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The Relative Costs of Engineered Geothermal System Exploration and Development in Australia

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ABSTRACT

Generalized cash-flow models for geothermal exploration and development projects in Australia have been created for a hypothetical case using different play concepts, heat flow conditions and site-specific costs. A comparison of the levelized cost of power production for play types and site-specific costs has been generated using standard assumptions for flow rate and temperature.

A sensitivity analysis of model variables, including conductive heat flow, demonstrates the relative advantages and disadvantages of Engineered Geothermal System plays over Hot Sedimentary Aquifer plays. For smaller-scale developments (~30 MWe) costs become highly sensitive to the interplay between target reservoir depth (heat flow and thermal conductivity dependent) and expected net output at the wellhead for a given target temperature. Likewise infrastructure costs, particularly drilling and transmission connection costs (distance dependent) and the expected revenue stream from carbon trading schemes can have a dramatic impact on project economics.

This paper presents relative data for conceptual cost and present-value models in the Australian context.

1. INTRODUCTION

The relative costs involved in geothermal exploration and development have been widely researched and published, although much of this work pertains to conventional geothermal systems, particularly in the USA (eg. Mansure and Carson, 1982; Cooley, 1997; Lovekin, 2000; Klein *et al*., 2004). A great deal of this work was summarized by the Geothermal Energy Association on behalf of the US Department of Energy (Hance, 2005). Apart from providing a comprehensive study into geothermal costs, the later study highlighted the significant 'confusion' within the sector relating to methods and nomenclature for quantifying the cost of geothermal energy, and noted the dominant control of site-specific costs, often associated with geology.

Cost estimates and project economics associated with Engineered Geothermal Systems (EGS) are still in a developmental stage. EGS economics were broadly addressed in the seminal MIT study (2006) headed by Professor Tester, although more recent work by GeothermEx Inc. regarding the economics of EGS development have provided a more detailed assessment of site-specific costs and has demonstrated that EGS plays are rapidly approaching feasibly competitive cost levels (Sanyal *et al*., 2007a; Sanyal, 2009).

In contrast, the Australian geothermal industry is still in its infancy, and although recognized as a world leader in EGS technology, there is a lack of production and costing data to develop a comprehensive understanding of the economics of geothermal exploration and development.

Unlike conventional geothermal systems, heat flow in Australia is principally conductive (Beardsmore and Cull, 2001), and geothermal exploration and development will therefore typically require deeper drilling to access a target's resource temperature. Australia also has a number of unique characteristics associated with the pricing and access to the National Electricity Market as well as Governmental policy relating to the *Carbon Pollution Reduction Scheme* (CPRS) which will impact on the economics of geothermal exploration and development.

This paper discusses a Project Cost Model approach for Australian geothermal exploration and development and applies best-estimate cost and revenue values to general cash-flow scenarios. The Levelized Cost of Electricity (LCOE) and the Net Present Value (NPV) have been estimated for four hypothetical projects. These four scenarios cover the broad range of most geothermal projects presently being assessed in Australia. In particular the site-specific impacts of geology, principally conductive heat flow and rock thermal conductivity, have been integrated into each assessment of project economics.

This approach uses simple project economics as would be broadly applied in the Australian petroleum industry, although project risking (geological and engineering) has not been addressed. The methodology is consistent with the draft procedure for calculating geothermal energy levelized cost as developed by the *Australian Geothermal Energy Association* (AGEA, 2009).

2. THE AUSTRALIAN GEOTHERMAL EXPLORATION AND DEVELOPMENT CYCLE

In May 2009, the Australian geothermal sector comprises about 48 registered companies holding exploration licenses or application, including at least 12 listed on the Australian Securities Exchange (ASX). There are over 383 exploration licenses granted or under application in all states covering over 358,000 km^2 (almost exactly the land area of Germany). Despite common perceptions, activity is almost equally divided between EGS plays and Hot Sedimentary Aquifer (HSA) plays. The combined market capitalisation value of the top 10 listed geothermal companies is AU$513 million.

Geothermal exploration and development in Australia is unique in that it is mainly driven by capital investment via public share issues, hence costs and timing are strongly influenced by the capital-raising cycle. Most Australian geothermal exploration activities can be summarized in a five-year cycle (Figure 1).

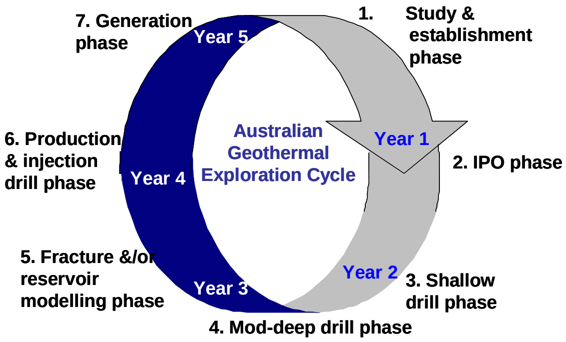

Figure 1: The Australian Geothermal Exploration Cycle showing the progress of activities typical in a five-year exploration cycle leading to the establishment of a small 'proof-of-concept' plant by the end of year 5.

The Australian geothermal exploration cycle is characterized by a phase of early study and company establishment prior to public listing on the ASX by the end of year 1 to raise capital via an Initial Public Offer (IPO). Successful listing on the ASX typically provides the funds required to commence an early Geological and Geophysical (G&G) Program which will typically progress the company towards the drilling of a moderate-to-deep well for heat flow determination and initial reservoir characterization by the end of about year 3. In 2007–08, four companies listed on the ASX with IPO values raised ranging from AU$5–10 million, with an average value of AU$7 million (Figure 2).

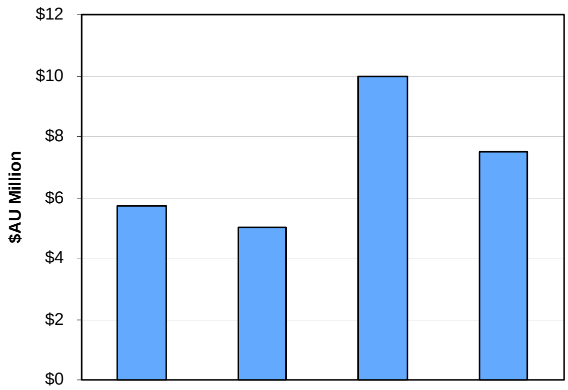

Figure 2: IPO amounts raised by four Australian geothermal exploration companies floated on the ASX in 2007–08.

Further exploration and development beyond stage 5 typically requires either further capital raising through the ASX or Joint Venture farm-in, and/or through access to Governmental grants such as the *Geothermal Drilling Program* (GDP). By year 5, successful companies will be seeking to establish a small 'proof-of-concept' generation system, usually based on one or two production wells, as a means of demonstrating technical success to the market, prior to raising more capital for full-scale commercial development (Figure 1).

3. BASE-CASE MODEL

3.1 Project Cost Model

This study has used the exploration cycle (Figure 1) to establish a Project Cost Model using line-item expenditures for each phase of the cycle. In the absence of measured data for many cost inputs in the Australian context, estimations have been used from a variety of sources including selected annual reports as published by Australian geothermal companies. This study aims to establish costs from the perspective of a 'start-up' company, which is applicable for an embryonic industry. In the case of a mature industry, some costs in the early phases of the cycle (Figure 1) may be regarded as sunk costs.

The base-case assumes a typical geothermal 'start-up' company of five salaried employees/directors. Standard operating costs for each year have been estimated and include all employee costs, rents, insurances, license fees, legal fees, consulting fees, banking and accounting costs, hardware, software, travel and accommodation etc. At the IPO stage full costs covering listing fees, underwriter costs, dealer's commission and full prospectus costs have also been included.

Base-case G&G expenditures include the drilling of five shallow heat flow wells (300 m each), one moderate-depth heat flow well (2,000 m) and various rock property measurements, modeling, consulting reports and a specialist survey (such as MT). By the end of phase 4 (Figure 1), line-item costs total AU$6.8 million, which is consistent with the initial capital raised in the IPO phase (Figure 2).

Large capital costs in phases 5 to 7 (drilling and generation costs) are described in Section 4 and a breakdown of key inputs and outputs for each modeled scenario is shown in Table A1 (Appendix).

3.2 Engineering and Production Assumptions

Whilst site-specific engineering and production characteristics have a significant impact on project economics (Sanyal *et al*., 2007a; Sanyal, 2009), this paper aims to quantify the impact of general geological and economic variables on hypothetical scenarios. Consequently only a generalized engineering and production model has been assumed and is based on the estimated net well outputs (MWe) for a given resource and flow rate (Sanyal *et al*., 2007b). This relationship is combined with a generalized conductive heat flow model using Cooper Basin stratigraphy and rock properties (Section 3.3), to estimate drilling depths and net outputs for four hypothetical scenarios. The outcomes of this study should be viewed within the context of the modeling of hypothetical scenarios, and do not relate to, or can not be applied directly to, any specific site or prospect.

Although the Habanero well in the Cooper Basin intersected considerable overpressure in the fractured granite reservoir at ~4,400 m depth, significant overpressure in the Australian context is not typical. The vast majority of petroleum wells drilled in Australia have not intersected significant overpressure, hence it is assumed that mainly hydrostatic conditions will prevail through most Australian geothermal reservoirs. Hence this study has used the assumptions of the pumped-well scenario as described by Sanyal *et al*. (2007b) as the basis for estimating hypothetical net well production. This scenario also assumes a well casing diameter of 13⅜", a flow rate of about 100 l/s, pump efficiency of 75%, fluid gas saturation of 0% and temperature decline of 1°C/year. No assumptions have made for pressure decline, although this is a likely outcome for most cases. Any change in these engineering and production variables and conditions will have an impact on project economics.

3.3 Geological Model

A principle aim of this study is to assess the impact of geological conditions, namely heat flow and rock thermal conductivity, on estimated project economics in Australia. Conductive surface heat flow in Australia is highly variable (eg. McLaren *et al.*, 2003) and geothermal exploration is presently being undertaken in a wide variety of geological settings where heat flow broadly varies from about 65 mW/m^2 to 120 mW/m^2.

For the purpose of this study a constant stratigraphic column has been used, based on the petroleum well Welcome-1 in the Cooper Basin (Figure 3). Measured rock thermal conductivity data for formations in the Cooper Basin have been incorporated into the conductive heat flow model based on published values (Beardsmore, 2005). The model in Figure 3 provides a sample temperature-depth relationship, based on realistic values, which have been used to estimate target isotherm depths for four hypothetical scenarios:

- Scenario A: HSA play with a resource temperature of 160°C
- Scenario B: HSA play with a resource temperature of 180°C
- Scenario C: EGS play with a resource temperature of 190°C
- Scenario D: EGS play with a resource temperature of 215°C

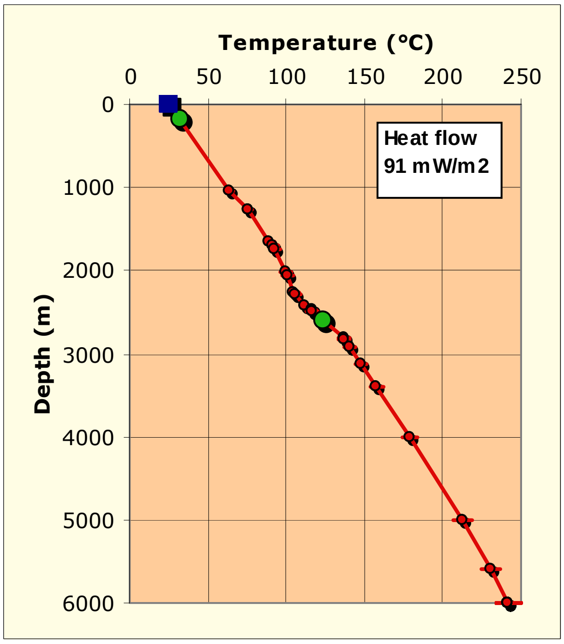

Figure 3: Conductive heat flow model for Welcome-1 in the Cooper Basin using measured rock thermal conductivity data from Beardsmore (2005). This model is used in this study to define the geological inputs for the economic base-case.

Whilst the stratigraphy and conductivity profiles in this study have been based on measured values from the Cooper Basin, it is noted that basins throughout Australia have highly variable rock thermal properties such that the depth-temperature relationship for any given heat flow will vary significantly from basin-to-basin and site-to-site.

The study estimates the costs for each scenario leading to the commissioning of a power plant with a plate capacity of ~30 MWe at the end of a 5 year cycle. However as net well output varies with resource temperature (Sanyal *et al.*, 2007b), the four scenarios tested in this study each have slightly varying plant capacities, ranging from 29.4 to 34.1 MWe net (Table A1). In each scenario the well configuration is kept constant—two sets of three producing wells and one injector (8 wells in total). Changes in the ratio of injector to producing wells will impact on the project economics. A sensitivity test of our model suggests that a 1;1 ratio may add about 20% to the estimated Levelised Cost of Electricity (LCOE). The initial ratio will only be determined after detailed reservoir modeling. This emphasises the value of dynamic hydro-geomechanical modeling of the reservoir using products such as FEFLOW, prior to developing detailed project economics for drilling decisions.

Each scenario assumes single-phase (liquid) production via a binary rankine cycle. One of the key findings of the costing work presented by Sanyal *et al*. (2007b) was that with increasing reservoir temperature, net output increases to a maximum of about 190°C for single phase (liquid) pumped-well scenarios. Beyond this temperature production declines rapidly, associated with the generation of gas bubbles that impede the efficiency of the pump impeller via cavitation. Net output does not begin to increase again until after the well fully enters the steam phase at about 230°C. This ‘declining production window’ for single-phase pumped-well systems between ~190°C and 230°C is reflected in the economic outcomes for models in this paper.

4. KEY COSTS AND ECONOMIC VARIABLES

All costs assumed in this study are on a relatively ‘trouble-free’ basis, although realistic values have been used throughout. The model expresses all values in pre-tax Australian dollars (AU$) as at mid-2009 value. The model does not include any possible impacts from taxation benefits, including asset depreciation, unless otherwise stated. No economies of scale (eg. extended rig booking program) have been assumed.

4.1 Large Capital Costs

4.1.1 Drilling Costs

In the absence of an Australian database for ‘trouble-free’ geothermal drilling, this study has relied on published cost data from the USA (Augustine *et al*., 2006). Although various depth-cost drilling relationships have been published for geothermal drilling in the USA (eg. Sanyal *et al*., 2007a) the work by Augustine *et al.* (2006) also provides a comparative cost curve for petroleum wells from the Joint Association Survey (JAS). This at least allows a comparison of US and Australian petroleum wells costs from the same study as a method of standardization. Augustine *et al.* (2006) found that US geothermal and petroleum well costs reasonably fit a polynomial function with depth. This relationship was built into a generalized WellCost Lite Model.

Both geothermal and petroleum well costs from the Augustine *et al.* (2006) study were converted to AU$ using historical exchange and CPI rates published by the Reserve Bank of Australia (RBA; http://www.rba.gov.au/). The converted US petroleum cost-trend was then compared with available data for onshore Australian petroleum drilling (Leamon, 2006) and the relationship was found to be very comparable.

Well costs increase markedly with depth, associated with the increasing number of casing strings required. However a significant component of cost is related to the Rate of

Penetration (ROP), with competent lithologies such as granite being a more costly drilling target (Augustine *et al*., 2006). This study provides an additional weighting of drilling cost to EGS plays based the ROP relationship described by Augustine *et al*. (2006).

Although there is some uncertainty with regards to probable geothermal drilling costs in the Australian context, the approach used in this study appears to provide a reasonable estimate of a well depth-cost relationship, expressed in mid-2009 AU$ based on known data and approximations from the Augustine *et al*. (2006) study. It is however possible that drilling costs may decline slightly in the immediate term, associated with the decline in oil and steel prices.

Actual well costs as used for each scenario in this study are shown in Table A1. Testing costs and stimulation costs (for EGS wells) have also been incorporated. In each scenario 10 wells have been included in the initial project CAPEX with one make-up well costed in the O&M program for year 10.

4.1.2 Generation and Transmission Costs

Generation costs, based on binary rankine cycle systems, have been estimated at AU$2 million per installed MWe, although the real cost of this technology in Australia is currently unknown. This cost is consistent with the ORMAT contract price for the Landau binary system. Costs for pumps and surface infrastructure have also been included in the model.

Major transmission line, substation and switchyard costs have not been included in the base-case, with only minor cabling costs included. Substation and switchyard requirements may vary significantly from site-to-site. However the impact of transmission line costs has been shown for two scenarios as part of the sensitivity analysis. These costs will vary significantly with site conditions including terrain, circuit type, voltage, pole-type, tie-line and tee-in requirements. Some recent sample costs of Australian electrical connectivity are shown in Table 1.

For the purposes of the sensitivity analysis an estimated cost of AU$0.64 million per line kilometer was used for an assumed 220kV transmission line on towers, based on the estimated cost of the Collie transmission project in Western Australia.

The market operator, the National Electricity Market Management Company (NEMMCO), imposes participation charges that are levied on the basis of the category under which the generating asset is registered (market and scheduling category). There may be significant administrative and cost-advantages for generators with name plate capacities <30 MW, hence this study focuses on a 30 MWe base-case scenario.

4.1.3 Operating and Maintenance (O&M) Costs

In conventional geothermal settings O&M costs can exceed more than ⅓ the value of revenues (Hance, 2005; Sanyal *et al*., 2007a). However up to 15% of this cost is associated with chemical treatments (common for volcanic water systems) and up to 74% of O&M costs can be associated with monitoring and maintenance of the steam field (Hance, 2005). It is unlikely that either of these cost components will have a major impact in the Australian context. Consequently this study has conservatively estimated that O&M costs may be around 20% of production revenues. It is, however, recognized that O&M costs in Australia are largely unknown, and US experience suggests that real costs tend to be greater than initial estimates. A plant efficiency rate of 95% and a Marginal Loss Factor (MLF) of 5% have been assumed.

Table 1: Some recent examples of Australian electricity connectivity costs. These costs vary significantly with site requirements.

Connection/transmission infrastructure (year)	**Cost (AU$ million)**	**Source**
132 kV / 22 kV zone substation, 1 transformer (2008)	7.10	Westernpower (WA)—SKM (2008)
132 kV, terminal yard, 3CBs (2008)	5.30	Westernpower (WA)—SKM (2008)
330 kV, terminal yard, 3CBs (2008)	7.90	Westernpower (WA)—SKM (2008)
330 kV, terminal yard and lines (2006)	5.10	IMO study (WA)—SKM (2006)
330 kV, terminal yard and lines (2006)	5.30	IMO study (WA)—SKM (2006)
88 kV double circuit tie-line and tee-in (2005)	0.35/km	NE Tasmania upgrade—Transend (2005)
110 kV single circuit tie-line and tee-in (2005)	0.36/km	NE Tasmania upgrade—Transend (2005)
110 kV double circuit tie-line and tee-in (2005)	0.42/km	NE Tasmania upgrade—Transend (2005)
132 kV wood pole, 20 km (2008)	0.28/km	Westerpower (WA)—SKM (2008)
132 kV single circuit steel pole, 100 km (2008)	0.41/km	Westerpower (WA)—SKM (2008)
132 kV double circuit steel pole, 100 km (2008)	0.64/km	Westerpower (WA)—SKM (2008)
220 kV line, 300 km, plus substation (2006)—Collie (WA)	0.60/km	Westernpower (WA)—SKM (2006)
330 kV single circuit tie-line (2006)	0.36/km	IMO study (WA)—SKM (2006)
330 kV single circuit tie-line (2006)	0.38/km	IMO study (WA)—SKM (2006)
330 kV double circuit tower, 100 km (2008)	0.91/km	Westernpower (WA)—SKM (2008)

4.2 Economic Inputs

4.2.1 Consumer Price Index (CPI)

Annual general inflation as measured by the CPI (all goods) has ranged from 1.3 to 6% in Australia since 1998 (RBA). Following the tabling of the Budget Appropriation Bill in May 2009, the RBA revised downwards its forward estimate of inflation from the current value of 2.5% to 1.5% by 2011. However, for the purpose of this study, the 10 year average of 2.9% has been used.

4.2.2 Commercial Lending Rate and Project Debt-Equity Ratio

Commercial bank lending rates for large projects in Australia have declined from 8.6% to 6.7% over 2008–09 (RBA). However, this study has used a rate of 8.2% in-line with the current upward pressure on interest rates for the mid-long term. Whilst there is considerable uncertainty about geothermal project debt ratios in Australia, it is expected that the high capital cost of exploration and development will mean that a significant proportion of capital is borrowed. Hance (2005) estimates that US geothermal projects tend to have 70% debt, hence this study has used the same proportion. The cost of borrowing has been amortized over the life of the project at the stated lending rate.

4.2.3 Discount Rate and Project Life

This study has used practices broadly consistent with the Australian petroleum industry and has viewed a discount rate of 10% as being adequate in comparison to long-term Government bond rates. Depending on the security, Australian Government bonds presently vary between about 4 and 6% (RBA).

The project life of the base-case is 20 years, although the sensitivity analysis shows the influence of variable life spans on levelized cost.

4.2.4 Carbon Costs

As part of the Australian Government's response to climate change, the Department of Climate Change released the *Carbon Pollution Reduction Scheme* (CPRS), which is described in the Green Paper (2008). The operation of the, now delayed, CPRS remains unclear except that it is unlikely that zero-emission renewable generators will be significantly adversely effected. Under the CPRS, and as required under the *National Greenhouse and Energy Reporting Act* 2007 (NGERA), all electricity generation facilities which emit 25,000 tonnes of CO_2 or more, or which produce or consume 100 terajoules of energy per year or more will be required to report and comply under the CPRS. It is not known how or if this will impact on geothermal energy producers except that some carbon costs may be incurred during the construction phase of geothermal power plants. Due to the uncertain impact of the CPRS, no particular cost has been ascribed in this study.

5. REVENUE CONSIDERATIONS

5.1 Electricity Prices

The eastern states of Australia and South Australia are linked via the National Electricity Grid on which power is traded and managed by NEMMCO, the operator of the National Electricity Market (NEM). NEMMCO is responsible for the registration of participants, the scheduling and dispatch of generators, the management of transmission constraints, and the financial settlement of trades in the market.

A Regional Reference Price (RRP) determines electricity prices through a process by which generators must bid to sell their power within a pool every 30 minutes. Alternatively generators may sell their power to consumers at a fixed price via hedging contracts. As hedging prices are confidential, this analysis has been conducted using RRP data as published by NEMMCO.

The average monthly RRP varies significantly between states and is also influenced by seasonal factors such as drought, bushfire and temperature extremes, all of which lead to sudden changes in supply and demand requirements. In recent years, energy-constrained states such as Tasmania and South Australia have often had RRP in excess of AU$50–60 per MWh, whilst states with significant coal-fired generators have RRP averaging AU$40–45 per MWh (Figure 4).

The amount of variance in RRP means that the distribution of prices is slightly log–normal, influenced by extreme peaks in spot price. Consequently it is difficult to assess any long-term price trends without considering median prices. Since 1999 the national monthly median RRP has risen by about 55%, although much of that increase has occurred since 2007 (Figure 5). In general terms, this increase in RRP has been consistent with CPI trends over 10 years, increasing above CPI in the last 3 years (Figure 5). Much the same assessment has been made based on US electricity price trends since 1915 (Sanyal *et al.*, 2007a).

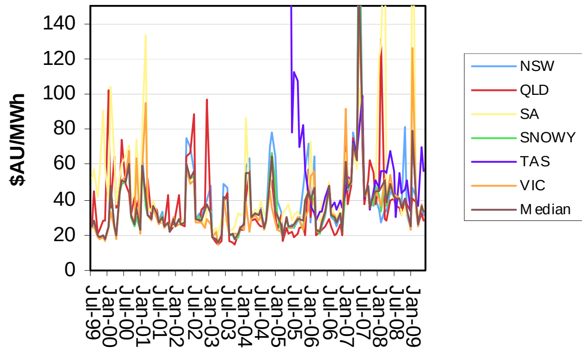

Figure 4: Regional Reference Prices (RRP) for electricity traded on the National Electricity Grid by state since 1999.

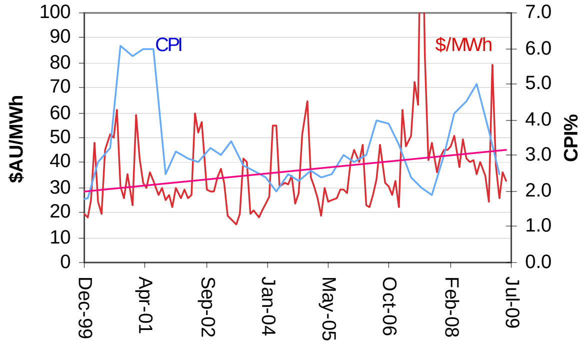

Figure 5: Median of all Australian electricity prices (RRP) traded on the National Electricity Grid since 1999 and CPI for the same period.

Consequently it is reasonable to assume that long-term electricity prices will increase at a rate consistent with long-term inflation. This is also the case in the US where average annual residential electricity prices have shown a steady increase since 1960, whilst oil prices have behaved in a more reactionary manner (Figure 6). This study has used an electricity price of AU$43.30 for the base-case which is the median RRP for Victorian electricity in the period 2007–09.

5.2 Renewable Energy Revenues

The CPRS Green Paper (2008) notes that the scheme will impose no increase in the operating costs of renewable energy generators but wholesale electricity prices will rise. Consequently it is expected that geothermal producers will benefit from the price increase under the CPRS.

Renewable energy generators may be accredited to issue Renewable Energy Certificates (RECs). RECs can be issued at a rate of one-per-renewable-MWh produced, after one year of operation. The generator may freely trade these RECs. The traded value of RECs is confidential, but is presently thought to be in the range AU$20–$50 per REC.

This study incorporated a REC price of AU$30, although we note that the draft procedures for the estimation of levelized cost (AGEA, 2009) do not allow for the inclusion of RECs. The model used in this study attributes O&M costs as a percentage of production revenues only, and as RECs do not impact of physical production, they have no significant impact on levelized cost. RECs do, however, impact on the revenue stream and, hence, influence NPV. This study, therefore, includes a zero REC value case in the sensitivity analysis to illustrate the influence of RECs on overall project economics.

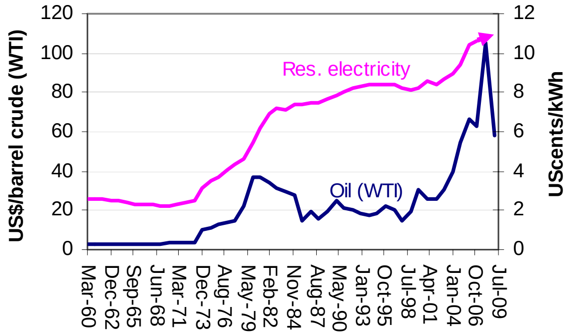

Figure 6: Average annual residential electricity prices in the USA since 1960, and oil price (West Texas Intermediate cruse) for the same period. Electricity prices tend to show a gradual and increasing trend consistent with inflation whilst oil price has a more reactionary behavior.

6. LEVELIZED COST OUTCOMES

LCOE is the standard method of estimating the cost of energy over a project life and is used to compare the relative costs of various forms of energy (eg. coal, solar, wind, geothermal). It is defined as the sum of all discounted project costs over a stated lifetime divided by the sum of discounted net electricity generation:

$$\mathrm{LCOE} = \frac{\sum_{t=1}^{n} \frac{I_t + M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \qquad \text{Eq.1}$$

where n is the project life in years, I_t is capital expenditures in year t, M_t is O&M expenditures in year t, E_t is net electricity generation in year t, r is the discount rate.

The outcomes for the four scenarios of the base-case at a heat flow of 90 mW/m^2 are summarized in Table A1.

6.1 Influence of Project Life on LCOE

The base-case assumed a project life of 20 years. Varying the project life has a significant impact on LCOE, such that increasing project life by 25% (to 25 years) decreases the LCOE by about 10% (Figure 7). This is approximately the same level of variance exerted by lending rate on LCOE. As definitions of project life are largely subjective, it is important that all comparisons of LCOE take into account the stated project life used in the calculation.

6.2 Influence of Heat Flow on LCOE

Varying heat flow for the four scenarios of the base-case has a marked impact on LCOE (Figure 8). In each scenario, increasing heat flow reduces the depth to the target isotherm, thereby reducing drilling depth and LCOE. However the relationship is neither linear nor simple.

The relationship between heat flow and LCOE partly reflects economic inputs such as discount rate, but also reflects non-linear geological and engineering inputs. These include temperature-depth relationships and net well output (MWe) based on the relationship of Sanyal *et al*. (2007b). This emphasizes the dominant control of site-specific costs associated with geology and engineering. At a heat flow of 90 mW/m^2 for scenario C, a variance of 10% in heat flow results in ~5.5% variance in LCOE, which is similar to the influence exerted by drilling costs (See Section 6.3).

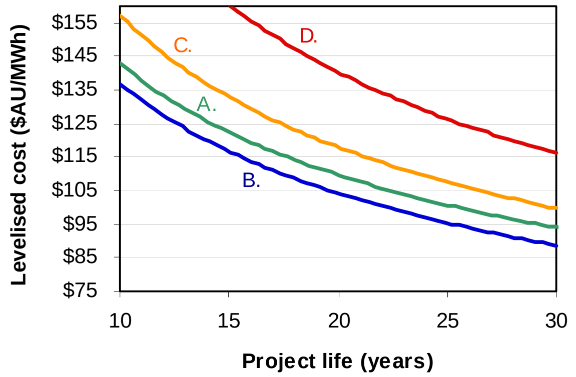

Figure 7: The influence of project life on LCOE for a 30 MWe plant and a heat flow of 80 mW/m^2 (A=HSA play at 160°C, B=HSA play at 180°C, C=EGS play at 190°C, D=EGS play at 215°C).

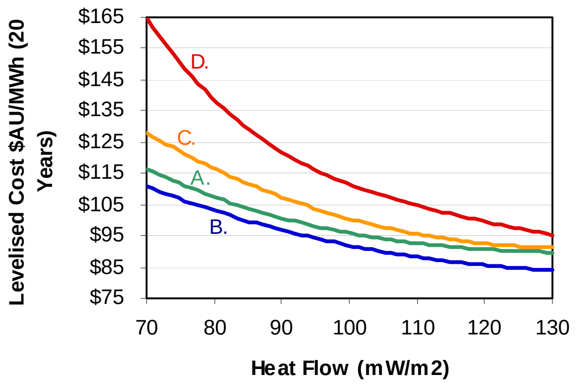

Figure 8: The influence of heat flow on LCOE over 20 years for a 30 MWe plant. Higher heat flow reduces drilling cost (A=HSA play at 160°C, B=HSA play at 180°C, C=EGS play at 190°C and D=EGS play at 215°C).

In all scenarios, lower heat flow equates to higher relative cost, particularly for the deeper EGS scenario (D) as granite conductivity in the geological model is high (3.20 W/mK) compared to overburden lithologies. Drilling costs are, therefore, greater at lower heat flows. Geology exerts a strong control on this relationship and basins/sites with different thermal resistance properties (m^{2}K/W) are likely to have markedly different cost-curves.

Importantly, the two HSA scenarios (A and B) have lower LCOE than the two EGS scenarios (C and D), again reflecting the influence of drilling and stimulation costs. Although cost-curves begin to coalesce at very high heat flows (Figure 8), EGS scenario C does not approach the HSA scenarios until heat flows are >120 mW/m^2, which constitutes the upper percentiles of documented surface heat flow in Australia. Consequently, despite higher temperatures, EGS plays in Australia may offer no commercial advantage over HSA plays and may have higher costs if the target resource temperature is >~190°C.

The increased net well output for the hotter HSA play (scenario B) creates a cost advantage over scenario A, despite the deeper drilling requirements. This is not the case for the two EGS scenarios, though, where the hotter scenario (D) always has a higher LCOE than scenario C. This reflects the modeled impact of declining net well output at temperatures >~190°C for a single-phase pumped-well system as described by Sanyal *et al*. (2007b).

6.3 Sensitivity Analysis of LCOE

Figure 9 shows a sensitivity analysis of selected cost inputs for scenario C of the base-case at a heat flow of 90 mW/m^2. Of the modeled parameters, 'drilling, testing and stimulation costs' exert the greatest influence on overall project LCOE. Whilst not insubstantial, costs associated with O&M in the Australian context will probably not be as great as in conventional volcanic geothermal settings—hence the impact of O&M in this model is not as marked as shown by other studies (eg. Sanyal *et al*., 2007a).

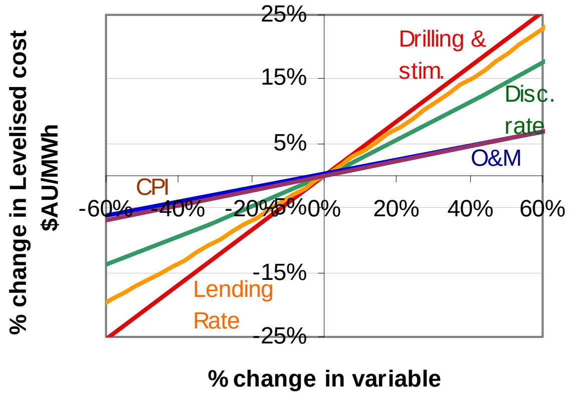

Figure 9: Sensitivity of LCOE to cost variables for a 30 MWe plant over 20 years (EGS play at 190°C).

The influence of both lending rate and discount rate on LCOE is also substantial. Consequently, any LCOE modeling should carefully consider debt-equity ratios and the level of discounting in relation to bond rates as overall project economics can be significantly biased by the arbitrary or inappropriate use of rates. The influence of both discount rate and lending rate will also vary with project life. Consequently a consistent length for 'project life' is required for reliable comparative analyses.

6.4 Influence of Transmission Line Costs on LCOE

Transmission line costs are not included in the base-case, but Figure 10 illustrates the possible impact of transmission costs on the LCOE. Scenarios A and C are shown with varying transmission line requirements. On average, a 10% increase in transmission costs increases LCOE by ~2.5–3%.

6.5 Summary of Influences on LCOE

There has been an historical concentration on the influence of physical engineering and finance costs, such as drilling costs and interest rates etc, on LCOE. However site-specific considerations associated with the inherent geology of an area have an equal, if not more pronounced impact on LCOE (Figure 11). Although the influence of variables on LCOE will change with scenario, Figure 11 shows the general impact on LCOE caused by a 20% variance in key inputs to this model.

Whilst financial variables such as CPI and lending rate receive a great deal of attention for quantifying LCOE, the more subjective variables of project life and discount rate also have a marked impact on LCOE. Although industry-wide standardization of these parameters is unlikely for LCOE calculation, workers should be cognizant of their influence when comparing LCOE data.

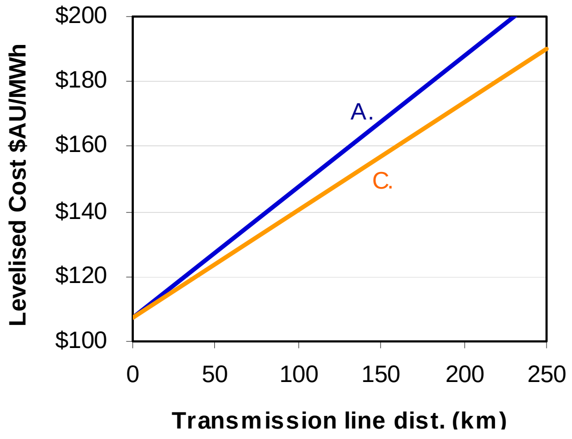

Figure 10: Influence of transmission line distance (and cost) on LCOE over 20 years (A= HSA play at 160°C, C=EGS play at 190°C).

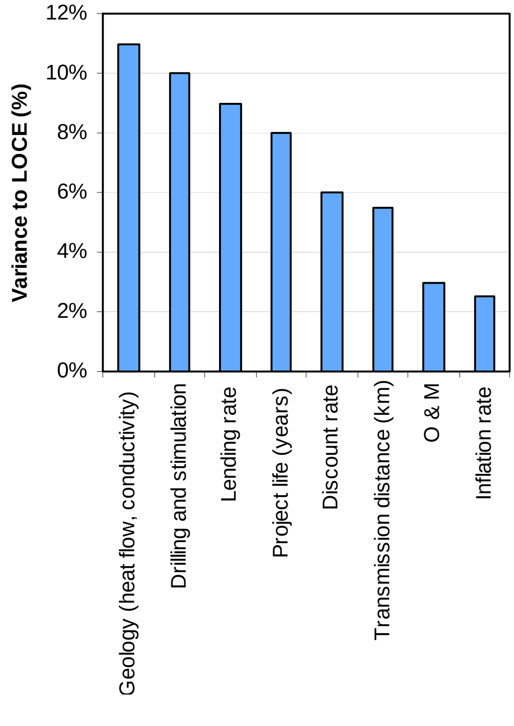

Figure 11: Generalized influence of a 20% variance to selected inputs, used in this study, on LCOE.

7. NET PRESENT VALUE (NPV)

Net Present Value (NPV) is the sum of all present value (PV) of a time series of cash flows. It is a standard method for appraising the viability of long-term projects and is a measure of the excess or shortfall of cash flows, in present value terms, once financing charges are met.

Whilst NPV is probably the most commonly used economic tool in the Australian petroleum industry for determining the relative value of a proposed project, it is not commonly used in the geothermal sector. This may be because of a combination of the comparatively higher CAPEX costs and longer project life times involved in geothermal exploration and development. In addition to this, geothermal costs and revenues are typically less well constrained due to the lack of historical data. As a consequence, it is not uncommon to find that the NPV for geothermal projects is less than zero (Table A1).

However, given the number of uncertainties involved in the modeling of geothermal NPV, results less than zero should not necessarily be used to reject a project. The use of absolute NPV for geothermal project economic assessment may yet be unwarranted, but the use of NPV to assess the relative economics of different geothermal scenarios may still be useful.

Although this study does not address aspects of risk, incorporating risk with NPV should ultimately be a goal in project economics. Relative assessments of geological risk (Pg) and engineering risk (Pe) can be combined with NPV, where Pg comprises the inherent risks of the geothermal system as defined by Cooper and Beardsmore (2008), and Pe comprises perceived drilling and completion risk. The product of these variables constitutes the net Expected Monetary Value (EMV) for the success case of a project. As LCOE does not account for Pg or Pe, the use of LCOE alone to assess the relative value of a project can be misleading. Consequently, the geothermal sector as a whole would benefit from a more structured use of risk and EMV.

The NPVs for the four scenarios of the base-case follow the same trend as LCOE, with HSA scenario B having the most attractive NPV (Table A1). Whilst the NPV of all scenarios is negative (some only marginally negative), a sensitivity analysis of selected model inputs shows how expenses and revenue (and thus NPV) can change markedly with relatively minor fluctuations in key parameters (Figure 12).

Minor decreases in costs (particularly drilling costs) can have a major positive influence on NPV. With regards to the revenue stream, the importance of non-production revenues (such as RECs) becomes apparent. Whilst the base-case used a relatively modest REC value of AU$30, an increase in REC value to just AU$33 (10% increase) can increase the NPV by about 25% (Figure 12). In the case of the best scenario (C) at 90 mW/m^2, this change in REC (10%) would be sufficient make the NPV positive.

Consequently, whilst it may be difficult to reduce CAPEX costs to improve the economic case for a geothermal project, minor changes to the revenue stream via RECs can have a profound impact on NPV without significantly affecting LCOE.

8. COMPARING COST ESTIMATES

In March 2004, the US Geothermal Program Review was held at the Lawrence Berkeley Laboratory where conflicting cost/price models were discussed. According to Hance (2005), the Executive Director of the US Geothermal Energy Association (GEA) noted, "*There is considerable confusion and contradiction in how individuals within the geothermal community talk about cost*". The Australian geothermal sector is currently having a similar dialogue.

A number of recent studies of levelized cost for various forms of renewable energy have produced various results (Figure 13). In August 2008, AGEA commissioned economic modeling consultants McLennan Magasanik Associates Pty Ltd (MMA) to study the costs associated with geothermal exploration and development in Australia and establish a range of expected levelized costs. This report was followed-up with a comparative note in February 2009.

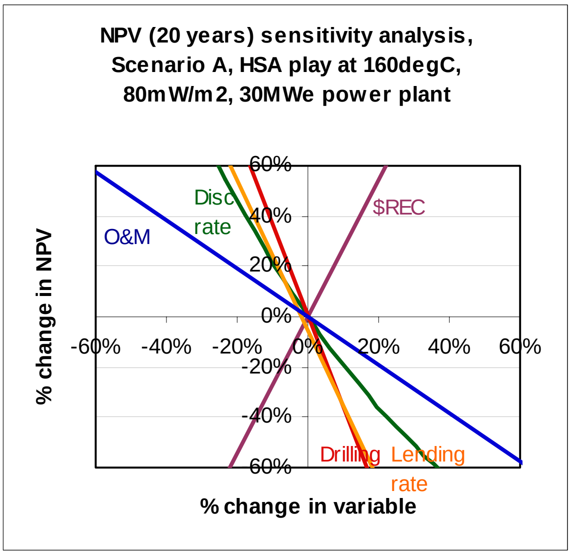

Figure 12: Sensitivity of expenses and revenue over a 20 year project life for selected variables. Note that minor increases in REC value can have a major positive influence on NPV (HSA play at 160°C).

The MMA study estimated long-run marginal costs for various sources of energy in the Australian context, with the expected cost for HSA geothermal plays and EGS geothermal plays being AU$93 and AU$95 respectively. Credit Suisse released a similar study in January 2009, based on US data. Figure 13 shows LCOE outcomes for selected energy sources from the Credit Suisse study (estimated in AU$ based on RBA currency rates), the MMA study and our study.

The results from this study for the most likely scenarios in Australia (B and C) suggest that, for the expected range of heat flows in HSA plays, LCOE may vary from AU$94–AU$115. EGS plays will have a similar range of AU$92–AU$110. These outcomes are consistent with the outcomes of the MMA study. However, the Credit Suisse cost estimates are slightly lower.

Inputs used in all three studies were generally similar—approximately 20 year project life, discount rates of ~10% and low inflation rates. However the approaches of each study were different, although our study used a broadly similar method to the MMA study, hence the similarity in outcome is not surprising.

The Credit Suisse study, however, has two marked differences. Firstly, it included tax considerations, particularly depreciation, and secondly it appears to have incorporated Discounted Cash Flow (DCF) into the LCOE estimation, as opposed to discounted costs alone. The Credit Suisse approach is therefore different to that of both this study and the MMA study. Although the Credit Suisse study does discount energy output over project lifetime, the practice of using non-discounted energy output is a common variance to the LCOE method, which also results in a lower estimate of cost.

None of these variant methods for estimating LCOE are necessarily 'incorrect', but they demonstrate the widely disparate practices being applied across the energy sector (not only restricted to geothermal) to estimate costs.

Consequently, investors should be wary of comparing relative costs across studies without fully investigating the variables used in the model and the approach adopted for calculating LCOE.

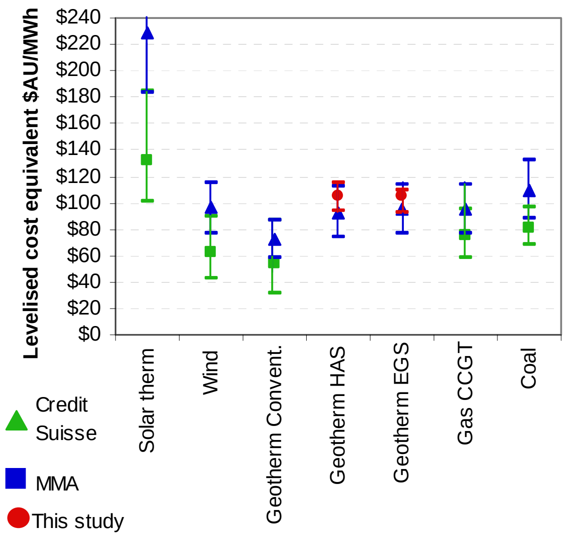

Figure 13: Comparison of LCOE estimates for selected energy sources from Credit Suisse (2009), MMA (2009) and this study. The results of this study agree well with the MMA study whilst the Credit Suisse costs tend to be slightly lower.

9. CONCLUSIONS

Although there is a paucity of data relating to geothermal exploration and development in Australia, there is sufficient information from the petroleum sector and from the international geothermal sector to make reasonable estimates of the likely cost and overall economics of geothermal energy in Australia.

Project cost modeling, using expected line-item costs and revenues over a project life, demonstrates that the LCOE from geothermal energy in Australia is likely to be competitive with most other energy sources. LCOE may range from AU$94–AU$115 for HSA plays, and AU$92–AU$110 for EGS plays, although site-specific effects will strongly influence both LCOE and NPV. However the use of LCOE alone to assess the viability of a project should be avoided, as project risk (geological and engineering) is not reflected in LCOE.

Whilst previous cost studies have concentrated on large-scale engineering costs and financial variables such as interest rate, this study demonstrates that LCOE in Australian geothermal exploration and development will be strongly influenced by site-specific costs such as heat flow and thermal insulation, which ultimately impact on drilling depth/cost and net well output. Despite higher expected temperatures for EGS plays in Australia, greater drilling costs may offset any commercial advantage EGS plays have over HSA plays, unless heat flow is very high and the target resource temperature is ~<190°C.

As LCOE is sensitive to a large number of variables, particularly project life and discount rate, caution needs to be applied when comparing LCOE results across different energy sectors and studies. Different analysts use various methods, which can result in significantly different estimates of LCOE. A full understanding of the inputs and methodology used is required before LCOE results can be compared meaningfully.

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Appendix: 1

Table A1 Base-case inputs and outputs for modeling in this study

BASE Case Inputs and Outputs	**Scenario A**	**Scenario B**	**Scenario C**	**Scenario D**
Conductive Surface Heat Flow	**90mW/m2**	**90mW/m2**	**90mW/m2**	**90mW/m2**
INPUTS	**HSA low temp**	**HSA high temp**	**EGS low temp**	**EGS high temp**
Resource Temp (C)	160	180	190	215
Approximate target temp depth (m)	3500	4000	4400	5200
Plate capacity of plant (MW)	29.7	33.5	34.1	29.4
Number of production wells	6	6	6	6
Number of injection wells	2	2	2	2
Length of tranmission cable required (km)	0	0	0	0
Unit cost transmission line ($AU million/km)	$0.64	$0.64	$0.64	$0.64
Minimal cabling costs ($AU million)	$5.00	$5.00	$5.00	$5.00
Cost per well $AU million (completion)	$7.7	$8.9	$10.9	$13.5
Number of make-up wells (Year 10)	1	1	1	1
Cost of make-up wells (Year 10)	$9.1	$10.6	$12.9	$16.0
Binary plant & pipeline costs ($AU million/MW)	$2.0	$2.0	$2.0	$2.0
Resource Temp decline (°C/per year)	1	1	1	1
Plant efficiency	95%	95%	95%	95%
Marginal Loss Factor (MLF)	5%	5%	5%	5%
O&M costs (% production revenues)	20.0%	20.0%	20.0%	20.0%
Notional start date	Jan-09	Jan-09	Jan-09	Jan-09
First generation date	Jan-14	Jan-14	Jan-14	Jan-14
Annual CPI	2.9%	2.9%	2.9%	2.9%
Project life years (for modelling only)	20	20	20	20
Commercial Lending Rate	8.20%	8.20%	8.20%	8.20%
Discount Rate	10%	10%	10%	10%
NEMMCO Price $AU/MWh (2009 dollars)	$43.3	$43.3	$43.3	$43.3
REC Price $AU/MWh (2009 dollars)	$30	$30	$30	$30
Debt % (%CAPEX from loans)	70%	70%	70%	70%
OUTPUTS				
Expected MWnet per well (year 1)	4.9	5.6	5.7	4.9
Total exploration phase costs ($AU million)	$6.8	$6.8	$6.8	$6.8
Total drilling program costs ($AU million)	$73.8	$84.1	$108.5	$129.6
Total generator plant & pipeline costs ($AU million)	$71.0	$78.5	$79.5	$70.5
Total CAPEX ($AU million)	$144.8	$162.7	$188.0	$200.1
Total borrowing costs amortised 20 years	$209.6	$235.4	$272.1	$289.6
Total tonnes CO2 abatement (20 years)	4,146,193	4,918,230	5,127,814	4,869,200
Average annual MWh out	211,339	252,020	263,519	252,650
Total MWh out (20 years)	4,226,771	5,040,408	5,270,373	5,053,006
Total expected revenues (20 years) $AU million	$399	$467	$483	$446
Total Discounted Cash Flows (20 years) $AU million	$130	$161	$135	$81
Net Present Value (20 years), $AU million	**($9)**	**($6)**	**($27)**	**($55)**
LOCE Levelised cost (20 year) $AU/MWh	**$100.45**	**$97.04**	**$107.13**	**$121.86**

Grey cells are constant values across scenarios