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The Potential for Investment in Indonesia's Geothermal Resource

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ABSTRACT

Indonesia has around 40% or the world's capacity for geothermal energy production, yet lags behind neighbors, such as the Philippines, in developing this resource. There are ambitious plans to increase production to nearly 6GW and then to 9.5GW, with the bulk of the investment coming from the private sector. With Chevron being the only overseas company currently investing in Indonesia, this paper explores the potential economic and other barriers investors perceive to exist.

The paper reports on the outputs from a spread sheet time series model, which collates the estimated costs and revenues that investors could expect. Based on these outputs a form of sensitivity analysis has been performed which identifies the required tariff to encourage investment.

Overall the model suggests that current feed-in tariffs are too low to stimulate the large scale investment Indonesia requires and particularly in eastern Indonesia where electricity shortages are most acute. Although the paper explores some potential solutions to the issues, the overall conclusion is that Indonesia's geothermal plans are likely to remain unfulfilled, with only limited investment occurring.

Keywords: *Geothermal Power; Indonesia; Energy; Overseas Investors; Market Regulation.*

1. INTRODUCTION

To meet increasing electricity demand (between 7% and 9% per annum) Indonesia needs to invest \$4-\$5bn per annum in generation and transmission. The National Electricity Development Plan (Ministry of Energy and Mineral Resources, 2008) suggests that by 2027 electricity demand will be 813,000GW, with plans for an additional 217,000GW of capacity. Quiet apart from the ecological impact of investment in coal fired power stations, to avoid a trade debt crisis from oil and gas imports, Indonesia must diversify its energy sources (International Energy Agency, 2008). Having the largest capacity in the world for geothermal energy (around two-fifths of the global resource), this would appear to be an obvious route for Indonesia's diversification. Indeed, Indonesia has so much geothermal potential that it could export additional capacity to neighbouring countries, such as Singapore and Malaysia; indeed the total potential is the equivalent of 11bn barrels of oil.

265 geothermal fields have been identified in Indonesia, although many of these are not sufficiently close to electricity grids to be economical to exploit (indeed nearly a half of the capacity is located in remote areas of Sumatra). In total, there is a plan to develop around a fifth of the country's most suitable capacity, so that nearly 6GW will be available; and further developed to 9.5GW by 2025. Large scale development has been identified for Bali, Java, Sulawesi and Sumatra (where the bulk of the potential is located, furthermore Bali, and Java share a grid, which connects to the Sumatra grid), where the fields are close to grids with investment by Pertamina, PLN and the private sector. For other islands small scale development is planned with investment by the Government and PLN (Ministry of Energy and Mineral Resources, 2009). Nevertheless compared with the Philippines (de Wilde 2009) where 27% of total energy is derived from geothermal even these plans look modest.

In total, the investment required to achieve the 6GW is around \$12bn (or \$30bn for the full 9.5GW), of which it is anticipated that 70%-80% will come from the private sector (although the World Bank has pledged a \$300mn loan, with the potential for more from its Clean Technology Fund). Currently the tender process for private investors is that the Government, or Local Government (as it is now their responsibility), conduct a preliminary survey and initial exploration activities to define the field. Then private companies conduct advanced exploration, feasibility study, exploitation and steam production activities. The private company that conducts the advanced exploration is expected to then supply the electricity. Although recent legislation makes this mandatory, the commercial reality is that exploration companies may not follow up on a field that others would wish to exploit, meaning that the exploration company and producer are not necessarily the same. Previously the company producing the steam and the company producing the electricity were also different, creating issues of synchronisation and commercial conflict (de Wilde, 2009).

Reflecting the lower size of potential fields in eastern Indonesia and as a consequence their higher cost of electricity production, the Ministry of Energy and Mineral Resources (MEMR: decree No.31, and No.32) had set a differential feed-in tariff in 2009, with lower rates in Java, Sumatra and Bali. The tariff was capped later in 2009, so that the maximum that can be earned is $0.097 per kWh, lower than the typical $0.1-$0.12, paid elsewhere in the world. Nevertheless, the initial impression is that this rate appears to be generous when compared to international costs which can be as low as $0.0543 (Sayal, et al., 2007) and generally speaking international investors would be looking for a minimum of $0.08 (Geotherm Ex Inc., 2010, estimate $0.086). In fact, Geotherm Ex Inc., (2010), in a study for the World Bank, shows that costs are lower in Indonesia than other producing countries, due to lower drilling costs and higher well productivity.

2. METHODOLOGY

This paper explores the potential costs and revenues, for private investors, in developing geothermal fields in Indonesia. It sets out to understand if current feed in tariffs are set at an adequate level to secure the investment Indonesia needs.

Cost and revenue data has been taken from a variety of sources (Augustine et al., 2006; DiPippo, 1999; Engineering and Consulting Firms Association, 2008; Kutscher, 2000; PT Castlerock consulting, 2010 and 2011; Sanyal, 2004; Sanyal, et al. 2007; whilst the main assumptions are identified within the paper) and analysed in a spreadsheet financial cash flow (time series) model.

The major components of a geothermal power plant include (SKM 2009):

- The geothermal field and the wells tapping it;
- The system of taking and removing fluids from the well;
- The power plant;
- The electricity transmission system.

The major cost elements are, therefore:

- Establishment Costs: land, survey and exploration, well testing, feasibility studies, civil and infrastructure, operations;
- Drilling Costs (dependant on the number and depth of the wells and the geology, these can account for between 40% and 95% of total costs);
- Stimulation Costs (dependant on the type of field, resource temperature and terrain): fluid pipes, plant, civil works;
- Power Plant: (dependant on size and type of plant);
- Transmission costs (dependant on distance from suitable grid connection);
- Operations and Maintenance (although dependant on capital costs other factors such as sulphur content, climate and terrain can impact on these).

Clearly there is great variability in the costs for geothermal electricity production, but Geotherm Ex Inc., (2010) provide a useful rule of thumb in estimating investment (fixed) costs in Indonesia (see Table 1).

Table 1. Geothermal Development Costs in Indonesia

US $mn	Power Plant Size MW		
	20	50	100
Total Exploration Cost (including establishment costs, but not including land purchase, bidding, licencing)	9.05-28	9.05-28	9.05-28
Total Power Plant Costs (not including transmission)	40.5-62.5	69.65-90.05	109.05-134.5
Total Cost/MW	2.05-3.12	1.38-1.8	1.09-1.35

They (Geotherm Ex Inc., 2010) also suggest that for new fields in Indonesia for every three wells drilled typically it will yield one production well and one marginal well, depending on the input tariff. However, costs decline in established fields so that on average drilling costs come down to around $4mn per well. Understanding the impact of the learning curve and economies of scale are critical in setting the correct tariffs, to obtain the required investment.

In terms of the operations and maintenance (variable) costs, these are normally thought to be around $0.027 per kWh, however, the model uses a range of $0.02-$0.03 as identified by Geotherm Ex Inc., (2010).

These costs form the basis of the model, which has excluded reconnaissance and surface exploration from them, as these are normally provided for investors in Indonesia. However, I have added interest to the overall costs (my model uses payback period rather than internal rate of investment: as it is useful to consider reducing tariffs over time, to offset the potential for windfall profits resulting from the learning curve; it is therefore a discounted payback model).

Revenues are taken directly from the 2009 feed-in tariff for power plants under 10MW, in Indonesia, including the cap. The model generously assumes full production in year five, when the reality in Indonesia is year eight, it is probably also over generous in revenue allocation, compared with actual revenues at existing plants.

Given the number of variables and the uncertainty surrounding many of them, a full sensitivity analysis is not possible. Nevertheless, by taking average costs, at a fixed point, it is possible to output a form of sensitivity analysis, which provides evidence on the adequacy of current tariffs. This is based on the assumption that investors would be looking for payback after ten years, even though a plant will typically go on producing for 30 years. This is consistent with an Internal Rate of Return of around 20%, a rate that many believe to be necessary (Geotherm Ex Inc., 2010), although the Indonesia Government believe that it should be between 15% and 20%.

Revenue return outputs are taken from the model as simple line graphs from the time series. These are displayed over the full time a private investors would be engaged, which without the sort of delays that past projects have been subject to would be around 34 years. They are also displayed over a 16 year period to more readily identify the position at year 10.

3. RESULTS

Firstly, I consider the returns from that would come from the highest level of tariff (i.e. the $0.097 cap) and with the lowest cost estimate for 20MW, 50MW and 100MW power plants. I then consider the lowest level of tariff (i.e. $0.0713 which is applied to middle voltage point power plants of less the 10MW, in Java, Madura and Bali) applied to the highest cost estimate (Figure 1). These give the parameters which under normal conditions many projects would fall between (although for power plants over 10MW the lower tariff parameter could reduce).

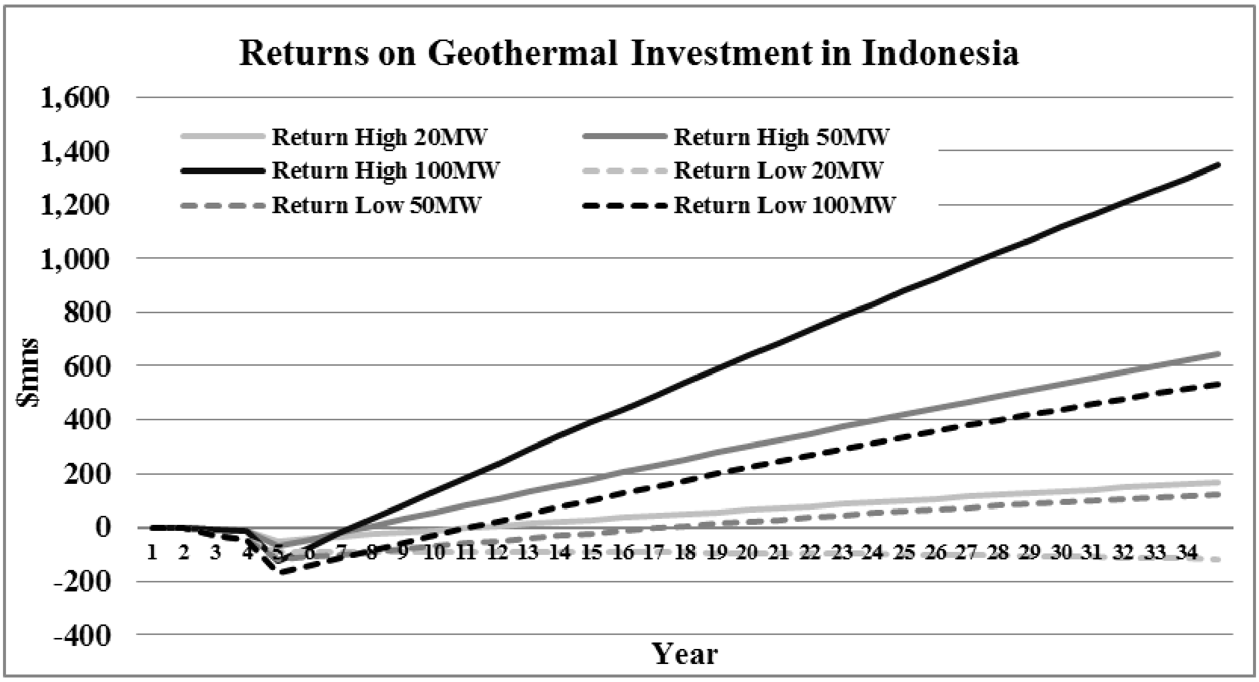

Figure 1. Hypothetical Parameters on Returns

The model suggests that if investor costs are at the high end and they only receive the $0.0713 tariff they will never get a return on their investment on a 20MW power plant (Figure 2). But if they receive the high capped tariff of $0.097 and their costs are low they will get a return in year 11. For 50MW power plants the maximum time for investment to be paid back is 17 years (for the low tariff and high costs). Whilst the minimum payback for a 50MW power plant (for the high tariff and low costs) is a much more attractive 7 years. More positive again for the 100MW power plant the payback is between 11 and 7 years.

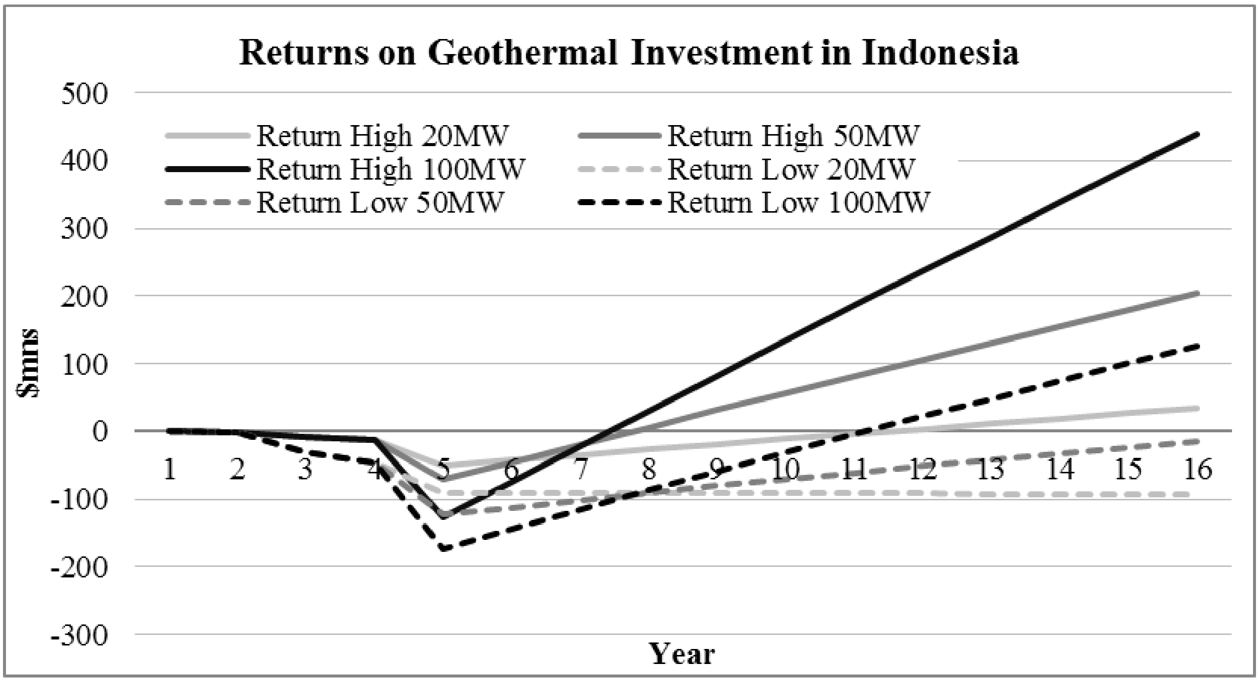

Figure 2. Hypothetical Parameters on Returns

Although the boundaries of what is probable in terms of costs and revenue are important to investors, what they believe is 'likely' is much more relevant to investment decisions. As we cannot speculate on how optimistic, or pessimistic, investors would be I have simply taken averages of costs (arithmetic mean) for each scenario (Figure 3).

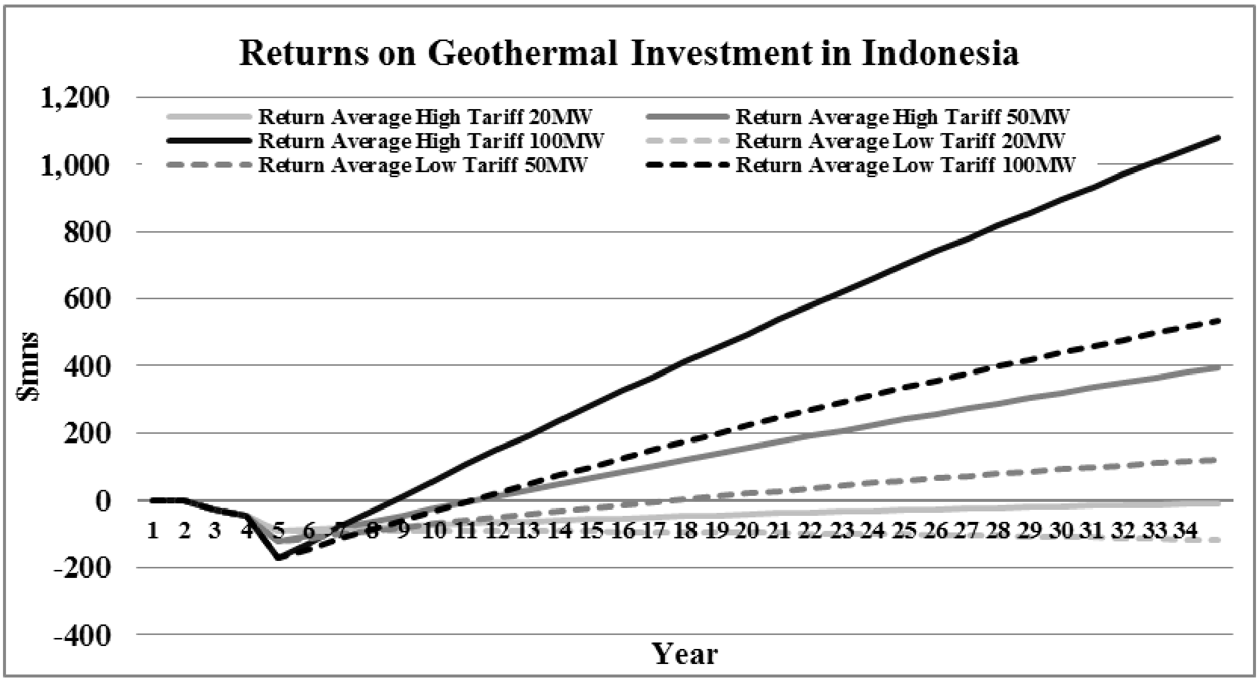

Figure 3. Hypothetical Returns Based on Average Costs

Once again a 20MW power plant would never be paid back at the lower tariff rate, even when average costs are assumed; it still does not produce a payback at the higher tariff level (Figure 4). For a 50MW plant the payback period is between 17 years and 11 years. For the 100MW plant the period is between 11 and 8 years.

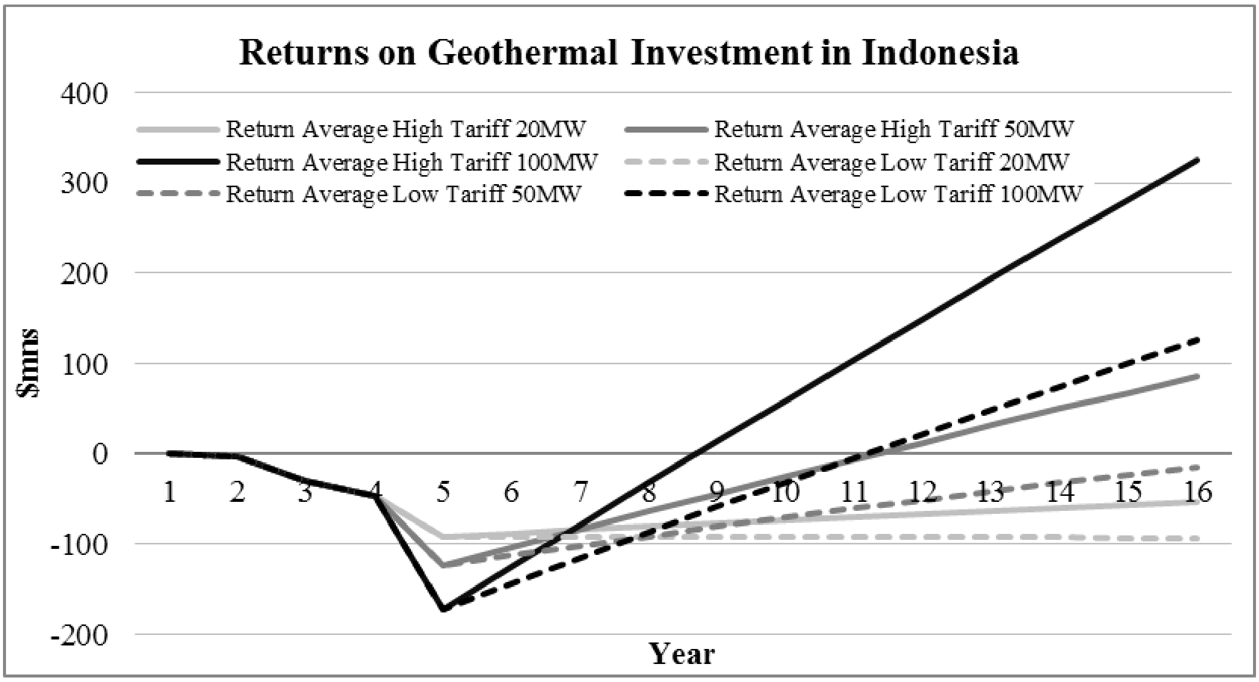

Figure 4. Hypothetical Returns based on Average Costs

Having considered average costs it is also useful to consider the effects of an average tariff rate (again the arithmetic mean of the lowest and the capped rate) and then the rate the tariff would need to be at to achieve a payback in ten years (which is a form of sensitivity analysis; Figure 5). Despite these average tariffs being independently calculated they are remarkably close to those recommended by PT Castlerock Consulting (2011), albeit they differentiated by region rather than by plant size (with plant size being somewhat determined by region).

Taking average costs and revenues a 20MW plant, as might be expected, would never produce a return (Figure 6). A 50MW plant pays back in 14 years and a 100MW in 11 years. Looking at the ten year payback requirement this could be achieved at a $0.0875 feed-in for 100MW power plants, $0.1065 for 50 MW and a high $0.188 for a 20 MW power plant (this is consistent with PT Castlerock Consulting's, 2010, finding that a $0.13 tariff is required for plants below 55MW).

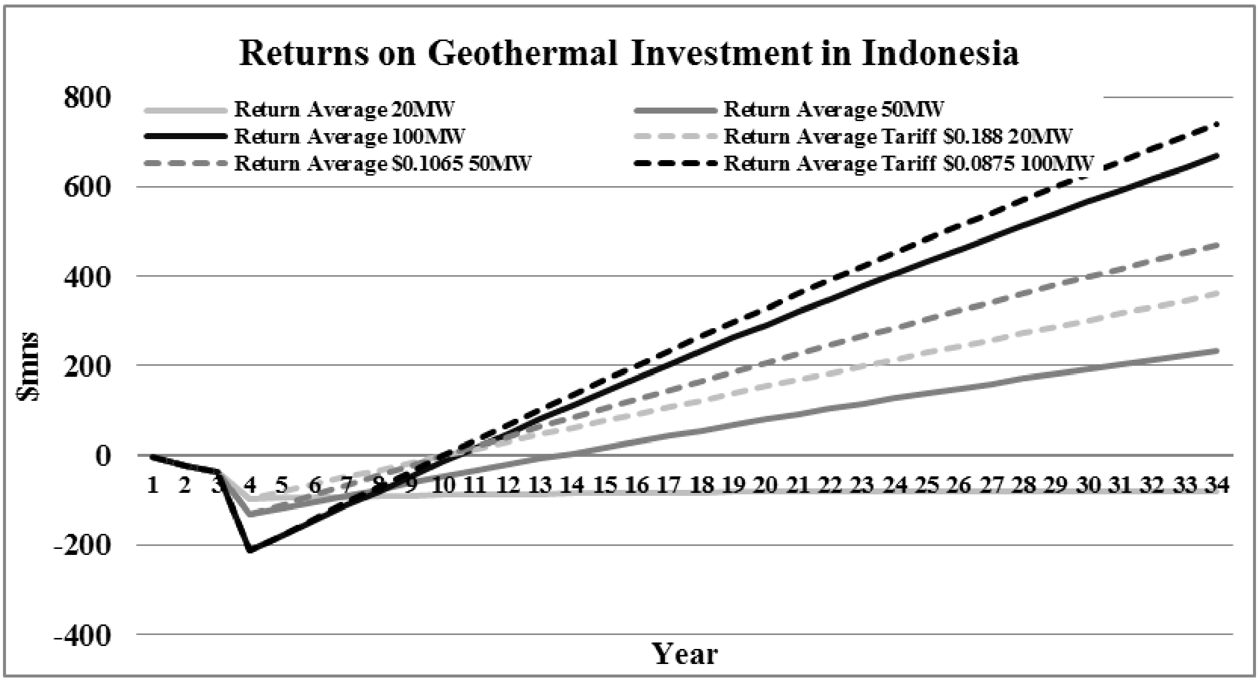

Figure 5. Hypothetical Returns on Average Costs and Tariff and Sensitivity Analysis

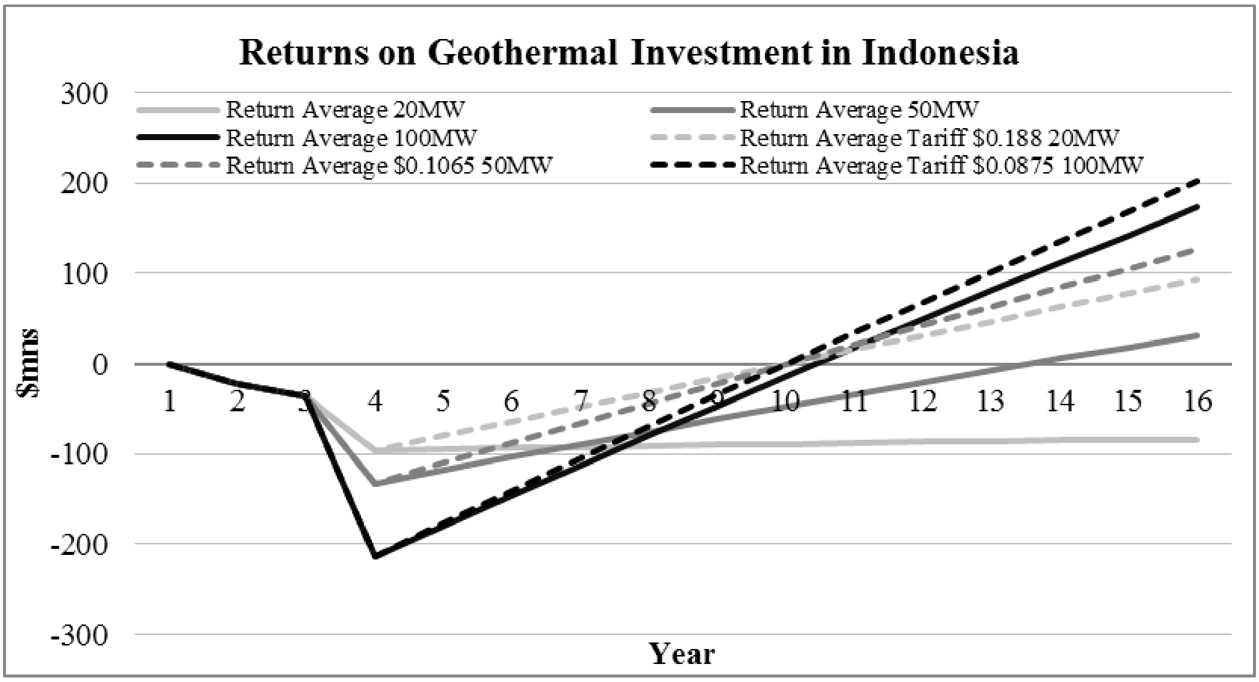

Figure 6. Hypothetical Returns Based on Average Costs and Tariff and Sensitivity Analysis

4. DISCUSSION

The outputs from my model appear to suggest that the current feed-in tariffs are set a little too low to encourage major investment in Indonesia's geothermal resource. Whilst a tariff of around $0.0875 may be enough to encourage investment in existing fields with the capacity for large power plants, it is clearly nothing like enough to stimulate investment in the small fields and power plants of eastern Indonesia. Indeed the original 2009 published tariffs which went up to $0.1636 per kWh, for low voltage connections of power plants below 10MW in Maluku and Papua, look far more realistic without the cap, for all sizes of power plants.

Jagannathan (2010) of the World Bank argues that the current pricing structure fails to account for the incremental costs of geothermal generation (of which the learning curve is one component); which begins to rise steeply over the planned 6GW, largely due to the uncertainties regarding drilling costs in developing new fields (PT Castlerock Consulting 2010). Despite the cap of $0.097 per kWh, the Engineering and Consulting Firms Association (2008) argue that for development to be viable in eastern Indonesia a feed-in tariff of at least $0.14 would be required. Whilst Partowidagdo (2000) argues that Government backed exploration insurance would stimulate investment outside of existing fields. Again the Ministry of Finance (2010) reinforce these findings:

"It is therefore economically reasonable for the government to pay at least 13 cents per kWh for geothermal electricity with any excess profits by operators recouped through profit sharing arrangements."

In fairness, to the Government, they are willing to waive the cap for more difficult areas of eastern Indonesia and let the investor take any carbon credits (which are the subject of great uncertainty regarding their future and future price). Unfortunately, this just adds to the risks that investors would seek to mitigate.

There are also a number of non-price barriers facing private investors; de Wilde (2009) identifies the following:

- The regulations and tender process do not encourage the development of total projects (steam and electricity production), despite these now being mandatory.

- PLN's effective monopsony over the purchase of electricity and its lack of incentive to enter into Purchase Power Agreements (PPAs), because it loses money on subsidised electricity sales.

In addition, there have been a number of international disputes between investors and PLN and cancellations of PPAs (due to escalating costs of contracts in US $'s, following the Asian financial crisis). This has led the Government to guarantee PPAs, but does not remove the fundamental tensions within the commercial relationship with PLN and therefore, the potential for conflict. Investors also complain that initial surveys provide inadequate data on which to risk developing a new field, which is then complicated by devolution. Nevertheless, there is actually more data available to investors than in many other countries and it suggests that Indonesia has a large number of potentially commercial fields. This issue would be resolved if PT Castlerock Consulting's (2011) recommendation to establish independent expert bodies is taken up.

Responsibility for electricity production is now devolved and the often opaque land rights in rural eastern Indonesia probably do act as barrier to investment. Indeed, these barriers are a part of the reason for Indonesia's low level of electrification (around 70% and even lower in eastern Indonesia), when compared to its ASEAN neighbours.

Even the Ministry of Finance (2010) have cast doubt on the potential for investors:

"… geothermal energy cannot compete with conventional energy sources, given the existing distorted price structure of the Indonesian energy sector. The distortions arising from explicit and implicit subsidies favour fossil fuel generation, to the near exclusion of geothermal."

Huenges et al (2011) also argue that skills shortages, at all levels, exist in Indonesia for geothermal exploration and production.

These resultant problems mean that currently Chevron is the only overseas investor in Indonesia's geothermal potential.

5. CONCLUSION

Investment in geothermal drilling and power plants is of enormous importance to the ecology and economy of Indonesia. The Government requires the bulk of this investment to come from the private sector and is using published feed-in tariffs to stimulate interest. Unfortunately, these tariffs, and particularly the cap imposed on them, have been set too low to encourage investment outside of the large established fields in Bali, Java and Sumatra. This means that those areas of eastern Indonesia that are current facing severe shortages of electricity are unlikely to receive the investment they need in generation, unless it comes from central, or regional government.

Overall under current market conditions, Indonesia is unlikely to meet its 6GW of geothermal power target, let along the more ambitious 9.5GW. Some reform of the tariffs is required. A simple stimulus would be to remove the $0.097 cap, allowing the higher tariffs to come into play in eastern Indonesia (which PT Castlerock Consulting, 2011, show are still cheaper than the diesel genset alternative). In the past PLN has reduced the tariff over time, this may be a more realistic approach to rewarding investors to take on the risk, but ensuring that they do not gain windfall profits. Nevertheless it could only work if the reduced tariff structure was known and explicit prior to the investment. A less palatable alternative would be a windfall tax. A more complex and potentially impractical approach (for new fields where the productivity can only be estimated) would be to also publish differential tariffs dependent on the size of the field, or power plant (as recommended by PT Castlerock Consulting, 2011).

There are also a number of non-price issues affecting investors' perceptions of Indonesia. With the west heading back into recession, there will be a lot of spare capital looking for investments, which may reduce some of the reluctance of international investors. Coupled with low interest rates in the west, it is possible that investors will reduce their internal rate of return threshold. But how wise is it to gamble Indonesia's future on what is only speculation? Therefore, I have to conclude that Indonesia's geothermal ambitious are currently a long way from becoming a reality.

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