Geological storage of CO_2 (sequestration)

There are some concerns about use of CO_2 compared to water. When referred to binary power plants, the mass heat capacity of $SCCO_2$ is only 2/5 that of water, however, the ratio of fluid density to viscosity, which reflects reservoir flow potential, is 1.5 times that of water due to low viscosity of CO_2. This makes the geothermal energy production using CO_2 60% that of water-based system. However, again the pumping power requirements are low for CO_2-based systems, thus making it equivalent to the water-based system as far net power production is considered.

Another advantage is while improving the economics of the HDR power generation this also allows continuous sequestration of CO_2. Such a power plant would have a capacity to sequester about same amount of CO_2 per MWe produced as much produced by coal fired plant (24 tons of CO_2 per day per MWe).

The first ever three dimensional simulations of CO_2 injection-production system[19] shows very strong effect of gravity on mass flow and heat extraction due to large density difference between cold injection and hot production wells. The problem of dense cold CO_2 flowing along the bottom of the reservoir can be avoided by producing from the limited depth at the top of the reservoir.

Evaluation of thermophysical properties of CO_2 and water using numerical simulations[20] to explore the fluid dynamics and heat transfer issues in use of CO_2 show that the heat mining ability of CO_2 is somewhat superior to water. The lower density and higher compressibility / expansivity of CO_2 help reduce the fluid circulation power consumption.

Aqueous solution of CO_2 can be quite corrosive and can dissolve rock minerals. The CO_2 induced chemical interactions between rocks and fluids, indicates potential for increased porosity and reservoir growth. The possibility of aqueous CO_2 solution being harmful to the steel pipes and casings can be ruled out since flowing CO_2 stream would quickly remove water from the reservoir and continuous operation would produce rather dry CO_2.

Another advantage with $SCCO_2$ relates to the inevitable fluid loss in EGS. While loss of water in conventional EGS systems is undesired and costly, loss of CO_2 would offer geological storage of CO_2 and may prove to be beneficial for future carbon management needs. Further, CO_2 uptake and sequestration by rock minerals is much faster at elevated temperatures[21].

Impact of these technologies on individual cost components is shown in Figure 1. As drilling confiscates the major portion of the total cost, any improvements in drilling would lead to a significant cost reduction. Technologies such as expandable tubular, spallation and particle jet drilling demonstrate potential to reduce the drilling cost by 50% while well stimulation is another area where chemical stimulation can save 40% on total stimulation cost. Improvements in the power plant lead to up to 30% cost reduction. Using this information, LCOE reduction was modeled which is discussed in next section.

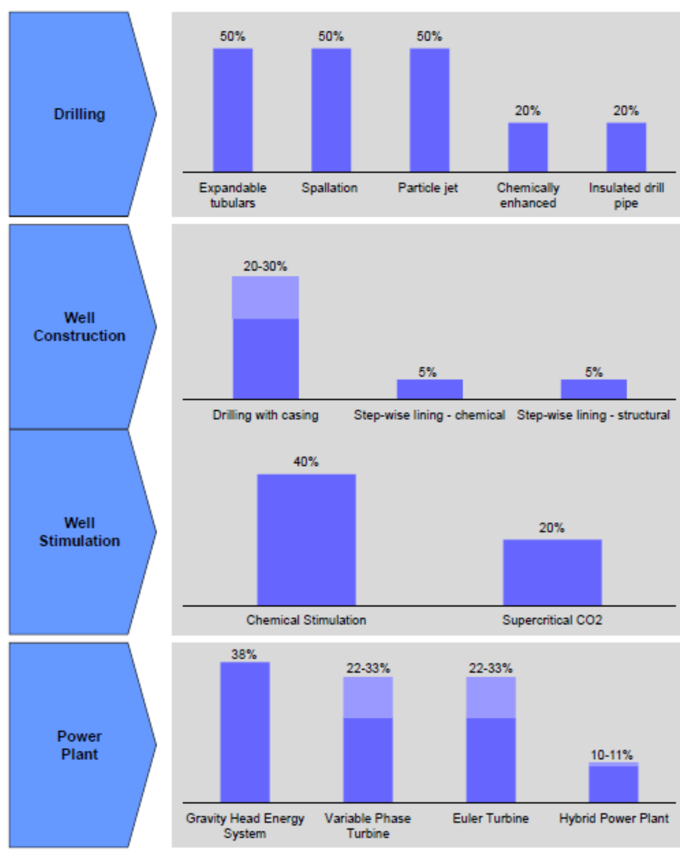

Figure 1. Impact of new technologies on cost of EGS components.

Estimation of LCOE Reduction

Based on above technological advancements and their potential to reduce the cost, we conducted some modeling studies using DOE's GETEM model. The resulting estimation for reduction in LCOE is shown in Figure 2 and Figure 3. We studied two reference scenarios considering deep EGS and near-field EGS conditions. As can be seen from the figures, there is a significant reduction in LCOE as a cumulative effect of the technological improvements described in this paper. Improvements in drilling have a major contribution to the LCOE reduction followed by power plant and well stimulation. In case of near-field scenario, these improvements bring down the final estimated cost closer to DOE target for 2020.

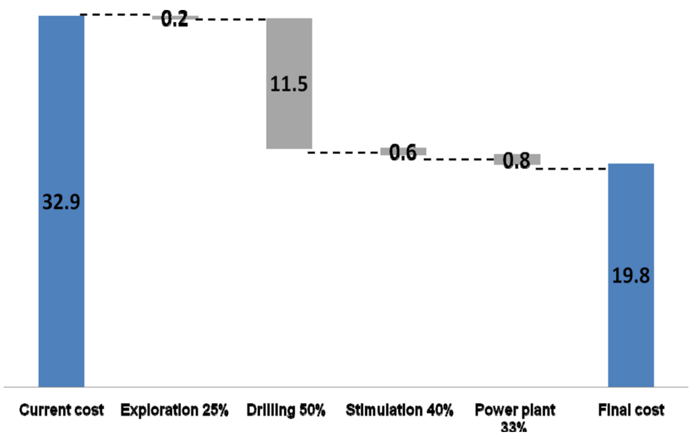

Figure 2. Impact of various technological improvements on LCOE for deep EGS scenario.

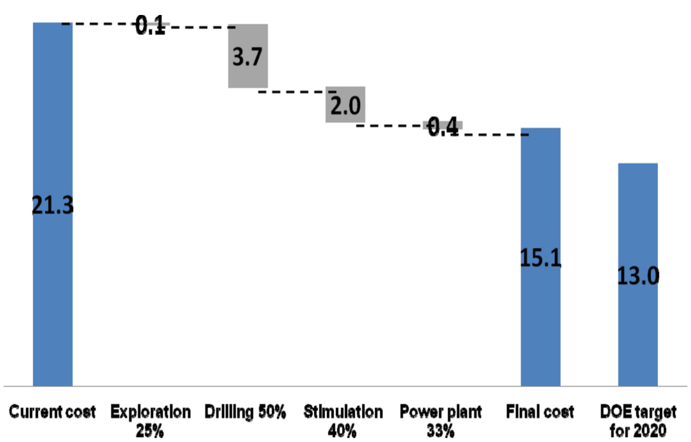

Figure 3. Impact of various technological improvements on LCOE for near-field EGS scenario.

Conclusions

Our analysis and expert elicitation has validated drilling, power plant and reservoir stimulation as the major cost components in the development of commercial EGS plant. However, a number of technologies were examined for potential to reduce EGS costs. Our modeling efforts showed that these technological advancements can reduce the cost of drilling and well stimulation by upto 20-50%collectively resulting in upto 30-40% reduction in LCOE.

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