Geothermal Energy Along The US Pacific Coast

The Costs and Risks Associated with Geothermal Development

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The United States has been slow to adapt geothermal power as a major energy player in large part due to the system's high initial investment and high risk during each stage of the development process. The result of this high risk and high cost dilemma has caused only the most secure and high grade projects to be undertaken, leaving numerous productive geothermal regions untapped along the Pacific Coast of the United States. In this paper, potential factors that could change the cost and risk properties of geothermal development are identified and historical and potential costs and risks are extrapolated. Expected values of baseline and potential scenarios are modelled and compared. With significant market intervention and the implementation of new technologies, risk premiums decline leading to increased investment and a broader range of financially viable geothermal development regions.

Overview

Geothermal development within the United States lags significantly behind that of alternative energy sources. Geothermal energy's growth rate in the United States stands at a modest 5%. Other forms of renewable energy such as wind and solar PV have growth rates in the range of 20% to 40%. The United States has been slow to adapt geothermal power as a major energy player in large part due to the system's high initial investment and high risk during each stage of the development process. The result of this high risk and high cost dilemma has caused only the most secure and high grade projects to be undertaken, leaving countless sites untapped and unexplored within the region. Technology improvements such as enhanced geothermal systems (EGS) and market intervention by government entities will mitigate a portion of these barriers to entry and stimulate the growth of geothermal energy along the US Pacific Coast.

While the Energy Portfolio of the Pacific Coast is diverse, Washington and Oregon have seen very little geothermal energy development and have instead invested heavily in hydroelectric and wind power. California, on the other hand, has more than 2,700 megawatts of installed capacity and is the top producer of electricity of geothermal energy in the nation. [7] Figure 1 shows temperatures 6.5km beneath the ground, a good measure of geothermal feasibility. The map shows Oregon, California, and Washington as having relatively high subsurface temperatures, seemingly making the region suitable for geothermal development. Substantial geothermal resources can be found in California's coastal mountain ranges, volcanic hotspots in northern part of the state, along the Nevada border, and Salton Coast [7] Although Oregon has nearly no geothermal development, The Department of Energy ranked the state as the third highest potential for geothermal development in the country due to its tremendous potential east of Cascade Mountains. [8]

This paper will examine what role geothermal energy plays in the energy production portfolio of these states and what factors might alter the initial costs and risks associated with development to enable geothermal to grow within the region. The first step this analysis will take will be to examine the costs geothermal developers face when developing a geothermal site. In conjunction with this, statistics about an average project's risk at these development stages will be drawn from well failure studies. From this cost/risk groundwork, this paper will then investigate how new technologies, namely EGS, as well as government market manipulation and investment in more accessible and widespread drilling information may make these barriers more manageable. Having outlined these potential modifications to the geothermal investment landscape, two theoretical projects will be juxtaposed: the first will base its risk and cost values on that of the average geothermal project in 2016, the second will have modified risk and cost values to reflect those factors that help mitigate geothermal energy's inherent barriers. Using a developer's theoretical risk function, the risk premium and certainty equivalent for each developer will show how these mitigating forces might change the decisions of potential geothermal energy developers.

Cost and Risk

In order for a geothermal well to be commercially viable, it needs to produce power at a levelized cost of electricity (LCOE) lower than today's typical power price level of 6 to 7¢/kWh. [2] This LCOE figure contains a system's lifetime costs and are divided by the its lifetime power output. Therefore, because the majority of a geothermal project's costs are associated with the plant's construction those initial costs are lower, the corresponding LCOE will drop as well.

The effects of geothermal energy's high initial investment are experienced by developers before drilling even begins. The most immediate costs that a developer confronts in the process are identification costs. These costs take the form of research and reconnaissance. This first step in creating a geothermal well, holds only 6 to 8% of a project's overall development investment, but has an extremely low success rate, as shown in figure 2. [6] In large part, the failure rate is so high because there is very little information that is both reliable and widely available to those who wish develop. Comparatively, wind power and solar energy are both easier to measure and have a more widespread implementation across the United States, resulting in vast amounts of public data¬¬¬.

The most prominent area of risk and investment is the drilling of wells. Drilling at any stage in the development process poses a prominent area of risk to developers. Forecasting this level of this risk for any specific site is generally a matter of speculation or an educated guess based on empirical data from similar projects. Additionally, drilling a high grade well field often accounts for around 30% of total capital investment while low grade wells can have a drilling cost that accounts for 60% or more of the project's total capital investment. [3] The risk associated with drilling a well comes from a variety of failures in the drilling or reconnaissance process. Circumstances that constitute well failure may consist of little to no self-flow (also known as dry-hole). A well with this symptom cannot be pumped with an external water source as the internal diameter of the casing is too narrow to accommodate a pump and the heated fluid temperature exceeds the limit of the pump. Additionally, a well that produces fluid to cool for commercial use would also be considered an unsuccessful well. [3] The frequency with which these circumstances occur makes geothermal energy's widespread implementation difficult.

These high upfront costs and high rates of well failure, as well as exploratory failures in the research and reconnaissance phase of development create gaps in available financing for geothermal projects. This gap creates two significant challenges for a developer: First, there is no risk-sharing mechanism, therefore the developer must bear a disproportionate share of project risk compared to other competing investments. [6] Second, there is a "money gap" created as a result of this risk construct: developers are not getting enough money needed to push the project past early drilling stages. [6] These financial issues effectively multiply the impact of failure for those risking development.

Potential Costs and Risk Mitigation

One remedy for these barriers to entry is the "learning curve effect", which essentially says that as the developer drills more wells, they gain more information about their specific drilling site. As the quality and quantity of site specific information increases, future wells will become more accurate in their risk assessments and increase development of successful wells. This effect is illustrated in Figure 4, the average Drilling success rate fluctuates heavily around 33% in the exploration phase and increases to a more consistent 70% average rate of success within the operations phase. The drilling success rate in the development stage (after 5 wells) is expected to be between 60%-100% while the rate after the operational stage (40 wells) is expected to be about 90% (the average is dragged down by former wells to around 70%). [3]. This increase in well success rate over time isn't exclusively due to the "learning curve effect" but also contains the effect of increasing the statistical size of the developer's sample.

Enhanced Geothermal Systems (EGS) may help decrease the risk of developing a high grade geothermal resource, low grade geothermal resource, or may help revitalize wells that are currently not commercially viable or underperforming. Enhanced geothermal systems would recover heat in the subsurface rock by creating or accessing a system of open, connected fractures through which water can be circulated down into injection wells, heated in the rock, and returned to the surface. Unlike traditional hydrothermal systems, EGS would not require naturally flowing reservoirs, but could instead draw steam from anywhere hot rock exists within the technology's drilling range. Traditional hydrothermal plants were highly site specific. The implementation of EGS would dramatically increase the number of potential high and low grade geothermal wells available for development as it solves the issue of site specificity. With a resource capacity estimated at more than 100 GWe in the United States alone, EGS has wide enough reach to make a dramatic contribution to the domestic renewable energy sector. [3] This higher quantity of sites now feasible for development will allow projects that are undertaken to have a higher probability of being successful.

EGS testing and early implementation demonstrates that the technology can improve the productivity of existing wells and have a dramatically lower possibility of failure. In 2013, Nevada-based Ormat Technologies increased power output by 38% within an operating geothermal field at the Desert Peak 2 demonstration site, generating an additional 1.7 MW of power. The increase marked the first commercial success of the technology. The technology increased the water injection rate up to 1500 gallons per minute generating new revenue, greater resource reserve, and production certainty. Even more important to the expansion of geothermal energy is EGS technology's inherently lower risk of failure. Once the wells are drilled and the reservoir is created and adequately tested, operating an EGS is less subject to "the vagaries of nature than a conventional geothermal system for the following reason. Operating a conventional geothermal project must deal with the uncertainties about hot water recharge, groundwater influx, increases in fluid acidity or gas content, success rate in make-up well drilling, and so on; these uncertainties all too often lead to "surprises" over the project life." [2]

Additionally, the economic viability of most geothermal generation projects are dependent on the financial support created by national and state-level energy policy. In both the short and long-term, these policy-based supports will be necessary to produce any level of investment in all but a select group of fringe projects. Government programs such as the Production Tax Credit (PTCs) as well as Renewable Energy Credits (RECs) have been installed in Washington, Oregon and California [6] and have improved the viability of renewable development in their respective state¬. Production Tax Credits offer $0.023/kWh for geothermal electricity generation for the first five years of a plants operation. [3] Further Government Programs that put a price on carbon such as California's Cap and Trade policy from 2012, and Washington's (potential) Carbon Tax from 2016 would increase the demand for renewable energy along the Pacific Coast as the fossil fuel industry exit the market in those states.

In conjunction with government subsidy programs, a national database of potential geothermal development sites would decrease the exploration costs of firms looking to develop along the Coast. As with any investment decision, the availability of additional information reduces uncertainty and increases investor confidence. The greater amount of information available about the potential geothermal resources a developer has, the stronger a foundation they have for decisions on actual exploration and project development [6] With this, allows for a greater access to capital. Databases that do exist are unreliable or not widely available.

Expected Value, Risk Premia and Certainty Equivalents

To determine the effect of potential factors that alleviate the initial cost and risk of developers undertaking geothermal development, this paper will determine the expected value of a current and traditional geothermal investment and an investment that utilizing the potential cost and risk mitigating strategies above. The expected value, EV of an investment is given by: (Pr(x)*x) + (Pr(y)*y) + (Pr(z)*z)… of a hypothetical Firm A for which traditional geothermal technologies have been employed. While the EV of Firm B is given by a project that has employed EGS technologies.

The cost of a firm's potential losses is determined by the sum of the firm's total investments. For simplicity, this paper will assert that the decision to undertake a geothermal energy project is an all or nothing decision, not one that is evaluated at each point in the process. This assumption will create a binary scenario: project success or project failure, where the cost of failure is the sum of all costs incurred by the firm across the project's timeline and the expected payout is that of the project's revenue stream across time, in discounted terms.

Firm A's potential losses on a 50MW geothermal power plant investment are the sum of: identification costs ($1 million), exploration costs ($9 million), drilling costs ($15 million), and production costs ($60 million) totaling an $85 million investment. [risk mitigation] Our second firm, Firm B's potential losses modify those traditional costs by implementing EGS technologies. The identification and exploration costs remain the same, while drilling and production costs rise. The current cost of EGS drilling is roughly two times that of traditional technologies but will decline as the technology nears commercialization. [1] An accumulation of estimates from The Center for Climate and Energy Solutions and MIT's The Future of Geothermal Energy [3] place production and drilling costs estimates for an equivalent 50 MW plant at $22.5 million and $100 million respectively. Therefore, Firm B's potential losses on a 50MW EGS power plant are the sum of: identification costs ($1 million), exploration costs ($9 million), drilling costs ($22.5 million), and production costs ($100 million) totaling a $132.5 million investment.

The next component in determining the expected value for each investment is the probability of success for each scenario. Ignoring reconnaissance project failure, a traditional geothermal project will encounter project failure roughly 50% of the time. This corresponds to a 50% project success rate. For Firm B, the probability of project failure is modified dramatically. However, predictions that discuss how much that failure rate is likely to be modified by EGS and other risk / cost mitigating factors is highly uncertain and based in speculation. Therefore, excluding reconnaissance project failure, I will assert 10% overall project failure rate and corresponding 90% project success rate in order to clearly isolate the effect a significant change in project failure can have on the market. The final component needed to assess the expected value for each investment is each project's expected payout which we can assert is $200,000,000, a value higher than the projects total cost.

FIRM A (Traditional) Drilling / Project Success Drilling / Project

Failure

Probability 50% per well 50% per well

Payout for

Drilling / Exploration$200,000,000 $-85,000,000

FIRM B (EGS) Drilling / Project

Success (S) Drilling / Project

Failure (F)

Probability 90% per well 10% per well

Payout for

Drilling / Exploration$200,000,000 $-135,000,000

The expected value of Firm A's development per well: EV(A) = .5(200,000,000) + .5(-85,000,000). This comes out to EV(A) = $57,500,000. The Expected value of Firm B's development per well: EV(B) = .9(200,000,000) + .1(-135,000,000). This comes out to EV(B) = $133,000,000 per well. Assuming each firm is risk averse with a simple utility function of U(I)=Sqrt(I) then the expected utility for Firm A would be: sqrt(200,000,000)*(.5) + sqrt(85,000,000)*(-.5) = a utility value of 2,461. Firm B's expected utility would then be (.9)*sqrt(200,000,000) + (-.1)*sqrt(135,000,000) and yield a utility value of 11,566. With these utility values we can find the certainty equivalent for which Firm A and B. This would the be guaranteed amount of money that each firm would accept as equally desirable to avoid the risky geothermal investment. The certainty equivalent for Firm A is $6,000,000 and the certainty equivalent for Firm B is $80,000,000.

With these values we can then assess what each firm's risk premium would be. For Firm our two firms this is given by Premium = EV – CE. For Firm A this would be $51,500,000 and Firm B's would be $33,000,000. These values tell us the minimum amount of money by which each respective project's expected return must exceed the return on an alternative risk-free asset in order for the firm invest in the geothermal project's development. Given our assumptions of a 40% increase in Project B's success, we can clearly identify that Firm B's EGS oriented investment is far superior to A's. While both firms would undertake their projects, Firm A is far less comfortable with their project and would be willing to pay $18,000,000 more than Firm B in order to not take the risk at all, and instead invest in an equivalent risk free asset.

Should the expected value for either firm be negative, they would not undertake their project and look elsewhere for investment. This is why government subsidies are vital to the legitimacy of geothermal development along the Pacific Coast. By subsidizing firms for producing geothermal power by way of, for example, Production Tax Credits (PTCs), the payout of a successful geothermal project will increase by a rate of $0.023/kWh. This, in turn will drive the expected value (EV) of a geothermal development up, incentivizing more firms to take the risk of geothermal development.

Should such a growth in geothermal development take place along the Pacific Coast of the United States, there will be a second wave of cost/risk reduction in the exploratory phase of the average geothermal development project. This would be due to the growth of information of possible locations for well development which would very likely be supplemented by a resource database for the region. Additionally, as more wells are drilled, the likelihood of drilling a successful surrounding well increases as well – dubbed the "learning curve effect". This second wave of risk/cost reduction would increase the expected value of further geothermal developments in the regions to which the above effects took place, causing even more firms to risk the development of geothermal systems in those areas. Therefore, by reducing upfront costs and risk of geothermal development, we will see higher amounts of investment in the energy source in both the long and short run.

In conclusion, should risk/cost mitigating factors such as enhanced geothermal systems (EGS) and market intervention by government entities overcome the initial barriers to entry for geothermal then the Pacific Coast will likely see geothermal energy gain a higher share of the region's energy portfolio in the coming years. The result could provide a higher amount of clean and renewable energy, supplied at base-load power, with a low physical footprint.

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