Assessment of Current Costs of Geothermal Power Generation in New Zealand (2007 Basis)

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Sinclair Knight Merz (SKM) has completed a study for the New Zealand Geothermal Association (NZGA) which assesses the cost of developing typical greenfield New Zealand geothermal resources in single blocks of either 20 or 50MW capacity.

Figure 1 High temperature geothermal fields in New Zealand

The method used in the study consisted of the development of a spreadsheet financial model which was then applied to a band, or envelope, of estimated capital costs based on an assessed range of resource characteristics. Capital and operating costs were iterated across a diverse range of New Zealand geothermal industry participants until agreement on costs was obtained while avoiding disclosing confidential information. Using the model, electricity tariffs were derived for geothermal resources in a New Zealand setting from analysis of a total of 32 greenfield geothermal development scenarios.

Keywords: geothermal resource, capital cost, electricity selling price, greenfield, estimation, geothermal power generation

Development Scenarios

The 32 development scenarios derive from selected combinations of 4 resource variables critical in any given development: (i) resource temperature (3 cases); (ii) development size (2 cases); (iii) plant technology (4 cases), and; (iv) well flow rates based on permeability (2 cases). These variables and the rationale for their assumed values are described. A total of 16 cases at a high flow band (150 $kg.s^{-1}$) and 16 cases at a low flow band (50 $kg.s^{-1}$) have been studied. The cases are realistic in that there is over 50 years of experience in exploration, development and operation of New Zealand geothermal fields and so good data are available on which to base the resource performance characteristics.

A number of resource temperatures for developed and undeveloped geothermal resources, which may be available for development, are considered in the model. For New Zealand fields likely to be developed under the current regulatory and pricing regime, maximum resource temperatures at depths currently drilled in the natural state range from 230 to 330°C with an average value of around 280°C.

Accordingly, four development cases have been allowed for resource temperatures, well deliverability and development size. Wells are assumed to self-discharge rather than be pumped. The first development case is for a high temperature and highly productive resource (Mokai, Rotokawa and Kawerau) with resource temperatures in excess of 300°C. In this case, wells have some excess enthalpy, which is assumed to be 10% above the enthalpy of water at 300°C, and high well head delivery pressures of typically 20 barA. The development size is assumed to be 50 MWe.

The second development case includes medium temperature and moderate productivity resources (Wairakei, Ohaaki and Tauhara), and the lower temperature zone of higher temperature fields with resource temperatures averaging 260°C. In this case, liquid reservoir conditions prevail with no excess enthalpy, and wells have moderate wellhead delivery pressures of about 5 barA. The development size is set at 50 MWe. The third case is the same as the second case, but the assumed development size is set at 20 MWe.

The fourth case includes lower temperature and moderate productivity resources such as Ngawha and outflow zones of higher temperature resources, with resource temperatures averaging 230°C. In this case liquid reservoir conditions prevail with no excess enthalpy, and wells have low wellhead delivery pressures of about 3 barA. The development size is limited to 20 MWe.

Four classes of plant technology commonly used in the generation of power from geothermal energy were selected in order to estimate costs for this study. These include: (i) Single flash steam Rankine cycle direct contact condensing plant; (ii) Double flash steam Rankine cycle direct contact condensing plant; (iii) Organic Rankine cycle (ORC) power plant, and; (iv) Hybrid steam-binary cycle plant.

Historical data indicate that the outputs of New Zealand geothermal wells vary up to a maximum of about 30 MWe per well, with the average value skewed to a relatively low value of about 4 to 5 MWe. This probably reflects that many of the wells were drilled between the 1950's and 1970's when hole depths were typically limited to 1,200 m and only rarely to depths greater than 2,000 m, and some, such as the early wells at Wairakei and Kawerau, were of smaller diameter than is now considered standard.

Outputs of wells drilled subsequent to these early wells are often higher due to being drilled to greater depth thus benefiting from both shallow (high enthalpy) and deep (liquid) production zones, and in some cases from having larger diameter production holes and production casings. Future geothermal wells in New Zealand and internationally should prove to be better than this past average for the same reasons. Given this historical data it is considered reasonable to assume future geothermal wells in New Zealand will have an average output in the range of 5 to 10 MWe, i.e. somewhat greater than wells typical of the Wairakei and Ohaaki developments, but significantly less than the larger output wells encountered in the higher temperature, central parts of the Mokai, Rotokawa and Kawerau fields. In each case the specific energy output of the wells was calculated from the flow rate.

Methodological Approach

Considering the range of resource characteristics discussed above and that the development options to be costed need to include a number of different power plant cycle types with cycle efficiencies that vary in response to plant inlet pressure, and well enthalpies (which dictate steam and brine flows), it is not very useful for comparative purposes to assign a single average MWe rating to wells drilled into the above four resource scenarios. Instead, the approach taken follows that of Barnett (2006 and 2007) in which the number of production and injection wells required at time 0 was calculated, while ensuring that those wells at time 0 covered not less than 110% of the selected capacity. Well capacity decline with time was modelled using a harmonic decline equation. An additional make-up production well was added whenever the capacity in a subsequent year would drop below the 10% reserve margin.

The method allows for investigation of the cost performance of the various options. This performance varies considerably depending on resource temperature and well flow rate. Total capital cost, specific capital cost (SCC) and the required Year 0 electricity tariff (NZc.kWh^{-1}) have all been estimated for each option and financial models developed for each of the 32 cases.

The estimated capital costs for each project scenario are inputs to this model together with operations and maintenance costs (O&M) and make-up and replacement wells, assessed over the operating life of the project which is assumed to be 30 years. Net delivery at the sales point is determined on a year-by-year basis, with assumptions made for scheduled and unscheduled outages, semi-annual inspection shutdowns, and recoverable and unrecoverable performance degradation.

Results

Full results are presented in Table 1 (Appendix 1). The relative rankings for thermal and financial performance are summarised below and presented in Figures 2 to 4:

Thermal performance (based on gross generation)

High temperature:
ORC < Single Flash < Hybrid < Double flash
Low temperature:
Single Flash < Double Flash < ORC < Hybrid

Financial performance

<u>Low Temperature (20 MWe gross)</u>
Specific capital cost:
Single flash < Hybrid < ORC < Double Flash
Electricity tariff:
Single flash < Double flash < Hybrid < ORC
[Range 10 to 14.5 NZc/kWh real]

<u>High Temperature (50 MWe gross)</u>
Specific capital cost:
Single flash < Hybrid < Double flash < ORC
Electricity tariff:
Single flash < Double flash < Hybrid < ORC
[Range 7 to 11 NZc/kWh real]

The ranking of the power cycle options in terms of thermal performance (gross) is quite different to the ranking in terms of financial performance. The advantage enjoyed by the binary plant options in terms of thermal performance at low temperature is not able to be translated into a financial advantage. There are two reasons for this, the first being that the binary plant options have somewhat higher plant parasitic loads which decrease their net thermal performance and thus their respective revenue streams, and although they have similar SCCs to double flash at low temperature (based on the cost assumptions made in the study), this is not enough to give them a levellised cost advantage.

Nevertheless, the range is quite close and innovative approaches to equipment marketing and financing may be enough to tip the balance in favour of one technology over the other, as can be witnessed by the market success of ORC and hybrid plants in New Zealand over the past 15 years.

Double flash plants have higher specific capital costs than the single flash steam or hybrid plant options, in spite of double flash plant having good thermal efficiency at all of the reservoir temperatures examined. This is due to the greater complexity and thus cost required within the steamfield and power plant to accommodate the second stage steam flash separators and piping / instrumentation and the additional cost for fitting out a turbine with two steam inlets. It is these additional costs which penalise the double flash option relative to the single flash and hybrid options.

The analysis undertaken here for the double flash option is relatively conservative conservative being constrained by limiting second stage flash pressure to control silica scaling potential. A more aggressive approach could be taken through reducing the second stage flash pressure further to generate a greater steam flow from the second stage flash step. This would improve the cost performance of this option, however, this would be at the risk of silica super saturation in the waste brine in excess of 130% with increased potential for scale deposition even with chemical treatment.

The key outputs from the model runs are estimates of the required “electricity tariff” for each project development option for a variety of financial assumptions of which corporate tax rate (30%), depreciation (straight line, 8 years), inflation (0%) and equity content (100%) are the most important. These tariff values are equivalent to the year 0 selling prices required to achieve the financial hurdle After Tax Internal Rate of Return (IRR) assumed in the model (10% real). Intermediate model outputs are specific capital cost (NZ\$.kWe(gross)$^{-1}$) and thermal performance (the ratio of thermal power supplied to gross electrical power generated).

The costs developed here (and presented in Figure 2) are in New Zealand dollars. They are based on 2007 values, and were internally calibrated against costs being incurred for New Zealand geothermal developments, of which there were a number in progress at that time, and several overseas geothermal projects which were also in progress at that time.

This study did not consider greenfield developments greater than 50 MWe. The main reason is that a greenfield developer would most likely not be able to attract the funds required for a larger development until some experience with the particular resource was gathered and the risks associated with a larger development were able to be well quantified. Furthermore a greenfield development of over 50 MWe may struggle to obtain resource consents in New Zealand, given the conservatism of regulatory authorities and their preference for staged developments, for the same reasons.

This contrasts with the current situation in New Zealand where large developments of medium to high temperature resources are occurring at brownfield sites (100 MWe at Kawerau and 132 MWe at Nga Awa Purua (Rotokawa)). Being brownfield sites, these larger, second stage developments are then appropriate. This implies that the anticipated returns on these larger investments within the current electricity market in New Zealand are attractive – and developers are on record as stating that “Geothermal is the lowest cost source of new generation for New Zealand” (Baldwin, 2008).

For several years prior to 2007, geothermal development costs rose steadily in line with global market commodity and equipment price rises. These rises continued until the middle of 2008 when the current global financial crisis occurred and commodity prices fell back to 2003 levels. It is not certain that there is enough market data available yet to determine what is currently happening to geothermal power plant, steamfield and well costs to be able to compare current (2009) costs with the 2007 estimates used in this study.

Applicability to Australia

The results of this study should be applied with caution to Australian geothermal projects. Although we consider the method to be robust and suitable for Australian projects, there are very real differences between the two countries which make the specific results inapplicable. Quite apart from the need to escalate costs to 2009, the general tendency will be for the differences to make New Zealand projects lower cost that Australian.

Significant differences include:

- The volcanic geothermal setting of New Zealand is demonstrably well suited to the occurrence of exploitable geothermal systems
- With an industry history of 60 years, exploration of New Zealand geothermal

resource is well advanced, reducing resource risks greatly

- New Zealand resources are generally hotter and much shallower than in Australia
- Some New Zealand wells encounter higher permeability than will be typical in Australia, and hydro fracturing and stimulation as necessarily required in the development of Enhanced Geothermal Systems (EGS) in Australia are not required in the New Zealand volcanic setting
- Wells in New Zealand do not generally need pumping whereas all Australian geothermal projects of the EGS and HSA (Hot Sedimentary Aquifer systems) types, with the possible exception of some in the Great Artesian Basin, will require both production and injection well pumping
- There is a highly developed and competitive geothermal drilling and service industry in New Zealand
- Use of evaporative cooling towers is common (for the non-ORC cases), and
- Distances to grid connection points are not great.

However, the method is equally applicable to the Australian context as to the New Zealand context when the above differences are taken into account.

To assist with transfer of costs, there are assessments of locally-sourced costs versus imported costs. Australian labour and materials costs can readily be substituted.

Acknowledgement

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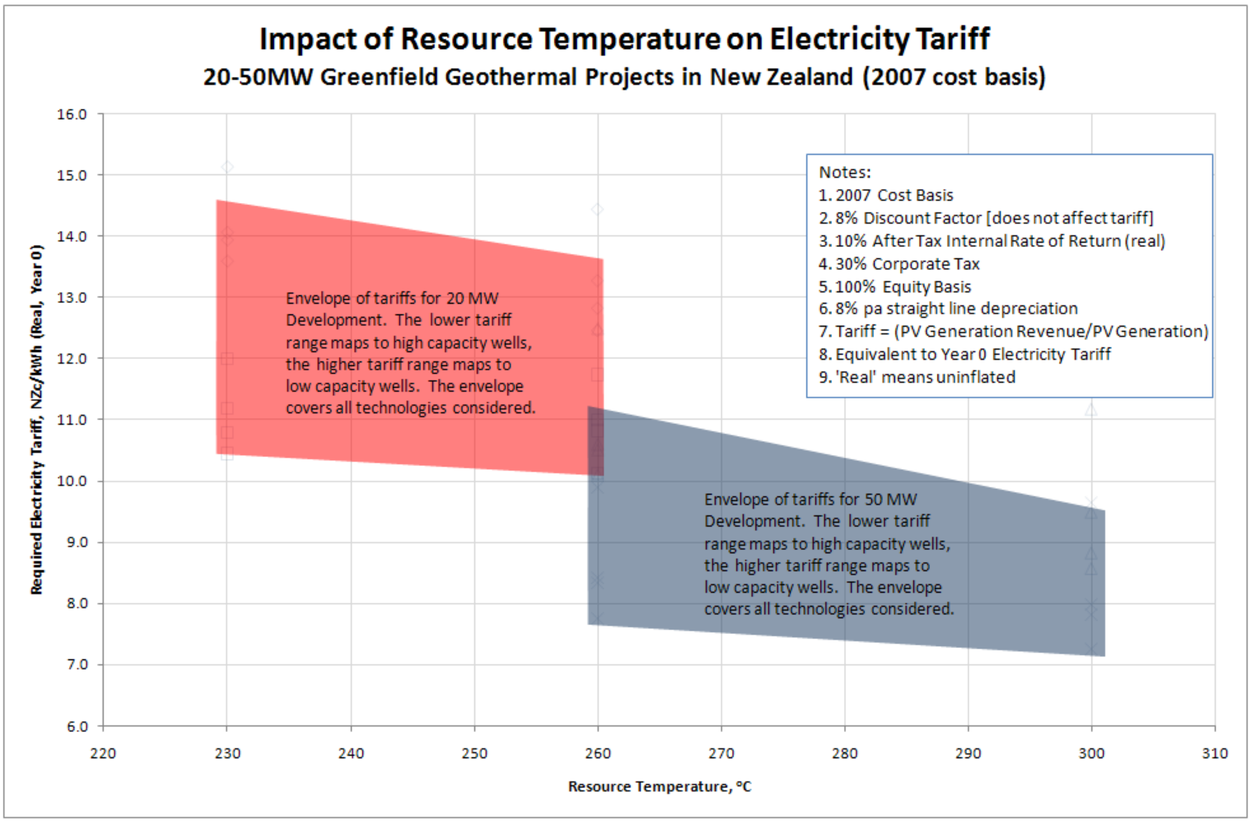

Figure 2 Electricity tariffs required for greenfield geothermal developments in New Zealand (2007 basis)

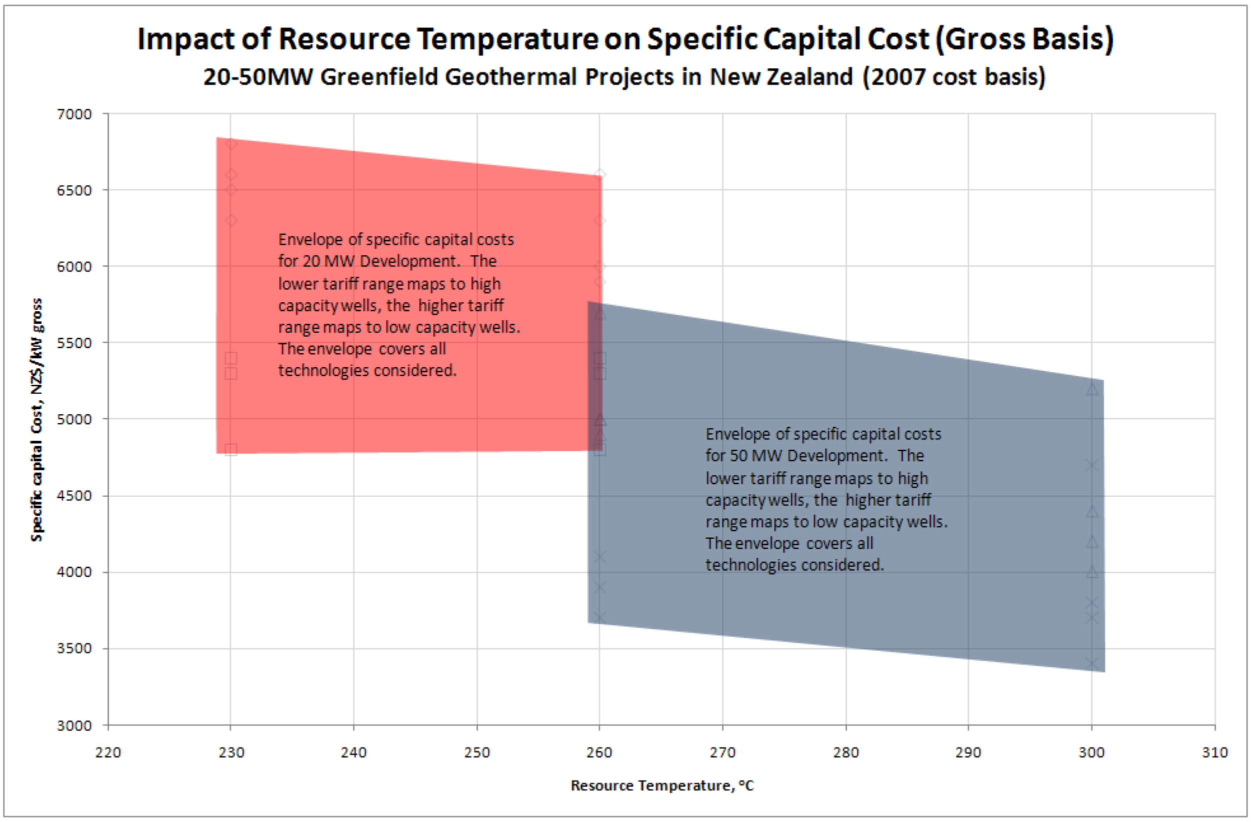

Figure 3 Specific capital costs of Greenfield geothermal developments in New Zealand (2007 basis)

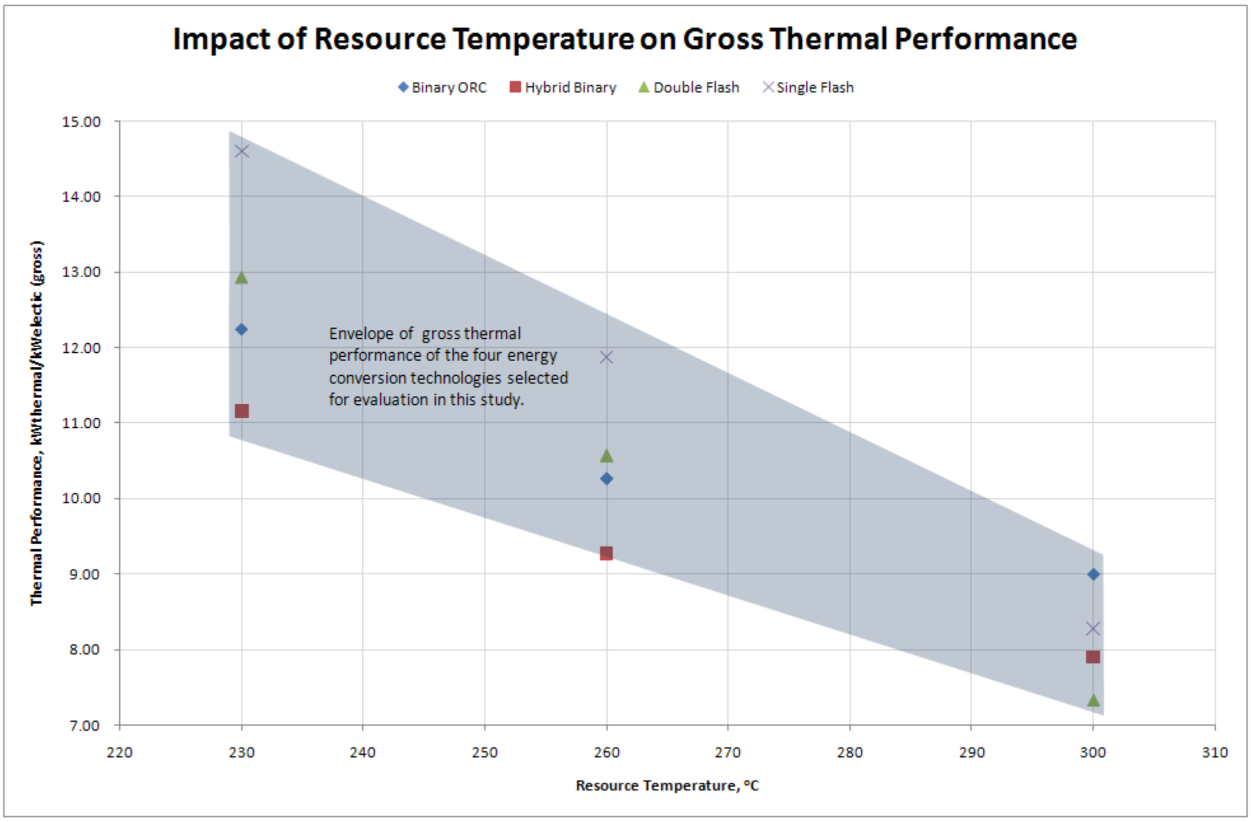

Figure 4 Thermal performance of the energy conversion options reviewed in this study

Appendix 1

Table 1 Outputs from study

Option	Well Capacity Envelope	Reservoir Temperature	Development Size	Power Plant Technology	Year 0 Tariff (Real)	Specific Capital Cost	Thermal Performance
#	High=150kg.s^{-1} Low=50kg.s^{-1}	^{o}C	MWe(gross)		NZc.kWh^{-1} (2007 basis)	NZ$.kWe(gross)$^{-1}$ (2007 basis)	kWthermal. kWe(gross)$^{-1}$
1	High	300	50	SF	7.3	3400	8.3
2	High	260	50	SF	7.8	3700	11.9
3	High	260	20	SF	10.1	4800	11.9
4	High	230	20	SF	10.5	4800	14.6
5	High	300	50	DF	7.8	3800	7.3
6	High	260	50	DF	8.3	4100	10.6
7	High	260	20	DF	10.8	5300	10.6
8	High	230	20	DF	10.8	5300	12.9
9	High	300	50	Hybrid	8.0	3700	7.9
10	High	260	50	Hybrid	8.4	3900	9.3
11	High	260	20	Hybrid	11.0	5300	9.3
12	High	230	20	Hybrid	11.2	5300	11.2
13	High	300	50	ORC	9.6	4500	9.0
14	High	260	50	ORC	9.9	4700	10.3
15	High	260	20	ORC	11.7	5400	10.3
16	High	230	20	ORC	12.0	5400	12.2
17	Low	300	50	SF	8.6	4000	
18	Low	260	50	SF	10.1	4900	
19	Low	260	20	SF	12.5	5900	
20	Low	230	20	SF	13.6	6300	
21	Low	300	50	DF	8.8	4200	
22	Low	260	50	DF	10.5	5000	
23	Low	260	20	DF	12.8	6000	
24	Low	230	20	DF	13.9	6800	
25	Low	300	50	Hybrid	9.5	4400	
26	Low	260	50	Hybrid	10.6	5000	
27	Low	260	20	Hybrid	13.3	6300	
28	Low	230	20	Hybrid	14.1	6500	
29	Low	300	50	ORC	11.2	5200	
30	Low	260	50	ORC	12.5	5700	
31	Low	260	20	ORC	14.4	6600	
32	Low	230	20	ORC	15.1	6600	