  

Geothermal Economics 101

Economics of a 35 MW Binary Cycle Geothermal Plant

GLACIER
Partners

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Preface

Many excellent papers have been written on the basics of how geothermal energy can be harnessed and the state of the industry (see the Geothermal Energy Association's "Geothermal 101: Basics of Geothermal Energy Production and Use" http://www.geo-energy.org/publications/reports/Geo101_Final_Feb_15.pdf and its September 2009 "U.S. Geothermal Power Production and Development Update" http://www.geo-energy.org/publications/reports/US_Geothermal_Industry_Update_Sept_29_2009_Final.pdf). However, little has been written addressing the question that, as financial advisors focused on the geothermal industry, we at Glacier Partners get asked most often: "What are the costs to develop a geothermal power plant and the associated returns on investment?"

While every geothermal project is unique, it is our goal to provide a high level framework to begin to answer this question with our basic financial model for a geothermal power plant and to address some of the fundamentals needed to be understood in order to answer this question with this paper. Additionally, it is our aspiration that our model will help interested parties explore the impact critical financial and operational factors have on the economics of a geothermal power plant.

We hope you find our model and this accompanying paper insightful and helpful in furthering your understanding of the economics behind the development of geothermal power plant development. Should you have further questions in this regard, please do not hesitate to contact any of the members of our geothermal team.

Regards,

Glacier Partners

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Introduction

Glacier Partners has built a simplified model, to demonstrate the average economics of a geothermal power plant built in the Western United States. As no two geothermal power plant developments are the same, we have had to include many simplifications and have incorporated many industry "rules of thumb" into our assumptions. While these assumptions may be generic, we believe they paint a picture clear enough for people outside the geothermal industry to begin to understand the key drivers of costs and potential financial returns of a geothermal power plant. By releasing our financial model, on a "generic" basis, we hope to provide a tool which can be used to explore how each of these assumptions affects the costs and returns of such projects and to reduce the fog surrounding geothermal economics.

This paper is intended to help guide users through the Glacier Partners Geothermal Model so that they will be able to understand the logic used in building the model and our perspective on assumptions we have made. We have included references to specific cells in our model in the form: *Tab Name Cell #* to help familiarize you with it and have highlighted assumption cells that users can vary in the model. We also recommend users open a "Watch Window" on using by going to the Formulas tab in Excel 2007. This will continuously display the IRRs we have calculated allowing the user to immediately see the impact of any changes they wish to make to our assumptions.

Key Assumptions

While there are several projects in high temperature areas such as the Salton Sea Known Geothermal Resource Area ("KGRA") and the dry steam Geysers KGRA in northern California, the majority of geothermal projects being developed in the western United States are low to mid temperature binary cycle projects. For this reason Glacier Partners chose to model a binary cycle power plant with a 35 MW capacity; a capacity that falls in the middle of the range of plants that we expect will be built in the western U.S. over the next few years.

CONSTRUCTION COSTS

Drilling costs are one of, if not the key factor, in determining the feasibility of a geothermal project and its ultimate financial return. In our generic Base Case scenario, drilling cost represent over 47% of the total project development costs. The production capacity of geothermal wells varies greatly depending on the fluid temperature and flow characteristics of the well. We assume wells will average 4.5 MW *(Assumptions B16)*, which is reasonable to expect of fields in Nevada where a majority of binary cycle development is being pursued. Thus, a 35 MW project would require 8 productions wells on average. In order to sustain the geothermal reservoir, cooled geothermal brine must be reinjected back into the well field requiring a series of reinjection wells. The ratio of reinjection wells to productions wells ranges from 0.7:1 to 1:1. Our model has assumed a 0.8 : 1 ratio *(Assumptions B18)*, thus requiring 7 reinjection wells. Finally, we assume that 20% of wells drilled will fail to be useable for either production or reinjection *(Assumptions B20)*. Hence, we arrive at a total of 18 wells required to operate a 35 MW plant. Based on our familiarity with drilling costs and historical data, we assume each well will cost $4.5 million to drill *(Assumptions B23)* and arrive at a total drilling cost of $81 million *(Assumptions B24)*.

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As the majority of plants that will be brought online prior to the expiration of the incentives the US government included in the American Recovery and Reinvestment Act of 2009 ("ARRA") are now at the feasibility stage of development, we assume only $10 million will need to be spent to bring properties to the point where they are ready for production wells to be drilled *(Assumptions B34)*. These expenses would include costs for environmental assessments, permitting, and any final exploration and confirmation work such as drilling slim wells.

We assume total plant construction cost of $2.0 million per MW *(Assumptions B27)*. This would encompass costs associated with the power plant, well pumps to maximize flow from production wells and assist with reinjection, the gathering system to collect the geothermal fluid from the well field and return it to injection wells and cooling towers required to cool the plant's working fluid. In addition, we budget $5 million to build transmission lines that will connect the plant to the grid *(Assumptions B31)*. With total cost of $171.5 million including interest on construction financing *(Assumptions B13)* ($166.0 million before interest), cost per net MW for a 35 MW net power plant is $4.9 million *(Assumptions B10)*.

(US$ in millions)	Exploration	Drilling & Design	Construction	Total
Well field preparation and Exploration	10.0			10.0
Drilling cost		81.0		81.0
Transmission - connection to grid			5.0	5.0
Power Plant and gathering systems			$70.0	$70.0
Total Cost Per Phase	**10.0**	**81.0**	**75.0**	**166.0**
% of Total Cost	*6.0%*	*48.8%*	*45.2%*	*100.0%*

OPERATING REVENUE AND COSTS

A number of western states have set aggressive Renewable Portfolio Standards (RPS) which we expect to help keep prices utilities will be willing to pay for baseload renewable power, such as geothermal, high despite declining natural gas prices. We have assumed a developer would be able to secure a long-term power purchase agreement ("PPA") at the price of $100 / MWh *(Assumptions B44)* and that this price would escalate by 2% a year *(Assumptions B45,* which we believe is realistically available in the current market place. It is typical that the utility purchasing the power will require any Renewable Energy Credits (RECs) or other "environmental attributes" be transferred to the utility as well, thus we do not include further revenue that may be associated with these aspects of the power sold. We have assumed a utilization rate of 70% during the first two quarters of the plant's life *(Assumptions B40)* to allow for optimization of well flow or other engineering tweaks that inevitably are made. In the long run we assume a 95% utilization *(Assumptions B39)* which is conservative given that binary plants often run closer to 98% of capacity. For simplicity sake, we have used an EBITDA margin to account for costs associated with running the plants rather than go through the more intensive process of making assumptions for the numerous factors that play into the operating, maintenance, general and administrative costs of a geothermal plant. We have assumed an EBITDA margin of 83% *(Assumptions B46),* which we believe is the middle of the range which is reasonable to expect. This margin would need to be adjusted as the output capacity is adjusted up or down to account for economies of scale that would likely be achieved by higher output plants.

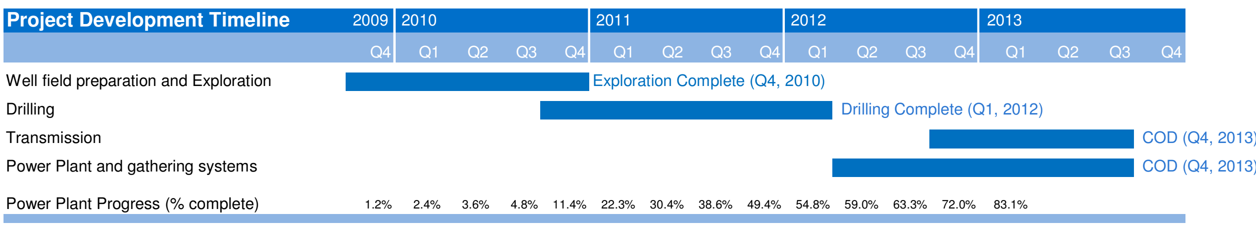
FINANCIAL ASSUMPTIONS

There are numerous financial assumptions that substantially affect the returns potentially achieved by investors. The limited number of plants that have been built over the last several years and the disruptions in the financial markets means that there is no prescribed or established financial path through which projects are currently financed. We have assessed the various means of financing a geothermal development may utilize to optimize returns, while being realistic about the constraints financial investors are likely to face under current capital market conditions.

The first of these practicalities is that we assume equity will have to pay for 100% of the development of the well field *(Assumptions B61)*. While in the past developers assumed constructions lenders would step in once 60% of the well field was drilled and proven out, recent experience has proven otherwise. Therefore, we assume equity will have to absorb all cost prior to this point and the construction facility will be only large enough to cover construction of the plant, gathering system, transmission and interest payable during construction. We believe this constraint will moderate over time, as more projects are developed, lenders come up the learning curve with respect to drilling risk and the debt capital markets improve. It is likely that construction lenders will be willing to offer an option whereby the construction loan will convert to a term loan with a maturity as long as 10 years. We have chosen to build our model such that a new term loan replaces the construction facility for maximum flexibility. We also expect that funding from insurance company investors will become increasingly more common via issuance of 15 to 20 year private placements. Insurance investors are attracted to the long life and highly predictable baseload nature of geothermal plants and have experience investing in geothermal via several offerings linked to Salton Sea and Coso plants as well as several Ormat related placements. Hence, we have modeled the term debt as a facility that amortizes over 15 years *(Assumptions B79)*. While it is typical for project finance debt to be sized according to an average and minimum debt service coverage ratio ("DSCR"), in order to avoid the iterations and sculpting of principal repayments necessary to properly size a facility via this method, we have taken a short cut to simplify our generic model. We instead use an EBITDA coverage ratio, the metric most often used as a benchmark to size corporate debt, to approximate the amount of debt the project can support. We assume a minimum EBITDA coverage ratio of 5.0x (*Assumptions B76)*. Based on a straight line amortization of the debt this results in a facility with an average DSCR of 1.62 *(Debt Structure R102)*, in the range of 1.50-1.65 that we would expect insurance investors to demand. We have further assumed a Debt Service Reserve of 6 months would be required by the investor as is typical *(Assumptions B80)*. These assumptions result in a term debt financing that will repay the construction loan *(Summary M12 and M13)* as well as a portion of the equity invested in the project *(Summary M17)*.

DEVELOPMENT TIMELINE

We have assumed a three and a half year development timeline. During the first year, starting October of 2009, we assume exploration to target wells and other well field preparation is completed, and permits needed to move the project are obtained *(Assumptions B113:F113)*. In our analysis, drilling is the bottleneck in completing geothermal development. In order to drill the 18 wells needed to complete the project before the December 31, 2013 deadline to make it eligible for the Grant in Lieu of ITC, the developer will have to employ two drilling rigs. At a rate of 8 weeks per well per rig, drilling can be completed in slightly less than a year and a half *(Assumptions F114:K114)*. Construction begins in the first quarter of 2012 as drilling is completed. The plant is built over the course of 18 months, which is typical of what we have observed Ormat achieve for the construction of a binary plant. Construction spending ramps up over time and peaks in the fourth and fifth quarters and a small amount is spent in the final quarter as the plant is finalized and goes thought testing *(Assumptions L117:Q117)*. We assume a concurrent one year period over which transmission lines are built and system upgrades are made to the point of connection *(Assumptions N116:Q116)*. The build out and cost of transmission will obviously be affected heavily by the distance and terrain over which the transmission will be built, and may vary greatly. Depending on the constraints that construction lenders impose it may be possible to begin construction earlier, in parallel with the completion of the drilling phase.



Other Financial Considerations

PTC VS. ITC AND GRANT IN LIEU OF ITC

The ARRA gives developers several valuable options to aid in the financing of renewable power projects. For geothermal plants, the Production Tax Credit ("PTC") was extended through 2013, the Investment Tax Credit ("ITC") was increased to 30% from 10% for plants in construction by 2011 and completed by 2013, and plants eligible to receive the ITC have the option to elect to receive a cash grant for the eligible amount from the U.S. Treasury. For more detail on the eligibility of facilities for the cash grant see the U.S. Treasury Department's July 2009 publication "Payments for Specified Energy Property in Lieu of Tax Credits under the American Recovery and Reinvestment Act of 2009" (http://www.treas.gov/recovery/docs/guidance.pdf). For an analysis of the economic benefits of the various credits and the grant we refer you to the National Renewable Energy Laboratory's March 2009 paper "PTC, ITC, or Cash Grant? An Analysis of the Choice Facing Renewable Power Projects in the United States" by Mark Bolinger et al, (http://www.nrel.gov/docs/fy09osti/45359.pdf).

The Glacier Partners Model includes a switch to allow users to toggle between taking the grant or the PTC so that the economics of each can be observed *(Assumptions B84)*. In the PTC case, we calculate the flows that would be generated over the 10 year span the plant is eligible to receive the credits. We then discount this series by our assumption for the market's required return on tax equity investments, which we currently estimate to be 10% *(Assumptions B89)*. Although in a typical tax equity transaction developers most often also transfer the NOL's generated through accelerated depreciation to their tax equity partner, we monetize these credits beginning at COD at the time they are incurred in both the ITC and PTC cases in order to most easily estimate the value of the NOL's under either scenario. In reality, we believe that the developer will either monetize their tax assets upon commercial operation of the plant or utilize them once the plant generates taxable income. By monetizing the tax assets at the time they are generated we look to find a middle of the road approach to these two options. Under the ITC scenario, we assume the developer elects to take the cash grant and that the cash grant is received 60 days after the plant reaches commercial operation *(Cash Flow Statement R8)*. We calculate the amount of the grant by assuming 85% of costs associated with the drilling of the well field and construction of the power plant are eligible *(Assumptions B86)*. As mandated under the ITC regulations, we reduce the amount of costs eligible for accelerated or MACRS depreciation by half of the ITC *(Assumptions B92)* or 15% *(Assumptions B93)*.

Our Base Case assumes the grant will be chosen as the current state of the tax equity markets has not displayed the capacity to allow developers to effectively monetize the PTC. We further assume that the plant will be eligible for the grant, despite plant construction not beginning until 2012, as the Treasury considers construction to begin when “physical work of a significant nature begins” (Treasury goes on to define a Safe Harbor under which work of a significant nature begins once more than 5% of the total cost of the property has been incurred). Therefore, we assume that, having incurred more than 5% of total plant cost through drilling production wells prior to this date, the project is eligible for the grant.

AVAILABILITY OF MEZZANINE DEBT TO FINANCE DRILLING

In the past, financing for a portion of well field drilling cost has been available to developers in the form of mezzanine-style debt. While the availability of this type of financing is currently absent from the marketplace, we believe it will return in time. Consequently, we have included a toggle switch to allow the incorporation of this type of financing *(Assumptions B63)*. In the scenario where drilling finance is available, we assume that a minimum of 6 production wells have been completed in order to prove the production capabilities of the field and entice the mezzanine lender to lend to the project *(Assumptions B59)*. We assume interest on the facility of 15% *(Assumptions B66)* which would be PIKed (or capitalized) to the loan quarterly. In addition we assume that the financier would require an equity stake in the project of at least 15% *(Assumptions B67)*. Our model is built such that a construction lender would finance up to 70% of project costs *(Assumptions B73)*. In the mezzanine loan scenario, we assume the developer takes the maximum amount available under a construction loan and thus any funds not required for actual construction would be used to repay a portion of the mezzanine loan at the time the construction loan is first drawn on *(Debt Structure L76)*. The remainder of the mezzanine loan balance is repaid with proceeds from the term debt, upon commercial operation of the plant *(Debt Structure Q81)*.

Conclusions

In our Base Case scenario total plant costs equal $171 million. Our assumption that equity will be required to develop 100% of the well field results in an equity requirement of $91 million *(Summary B22)* with an $80 million construction loan used to finance the plant *(Summary B24)*. Based on the timing of the equity requirements, we calculate two discrete IRR’s: an IRR over the project’s assumed 30-year life span “Equity IRR Project Life” *(Summary M28, which we have named Equity_IRR_Project_Life)*; and another IRR which assumes the equity sponsor sells its participation in the project once it reaches commercial operations “Equity IRR through COD” *(Summary M27, which we have named Equity_IRR_through_COD)*. Our Base Case results in an equity IRR over the project’s life of 17% and an IRR through COD of 27%.

SENSITIVITY TO ITC / PTC DECISION

Assuming the project developer chooses to receive Production Tax Credits in lieu of the ITC/Grant and monetizes the value of the PTC at COD *(Assumption B84 to "Yes")* the lifetime IRR increases to 19% and the IRR through COD increases to 30%. These results are in line with the findings of in the NREL paper referenced above, that the PTC is more valuable than the ITC to geothermal developers, given the high capacity factor of geothermal plants generate a substantial amount of credits.

IMPACT OF MEZZANINE DEBT ON RETURNS

If we assume that the project's developer is able to attract mezzanine debt to finance a portion of drilling costs *(Assumption B63 to "Yes")*, total project costs increase to $189 million from the Base Case $171 million, as interest during construction increases due to the interest payments made to the mezzanine lender. The increase in interest is offset by a substantial reduction in equity required (from $91 million to $37 million). Despite also sharing 15% of the project's distributable cash flows with the mezzanine lender, equity's IRR through COD increases to 32% from 27%, and IRR through the project's life is 17%.

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