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Forecast Costs for Geothermal Energy in Australia

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ABSTRACT

This paper presents forecasts for the costs of utility scale electricity production from geothermal energy in Australia. The costs were modeled using the System Advisory Model (SAM). Considering a range of play types the range of LCOE's for geothermal energy in Australia in 2020 was forecast to be between $170/MWh and $330/MWh. Drilling costs are the biggest contributor to the LCOE for geothermal energy and these costs have increased significantly over the last decade. A scenario where technical and market factors are favourable for geothermal energy by 2030 was also considered, with the LCOE falling to between $99/MWh and $130/MWh.

1. INTRODUCTION

The Australian geothermal energy sector has gone through a period of rapid growth and then decline over the last 10 to 15 years without the development of any significant new generating capacity. This is despite predictions of significant development. For example, the 2010 Australian Country Update predicted 100 MWe of installed capacity by 2015 ((Beardsmore & Hill, 2010). The failure to reach these predicted levels of generating capacity appear to be driven by a combination of the high costs and perceived risks associated with developing geothermal energy resources in Australia. Australia's geothermal energy resources are dominated by conductive heat flow processes. This means the resources are in geothermal play types that have had little development globally including those described as Enhanced Geothermal Systems (EGS) and Sedimentary Geothermal Systems. There is little global experience with the costs of developing these resources at utility scale (10's of MW) aside from some recent activity in Europe. Understanding the forecasts costs of geothermal power and the main contributors to these costs is important for anticipating the potential future contribution of this energy source.

The costs of electricity generation from geothermal energy are primarily driven by the capital costs of developing a geothermal energy power station. In this regard, geothermal energy is quite similar to other renewable technologies such as wind and solar. The component that sets geothermal energy apart is the cost of accessing the resource itself. While wind and solar projects would still need the resource to be characterised before a project using these resources could proceed, characterising and then accessing (through drilling) a geothermal resource is a significantly more involved and expensive process. These complexities are offset by the constant availability of a geothermal resource once it has been developed.

Figure 1 shows the evolution of risk and cost in the life cycle of a geothermal project. There is a considerable degree of risk in the early exploration stages and in fact many project do not proceed beyond this point, despite considerable expenditure. This is no different to most earth resources (e.g. oil and gas, metals).

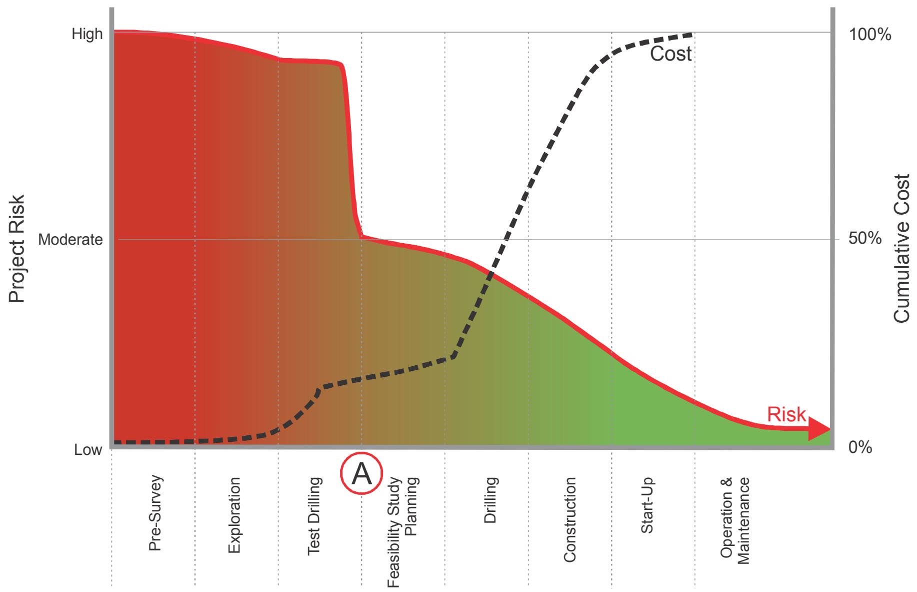

Figure 1: Project costs and risk profile through the development of a geothermal resource. There is significant risk up to the point where test drilling has confirmed the resource size and that it can be extracted economically (labelled A). After Gehringer & Loksha, (2012). This profile of costs and risk is very similar for a range of earth resource base projects (i.e. gas resources, mines).

2. EXISTING COST FORECASTS

A summary of current projected estimates of capital costs and LCOE for EGS plants are shown in Table 1. The variation in costs reflects the uncertainty surrounding this emerging technology and the assumptions that need to be made regarding the cost of drilling, the temperature and depth of the resource and the cost of the balance of power. The cost submitted by "Company X" is substantially lower than the other forecasts. Details provided by this company indicate that they are assuming a much lower cost of drilling than used in the other models (approximately \$12 million per 5,000 m well), which they base on the costs over a 60 well program. Their operating and maintenance costs are also significantly lower than used in other models (approximately \$90 per kilowatt of installed capacity). Their assumptions for flow rate are also high (over 110 kg/s).

Table 1: Capital cost estimates for a hot fractured rocks plant in AUD 2014/kW sent out. CSIRO (2011) is from Hayward et al.(2011), EPRI (2010) is from the Australian Electricity Generation Technology Costs - Reference Case 2010 (EPRI and Commonwealth of Australia, 2009), Gurgenci (2013) is from (Gurgenci, 2013), Mines 2013 is Scenario C from (Mines & Nathwani, 2013), Company X is from a detailed commercial-in-confidence submission made by an Australian geothermal company to the IGEG, and the two AETA costs are from the Australian Energy Technology Assessment (Bureau of Resources and Energy Economics, 2012). The LCOE's are in AUD 2014/MWh.

	CSIRO (2011)	EPRI (2010)	Gurgenci (2013)	Mines (2013)	Company X (2014)	HSA AETA (2012)	EGS AETA (2012)
Capital Cost	**\$7,363**	**\$9,199**	**NA**	**\$11,850**	**NA**	**\$7347**	**\$11,125**
LCOE	**\$156**	**\$188**	**\$195**	**~\$260**	**\$60**	**\$161**	**\$222**

The Australian Energy Technology Assessment (Bureau of Resources and Energy Economics, 2012) is the most recent authoritative assessment of geothermal energy costs in Australia. Table 2 shows the technology specific assumptions that were used in these calculations.

Table 2: Input parameters for the AETA models. Provided by the Bureau of Resources and Energy Economics. Data provided by the Bureau of Resources and Energy Economics.

Parameter	**EGS**	**HSA**
Capacity	50 MW	50 MW
Production Wells	12	13
Injection Wells	6	7
Resource depth	5000 m	4000 m
Resource Temperature	250° C	150° C
Rejection Temperature	70° C	70° C
Flow Rate	60 kg/s	100 kg/s
Production Well Costs	\$281 million (\$23.4 million per well, including stimulation)	\$120 million (\$9.3 million per well)
Injection Well Costs	\$128 million (\$20.3 million per well)	\$65 million (\$7.3 million per well)
Power Plant Costs	\$100 million (\$2,000 per kW)	\$125 million (\$2,500 per kW)
Power Plant Efficiency (net of all parasitic loads)	9%	12%
Brine Reticulation Costs	\$15 million	\$20
Geology and Permitting Costs	\$15 million	\$20
Fixed O&M Costs	2% of total capital cost	3% of total capital cost
Thermal draw down	None	None
Project life	30 years	30 years

Table 3 shows the results of some recent modelling conducted by the US Department of Energy (Mines & Nathwani, 2013). These models use significantly higher costs for the power plant installation and operating and maintenance than used in the AETA model.

The resource types in these projections are based on significantly higher geothermal gradients than are found in Australia. It is also unlikely that Australian geothermal resources would ever use flash power plants. The costs of binary power plants at high resource temperatures (over 200 °C) are poorly constrained as they are rarely used at these resource temperatures.

Table 3: EGS cost modelling results for various scenarios in the USA. Costs are in US Dollars (Mines & Nathwani, 2013)

EGS Results	Scenario A	Scenario B	Scenario C	Scenario D	Scenario E
Temperature	100°C	150°C	175°C	250°C	325°C
Resource Depth	2 km	2.5 km	3 km	3.5 km	4 km
Plant Type	Air-Cooled Binary	Air-Cooled Binary	Air-Cooled Binary	Flash Steam	Flash Steam
# of Production Wells	21.5	7.6	7.9	6.4	4.3
Ratio of Production to Injection Wells	2:1	2:1	2:1	2:1	2:1
Production Well Cost - each	$5,187K	$6,965K	$8,973K	$8,237K	$10,280K
Injection Well Cost - each	$5,187K	$6,965K	$8,973K	$11,210K	$13,678K
Total Geothermal Flow	860 kg/s	303 kg/s	316 kg/s	256 kg/s	171 kg/s
Power Sales	10 MW	15 MW	20 MW	25 MW	30 MW
Geothermal Pumping Power	3,499 kW	738 kW	383 kW	997 kW	679 kW
Plant Output	13.50 MW	15.74 MW	20.38 MW	26 MW	30.68 MW
Generator Output	17.07 MW	20.34 MW	24.4 MW	27.42 MW	31.72 MW
Power Plant Cost	$8,128/kW	$4,668/kW	$3,597/kW	$2,091/kW	$1,571/kW
Overnight Project Capital Cost (with contingency)	$343,960K	$187,291K	$217,994K	$176,620K	$152,299K
Present Value of Project Capital Cost	$396,252K	$235,706K	$276,042K	$229,634K	$211,177K
Exploration & Confirmation (¢ /kW-hr)	9.44	7.27	6.56	4.83	4.88
Well Field Completion - Including Stimulation (¢ /kW-hr)	32.46	7.47	7.24	4.56	2.53
Permitting (¢ /kW-hr)	0.37	0.23	0.17	0.13	0.11
Power Plant (¢ /kW-hr)	16.98	7.13	5.30	3.09	2.33
O&M (¢ /kW-hr)	17.22	5.65	4.74	4.78	3.53
Levelized Cost of Electricity - LCOE (¢ /kW-hr)	**76.47**	**27.75**	**24.01**	**17.4**	**13.39**

3. COST MODELLING

The costs of geothermal energy projects are dependent on a wide range of variables many of which are interdependent. For this reason a range of scenarios have been modelled in an attempt to identify the range of costs for geothermal energy in Australia. The scenarios are shown in Table 4. The scenarios have been chosen as they represent the range of resources that have been targeted in Australia.

These scenarios are based on a range of assumptions on the technical performance of geothermal energy systems that have yet to be demonstrated for conductive geothermal resources in Australia (primarily flow rate). It is also important to note that there have been no utility scale power stations built anywhere in the world that utilise the types of resources that are found in Australia. The global experience is limited to plants that are a few MW in scale.

Table 4: Scenarios used for cost modelling with base case parameters.

Parameter	**Natural Reservoir A**	**Natural Reservoir B**	**EGS A**	**EGS B**	**EGS C**	**EGS D**	**EGS E** 6” Wells
Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Temperature °C	150	180	150	180	220	250	220
Flow rate (kg/s)	100	100	80	80	80	80	40
Stimulation	No	No	Yes	Yes	Yes	Yes	Yes

3.1 System Advisor Model

The System Advisor Model (SAM) is a performance and financial model for renewable energy technologies that has been developed by the National Renewable Energy Laboratory (NREL) (Blair et al., 2014). SAM uses system design parameters, insulation costs and operating costs to determine the performance and costs of the renewable energy. Modelling of a range of technologies including solar, wind, biomass and geothermal can be performed in SAM. AUSTELA commissioned a guide for modelling Concentrating Solar Power using SAM in Australia (Lovegrove, Franklin, & Elliston, 2013). SAM allows a comprehensive range of system design parameters to be used for modelling geothermal energy systems including: resource type, depth and temperature; drilling costs; pumping requirements; reservoir performance; plant costs and efficiencies; and ambient conditions (SAM can predict hourly, monthly and annual output of a system). A range of financial inputs can be used with SAM, including: installation costs; operating costs; required return on investment; financial incentives; tax and inflation rates; and sources of funding (i.e. equity versus debt). A more detailed discussion of how SAM calculates LCOE is available in AUSTELA's Companion Guide to SAM for Concentrating Solar Power (Lovegrove et al., 2013) from the SAM website (https://sam.nrel.gov/).

SAM was chosen for this project because it allows a range of system design parameters and costs to be modelled rapidly as well as allowing parametric analysis of some of the inputs. The standard version of SAM uses default cost curves for drilling. Modelling conducted here is used for the version of SAM that allows users to input their own costs for drilling directly. This feature will be included in a future official release of SAM.

SAM was used to model the seven scenarios set out in Table 4. ***ALL*** of the parameters used in the model scenario base cases are presented in Appendices A.1 and A.2. Some commentary on the selection of these parameters is presented below. The SAM models are for geothermal costs in 2020. Accordingly, there are some assumptions made about technology development and costs between now and then.

3.2 KEY INPUT PARAMETERS

The input parameters for the SAM models are listed in Appendices 1 and 2. The key assumptions in the models are discussed below.

Total exploration costs are $2 million plus the cost of drilling of two confirmation or test wells. The cost of these wells is assumed to be 20% higher than that of the production wells to reflect the higher costs of these wells early in the life of a project. Lower cost slim exploration wells to reservoir depths have not been demonstrated for the resource depths being considered here. One of the two confirmation wells is converted into a production well. For most resource exploration, a company would normally evaluate several prospects simultaneously in order to spread the risk, with exploration shifting its focus to the more promising of these prospects as they are evaluated. The costs of exploration across all of the sites would be attributed to the final successful project. For the scenarios modelled here, these additional costs have not been considered.

The resource temperatures used in the SAM models are based on those found in the four projects that drilled to reservoir depths in Australia. They represent thermal gradients in the order of 40°C to 50°C per kilometre, with the exception of the Natural Reservoir A, which has a much higher thermal gradient (similar to that observed at Celsius 1).

The flow rate per well of the geothermal brine is one of the most critical parameters in determining the costs of geothermal energy. The flow rates used in the base scenarios of 100 kg/s for Natural Reservoirs and 80 kg/s for EGS Reservoirs represent the flow rates that the industry has been aiming for over the last 10 to 15 years. These flow rates have yet to be demonstrated in Australia and the assumption that they can be achieved routinely by 2020 is the most uncertain in these scenarios. EGS E is included with a 40 kg/s flow to provide a scenario with a flow rate that matches the best achieved from EGS wells so far.

There is only one resource in Australia that has been properly flow tested. That is Geodynamics Ltd's Innamincka Deeps project in the Cooper Basin. The maximum flow rate achieved in a closed loop was 18 kg/s (Hogarth, Holl, & Mcmahon, 2013). This flow rate was restricted by damage to the reservoir around the injection well, Habanero 1. The maximum production flow rate achieved at this project was around 40 kg/s from the Habanero 4 well, and this demonstrated flow rate forms the basis for scenario EGS E.

Drilling cost is the most significant contributors to the overall capital costs of a geothermal energy project. The Australian drilling services sector is relatively small with only 13 land-based rigs capable of drilling to the depth required for geothermal energy development, compared to well over 1000 drilling in the United States as of the end of March 2013 (data from the Baker Hughes Rig Count accessed from http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsoverview on 30/04/2014). As a result of the relatively small size of the industry in Australia, drilling costs are quite volatile and can vary markedly depending on contractual arrangements for individual wells or drilling campaigns. Further compounding this uncertainty has been the high volatility in drilling costs globally over the last decade. This volatility is illustrated in Figure 2 and while these data are for the United States, similar cost increases have been observed globally. The close link between the costs of geothermal wells and petroleum wells has been demonstrated many times (e.g. Augustine, Tester, Anderson, Petty, & Livesay, 2006; Mansure & Blankenship, 2011; Tester et al., 2006). It follows therefore that there is a link between the costs of drilling geothermal projects and the price of oil and gas (Mansure & Blankenship, 2011).

A study of drilling costs for petroleum wells in Australia (Leamon, 2006) suggested a correlation between drilling day rates and overall costs per day for drilling activities. This correlation allows for some estimates of current well costs to be made based on current drilling rig day rates. The relationship is as follows:

Well Cost = (Rig Day Rate/Rig Ratio) x Well Time

The well time is the number of days that the drill rig spends drilling a well (between spudding and rig release). The well time is dependent on the depth of the well, the nature of the formations being drilled through, the size (diameter) of the well, and the design of the well (including the number of casing strings). The rig ratio is a factor that relates the rig day rate to the daily cost of drilling. Leamon (2006) found that the rig ratio varied between 0.25 and 0.40. For this study, a rig ratio of 0.25 has been assumed as this seems to produce drilling costs identified through consultation with the drilling sector.

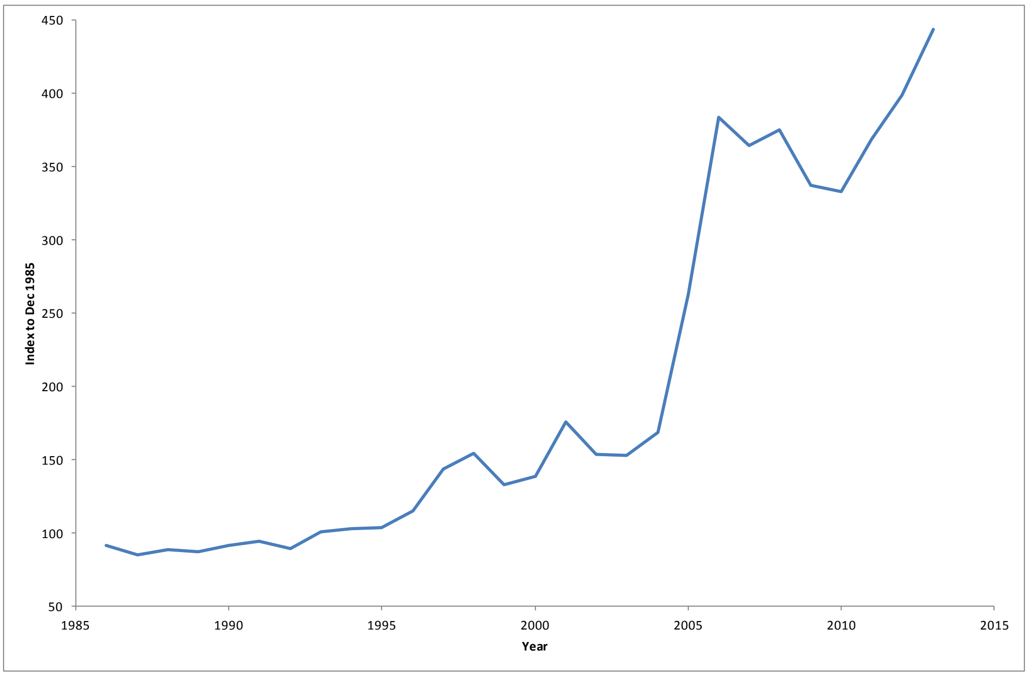

Figure 2: Producer price index of drilling oil and gas wells services in the United States from 1985 to the end of 2013. Data sourced from the United States Bureau of Labour Statistics (http://www.bls.gov/).

Table 5 shows how this formula has been applied to wells for the scenarios model here with SAM. These costs do not include mobilisation or demobilisation costs. The costs also assume that there are no unusual geological conditions that may increase the cost of drilling. For example, drilling at Geodynamics Ltd's Innamincka Deeps project has encountered significant overpressures in the reservoir. Overpressures are where the fluid pressure in the reservoir is higher than the hydrostatic gradient. The fluids will flow from the well under their own pressure unless they are controlled. Controlling such overpressures can add significantly to the costs of drilling.

The well time in Table 5 assumes that drilling in sedimentary basins is quicker than drilling in crystalline basement (i.e. granite or metamorphic rocks). It has also been assumed that the wells are drilled as part of a campaign and that the drilling is being conducted in an area that has been drilled previously allowing some local learning. The costs also assume that the drilling is "trouble free". Drilling "trouble" can be caused by adverse geological conditions or equipment/operator failures and can increase the well time, and therefore costs, significantly. These problems are more common at the start of drilling program than at the end. This improved performance results in a reduction of drilling costs by as much as 20% over the life of a large drilling program. The rig size increases with well depth because of the extra weight of casing that the rig needs to be able to lift in deep wells.

Scenario EGS E uses 6 inch wells as this size is large enough to accommodate the lower flow rate of 40 kg/s used in that case.

Table 5: Drilling costs used for the seven base case scenarios modelled with SAM

Well Description	Rig Size	Rig Day Rate	Well Time	Well Cost
Natural Reservoir A, completely within sedimentary basin, 8" diameter, 2,500 m total depth.	1,000 HP	$60,000	30	$7.2 million
Natural Reservoir B, completely within sedimentary basin, 8" diameter, 4,000 m total depth.	1,500 HP	$70,000	40	$11.2 million
EGS A, sedimentary basin with crystalline basement, 8" diameter, 3,000 m total depth.	1,500 HP	$70,000	40	$11.2 million
EGS B and C, sedimentary basin with crystalline basement, 8" diameter, 4,000 m total depth.	2,000 HP	$80,000	60	$19.2 million
EGS D, sedimentary basin with crystalline basement, 8" diameter, 5,000 m total depth.	2,000 HP	$80,000	90	$28.8 million
EGS E, sedimentary basin with crystalline basement, 6" diameter, 4,000 m total depth.	1,500 HP	$70,000	60	$16.8 million

No allowance has been made for unsuccessful wells and all wells drilled are assumed to perform as expected. The scenarios modelled here assume that dry wells will not occur as either reservoir stimulation will always be able to create a reservoir, or exploration methods will allow the appropriate geology to be targeted ahead of drilling. The assumptions made about these drilling costs mean they should be considered to be minimum costs. The SAM model doesn't allow contingency to be applied to the drilling component of the project costs. Instead, a 15% contingency applied to the overall capital costs of the project has been included in the models to factor in the likelihood of additional costs in the drilling program (as well as for other components of the project, including costs associated with engineering, procurement and contracting, land access, licensing and permitting).

The ratio of injection wells to production wells has been assumed to be one for the base case in each scenario.

In addition to the drilling costs, a fixed rate of $2 million per well has been included for surface equipment including the well head and brine reticulation systems. For the EGS scenarios a reservoir stimulation cost of $1 million per well is included.

The rate of heat extraction from a geothermal reservoir in a conductive regime is likely to exceed the rate at which heat is replenished into the reservoir. As a result, the temperature of the geothermal brine produced from the reservoir will decrease over time. For the scenarios modelled here, an annual rate of decline of 0.2% has been assumed for natural reservoirs and 0.3% for EGS reservoirs. The rates of decline chosen mean that the reservoir temperatures do not decline by these amounts over the life of the plant modelled in these scenarios.

Air cooled binary power plants have been used for all scenarios. The use of flash steam power plants is considered to be unlikely in Australia because of the scarcity of water to use for injection into the reservoir. SAM calculates the power plant performance based on an empirical formula derived from data from the United States. These data assume a lower ambient temperature than the average ambient temperature in Australia (10°C for the United States versus 22°C for Australia). The effect of this difference and ambient conditions is most noticeable at lower resource temperatures. The brine effectiveness has been calculated based on the ideal efficiency of binary power plants in DiPippo (2007), using the following equation:

$$b_e = 0.65\, C_p \,\frac{(T_r - T_0)}{(T_r + T_0)}\,(T_r - T_c)$$

where Tr is the temperature of the resource, T0 is the ambient temperature, Tc is the temperature of the geothermal brine leaving the exchanger and Cp is the specific heat of the brine. For all scenarios, T0 is 22° C, Tc is 80° C and Cp is 4.25 kJ/kg. The efficiency factor used here of 0.65 is at the upper ends of the range that DiPippo used, and assumes that power plants built in or after 2020 will incorporate modern technology at the upper end of the efficiency range. The brine effectiveness cannot be entered directly into SAM, however the plant performance can be adjusted to a user-defined percentage of the calculated performance so that the brine effectiveness that SAM uses matches the user's requirements.

The capacity factor of the power plant is another important parameter. The output of air-cooled binary plants that are expected to be used in Australia is expected to be significantly impacted by seasonal variations in ambient temperature. For these reasons a value of 83% has been used for the capacity factor here which is also consistent with the AETA forecasts (Bureau of Resources and Energy Economics, 2012).

The costs of the geothermal power plant have been assumed to be $2500/kW for resource temperatures of 180°C or less and $2000/kW for resources above this temperature. Again, these costs are based on those presented in the AETA. Recent cost estimates suggest that the costs of binary power plants may be significantly higher than this, with Mines and Nathwani (2013) suggesting costs of around $US 3600/kW for geothermal power plant a resource temperature of 175° C.

For the scenarios modelled here, the operating and maintenance costs have been calculated based on a fixed rate per installed capacity of $210/kW-yr. Again, this is based on AETA where the operating and maintenance costs are calculated as a percentage of total capital costs (see Table 2), which are equivalent to approximately $210/kW-yr installed capacity. Mines and Nathwani (2013) calculated operating and maintenance costs for binary power plants of approximately $400/kW-yr.

4. SAM RESULTS

4.1 Geothermal Energy LCOE's - 2020

Table 6 shows the results of the base case models, the LCOE's ranging from $170/MWh to over $300/MWh. The wide range of LCOE's across the seven scenarios show how dependent the cost of energy production is on the resource characteristics and the assumption regarding the construction costs. Many of the assumptions made in the SAM models could be considered to be favourable towards lower cost forecasts of geothermal energy, including the flowrate. The EGS E scenario is included to show the LCOE based on further development of Geodynamics Ltd's Innamincka Deeps resource. The scenario assumes that no further exploration is required and 6 inch wells would be drilled to handle the 40 kg/s flow rate that has been demonstrated from this resource.

Table 6: Results of the SAM modelling of base cases.

Parameter	**Natural Reservoir A**	**Natural Reservoir B**	**EGS A**	**EGS B**	**EGS C**	**EGS D**	**EGS E 6" Wells**
Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Temperature °C	150	180	150	180	220	250	220
Flow rate (kg/s)	100	100	80	80	80	80	40
Overnight Capital Costs ($2014/kW)	10,077	9,273	14,124	19,532	10,754	11,941	13,931
2020 LCOE (2014 $/MWh)	**187**	**172**	**252**	**345**	**202**	**221**	**248**

4.2 Geothermal Energy LCOE's - 2030

The following section looks at the possibilities for improvements in the commercial viability of geothermal energy over the timeframe 2020 to 2030. A reduction from the levelised cost of electricity in 2020 to commercially competitive levels by 2030 would require improvements in a number of areas. The following discussion outlines a future scenario in which the right technical and market improvements have occurred to allow geothermal energy to be commercially competitive. An underlying assumption is that the imperative for reducing global reliance on fossil fuels increases, creating stronger demand for low emissions energy generating technologies.

Reliable production of geothermal brine at high flow rates is a key component of commercially competitive geothermal energy projects. The effectiveness of reservoir stimulation could increase significantly over the next decade as a technology is driven by developments in the international geothermal and unconventional gas sectors. High-pressure high-temperature unconventional gas resources have reservoir conditions that are similar to those found in conductive geothermal resources. Exploration techniques are also likely to improve that will allow the targeting of resources with favourable conditions for reservoir stimulation. In addition to improving the performance of individual wells, improved stimulation methods may also allow the ratio of production wells to injection wells to be increased.

Drilling costs are the largest contributor to the overall capital costs of geothermal energy projects. The costs of drilling in Australia would need to fall substantially for geothermal energy to be commercially viable in Australia. The Australian drilling sector is small, with only 13 land-based rigs operating as at the end of April 2014. The expected growth in unconventional gas development in Australia over the next decade may result in the Australian drilling market growing markedly in size. The increased size of industry would improve supply chains and increase experience in drilling in Australian basins, reducing the costs of drilling. Another contribution to a reduction of drilling costs would be the relaxation of the requirement for a double barrier in geothermal wells. Other well field services, such as reservoir stimulation, would also be expected to have reductions in cost for similar reasons.

Increased activity in the unconventional gas sector in Australia would also assist the geothermal sector through the collection of data (3D-seismic data, drilling data). This additional data would reduce risk and cost during the exploration stage of geothermal project development. Global efforts to develop geothermal resources in conductive settings would lead to improved workflows for exploration and project development. Global developments in the geothermal sector (with both convective and conductive resources) are expected to improve the performance and reduce the costs of geothermal power plants.

If these technology advances or market-driven changes in price of component technologies for geothermal energy systems do not occur, then there will be no significant movement in the real levelised cost of electricity generated from geothermal energy projects between 2020 and 2030.

Table 7 shows the results of SAM models is on the EGS C scenario with improvements in flow rate, drilling costs, stimulation costs, plant capacity factor and reductions the costs of brine reticulation system through the use of pad drilling. Two cases are shown, a moderately favourable case and a highly favourable case. The LCOE drops by 35% to 50% with the reduction in the cost of drilling, the reduction in the wells due to a lower injection well to production well ratio and higher flow rates having a significant impact on costs.

Table 7: SAM input parameters and model results for 2030 levelised costs assuming moderately favourable and highly favourable scenarios for geothermal energy production. These models are based on the EGS C case used in the 2020 forecast with all parameters kept the same except for those listed below.

Parameter	2020 Base Case (EGS C)	2030	
		Moderately Favourable	Highly Favourable
Temperature (° C)	220	220	220
Depth (m)	4,000	4,000	4,000
Flow Rate (kg/s)	80	90	100
Number of Fractures	3	4	5
Plant Capacity Factor	83%	95%	95%
Plant Efficiency	90% of SAM model	95% of SAM model	100% of SAM model
% Of Confirmation Wells Used	50%	100%	100%
Well Costs	$19.2 million	$16 million	$12 million
Ration of Injection to Production Wells	1	0.75	0.5
Surface Equipment, Installation	$2 million	$1.5 million	$1 million
Stimulation Costs	$1 million	$0.7 million	$0.5 million
Plant Capital Cost $/kW	$2000	$2000	$2000
LCOE ($2014/MWh)	**$200**	**$130**	**$99**

5. CONCLUSIONS

This study of forecast geothermal energy costs in Australia suggests LCOE's in a range of $170/MWh to $270/MWh by 2020. This forecast is based on the following key assumptions: that the required flow rates can be achieved (80 kg/s to 100 kg/s); drilling costs do not increase in real terms; and, drilling can be conducted at a very high success rate.

These assumptions could be considered to be optimistic. These flow rates have yet to be demonstrated in Australia or internationally in resources that are directly comparable to those found in Australia. Drilling costs are highly variable and are strongly influenced by market factors. The first deep geothermal well drilled in Australia, Habanero 1, is reported to have been drilled with a trouble-free cost of around $7 million (Tester et al., 2006) in 2003. The most recently completed well, Habanero 4, had a trouble-free cost several times higher than this in 2012. This difference can be partly explained by well design but is largely due to market-driven increases in the cost of drilling in Australia.

The 2020 LCOE for geothermal energy is significantly higher than the other energy generating technologies such as wind and solar, even if the flow rates required can be routinely achieved and drilling costs not increase in real terms between now and 2020. It should also be noted that with the long lead times for developing utility scale geothermal energy projects, it is unlikely that any significant capacity could be developed between now and 2020 even if the costs were competitive. A scenario where market forces and technology improvements reduce the cost of drilling significantly and technology for engineering geothermal reservoirs to achieve the high flow rates required can be achieved by 2030 has been considered. In this scenario, the LCOE of geothermal energy is approaching that of other renewable technologies.

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APPENDIX 1 TECHNICAL INPUTS

Parameter	Natural Reservoir A	Natural Reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6” Wells
Ambient Conditions Input Page Not used in these models (GETEM power block used)							
Geothermal Resource Input Page							
Resource Characterisation							
Resource Type[1]	EGS	EGS	EGS	EGS	EGS	EGS	EGS
Total Resource Potential (MW) [2]	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Resource	150	180	150	180	220	250	220

Parameter	Natural Reservoir A	Natural Reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6” Wells
Temperature (°C)							
Resource Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Reservoir Parameters							
	Calculate the reservoir pressure change using permeability * area selected						
Width (m)	1,000	1,000					
Height (m)	200	200					
Permeability (Darcy)	0.25	0.25					
Distance from Injection to Production Wells (m)	1,000	1,000					
			Calculate the reservoir pressure change using simple fracture flow (EGS only) selected				
Fracture Aperture (m)			0.0003	0.0003	0.0003	0.00025	0.0003
Number of Fractures			3	3	3	3	3
Fracture Width (m)			500	500	500	500	500
Fracture Angle (deg from horizontal)			1	1	1	1	1
Subsurface Water Loss (% of water injected)			1	1	1	1	1
Distance from Injection to Production Wells (m)			1,000	1,000	1,000	1,000	1,000
Plant and Equipment Input Page							
Plant Configuration							
Specify plant output (kW)	50,000	50,000	50,000	50,000	50,000	50,000	20,000
Conversion Type	Binary	Binary	Binary	Binary	Binary	Binary	Binary
Plant Efficiency (%)	65	70	65	70	90	100	90
Plant Design Temperature	Automatically set to resource temperature for all cases						
Temperature Decline							
Specify temperature decline rate (%/yr)	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Maximum temp to decline before reservoir replacement (° C)	20	20	30	30	30	30	30
Pumping Parameters							
Production Well Flow Rate kg/s per Well	100	100	80	80	80	80	40
Pump Efficiency	60%	60%	60%	60%	60%	60%	60%
Pressure Difference across Surface Equipment (psi)	25	25	25	25	25	25	25
Excess Pressure at Pump Suction (psi)	50	50	50	50	50	50	50
Production Well Diameter (inches)	8	8	8	8	8	8	6
Production Pump Casing Size (inches)	8	8	8	8	8	8	6
Injection Well Diameter (inches)	8	8	8	8	8	8	6
Power Block Page							
Power Block Model							
Model	GETEM	GETEM	GETEM	GETEM	GETEM	GETEM	GETEM
Power Block Design Point **NOT USED**							

Parameter	Natural Reservoir A	Natural Reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Cooling System **NOT USED**							
Performance Adjustment Page							
System Output Adjustments							
Percent of annual output (%)	83	83	83	83	83	83	83
Geothermal System Costs Page							
Number of Wells to Drill							
% of Confirmation Wells Used for Production	50	50	50	50	50	50	100
Ratio of Injection Wells to Production Wells	1	1	1	1	1	1	1
Drilling and Associated Costs							
Exploration Well Cost Multiplier	1	1	1	1	1	1	1
Exploration Number of Wells	0	0	0	0	0	0	0
Exploration Non-Drilling Cost	\$2 million	\$2 million	\$2 million	\$2 million	\$2 million	\$2 million	\$1 million
Confirmation Well Cost Multiplier	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Confirmation Number of Wells	2	2	2	2	2	2	0
Confirmation Non-Drilling Cost (per well)	\$500,000	\$500,000	\$500,000	\$500,000	\$500,000	\$500,000	\$0
Cost Curve Multiplier	7,200,000	11,200,000	11,200,000	19,200,000	19,200,000	28,800,000	16,800,000
Cost Curve Exponent	7,200,000	11,200,000	11,200,000	19,200,000	19,200,000	28,800,000	16,800,000
Production and Injection Wellss – Non-Drilling Costs	0	0	0	0	0	0	0
Surface Equipment, Installation[4]	\$2 million	\$2 million	\$2 million	\$2 million	\$2 million	\$2 million	\$2 million
Stimulation Cost (per well)	0	0	\$1 million	\$1 million	\$1 million	\$1 million	\$1 million
Plant Capital Cost Set to "Calculate".							
Cost (\$/kW)	2,500	2,500	2,500	2,000	2,000	2,000	2,000
Pump Cost Inputs Set to "Calculate".							
Installation and Casing Cost (\$/ft)	75	75	75	75	75	75	75
Pump Cost (\$/hp)	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Recapitalisation Cost Set to "Calculate". Only required if the reservoir needs to be redrilled due to thermal draw down.							
Total Installed Costs							
Contingency	15%	15%	15%	15%	15%	15%	15%
Indirect Capital Costs							
Engineer, Procure, Construct (% of Direct Cost)	0	0	0	0	0	0	0
Project, Land, Miscellaneous (% of Direct Cost)	0	0	0	0	0	0	0
Sales Tax	0	0	0	0	0	0	0
Operation and Maintenance Costs Escalation Rate set to 0%							
Fixed Annual Cost	0	0	0	0	0	0	0
Fixed Cost by Capacity (\$/kW-yr)	210	210	210	210	210	210	210

Parameter	Natural Reservoir A	Natural Reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Variable Cost by Generation	0	0	0	0	0	0	0

APPENDIX 2 – FINANCIAL INPUTS

Parameter	Value	Description
SAM Case		
Financial Model	Utility Independent Power Producer	SAM has a range of financial models that can be used. The Utility Independent Power Producer model is for a project developed and owned by single entity that sells electricity at a price negotiated through power purchase agreement. The model calculates project LCOE, NPV and PPA price based on a target IRR.
SAM Financing Tab		
Solution Mode	Specify IRR Target	SAM has two solution modes for this financial model. In this case an IRR target is specified and SAM calculates a PPA price.
Minimum Required IRR	12.75.%	The target IRR. To calculate the correct real LCOE in SAM, the target IRR and the nominal discount rate must be the same (Lovegrove et al., 2013).
Require a minimum DSCR	No	No minimum debt-service coverage ratio.
Require a positive cash flow	No	Positive cash flow not required.
Financial Optimization	No	SAM can pick the debt fraction to minimise LCOE or pick a PPA escalation rate to minimise LCOE. These options aren't used in this model.
Debt Fraction	0%	AETA does not consider the source of finance and so it is not considered here..
Loan Term	0	AETA does not consider the source of finance and so it is not considered here.
Loan Rate	0	AETA does not consider the source of finance and so it is not considered here.
Analysis Period	27 years	27 years as the default period used in AETA. This period is from the commencement of construction. AETA assumes a three-year construction period.
Inflation rate	2.50%	This is the midpoint of the Reserve Bank of Australia's target range for inflation.
Real discount rate	10.00%	This is the default value used in AETA.
Federal income tax rate	0%	AETA does not consider federal taxes and so they are not considered here.
State income tax rate	0%	State taxes are not applicable within the Australian context, although the state governments are likely to impose some kind of royalty on geothermal projects. AETA does not consider royalties and so they are not considered here.
Sales tax	0%	Sales tax is not applicable in the Australian context. The GST has not been included.
Property tax	0%	Property tax is not applicable in the Australian context.
Salvage value	0%	Salvage costs are assumed to cover the commissioning costs.
Construction financing	See Note	AETA assumes a three-year construction period with capital costs of 40%, 40%, and 20% across those three years although the cost of construction financing is ignored. SAM calculates an overnight capital cost, and the cost of construction finance will also be ignored these models.