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Assessing Geothermal Tariffs in the Face of Uncertainty, a Probabilistic Approach

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ABSTRACT

The majority of geothermal projects worldwide produce electricity for sale. Depending on the local electricity market, the price may be determined dynamically by the market, or pre-determined by contract (eg via a Power Purchase Agreement (PPA)). The feasibility of developing a new geothermal power project depends on the financial return that would result from the investment. This return is affected by many input variables: capital and operational costs and their timing; the fiscal environment applicable to the project income and cost streams; the electricity tariff; the proportion of debt; the cost of debt, and; whether the analysis is based on 100% equity or on the equity actually invested. Whereas the Debt:Equity variables can be determined relatively precisely, assessments of project capital costs and their timing are affected by uncertainties regarding the number and cost of wells and the cost of field development (infrastructure, pipelines, power plant, transmission line). If the project is an additional unit at an existing development, these uncertainties are much lower than if the project is a greenfield development. This is particularly so where exploration drilling has not been undertaken to prove a geothermal resource exists and to confirm the fluid conditions and size of the reservoir. Where the parties to a PPA are willing to negotiate an equitable tariff, a Monte Carlo simulation of the tariff is a useful tool. Such a tool can be used to generate a probabilistic spread of tariffs which meets specific investment criteria (e.g. a given net present value or a target internal rate of return). As a project progresses from exploration to development, uncertainties (and thus risks) in the input variables can be expected to reduce. Correspondingly there will be a reduction in the range of tariffs which meets the investment criteria within a certain probability band (e.g. in the range 10 to 90% probability of exceedance). This paper describes such an approach and presents some results for hypothetical projects. The results demonstrate how the funding regime has a strong impact on the tariff required to meet a specified internal rate of return (IRR).

1. INTRODUCTION

Why do geothermal electricity projects get built? There are many reasons. Some of the important ones are:

1. They are an indigenous source of energy which can contribute to meeting a country's energy demand
2. Many are renewable in a cyclical pattern of exploitation followed by rejuvenation
3. Their social and environmental impacts are relatively benign if best practice is followed
4. In developing countries they contribute to human capacity development
5. They provide an acceptable return on the funds employed to build, operate and maintain them.

This paper focusses on the last statement and suggests an approach that could help developers and project decision makers determine whether they may expect an acceptable return, particularly when they are faced with investing in a project where there is uncertainty in the magnitude of future costs that may be incurred and uncertainty in the timing of these costs.

2. SOME DEFINITIONS

What is meant by "an acceptable return on the funds employed to build, operate and maintain"?

Several elements need to be considered to gain understanding of what this statement means. These are identified in Table 1.

Table 1 Definitions

Funds Employed	The money (capital investment) required firstly to Build, and secondly to Operate a geothermal electricity project. Provided by Investors as Equity and Lenders as Debt.
Return	In simple terms this is the ratio of funds invested to funds reimbursed to Investors, taking into account the different Timing of investment and reimbursement.
Acceptable	Returns acceptable to the Investors (and the Lenders), commensurate with the Risks associated with their investment.
Build	Construct Facilities which will deliver electricity reliably and in the expected quantities to a place where it can be sold to Customers.
Operate and Maintain	Operate and Maintain the Facilities so that they deliver electricity reliably and in the expected quantities to the place where it is sold to Customers.

This table introduces several additional important terms:

A. Investors (and Lenders)
B. Timing
C. Risks
D. Facilities
E. Customers

In the case of geothermal electricity generating projects the Facilities to be built include:

i. production wells,
ii. reinjection wells,
iii. steamfield above ground fluid gathering and disposal system (SAGS) connecting the wells to a
iv. power plant,
v. electrical transmission system connecting the power plant to its Customers,
vi. associated infrastructure such as roads, water supply, temporary power supplies, wellpads, pipeline routes, offices, stores, laydown areas, spoil disposal areas, workshops, accommodation, social and religious facilities, communications, construction power supplies
vii. project management resources required to define, scope, permit, procure and supervise the installation, commissioning and testing of the Facilities being built,

all of which must be capable of being operated and maintained at the specified capacity for a defined plant life.

"Return" is generally assessed by first determining the timing and amounts of capital investment required, income generated (based on an assumed selling price), operational costs incurred and tax to be paid. Funds are employed to meet the capital investment required – these can either be provided by the developer as equity, or provided as loans. In the case of loans, repayment of the principal will be required, and interest will be charged on the principal. In most tax jurisdictions, the interest on such loans will be a tax deductible expense, and depreciation of the assets created will be allowed when calculating the taxable income. To pay tax, it is first necessary to generate an income. When the income exceeds the costs, then tax is payable on the difference[1].

After all the costs and income over the project life are determined they can be presented on a net basis along the project timeline. Provided the selling price is high enough, the net amount (cash flow) will be sufficiently positive after the project starts to generate income such that the initial investment is recovered together with a margin commensurate with the risk of investing.

Discounted cash flow (DCF) analysis is applied to the net amounts along the project timeline. Discounting is essentially comparing investment in the project with investment at a desired rate of interest. Three calculations are commonly used in project financial and economic analyses:

Net Present Value (NPV)	The sum of the discounted net amounts (present values) over the project life using a nominated discount rate. If greater than 0, the investment is more attractive than the discount rate. Useful for comparing options within a project.
Discounted Profitability Index (DPI)	The ratio of the sum of the present values of the future cash flows to the sum of the present values of the initial investment. If greater than 1, the investment is more attractive than the discount rate. Useful for comparisons between different projects.
Internal rate of return (IRR)	The discount rate at which the net present value is 0. Useful for comparisons between different projects.

Discount rate is commonly set at 10% for geothermal projects. DPI values exceeding 1.2 are generally sought by investors in geothermal projects. IRR expectations for geothermal projects depend on whether the analysis is undertaken on a project basis (assuming 100% equity ie no loans and thus no loan repayments, the interest on which is tax-deductible), or on a leveraged-equity basis (typically 20-40% equity with the balance supplied through loans).

Equity investors entering a geothermal project where a resource has not been demonstrated will seek a higher return on their investment (since there might not be a resource) than if they were to enter a project where the resource has been demonstrated but the size has not been proven. They are likely to seek a return in the range 22-30% (leveraged-equity basis) or 14-18% (100% equity basis). And an investor entering a geothermal project where the resource has been demonstrated but the size has not been proven will seek a higher return on their investment than if they were to enter a project where the resource has been proven. They are likely to seek a return in the range 18-22% (leveraged-equity basis). Finally if the resource size has been proven and a certain number of production wells representing a certain portion (say 30%) of the power plant capacity to be installed and reservoir modelling supports the withdrawal of geothermal fluids over the project life to support this capacity, then institutional investors may provide debt through loans at commercial rates and conditions. Based on the returns mentioned herein, there is a significant difference between leveraged-equity IRR and project (unleveraged) IRR, and the two should not be equated.

[1] This is a very simple explanation but it highlights the fundamental basis of paying tax. In reality the determination of taxable income is a complex matter to be determined by specialists based on rules and regulations in the relevant tax jurisdiction.

It should be noted that where a government is the equity investor in an infrastructure project it is likely to have different investment criteria which may equate to lower internal rates of return than would be attractive to a private investor. Similarly, if the investor is a local entity they may not apply a country-based risk premium that an overseas equity investor would consider appropriate.

Commercial banks (eg HSBC, SCB) may offer interest rates in the range 8%-12%, but they have limited funds and frequently they syndicate together to provide the required debt. Even so, when the total funding requirements for a greenfield geothermal project are in the range US$500Million - US$1Billion even a commercial syndicate may not be able to cover the total debt and, in the case of projects in developing countries, bilateral or multilateral international development investment banks may need to be involved. These banks (such as JBIC, ADB, IADB etc) have greater funds available that commercial banks and can offer lower interest rates in the range 4%-8%. Additionally, in certain circumstances in developing countries, "government to government" cooperation can offer lower interest rates even less than 4% such as World Bank, JICA, KfW etc., with grace periods and much longer repayment periods than commercial or international development banks can offer.

Very few geothermal developers can fund 100% of a greenfield geothermal development by themselves (although some exceptions do exist). Even providing equity of 20-40% for a 200MW class development will involve funds in the range US$120-320Million. Very few geothermal concessionaires can provide such funds as developers, the majority of which will typically be expended prior to making the Financial Investment Decision (FID[2]) to build the power plant, drill the remaining production and injection wells and install the surface piping and facilities (SAGS) which connect everything together. Such concessionaire-developers must frequently turn to additional "deep pocketed" investors who will provide the "lion's share" of the equity funding. Such investors will require a commensurate return on their investment and will expect a commensurate share in the ownership of the project.

3. GEOTHERMAL RESERVOIR CONSIDERATIONS

Because geothermal electricity generating projects use geothermal energy as the fuel source, the geothermal reservoir must be capable of providing geothermal fluids of the required quantity and quality over the life of the project. This is necessary if the Return to the Investors is to be realised.

A geothermal reservoir, like all fluid filled reservoirs, experiences a decline in reservoir pressure as fluid is withdrawn from it. This decline in reservoir pressure is manifested in a decline in the output of production wells. This requires that make-up production wells be drilled and connected so as to maintain the desired quantity of geothermal fluids. Geothermal reservoirs contain energy in the form of heat – reservoir temperatures as well as reservoir pressures may also change under exploitation and this can mean that the heat content of the fluid discharging from wells may change with time. Managing geothermal reservoirs requires managing both pressures and temperatures so that sufficient fluids with sufficient heat content are available as required to meet future projections.

Ideally geothermal fluids would be 100% pure water or steam as there are many manufacturers of equipment that removes the heat from hot water and steam and converts this to electricity. Unfortunately this is not the case. Geothermal waters receive their heat from rocks and in doing so they dissolve some of the rocks. Geothermal waters also dissolve gases which may be present in the rocks. The dissolved solids may be scale forming in the facilities. The dissolved solids and gases may be corrosive in the facilities. Some dissolved gases do not condense when geothermal steam condenses (which is where a lot of energy is available to be converted to electricity) and must be removed from the process. Removal of these gases uses energy and such gases will have an impact on the environment if they are discharged to atmosphere. All these factors must be considered when planning and specifying the development of a geothermal resource. Many of them will not be known until the resource is explored and fluids are produced at the surface for testing. Over time and as the reservoir is exploited the composition of the fluids may change. These changes are difficult to predict.

4. GEOTHERMAL EXPLORATION AND APPRAISAL RISKS

It is a general rule of development that the bigger the development the lower the cost of the product resulting from that development. This is true of geothermal development. However, geothermal reservoirs have finite volume and limited recharge so if the chosen size of the development is bigger than the optimum size, reservoir pressures will fall faster than predicted and the requirement for makeup production wells may occur earlier and be more frequent than predicted. This may negatively impact the economics of a project if it is not possible to cover the increased costs through increased revenue from sales. Choosing the optimum size of a geothermal development therefore requires experience and a methodical approach to the improvement of resource information through exploration and analysis and feedback during exploitation.

The most conservative (lowest risk) approach to development of a greenfield geothermal project would be to carry out exploration surveys to inform the drilling and testing of subsequently drilled exploration wells which would then allow a conservative development size to be chosen. All the production and reinjection wells would then be drilled and tested to confirm that the chosen development size was appropriate and that the reservoir would most likely react in a predictable manner. The Power Plant and SAGS could then be specified, designed, fabricated, constructed and commissioned with a high degree of certainty that the resource could support its operation over the chosen project life. Future additional Power Plant capacity would be added as knowledge of the reservoir and its behaviour under exploitation supported such additional capacity.

The least conservative (highest risk) approach to development of a greenfield geothermal project would be to carry out exploration surveys and use the results from these to directly choose a development size in the upper range of likely development sizes. The Power Plant and SAGS would then be specified, designed, fabricated, constructed and commissioned. In parallel with this all the

[2] FID. Financial Investment Decision. There are many such decisions throughout the life of a project. This refers to the major investment decision which triggers the building of the power plant, the remaining production and injection wells and the surface piping and facilities which ties this all together.

required production and reinjection wells would be drilled in time to commission the Power Plant at its design capacity. Obviously with this approach there is a possibility that:

a. the Power Plant will be too large and sufficient wells cannot be drilled to allow the Power Plant to operate at design capacity, or
b. sufficient wells cannot be drilled to allow the Power Plant to be commissioned at design capacity when it is constructed, though additional drilling would allow the design capacity to be achieved somewhat later than planned, or
c. the resource is productive but the productive area turns out to be a long way from where the Power Plant and the SAGS is constructed, incurring high SAGS pressure drops, thus requiring more production wells than originally planned, or
d. sufficient wells are drilled so that the Power Plant is commissioned satisfactorily on time but the reservoir pressure drops faster and further than predicted and the Power Plant is not able to be operated at design capacity.

There are other approaches to development which lie between these two extremes. Correspondingly they will have risk profiles somewhere in between these two extremes.

5. VARIABLES AFFECTING A GEOTHERMAL TARIFF

The DCF analysis mentioned previously refers to income, which requires a selling price to have been set. Conversely, the selling price (tariff) can be adjusted to give a desired DPI or IRR. This is essentially a Financial Model.

The variables and costs which must be considered when setting up such a financial model fall into several clearly delineated categories which are presented in the following sections. These sections are presented in the chronological order in which they occur for greenfield geothermal projects. They are grouped under four major activity phases:

a. Exploration activities which are focused on demonstrating that a resource exists, and assessing how big it is
b. Appraisal activities which are focused on developing a technically and commercially feasible project up to the point where it is funded
c. Development activities associated with designing, building and commissioning the project, and
d. Operating the project, including managing the geothermal reservoir.

5.1 Geoscientific Survey and Exploration Drilling Costs

- Acquiring the concession rights
- Acquiring land access, obtaining environmental permits, obtaining construction permits, establishing and maintaining stakeholder relationships, meeting concession reporting obligations
- Demonstrating a resource exists by preparing the necessary infrastructure and drilling a successful exploration well
- Proving how big the resource is by drilling appraisal wells
- Selecting a power plant development strategy, including size and number of units and the timing of their first commercial operation, and incorporating this into a Feasibility Study

5.2 Appraisal Drilling, Analysis and Construction Contract Development Costs up to FID

- Satisfying lenders pre-conditions for debt funding by preparing any necessary additional infrastructure, drilling additional wells and carrying our reservoir modelling
- Carrying out FEED for steamfield and power plant, preparing scope of work, prequalifying suppliers and awarding construction contracts
- Managing all the pre-FID activities listed above and maintaining the project site and head office establishments necessary to achieve this

5.3 Major Project Construction Costs post-FID, pre-Commercial Operation Date (COD)

- Acquiring additional land access, obtaining environmental permits, obtaining construction permits, maintaining stakeholder relationships, meeting concession reporting obligations, obtaining operational permits
- Preparing the additional infrastructure required for construction and operation
- Drilling remaining production and injection wells and carrying our reservoir modelling
- Designing, constructing, testing and commissioning the steamfield and the power plant
- Managing all the post-FID pre-COD activities listed above and maintaining the project site and head office establishments necessary to achieve this
- Interest on mezzanine funds provided until replaced with debt funds at COD (or shortly thereafter, once reliable operation at design capacity has been demonstrated)

5.4 Costs post-COD

- Operating and maintaining the assets (infrastructure, wells, steamfield and power plant)
- Maintaining environmental and operational permits, maintaining stakeholder relationships, meeting concession reporting obligations
- Updating the reservoir modelling based on results from monitoring the reservoir behaviour
- Drilling makeup wells to maintain production and injection capacity
- Maintaining the head office establishments necessary to achieve the above
- Repaying principal and interest on debt funds
- Paying tax on taxable net income

5.5 Timing of Costs

Greenfield geothermal projects have long gestation periods and all of the fuel supply must be found and paid for before commercial operation can occur. This includes all the production and injection wells, but not the makeup wells. This is a unique feature of geothermal electricity generation which differentiates it from electricity produced from fossil fuels, biofuels, biomass, solar energy and wind energy. In this aspect it is similar to dam-based hydroelectricity.

A DCF based financial model discounts costs and income back to a reference date. The further into the future that a cost or income occurs, the greater is the discounting, and the smaller is the cost or income relative to the reference date. The largest costs for a geothermal project are those associated with power plant, wells, steamfield and infrastructure. As the gap between these large costs and first income increases, the tariff required to support a fixed IRR also increases. It is important to shorten this gap as much as possible, since there is a natural tension towards lower tariffs in most markets, and geothermal electricity must be competitive in any given market for a project to proceed.

5.6 Factors Affecting Costs and their Uncertainties

Greenfield geothermal projects have long gestation periods and all of the initial fuel supply must be found and paid for before commercial operation can occur. This includes all the production and injection wells, but not the makeup wells. This is a unique feature of geothermal electricity generation which differentiates it from electricity produced from fossil fuels, biofuels, biomass, solar energy and wind energy. In this respect it is similar to dam-based hydroelectricity.

Many variables affect the cost of a geothermal project and the timing of these costs. A robust financial model must take these into consideration. Table 2 highlights most of the major variables and provides an indication of their variability (and thus uncertainty). This table is based on a greenfield development of 2x55MW – the costs and timing for smaller or larger developments will vary from the typical values presented in this table. Readers should note that not all the co-authors of this paper are in agreement with the values presented herein – readers are advised to seek appropriate advice or counsel when developing their own cost estimates.

Table 2 Typical Costs and their Timing for a Greenfield Geothermal Project (late 2013 cost datum)

Phase	Cost Range	Timing Range	Comment	Selected Typical Value
Geoscientific Survey and Exploration Drilling				
Geoscientific Surveys	US$M0.5-2	0.5-1 year	Depends number and type of surveys	US$M1.5
Infrastructure (Water supply, Roads, Wellpads, Stores, Workshops, Offices, etc, including engineering and project management)	US$M10-50	1-2 years	Depends on location, topography, how much existing infrastructure requires upgrading, types of exploration wells	US$M20
Land Access			Linked to infrastructure and types of exploration wells: temporary or permanent?	US$M0.5
Environmental Permit Costs (exploration & appraisal drilling)	US$M0.25-0.75	0.5-1.5 years	Depends on impact assessment and approval processes	US$M0.5
Exploration wells	US$M3-12 each		Depends on type of exploration well: slimhole or standard geothermal	Choose standard: US$M10
Number of exploration wells	3-6	0.5-1 year	Depends on exploration strategy and value of information	4
Success rate	0-100%		Defined as demonstrating temperature, permeability and benign fluids	50%
Capacity per successful well (for use in subsequent development)	0-15MW		Depends on type of exploration well: slimhole or standard geothermal	10MW
Geoscientific & Reservoir Modelling Development	US$M0.5-1	0.5 year		US$M0.75
Pre-Feasibility Assessment	US$M0.25-0.5	0.25 year		US$M0.35
Owners Field and Head Office Charges	US$M1-3/year		Linked to overall duration of this phase	3*US$M2
Appraisal Drilling, Analysis and Construction Contract Development Costs up to FID				
Feasibility Assessment	US$M0.5-1	0.5 year		US$M0.75
Land Access			Linked to infrastructure	US$M1
Environmental Permit (development & operations phases)	US$0.5-1.5M	1-2 years	Depends on impact assessment and approval processes. Additional to	US$M1
Infrastructure (Roads, Wellpads etc)	US$1-10	0.5-1 year	Depends on how many more wells are required to meet Conditions Precedent for FID	US$M5
Appraisal wells	US$6-10	0.5-1 year		US$M8
Number of appraisal wells		0.5-1 year	Depends on how many more wells are required to meet Conditions Precedent for FID (%age of power plant capacity)	
Success rate	50-100%		Defined as demonstrating temperature, permeability and benign fluids	70%
Capacity per successful well (for use in subsequent development)	5-15MW			10MW
Geotechnical evaluation (power plant, pipelines, separator stations)	US$M0.2-0.4			US$M0.3
Geoscientific & reservoir modelling development	US$M0.5-1	0.25-0.75 year		US$M0.75
Prepare bid packages for main execution contracts	US$M0.5-1	0.25-0.75 year		US$M0.75
Steamfield Preliminary FEED costs	US$M0.5-1	0.25-0.75 year		US$M0.75

Phase	Cost Range	Timing Range	Comment	Selected Typical Value
Power Plant Preliminary FEED costs	US$M0.5-1	0.25-0.75 year		US$M0.65
Conclude all commercial agreements				US$M2
Owners Field and Head Office Charges	US$M2-4/year		Linked to overall duration of this phase	3*US$M3
Major Project Construction Costs post-FID, pre-Commercial Operation Date				
Land Access			Linked to infrastructure and asset development (wells, pipelines, power plant etc)	US$M10
Infrastructure	US$M1-10	0.5-1 year		US$M8
Development wells (production)	US$M5-8		Duration depends on number of rigs	US$M6
Number of development wells (production)			Depends on how many wells are required at COD (%age of power plant capacity)	120%
Success rate (production wells)	70-90%		Defined as demonstrating temperature, permeability and benign fluids	80%
Capacity per successful production well	5-15MW			10MW
Development wells (injection)	US$M4-8		Duration depends on number of rigs	US$M5
Number of development wells (injection)			Depends on enthalpy of produced fluid	
Success rate (injection wells)	80-100%		Defined as having sufficient injectivity	90%
Capacity per successful injection well	50-150kg/s		Injectivity	100kg/s
Steamfield	200-700$/kW	1-2 years	Depends on field power density, field enthalpy and topography	$450/kW
Field power density	10-30MW/km2			20MW/km2
Field enthalpy	Low-Medium-High			Medium
Power plant	1200-1600 US$/kW (@55 MW)	1.75-2.5 years	This is a function of capacity. This number applies to a capacity of 55MW	1360US$/kW First Unit; 10% reduction for Second Unit
Third Party Certification	US$M0.8-1.5			US$M1
Owners PM and Supervision (in house)	US$M3-6			US$M5
Owners PM and Supervision (contractor)	US$M3-6			US$M5
Owner's Costs to create a Permanent Operating Staff Establishment	US$M3-6			US$M5
Owners Field and Head Office Charges	US$M4-6/year		Linked to overall duration of this phase	2*US$M5
Costs post-COD				
Routine operations and maintenance, power plant & steamfield	US$14-22/MWh		A function of total power plant capacity	US$18/MWh for First Unit; US$11/MWh for Second Unit
Frequency of makeup production wells			A function of the reservoir, based on an assumed well output decline rate, in order to keep available capacity at a specified margin above total power plant capacity	
Frequency of makeup injection wells	1 per 7-12 injection wells, every 10 years		Commonly expressed as a number of makeup wells at a specified frequency	
Reservoir decline rate, harmonic	2-6% per year			4%
Well workovers	US$M1-3		Often undertaken at same frequency as makeup wells	US$2M
Overhauls of power plant and steamfield	Every 3-6 years		Expressed as major and minor overhauls, as a specified frequency	4 years, staggered
Major overhauls	US$M1-3		Once every 3-5 years	US$M2
Minor overhauls	US$M0.3-1		Once every 3-5 years (staggered with major overhauls)	US$M0.6
Other Variables Affecting Financial Modelling				
Tax rate			User adjustable	34%
Method of depreciation			This can get quite complex as the project is developed	Straight line, 10 yrs
Capacity factor of asset	88-92% (based on gross capacity)		Determines how many MWh will be sold over a defined period (normally one year)	90%
Debt:Equity Ratio			User adjustable	70:30
Timing of Equity			Normally equity is applied first, and usually to the exploration and appraisal costs, then any balance of equity is applied post-FID	Applied first
Interest during construction			User adjustable	12%
Debt interest and repayment terms			User adjustable rate, duration and type (fixed constant repayments or fixed constant principal, declining interest)	10%, 12 years, constant total annual payments
Cost inflation index	1.5-3.0%/year		User adjustable, compounded	2%
Tariff escalation index	0-100% of the tariff at the cost inflation index		Normally a portion of the tariff is escalatable, compounded	50%
Overall development timeline, Unit 1	5-8 years			6 years
Overall development timeline, Unit 2	0-5 years after Unit 1			1 year

5.7 Risk Mitigation Considerations

The phase-wise approach mentioned at the start of this section is very common in any type of project development where costs in the pre-operating phases increase significantly from one phase to the next. At the end of each phase there is a decision point where the results of the activities to date are evaluated, the costs and risks in the next phase are considered and a decision is taken whether to proceed to the next phase, to recycle or to stop (refer to Figure 1). This decision-gated approach helps to ensure that wise decisions are made which reduce the probability of failure of a subsequent phase to the lowest possible value.

Nevertheless, there is considerable risk and expense inherent in this type of greenfield development, particularly during the exploration and appraisal phases. Where investors are providing these funds, they expect a return commensurate with this risk.

Various schemes have been proposed and tried to reduce this risk, with varying degrees of success, such as:

a. Exploration drilling insurance, and
b. Exploration undertaken by government, with exploration costs recovered when the project achieves operation.

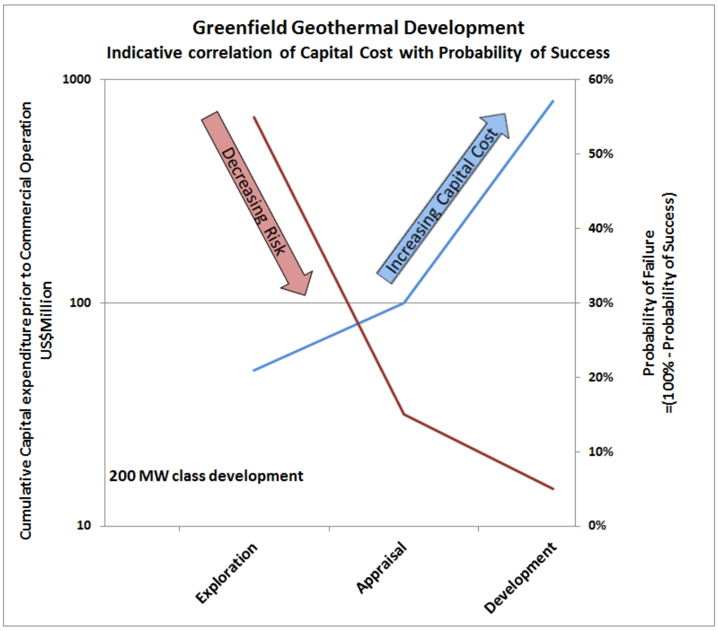

Figure 1: How Risks and Costs Change through the Project Life

In jurisdictions where the government is the sole buyer of electricity and awards concessions on the basis of the lowest electricity tariff bid (e.g. Indonesia and Kenya), then exploration by government, if undertaken in a cost-efficient and technically robust manner, may reduce the risks to an investor-developer. This may lead to less uncertainty in regard to a number of the parameters in Table 2, and this could allow bidders to be more certain of their future costs and therefore they could reduce the risk component of their bid. In an open market this should lead to lower tariff bids, or lead to tariffs which have a higher chance of incentivizing developers to complete and operate their projects.

5.7 Other Risk and Tariff Reduction Opportunities

Permit and licence processes associated with land and access to land are frequently a major risk to developers, and can stretch the timeline, requiring higher tariffs due to the time delay between expenditure and the generation of income. Governments can help reduce this rick by reducing red tape and supporting projects by assisting in the matter of land access and social acceptance of projects.

Government can also make projects more attractive to developers, investors and lenders by providing fiscal incentives such as lower tax rate, tax holiday (possibly coupled with accelerated depreciation) and allowing losses to be carried forward. However, although these may help to lower the tariff in a competitive bidding environment, they will not (of themselves), reduce the risks that developers, investors and lenders are exposed to.

6. DETERMINISTIC TARIFF

Selecting typical values for each of the variables listed in Table 2 and using these in a financial model which solves for a required tariff provides a result that is classed as a "deterministic" value.

For the set of typical values presented in the previous table, solving separately for Project and Equity IRRs results in the deterministic Year 0 tariffs presented in Table 3. The deterministic pre-COD (Commercial Operation Date) total project cost for a 2x55MW greenfield geothermal development, excluding interest during construction, financing costs and insurance costs, is estimated at just under US$500Million.

Table 3 Approximate Year 0 tariffs required to meet different financial criteria

Financial Criterion	Deterministic Year 0 tariff (US$/MWh) 2 x 55MW Greenfield Geothermal Project
Project IRR (nominal, after-tax) of 14%	150
Equity IRR (nominal, after-tax) of 18% [30% Equity]	140

7. PROBABILISTIC TARIFF

As noted previously, there are uncertainties (and therefore risks) in both the amounts and the timing of all the elements which make up a successful geothermal electricity project. These elements (expressed as variables) include both those which come before electricity begins to be produced (pre-COD) and those which come after (post-COD).

All these variables ultimately affect the timing and amounts of costs and income, and therefore the risk that an undesirable or unacceptable outcome may occur. There are an infinite number of possible combinations of these variables which affect both cost and timing. Faced with such variability, a useful tool which provides a measure of the likely range of outputs is the Monte Carlo Method (which involves probabilistic modelling, also known as stochastic simulation). Such a tool allows decision makers to quantify the risk that an undesirable or unacceptable outcome may occur.

The Monte Carlo Method *"performs risk analysis by building models of possible results by substituting a range of values—a probability distribution—for any factor that has inherent uncertainty. It then calculates results over and over, each time using a different set of random values from the probability functions. Depending upon the number of uncertainties and the ranges specified for them, a Monte Carlo simulation could involve thousands or tens of thousands of recalculations before it is complete. Monte Carlo simulation produces distributions of possible outcome values"* (Pallisade Corporation).

Proprietary software, generally applied as an add-on to spreadsheet computational models, is available for decision-makers to carry out their own Monte Carlo simulations. Figure 2 presents a typical output from a Monte Carlo simulation using the values and probability ranges assigned to the input variables as presented in Table 2. This has been produced by using @Risk® (Pallisade Corporation), an add-on applied to an Excel® (Microsoft Corporation) spreadsheet financial model.

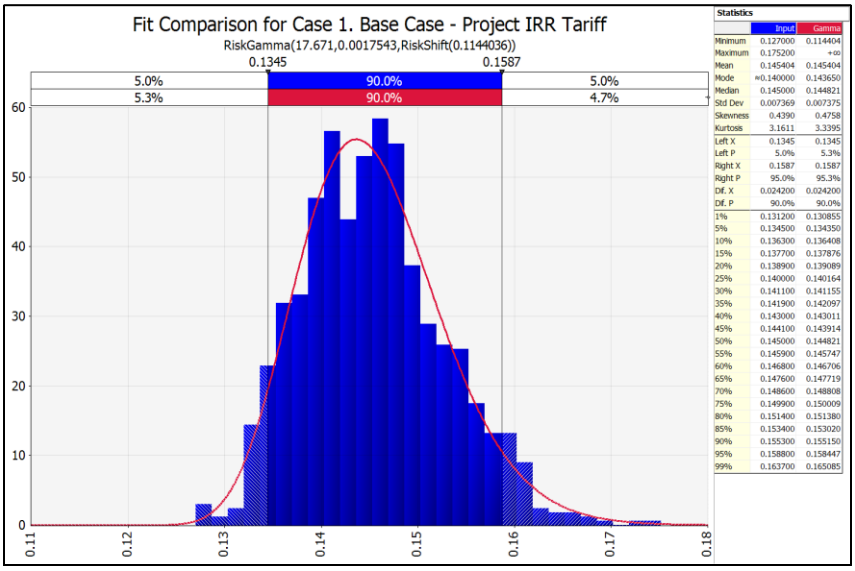

Figure 2: Typical output from a Monte Carlo Simulation of Geothermal Tariff.

7.1 Sensitivity Analysis and Market Considerations

Although variation in the capital cost expenditure (CAPEX), which is affected by a number of subsurface, location and equipment market factors, has a significant impact on the required tariff, by far the greatest impact is associated with variations in how the CAPEX is funded. To a lesser extent tax also has an impact. In order to demonstrate these impacts for the purpose of this paper the following factors have been varied:

A. Debt:Equity Ratio (from a base of 30% Equity:70% Debt: variations of 20%:80% and 40%:60% have been assessed)
B. Cost and tenure of debt (from a base of 4% with 20 year term: variations of 6% with 20 years and 12% with 10 years)
C. Tax rate (from a base of 34%: variations of 28% and 36%)

To limit the number of Monte Carlo simulation runs (1000 runs are performed each time a sensitivity is tested), the following five cases have been simulated:

Case 1.	30% equity,	70% debt,	34% tax,	4% debt with a 20 year term,	14% IRR[3] required
Case 2.	20% equity,	80% debt,	28% tax,	6% debt with a 20 year term,	14% IRR required
Case 3.	40% equity,	60% debt,	36% tax,	12% debt with a 10 year term,	14% IRR required
Case 4.	30% equity,	70% debt,	34% tax,	4% debt with a 20 year term,	18% IRR required
Case 5.	30% equity,	70% debt,	34% tax,	4% debt with a 20 year term,	25% IRR required

These five cases have been run both for a return on equity and for a return on project, for a total of ten combinations. The project cases are the same as assuming 100% equity, which requires no external funding. Case 1, Project IRR is considered the base case for this paper. The results of the analyses are presented in Figure 3.

The results for Cases 4P, 5E and 5P are significantly higher than the others. This highlights the impact of higher IRR on tariff. One might ask why these IRR cases are considered – the reason is that many project developers consider 25% return on equity to be their hurdle rate for investment in a greenfield geothermal project (ESMAP).

[3] In all cases in this paper the IRR is expressed as after-tax, nominal, and all tariffs are expressed in $ of the Table 2 cost datum (2013).

In an open electricity market (where the market determines the price to be paid for electricity) the geothermal developer, as potential seller, will have an assessment of the likely future price path performed on its own behalf. The developer will also assess the costs it will incur in developing and operating the project (per Table 2). The developer and its investors will then assess whether the project can be funded in a manner such that the sales income per the expected future price path, after deduction of operating costs and payment of taxes, will be more than sufficient to meet the developer's hurdle internal rate of return on the equity it invests while also repaying the debt principal and interest. In this situation all the risks are on the seller and its financiers.

In a closed electricity market (where the buyer and the seller agree in advance to the price to be paid for electricity under a long term PPA eg Indonesia and Kenya) the geothermal developer will assess the costs it will incur in developing and operating the project (per Table 2). The developer and its investors will then assess whether the project can be funded in a manner such that the sales income per this known future price path, after deduction of operating costs and payment of taxes, will be more than sufficient to meet the developer's hurdle internal rate of return on the equity it invests while also repaying the debt principal and interest. In this situation not all the risks are on the seller and its financiers since the future price path uncertainty has been removed (allowing however that the future creditworthiness of the buyer must be assured).

Referring to Figure 3, in an open market the seller will seek opportunities towards the right (higher tariffs) commensurate with the risks it will face and in a closed market the buyer will seek opportunities towards the left (lower tariffs) commensurate with its assessment of the project de-risking that it has offered to the seller through a known future price path.

Figure 3 therefore reflects the likely range of required tariffs that will satisfy one party or the other. For a 2x55MW greenfield geothermal development, the group of curves scattered around Case 1P is suggested as a middle ground in which both parties might find an acceptable position in a closed market situation. The grouping of values around Case 1P covers a variety of financing structures and desired IRR (equity or project) – some of these are attractive to the seller and not the buyer, and vice versa.

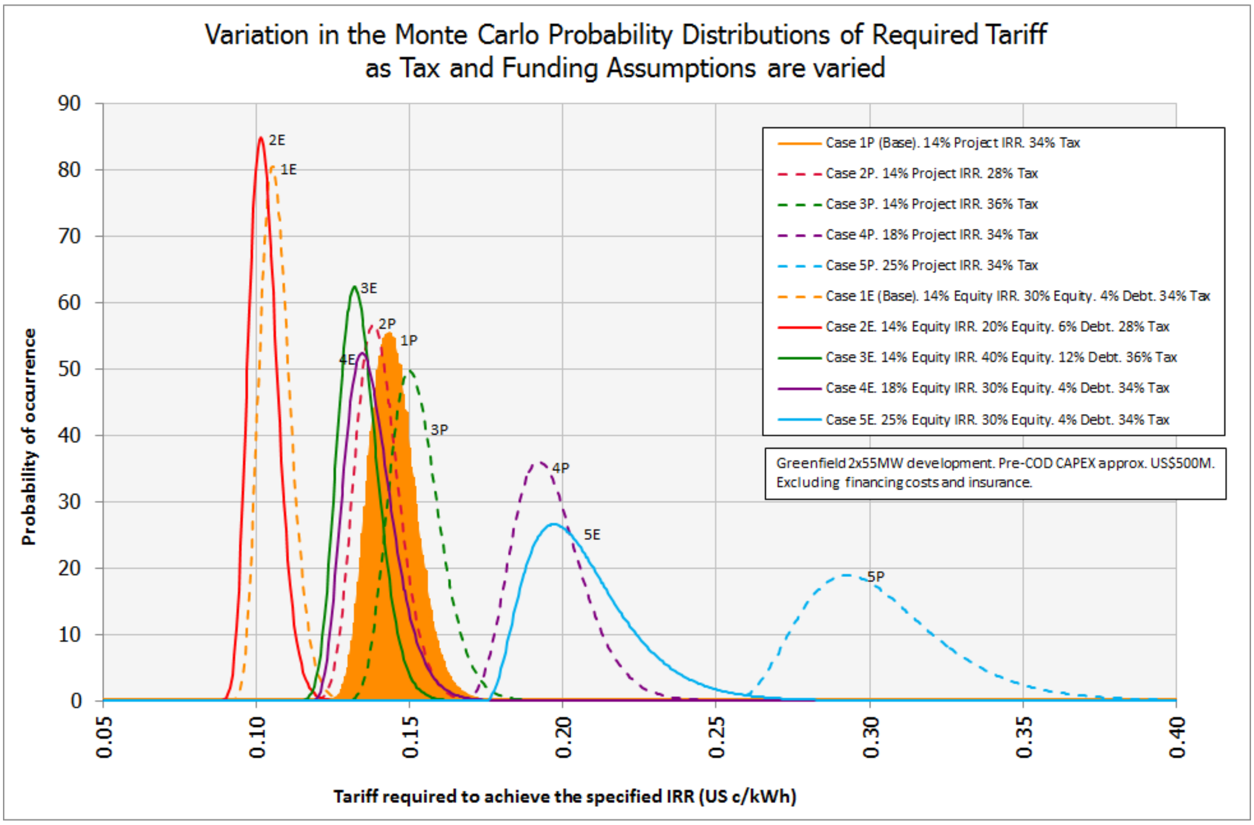

Figure 3: Sensitivity of required tariff to variations in tax and funding assumptions

8. CONCLUSIONS

Where the parties to a PPA in a closed market are willing to consider a probabilistic approach in support of reaching agreement on an equitable tariff, a Monte Carlo simulation of the tariff is a useful tool. Such a tool can be used to generate a probabilistic spread of tariffs which meet the seller's specific investment criteria (e.g. a given net present value or a target internal rate of return). As a project progresses from exploration to development, uncertainties (and thus risks) in the input variables can be expected to reduce. Correspondingly there will be a reduction in the range of tariffs which meet the investment criteria within a certain probability band (e.g. in the range 10 to 90% probability of exceedance). If the parties agree, and if the tariff negotiation process allows for it, at some point the parties may agree that the range of tariffs delivering an acceptable rate of return has narrowed sufficiently that the parties can agree to a specific tariff within that range. Where the seller is funding the project either with 100% equity or from a funding base that covers a wide range of projects, not only geothermal, the range of project hurdle rates of return used in this paper provide an indication of the range of tariffs that the buyer and seller may wish to contemplate. Ultimately the final choice of tariff is either by agreement or by regulation, and in the latter case the seller will ultimately be faced with the decision of whether to proceed with the project or not given the regulated tariff being offered.

REFERENCES

ESMAP (Energy Sector Management Assistance Program). 2012. *Reaching for High Returns*. Page 104 in Geothermal Handbook: Planning and Financing Power Generation. Technical Report 002/12. Washington DC: ESMAP.

Pallisade Corporation: Monte Carlo Simulation: What Is It and How Does It Work? Posted at: http://www.palisade.com/risk/monte_carlo_simulation.asp and retrieved on 29 May 2014.