LOW ENTHALPY GEOTHERMAL ENERGY: TECHNOLOGICAL ECONOMICS REVIEW

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For GNS Science

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EXECUTIVE SUMMARY

The use of geothermal resources in New Zealand presents a significant opportunity both for electricity generation and direct use for heating and cooling.

High temperature geothermal resources have been used in New Zealand for a number of years. There is also considerable value in the largely untapped low enthalpy resources available across the country.

The low enthalpy geothermal research programme of GNS Science seeks to foster more widespread and structured development of low enthalpy geothermal resources in New Zealand for the benefit of the nation.

This report has been written to support this programme. It looks briefly at the technologies behind direct use (including heat pumps and direct use of the heat) and for electricity generation (especially binary cycle plant) but its focus is on the economics behind the development of the resource and the associated technologies[1].

The report shows that while, internationally, there is significant growth in all forms of geothermal energy use (in particular heat pumps), in New Zealand the growth has been limited largely to electricity generation and a small number of direct use applications. In New Zealand there has been considerable growth in the uptake of air source heat pumps for space heating in the residential sector. This is despite a number of advantages that geothermal heat pumps (GHP) have over air source technology and why GHP are the largest direct use application for geothermal energy internationally.

It is clear that in a number of possible low enthalpy applications initial capital costs are a barrier to uptake. For large scale developments, exploration and development are high risk activities with no guarantee of return. Despite this higher risk and initial investment requirement, the operation and maintenance costs are low. The balance of high capital but low ongoing costs means that often, when analysed across the life of a project, geothermal projects are economically attractive.

Despite the relatively low number of direct use applications in New Zealand there are a representative range of applications where direct use of low temperature geothermal heat is being used in domestic and industrial/commercial contexts throughout New Zealand, including for timber drying, aquaculture, greenhouses for fruit and vegetable cultivation, and for recreational uses.

Geothermal energy is well suited to a range of uses and is often accessible at depths much less than would generally be expected. It can offer an attractive long term investment particularly where up front capital costs can be kept to a minimum.

Where conventional hydrothermal resources are not available deeper drilling may still access useable heat that is commercially viable when of a sufficiently large size, say for a major bathing facility, or a large glass house.

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[1] This report should be read in conjunction with the report "Low Enthalpy Geothermal Energy – Technology Review" (Gazo and Lind, 2010). However there is some overlap between the reports to minimise cross referencing and for completeness of this report.

To put the capital cost of ground source heat pump applications into context the overall economic benefit of GHP's depends primarily on their efficiency and the relative alternative costs of electricity and other fuels, which are clearly variable over time. Based on recent prices almost everywhere in the world, ground-source heat pumps have higher efficiency and lower operational costs than any other conventional heating source. In general, at the residential level, a homeowner may save anywhere from 20% to 60% annually on electricity or gas utilities by switching from an ordinary heating/cooling system to a ground-source system.

Many of the New Zealand geothermal power station cost assessments have been based on the use of high temperature geothermal resources but there are a small number of US low temperature applications which have been built under commercial conditions. It is expected that the costs of these small plants will not easily compete with large scale projects with their economies of scale unless there are special circumstances e.g. existing wells or the plant is embedded within an industrial site.

Currently, the generation of electricity from geothermal energy amounts to some 13% of total electricity generation in New Zealand with several additional developments in the pipeline. The current focus remains on high temperature resources but in time, developers may turn to lower temperature applications as the technology improves and capital costs reduce.

This report notes several barriers to the development of geothermal resources which are in the main not unique to New Zealand. This includes the low awareness and understanding of the characteristics of the geothermal resource and how the choice of technology can improve the economics. To many developers and potential users the economic advantage that geothermal presents over other energy sources is often not visible and the resource is often overlooked. There are however a number of barriers specific to New Zealand that in combination may prove difficult to overcome. These include the relatively low population density (limited opportunity therefore for bulk price purchasing to pass on to consumers), New Zealand's relatively mild climate (short heating and cooling seasons) and the lower level of comfort demanded by New Zealand householders relative to some overseas countries.

With regard to the knowledge barriers people are often not aware of geothermal options available to them and of the cost benefits. This report and other low enthalpy studies are aimed at addressing these barriers.

The many attributes of geothermal energy make it a strong contender as an economic energy resource at both high and low temperatures for electricity generation and direct use applications. While initial costs can often prove to be a deterrent, when viewed over the lifetime of a development (in both large and small scale developments) the economics will often be more favourable. Future efforts on the promotion of the resource, for low temperature in particular, need to overcome a number of misconceptions including the price and accessibility of the resource.

1.0 INTRODUCTION

The low enthalpy geothermal research programme of GNS Science seeks to foster more widespread development of low enthalpy geothermal resources in New Zealand. It considers the historical and current developments of direct use of geothermal energy and includes activities focussed on establishing inventories, and quantifying resources to assist with increase uptake.

A recent GNS Science study (Gazo and Lind, 2010) focused on the technologies associated with the use of low enthalpy geothermal energy resources for electricity generation (i.e. binary electricity plants) and for direct heat/cooling purposes (i.e. geothermal heat pumps). Both uses are widely expected to grow the sector considerably in the years ahead.

The focus of this report is the economics involved in the technologies associated with uses of low enthalpy geothermal energy resources both in New Zealand and overseas.

The economic position of low enthalpy geothermal electricity generation and domestic use systems relative to other alternatives is set out in this report by determining capital, life cycle economics and cost benefit analysis. New Zealand and overseas data is compared.

The report presents details on a number of technological economic case studies both from New Zealand and from overseas covering the following:

a. Low enthalpy geothermal energy domestic use systems (mainly geothermal heat pumps) and their position relative to other heating/cooling alternatives in terms of capital and cost benefit analysis.
b. Other applications of geothermal heat (including industrial/commercial, greenhouse and aquaculture use, district and space heating and recreational uses. These are generally conventional geothermal resources typically related to elevated ground temperatures.
c. Ready-for-use low-enthalpy geothermal energy technologies for electricity generation and how they rate with other energy alternatives.

Finally the report identifies knowledge gaps and barriers on the adoption of these technologies from low enthalpy geothermal energy in New Zealand.[2]

In an Appendix, the report also provides (for reference) details on typical economic evaluation tools (cost-benefit analysis, etc.) used for assessing and determining the economic viability that may be applicable to binary electricity plants, geothermal heat pumps, and other alternatives.

This report should be read in conjunction with the report “Low Enthalpy Geothermal Energy – Technology Review” (Gazo and Lind, 2010). There is some overlap between the reports to minimise cross referencing and for completeness of this report.

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[2] Note – all $ provided in this document are in New Zealand dollars. Where applicable, exchange rates used and assumptions made have been documented. Because of the large number of studies referenced and their respective dates no attempt has been made to normalize costs to a common date. Some costs will have escalated at different rates so readers are encouraged to use source data and apply it to their specific situation.

2.0 BACKGROUND

New Zealand has both high- and low-enthalpy geothermal energy resources.

High enthalpy geothermal energy resources are confined to the northern and central parts of the North Island, particularly the Taupo Volcanic Zone (TVZ) in the Waikato and Bay of Plenty Regions and at Ngawha in Northland.

Low enthalpy geothermal resources covering energy in the ground, groundwater and other water bodies are available across New Zealand.

The low enthalpy geothermal energy can be used directly ("direct heat use") and in some instances indirectly through electricity generation. The general range of energy use at various indicative temperatures is as follows:

a. 30-69ºC - Thermoculture, bathing
b. 70-140ºC - Space and water heating, drying
c. 140-220ºC - Drying, process heat, binary electrical plant

The current larger uses of geothermal direct heat in New Zealand are in the industrial pulp and paper mill at Kawerau, bathing and swimming, greenhouse heating, space heating and/or possibly space cooling. Industry projections confirm that the historical direct uses of geothermal energy will continue to dominate the sector in New Zealand (forestry processing, tourism, greenhouse farming, and significant growth in cascaded use and heat pumps). A significant new use is in the dairy processing industry in locations where elevated geothermal temperatures are known to exist or enhanced geothermal solutions are possible.

In addition to the traditional concept of drilling for geothermal resources, there are many surface waters, such as rivers, lakes, ponds, the sea or waste water sources that can act as heat sources for heat pumps. New Zealand has a small number of examples of applications using well, stream and lake water as a geothermal resource. Sea and river water are heat sources not currently used in New Zealand but have considerable potential. For example, any harbour-side development could tap into this resource, whether it is for large scale commercial development or smaller scale residential development.

3.0 LOW ENTHALPY GEOTHERMAL ENERGY USES

3.1. Direct Use

Direct use of geothermal energy is one of the oldest, most versatile and the most common form of utilization of geothermal energy.

Direct use can involve using geothermal heat 'directly' (without a heat pump or electricity plant) to heat buildings, industrial processes, greenhouses, aquaculture, public baths and pools. Direct use can utilise high, moderate and low temperature geothermal resources.

Very low temperature resources are exploited for heat applications using geothermal heat pumps (GHPs), also known as ground source heat pump (GSHPs) for space heating and cooling. The GHP/GSHP form of "direct use' dominates current worldwide direct use statistics as shown in the most recent review (2010) of worldwide direct utilization of geothermal energy presented in **Table 1**.

Use	**Utilisation, TJ/year**				**Capacity, MWt/year**			
	1995	**2000**	**2005**	**2010**	**1995**	**2000**	**2005**	**2010**
Geothermal heat pumps	14,620	23,280	87,500	214,780	1,850	5,275	15,380	35,240
Space heating	38,230	42,930	55,260	62,980	2,580	3,260	4,370	5,390
Greenhouse heating	15,740	17,860	20,660	23,260	1,085	1,250	1,400	1,540
Agriculture pond heating	13,490	11,730	10,980	11,520	1,100	605	620	650
Agricultural drying	1,120	1,040	2,010	1,660	70	70	160	130
Industrial uses	10,120	10,220	10,870	11,750	540	470	480	530
Bathing & swimming	15,740	79,550	83,020	109,030	1,085	3,960	5,400	6,690
Cooling/Snow melting	1,120	1,060	2,030	2,130	115	110	370	370
Others	2,250	3,030	1,045	960	240	140	90	40
Total	112,430	190,700	273,375	438,070	8,665	15,140	28,270	50,580

Table 1 – Worldwide direct use of geothermal energy (1995-2010)

MWt = MWthermal

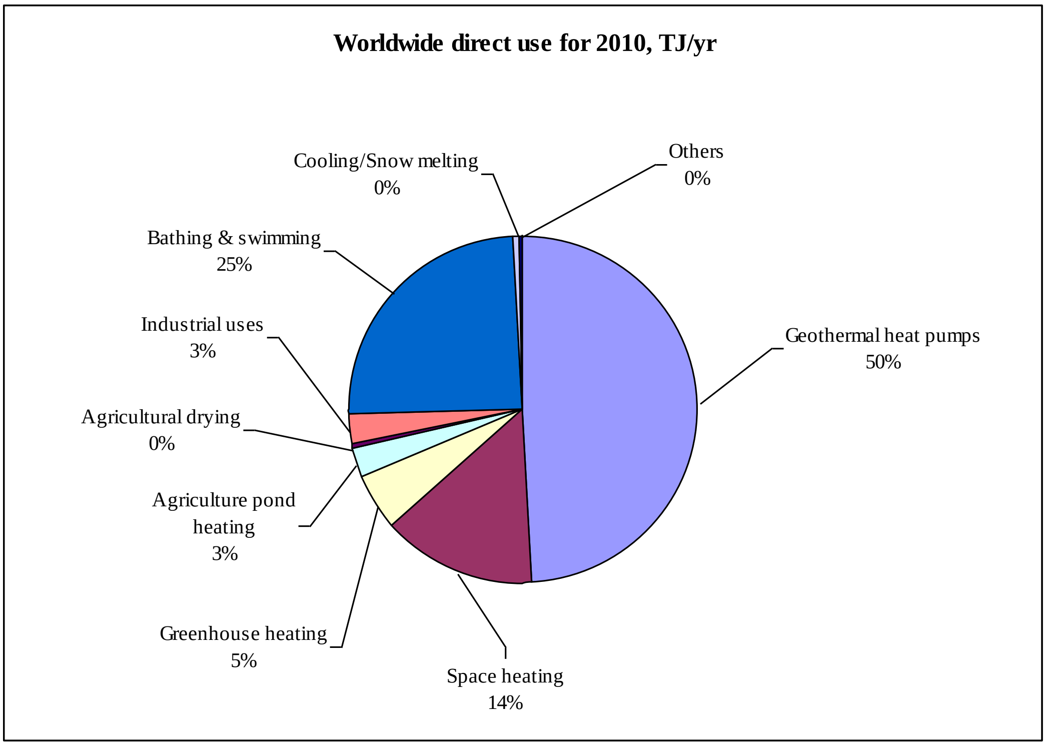

Figure 1 – Worldwide direct use of geothermal energy for 2010 (Utilization, TJ/yr)

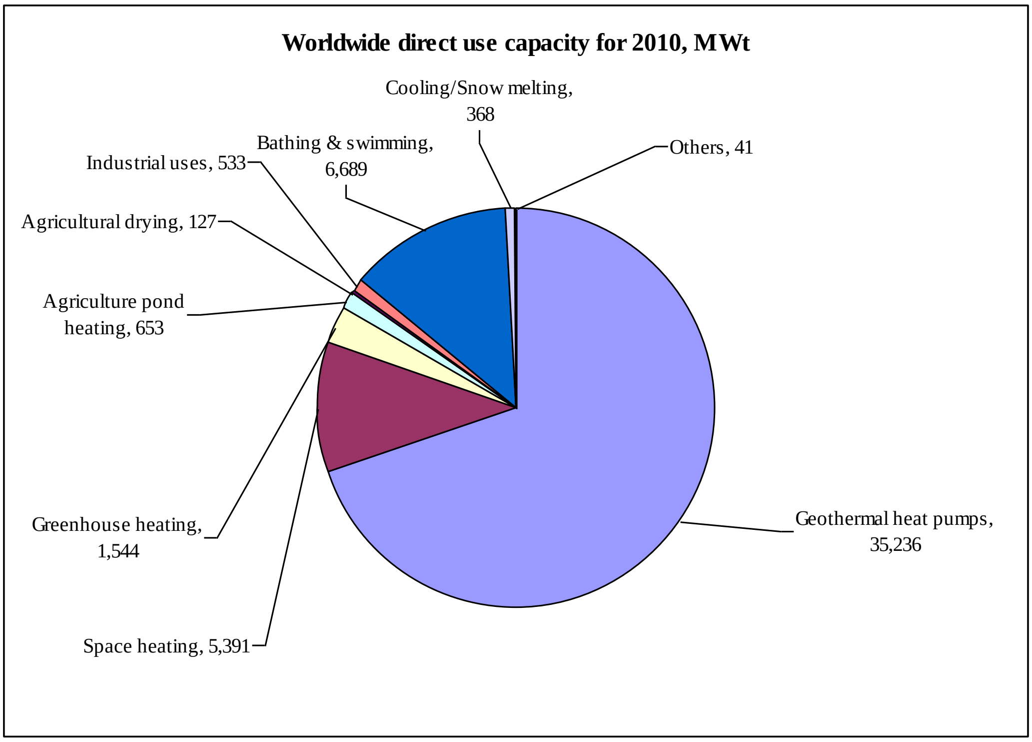

Figure 2 – Worldwide direct use capacity for 2010 (MWt)

In 2010, geothermal heat pumps accounted for 50% of worldwide direct use, bathing and swimming (25%), space heating (14%), and other (11%). Over the last 15 years, geothermal heat pumps exhibited the most notable and largest annual growth rates of about 20% and 22% for utilisation and capacity, respectively (**Table 2** and **Table 3**).

GHPs are the dominant and single largest category of geothermal direct heat use in the world, followed by space heating applications, then bathing and swimming applications.

Use	% Growth (2000/1995)	% Growth (2005/2000)	% Growth (2010/2005)	% Growth (2010/1995)	Yearly growth, %
Geothermal heat pumps (GHP)	59.2	276.0	145.5	1369.4	19.62
Space heating	12.3	28.7	14.0	64.8	3.39
Greenhouse heating	13.5	15.7	12.6	47.8	2.64
Agriculture pond heating	-13.0	-6.5	5.0	-14.6	-1.05
Agricultural drying	-7.7	93.9	-17.4	47.9	2.64
Industrial uses	1.0	6.3	8.1	16.1	1.00
Bathing & swimming	405.3	4.4	31.3	592.6	13.77
Cooling/Snow melting	-5.4	91.2	4.6	89.1	4.34
Others	34.9	-65.6	-8.5	-57.5	-5.54
Total	69.6	43.4	60.2	289.6	9.49

Table 2 – Growth rates in terms of utilisation

Use	% Growth (2000/1995)	% Growth (2005/2000)	% Growth (2010/2005)	% Growth (2010/1995)	Yearly growth, %
Geothermal heat pumps	184.5	191.6	129.0	1800.5	21.69
Space heating	26.5	33.8	23.5	109.0	5.04
Greenhouse heating	14.8	12.7	10.0	42.3	2.38
Agriculture pond heating	-44.8	1.8	6.0	-40.5	-3.40

Use	% Growth (2000/1995)	% Growth (2005/2000)	% Growth (2010/2005)	% Growth (2010/1995)	Yearly growth, %
Agricultural drying	10.4	112.2	-19.1	89.6	4.36
Industrial uses	-12.9	2.1	10.1	-2.0	-0.13
Bathing & swimming	264.7	36.5	23.8	516.5	12.89
Cooling/Snow melting	-0.9	225.4	-0.8	220.0	8.06
Others	-42.4	-37.2	-52.3	-82.8	-11.07
Total	74.8	86.7	78.9	483.8	12.48

Table 3 – Growth rates in terms of capacity

The major countries with the largest direct heat installations and utilisation of geothermal energy are shown in **Table 4** and illustrated in **Figure 3**.

No.	Country	Capacity, MWt	Annual Use, TJ/yr	Annual Use GWh/yr	Capacity Factor
1	United States	12,611	56,552	15,710	0.14
2	China	8,898	75,348	20,932	0.27
3	Sweden	4,460	45,301	12,585	0.32
4	Germany	2,485	12,765	3,546	0.16
5	Japan	2,100	15,698	7,139	0.39
6	Turkey	2,084	36,886	10,247	0.56
7	Iceland	1,826	24,361	6,768	0.42
8	Netherlands	1,410	10,699	2,972	0.24
9	France	1,345	12,929	3,592	0.30
10	Canada	1,126	8,873	2,465	0.25
11	Switzerland	1,061	7,715	2,143	0.23
12	New Zealand	393	9,552	2,654	0.77

Table 4 – World-wide direct use of geothermal energy, 2010

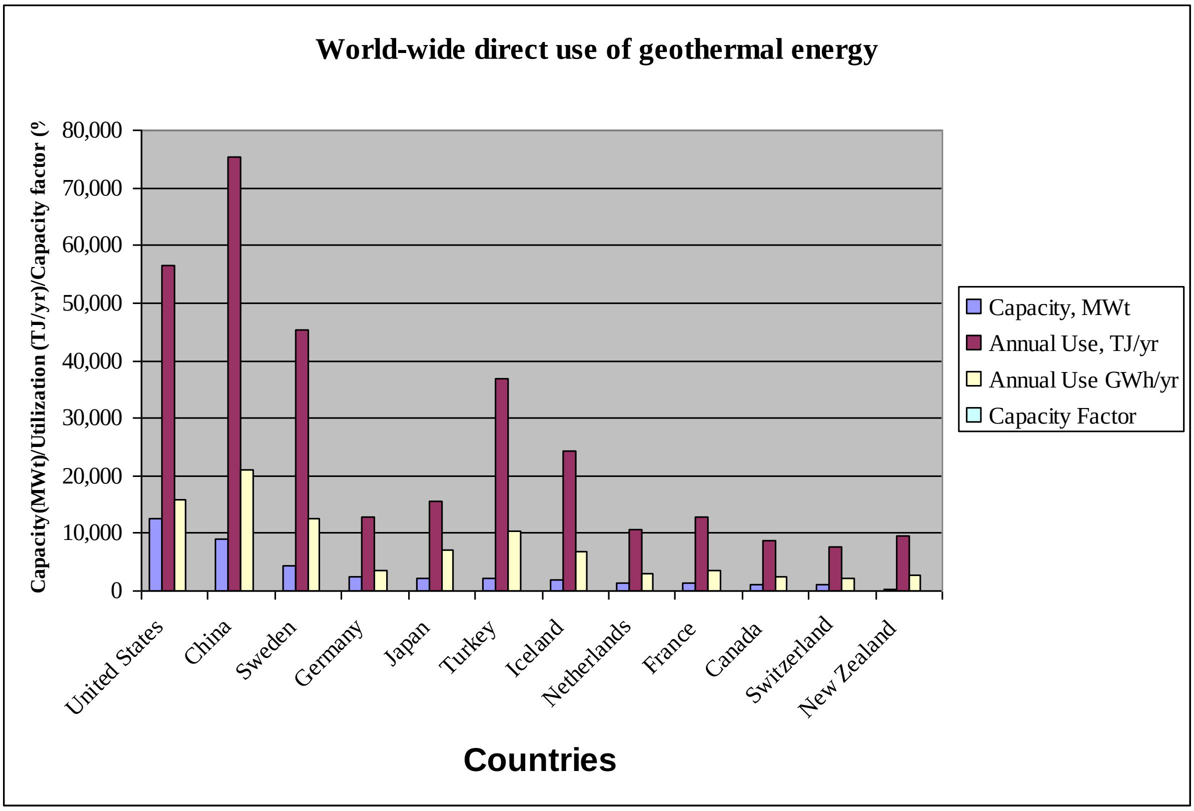

Figure 3 – Major countries with direct use of geothermal energy 2010

The detailed figures for New Zealand for 2010 are presented in **Table 5** and show a small percentage market share for GHP's.

Use	**Consumption**		**Capacity**	
	TJ/yr	**% share**	**MWt**	**% share**
Industrial process heat	224	57	6,104	64
Bathing and swimming	74	19	1,733	18
Fish and animal farming	17	4	273	3
Greenhouse heating	24	6	379	4
Space heating	19	5	181	2
Geothermal heat pumps	7.22	2	39	~
Other uses[1/]	27	7	843	9
Total	392.22	100.0	9,552	100.0

Table 5 – Assessed geothermal direct use in New Zealand (2010)

Note: [1/] - For irrigation, frost protection, geothermal tourist park

3.1.1 Geothermal heat pumps (GHPs)

Geothermal heat pumps (GHPs) are loop systems where heat is absorbed or rejected to the ground, and there is no need to provide the external energy to operate a boiler or cooling tower.

The GHP technologies are well described in Gazo and Lind (2010). Details are not repeated in this report.

Research indicates that GHPs are increasingly available in New Zealand with several companies now established to supply the necessary services for both residential and commercial applications. To date, most are considered to be water source installations. Most residential installations are in Queenstown, in the South Island, with some in the luxury housing market and residential homes in other parts of the country. Growth in the commercial building sector is also evidenced by the recent installation of GHP's in the Dunedin airport.

3.1.2 Other Direct Uses

While **Table 1** confirms the significant growth world-wide in GHP's, the collective 'other uses' of direct low enthalpy heat are nonetheless also significant with utilization on a par with GHP being 223,290 TJ/year and 214,780 TJ/year in 2010 respectively.

Gazo and Lind (2010) details direct uses including industrial, process heat, commercial applications, green house and aquaculture facilities. The technologies involved are also documented.

3.2 Electricity Generation

Geothermal energy resources can be used indirectly through electricity generation. Three types of geothermal electricity plants are operating today:

- Dry steam plants, which directly use geothermal steam;

- Flash steam plants, which produce steam from hot pressurized water; and
- Binary cycle plant which are a closed-loop system where the geothermal fluid (i.e. hot water, steam, or a mixture of the two) heats a “binary working fluid” (isopentane or isobutene), that boils at a lower temperature than water, with the working fluid driving the turbine.

Of these types, binary cycle plant is best suited for low enthalpy resources.

Gazo and Lind (2010) present technology details of binary cycle and more conventional organic rankine cycle plant.

Low enthalpy geothermal energy resources can also be used for combined heat and power plants (CHP), where the fluids first run through a binary electricity generating unit and are then cascaded for space, swimming pool, greenhouse and aquaculture pond heating, before being re-injected into the aquifer or discharged.

4.0 ECONOMICS

Typical economic evaluation tools (cost-benefit analysis, etc.) used for assessing and determining the economic viability of electricity generating plant are presented in this report in Appendix 4. While not discussed in the body of the report, they present a valuable and useful resource. They are applicable to binary cycle electricity plants, geothermal heat pumps, and other alternatives.

4.1 Development Costs

Development includes assessing the resource to be utilised, acquiring the necessary land access rights and consents that might be required, installing the necessary plant and engineering equipment (including the subsurface components), commissioning, operating and then decommissioning at the end of the life of the equipment. All these aspects need to be costed to enable an economic evaluation to be undertaken.

Inevitably every site has site specific requirements that need to be considered. This by itself makes economic comparisons difficult to consider in more than a general way.

Appendix 3 presents further and more extensive details on the development costs for geothermal electricity generation.

4.2 Direct Use - Geothermal heat pumps (GHPs)

The costs of a GHP system vary according to local conditions including labour rates, geological setting, drilling conditions, type and scale of system installed, and the equipment selected.

While geothermal heat pumps are commercially available worldwide, relative to the use of fossil fuels for space heating, market penetration is still low. On the other hand, the use of air-to-air heat pumps for residential space heating and cooling continues to grow as a result of successful marketing campaigns.

The costs associated with the development and utilization of low enthalpy direct use geothermal resources are broken down into the following sub categories (where possible):

- Capital Costs
- Operating and Maintenance Costs.

The findings are illustrated using a range of national and international case studies which are presented in Appendix 1. The case studies enable comparison with a range of energy use technologies.

Often, even with Life Cycle Cost (LCC) analysis, GHP's may have a higher cost compared with alternatives. It will then be a matter for the developer to weigh that additional capital cost premium against the other benefits such as efficiency; having a building facade without heat plant; the value of unobstructed views; or the delivery of messages associated with the use of clean energy. Many have value to clients that surpass simple calculations of energy cost.

4.2.1 Capital Costs

Kavanaugh et al (1995) suggest the cost of a GHP system can be broken down as follows:

a. Ground loop = up to 34% of the cost
b. Heat pump = up to 30% of the cost
c. Indoor installation = up to 21% of the cost
d. Ductwork = up to 15% of the cost
e. Pumps = up to 7% of the cost

Capital costs for geothermal heat pump systems are normally thought to exceed the cost of most, if not all, of the alternative heating and cooling systems. That said there is considerable variability in the capital costs associated with installation in various building types (for example, residential through to commercial buildings, offices and warehousing) and the type of ground loop used.

Although initially more expensive to install than conventional systems, properly sized and installed GHPs deliver more energy per unit consumed than conventional systems. Ground source heat pumps are generally characterized by high capital costs but low operational costs relative to other forms of heating and cooling. Several of the case studies presented in Appendix 1 confirm this.

On average, a geothermal heat pump system costs about \$3,600 per ton of capacity, or roughly \$10,700 for a 3-ton unit (a typical residential size).[3] A system using horizontal ground loops will generally cost less than a system with vertical loops. In comparison, other systems would cost about \$5,700 with air conditioning. Using another metric, on a \$ per square metre basis, GHP capital costs average \$150+/m^2, ranging from a low of \$50/m^2 for commercial space to as much as \$200/m^2 for correctional facilities (Moore, 1999).

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[3] Note - 1 ton of refrigeration is 3.517 kW (US) or 3.939 kW (Imperial).

Research indicates that vertical, closed-loop systems are the most expensive due to the cost of drilling.

Capital costs for horizontal-loop systems averaged less than 50% of the cost of the vertical-loop systems. However, for large installations, it may be impossible to find adequate areas for the installation of a horizontal closed-loop system, and for retrofit applications, this is nearly always the case. An obvious exception to this rule is a school with its associated grounds.

Table 6 presents details of the range of costs for GHP systems using different types of ground heat exchangers. It is assumed that all the systems are ground to water but the cost of the heat distribution system is not included. Single or multiple pipe horizontal systems generally will be slightly more expensive than slinky systems because the cost of additional trenching will outweigh the reduction in the material cost for the piping. DX systems ('direct expansion' systems) are also likely to be cheaper than the equivalent output indirect system as they require less ground coil. The actual costs for the ground heat exchanger will depend not only on the installed capacity of the heat pump but also the energy demands of the building and the ground conditions. For all types of ground collector, set up costs (design, equipment mobilization and commissioning) are a significant part of the total cost therefore the capital cost measured in $/m of borehole or $/m of trench will fall as the collector size increases. For example, for a group of 5 houses on a single site, the collector costs per house are likely to be between 10% and 15% lower than for an individual house.

System type	**Ground coil costs ($kW)**	**Heat pump costs ($/kW)**	**Total system costs ($/kW)**
Horizontal	540 - 760	760 – 1,400	1,300 – 2,160
Vertical	970 – 1,300	760 – 1,400	1,730 – 2,700
*costs include installation and commissioning but exclude the distribution system			

Table 6 – Indicative capital costs* for ground-to-water heat pump systems
Source: http://www.gshp.org.uk/documents/CE82-DomesticGroundSourceHeatPumps.pdf

The overall economic benefit of GHP's depends primarily on the relative costs of electricity and other fuels, which are variable over time and place in the world. Based on recent prices, ground-source heat pumps currently have lower operational costs than any other conventional heating source almost everywhere in the world. Natural gas is the only fuel with competitive operational costs, and only in a small number of countries where it is exceptionally cheap, or where electricity is exceptionally expensive (Dowlatabadi, 2007). In general, at the residential level, a homeowner may save anywhere from 20% to 60% annually on utilities by switching from an ordinary system to a ground-source system (Geothermal Heatpump Consortium. Lienau et al, 1995).

A BECA (2009) heat pump study (presented in Appendix 1) for New Zealand applications in which GHP's were compared with other heating technologies showed however that despite offering the lowest energy consumption in two situations (a residential healthcare building and a commercial office building) the capital costs associated with the GHP coupled with the relatively low unit electricity price resulted in higher NPV costs which in turn meant that it was uncompetitive and would not be the favoured heating option on a simple economic basis. An NZGA-EHMS (2008) study (see also Appendix 1) showed that GHP's will be uneconomical for small domestic loads unless combined with other domestic loads (such as in a community shared scheme) and with water heating that will give an economy of scale and higher load factor. In a domestic/residential context, as house size increases the economics move in favour of GHP’s. Where the price of electricity is high, the better Coefficient of Performance (COP) of a GHP makes it preferable to all other options.

Table 7 compares the current GHP and air-source heat pump (ASHP) systems available in New Zealand. Geothermal heat pumps tend to have a higher capital cost, especially at smaller sizes, as compared with other heating options. However, they have competitive operating costs (electricity cost is minimised by higher COP) and their performance is less affected by the outside temperature as compared with air source heat pumps.

Particulars	**GHP**		**ASHP**
	6 kW	**20 kW**	**20 kW**
Capital cost (NZ$)	Heat pump – $6 – 7,500 Ground loop – $2,500 Underfloor/ hot water system – $2,300 Total cost – $12,000	$24,000	$19,000
COP	4	5	3.7

Table 7 – Comparison between GHP and ASHP costs (NPV @NZ$)

The GHP system at 20kW peak heating capacity has a capital cost of $24,000 and will require 4kW of electricity. An ASHP system with the same capacity will cost $19,000 and require 5.5kW of electricity. The GHP system will be competitive with ASHP system at the 20kW heating capacity level, but will not be the favoured economic option at smaller heating loads.

From a commercial perspective, higher loads, economies of scale and the higher COP of the GHP’s all combine to make the GHP option attractive. The study showed that for larger loads the resulting life cycle cost (LCC) can be below that of a unit of electricity.

Details on the return on investment in geothermal projects are generally quite variable. One US study (Kavanaugh et al (1995)) found the total installed cost for a system with 10kW (3 ton) thermal capacity for a detached rural residence in the USA averaged $8,000–$9,000 in 1995 US dollars. More recent studies (Cummings, 2008 and Hughes, 2008) found an average cost of $14,000 in 2008 US dollars for the same size system (equivalent of NZ$20,000). The US Department of Energy (Energysavers.gov) estimates a 2008 price of $7,500 (equivalent of NZ$10,700). Prices over $20,000 are quoted in Canada, with one source placing them in the range of $30,000-$34,000 Canadian dollars (Natural Resources Canada 2005). The escalation in system price has also been accompanied by improvements in efficiency and reliability. A China (NREL, 2009) study (see Appendix 1) suggests that the investment cost for a GHP system could be recovered in 10 years. The Lind (2009) study indicates costs of between $3,860 to $15,440/unit (in NZ$) although fuel savings lead to a payback period of 10 years. New Zealand Consumer Magazine (Whitely, 2010) quotes $20,000-$25,000 for a ground source heat pump system for a 150 m^2 home. The NZGA study by EHMS (2008) looked at geothermal heat pumps, and the results are shown in **Figure 4**.

The report noted that for larger homes, and therefore for a range of commercial applications, heat pumps can be viable options. In essence, it takes a larger heat load to justify installation of a heat pump. At a lower IRR a much wider range of large houses from south to north can support heat pump installations.

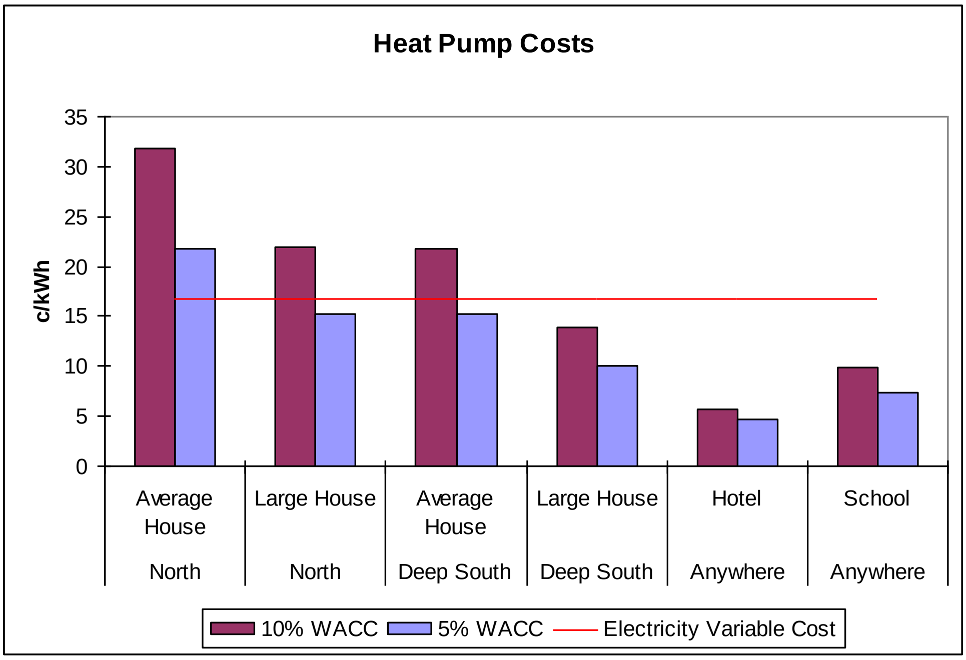

Figure 4 – Comparison of heat pump unit costs for a range of New Zealand house sizes and loads (in terms of cents per kWh of heating duty), and of larger applications with current variable electricity price

The space and water heating load levels looked at for this report were not as attractive as the maximum size identified in the BRANZ HEEP survey where 20% of houses had heating requirements greater than 14,000kWh/year and 10% of houses had heating use greater than 20,000kWh/year. There is clear potential for large houses with higher demand, especially in New Zealand's colder south, to install these units.

Despite the low load factor for schools and hotels, heat pumps in these locations are clearly viable options at either 10% or 5% IRR compared with electric resistance heating.

Capital costs are known to benefit from economies of scale, particularly for open loop systems, so they are more cost-effective for larger commercial buildings and in harsher climates. The initial cost can be two to five times that of a conventional heating system in most residential applications. In retrofits, the cost of installation is affected by the size of living area, the home's age, insulation, the geology of the area, and location of the home/property. Duct system design and mechanical air exchange or underfloor piping will be part of the initial system cost.

In some countries capital costs may be offset by government subsidies and in some countries electricity companies offer special rates to customers who install ground-source heat pumps for heating/cooling their building (e.g., US Dakota based company Capital Electric Co-operative). This is due to the fact that electrical plants in those countries (but not New Zealand) have the largest loads during summer months and much of their capacity sits idle during winter months. This allows the electricity company to use more of their facilities during the winter months and sell more electricity. It also allows them to reduce peak usage during the summer (due to the increased efficiency of heat pumps); thereby avoiding construction costs of new electricity generation plants. For the same reasons, other utility companies have started to pay for the installation of ground-source heat pumps at customer residences and lease the systems to their customers for a monthly fee, at a net overall savings to the customer. Some Governments that promote renewable energy offer incentives for the residential or industrial markets. For example, in the United States, incentives are offered both at the state and federal levels of Government.

4.2.2 Operational and Maintenance Costs

It is well documented that geothermal heat pumps save money in operating and maintenance costs. They are generally more efficient, they are less expensive to operate and maintain (relative to a number of conventional alternatives) (see Appendix 1) typically resulting in annual energy savings ranging from 30% to 60%.

Maintenance costs for GHPs are small. There is no requirement for an annual safety inspection as there is for combustion equipment. There are few moving parts. The circulation pumps are likely to have the shortest lifetime. The system should be designed for easy replacement of the circulating pumps. The compressor is likely to have a life of up to 15 years (25 years for scroll compressors) and be guaranteed for up to 3 years.

The refrigerant circuit will likely be pre-sealed and information about any requirements for maintenance concerning the refrigerant circuit should be provided. The ground loop is expected to have a long life (over thirty years for a copper ground coil providing the ground is non acidic and over 50 years for polyethylene pipe) and be virtually maintenance-free.

The lifespan of the systems are expected to be longer than conventional heating and cooling systems. Robust data on system lifespan is not readily available yet because the technology is relatively young, but many early systems remain operational after 25–30 years with routine maintenance. Most loop fields have warranties for 25 to 50 years and are expected to last at least 50 to 200 years. The higher investment above conventional oil, propane or electric systems may be returned in energy savings in 2–10 years for residential systems in the USA (Energy Savers Programme) (ECONAR® GeoSource™). If compared to natural gas systems, the payback period can be much longer or non-existent. The payback period for larger commercial systems in the USA is 1–5 years, even when compared to natural gas (Lienau et al, 1995).

Commercial systems maintenance costs in the USA have historically been between \$0.2 to \$0.3/m^2 per year in 1996 dollars, much less than the average \$0.8/m^2 per year for conventional HVAC systems (Bloomquist, 1999). Moore (1999) was unable to obtain operating cost data for each and every building type for which capital cost data was available. For all GHP systems evaluated, energy operating costs averaged \$8/m^2/year, while in comparison the mixture of conventional HVAC system types averaged \$16/m^2/year. This represents an average across the board saving in operating costs of 29 %. GHP applications in schools and retail space were found to have the lowest energy operating cost on average (around \$8/m^2/year). As was the case with capital costs for retail space, GHP operating costs are skewed by buildings that include warehouse and service areas that are either not cooled or under conditioned. This drives down the operating cost per square meter. However, even in these atypical situations, GHP systems were found to provide a cost savings of 39 %.

Maintenance costs are more difficult to establish but evidence suggests that costs associated with GHPs are the lowest relative to other systems and 39% less than those associated with an air-source heat pump. Bloomquist (1999) found that even those systems aged 30 years or more had maintenance costs that were significantly lower than the alternatives.

4.2.3 Comparison with other Technologies

In order to compare the economics of geothermal heat pump systems to other HVAC alternatives, a direct comparison must be made between capital costs, operating costs, and maintenance costs. Relative to a range of conventional HVAC systems, a Total Life Cycle Cost (LCC) analysis showed GHPs to have the lowest life-cycle cost of all. Research by Cane et al (1998) presented survey data from 25 systems which included in-house and contractor provided maintenance. The total maintenance costs for the sample were shown statistically to be significantly lower than those reported for conventional systems in the 1995 ASHRAE Handbook—Applications. The mean annual total maintenance costs for the most recent year of the survey ranged from \$1 to \$1.5 per 100m^2 for in-house labour and contractor provided maintenance, respectively.

Appendix 1 provides further illustration of these findings. Several studies have shown GHP's to offer the best performance relative to a number of alternatives. The Life Cycle Cost (LCC) analysis conducted by Higbee (1998) evaluated the costs and revenues associated with acquisition, construction and operation over the lifetimes of three heating systems – an electric resistance heater, an air-to-air heat pump and a GHP. The results confirm GHP's to be competitive with air-to-air heat pumps and significantly better that the electrical resistance heater despite having the highest initial capital cost. All technologies were reviewed with an assumed equal cost of electricity and with cost increases the GHP's are even more attractive.

The LCC process carried out by Higbee (1998) was adopted under recent New Zealand conditions and with a number of theoretical assumptions. The results are presented in Appendix 2 but it is noted that even if carbon charges are taken into account, the high investment cost and low cost of delivered heat for GHP affects its competitiveness with other heating options in New Zealand. GHP is ranked 4th behind wood, air source heat pumps and diesel.

4.3 Direct Use – Other Applications

The following sections discuss the conventional use of geothermal resources for example in heating and cooling applications in a range of direct use situations such as recreations uses, heating and cooling in buildings and heat provision in commercial and industrial applications.

4.3.1 Low Temperature Heating Applications

Low temperature geothermal energy is more widely available than most people realise. The notional thermal gradient found in sedimentary basins identifies temperatures of 60°C at depths of 1,800 m. **Table 8**, column 1 contains four options at two supply temperatures of 45 and 60°C at thermal gradients of 27 and 33°C/km respectively.

The costs of using a geothermal heat resource are site specific but indicative costs for a hot water supply are shown in **Table 8** with the data taken from work carried out for NZGA by

EHMS (2008). Annual operations and maintenance were assumed to be 2.5% of the capital cost, life is assumed to be 30 years, and the Weighted Average Cost of Capital (WACC) is post tax real with two cases considered at 5 and 10%.

Option	**Capital cost ($000s)[4]**	**Annual operations cost ($000s)**	**Annualised energy cost 5% WACC ($000s)**	**Annualised energy cost 10% WACC ($000s)**
45°C supply, 27°C/km, 1.2km deep well	600	15	64	98
45°C supply, 33°C/km, 1.0km deep well	500	13	53	82
60°C supply, 27°C/km, 1.8km deep well	900	23	95	147
60°C supply, 33°C/km, 1.5km deep well	750	19	79	123

Table 8 – Cost of a 45 to 60°C Heat Supply Outside Traditional Geothermal Areas

Drilling deep ground water type wells to depths of between 1 and 1.8 km to tap temperatures of between 45 and 60°C, for say bathing or other low temperature uses could be of the order of NZ$0.5 million to NZ$1.0 million for a 6 – 8” diameter well i.e., approximately NZ$500/m including mobilisation and demobilisation costs.

An example of a low temperature water supply is the Hanmer Springs bathing complex which attracts around 500,000 visitors per year (White, 2007) with a basic adult entry ticket price of $8 generating a multi-million dollar income stream.

4.3.2 Houses, Hotels and Schools

With the right technology both heating and cooling services in buildings can be provided by geothermal energy. This was discussed as part of a report “Assessment of Possible Renewable Energy Targets – Direct Use: Geothermal” by EHMS and GNS June 2007. The report included heat duration curves for a hotel in Rotorua (**Figure 5**) and a school (**Figure 6**).

The shape of the heat duration curve for a hotel in Rotorua was assumed to be typical of hotels throughout New Zealand. It indicated economically favourable conditions for a higher capital cost/low operating cost heat plant because the typical load requirement is around 60% of peak.

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[4] Assumes single well with artesian flow.

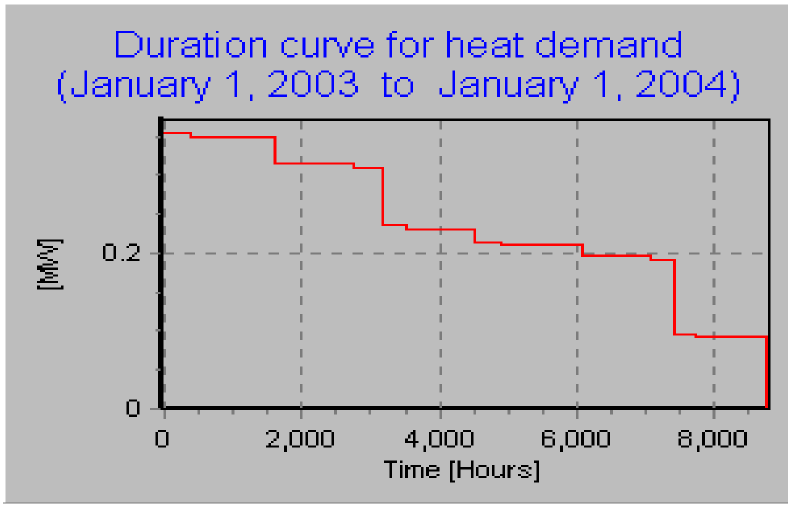

Figure 5 – Heat duration curve from a hotel, with annual demand including space heating, hot water and washing. (scale is 0 – 0.4 MW)

The shape of the heat duration curve for a school was less attractive than for a hotel, in that demand is at a high level for a relatively short period and boilers are idle for long periods. Although the load factor was much less than for a hotel, the higher demand meant some economies of scale could be achieved in terms of the cost of any heat plant.

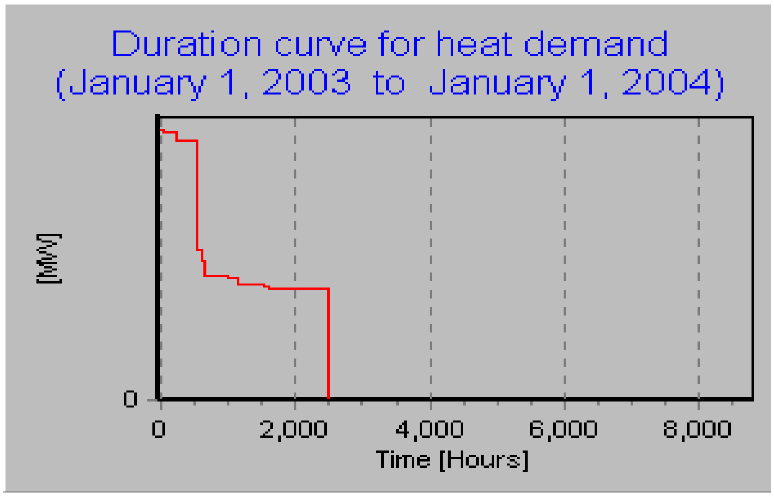

Figure 6 – Heat duration curve for a primary school with the heat covering space heating and a heated swimming pool. (Scale 0 – 1 MW)

Large New Zealand schools have heat plant capable of MW duty, while demand in universities is an order of magnitude greater again. The curve in **Figure 6** suggests a 1MW heat source could supply about 1.4GWh/year of heat.

The use of geothermal energy in the school sector is expected to be competitive to wood pellets. The conversion to wood pellets has an advantage over geothermal energy use however in cases where existing coal boilers can be converted to being fuelled by wood pellets.

Unit costs for a house, hotel and school using geothermal heating were analysed in the NZGA study by East Harbour Management Services (2008). The results are shown in **Figure 7** for direct use of geothermal heating. The capital cost used were; for the average house $9,000, large house $14,000, hotel $44,000 and school $514,000.

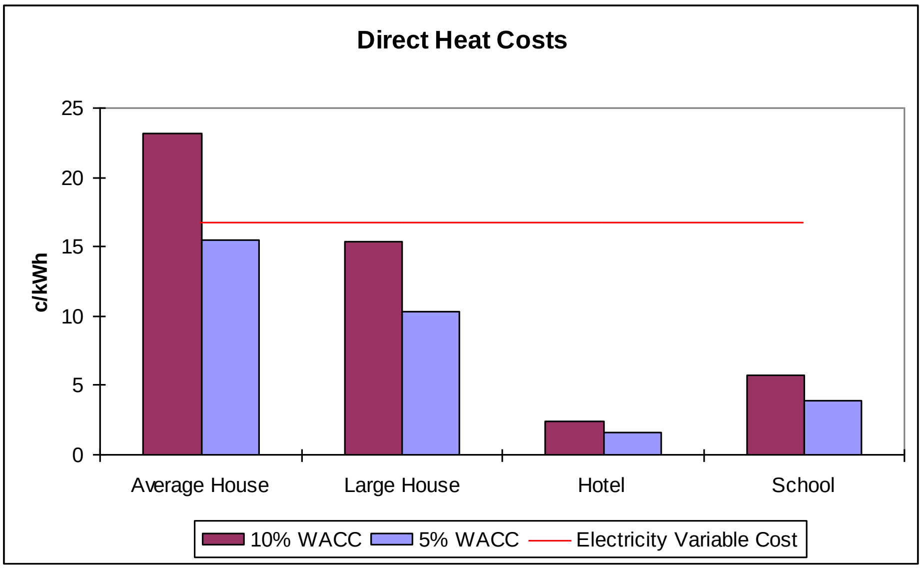

Figure 7 – Comparison of conventional geothermal direct heat unit costs (in terms of cents per kWh of heating duty) for a range of house sizes and loads, and of larger applications with current electricity price

Figure 7 shows that for all indicative sizes of houses (from average to large) direct use of wells for water and space heating can be an attractive option, more so at lower internal rates of return. For hotels and schools (and therefore for a wide range of commercial applications), direct heating is an economic option when compared with resistance heating. These examples are using conventional (higher temperature) geothermal sources and therefore represent costs at the lower end of the spectrum.

Table 9 extracted from EHMS (2008) compares the heating costs of a number of technologies (in NZ$2008).

			Heating Cost [5]	
Project	**Size**	**Load factor**	**5% WACC**	**10% WACC**
	kW		**No CO_2 charge**	**No CO_2 charge**
			c/kWh	**c/kWh**
GS Heat pump, 6 kW heating, average house	6	0.10	29	40
GS Heat pump, 20 kW heating, large house	20	0.12	16	21.5
GS Heat pump, 726 kW heating, commercial	726	0.29	6.5	7.5
GS Heat pump, 726 kW heating, industrial	726	0.40	4	5
GS Heat pump, 726 kW heating, school	726	0.16	8.5	11
Heat pump, (air Source) 6 kW heating, average house	6	0.10	13.5	16.5
Heat pump (air source), 20 kW heating, large house	20	0.12	15	19.5
Pellet burner, 6 kW, average house	6	0.10	19	23
Pellet burner 13 kW, Auckland large house	13	0.12	17	20.5
Pellet burner, 1000 kW heating, school	1000	0.16	7.5	8.5
Gas fire, 6 kW, average house	6	0.10	23	26.5
GS Heat Pump, (Blenheim house) 18 kW	18	0.22	14.5	18.5
Electricity resistance heating 6 kW, average house	6	0.10	26	26
Direct geothermal heating, average house	7	0.10	15.5	23
Direct geothermal heating, large house	13	0.12	10.5	15.5
Direct geothermal heating, hotel	55	0.58	1.5	2.5
Direct geothermal heating, school	1000	0.16	4	6

GS = ground source

Table 9 – Technology heating costs

4.3.3 Industrial Applications

Geothermal has the potential as a source of industrial process heat in regions that would not usually be considered "geothermal". This could apply to larger rural based energy users such as dairy processing plants and meat works. A feasibility study by East Harbour Energy (2009) was carried out to assess the potential of geothermal heat meeting the heating needs of Fonterra's Waitoa milk processing plant.

Fonterra's Waitoa plant is currently supplied with process heat from three coal boilers, and with electricity primarily from the grid. The study assessed the potential for a geothermal project whereby heat is extracted from hot deep rock structures to meet the site's heat demand and also generate around 8MW of electricity. The investment required for the heat and electricity generation plant was around $80m and this could earn a post tax project return of better than 15% with an NPV around $20m, based on a range of assumptions. The project would reduce CO_2 emissions from coal use by around 100,000 tonnes per annum and by a further 20,000 tonnes per annum as a result of the electricity generation. Further details are presented in Appendix 2.

Figure 8 is informative on the cost of industrial heat supplies from conventional geothermal energy compared with other heat sources. There are two geothermal lines of interest. One is the line labelled geothermal cogeneration. This represents the price/GJ that an electricity station owner would need to get for his steam to remain revenue-neutral offsetting his lost

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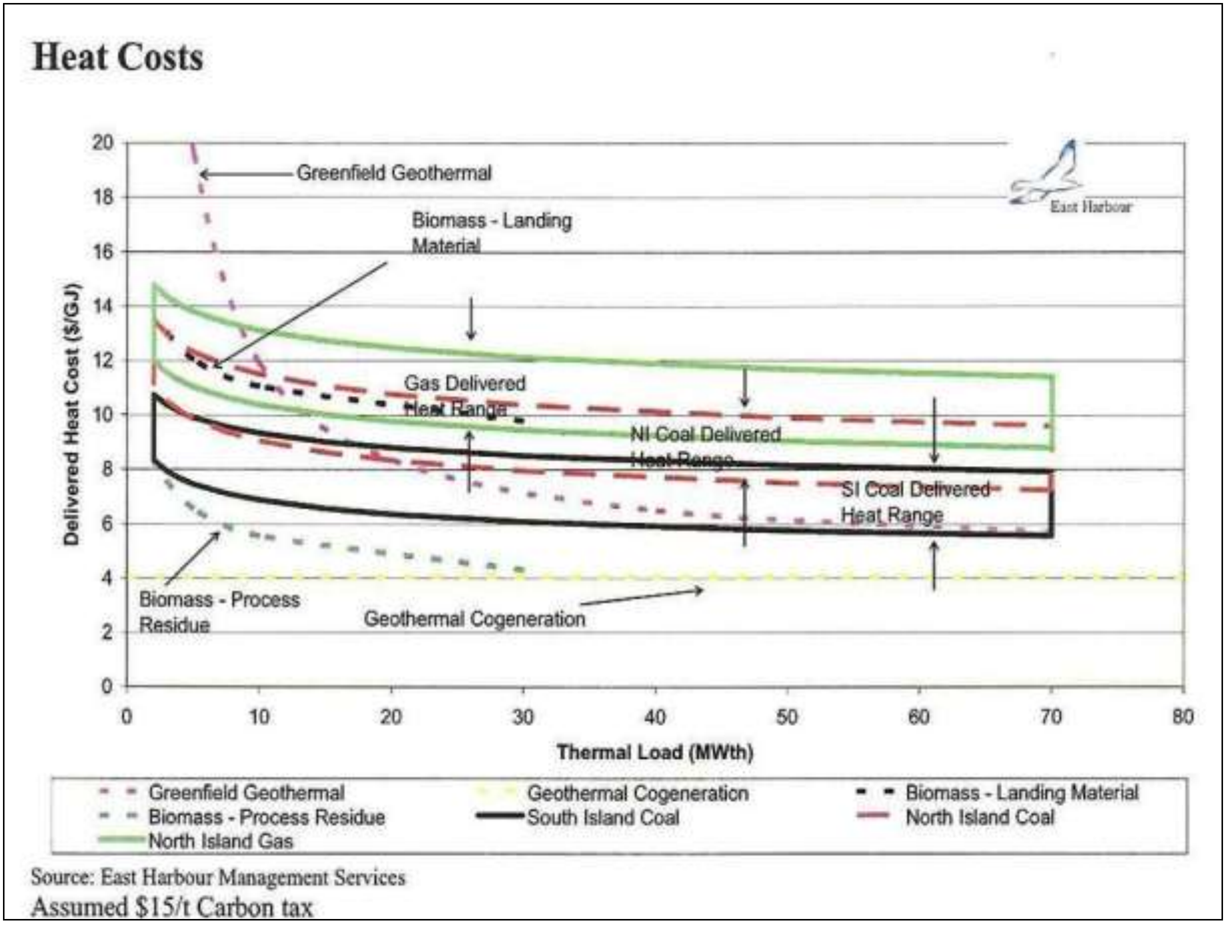
[5] For the generic cases electricity prices used are the variable component of average prices for New Zealand. In the case of the school a commercial electricity tariff was used. Analysis was performed with a 30% tax rate and is on a post tax real basis.

electricity generation. This price should be able to compete with almost any other heat plant. If there is no existing electricity plant on a field then the Greenfield Geothermal supply line applies. Actual costs will be field-specific, but it is likely that there will be a requirement for a critical size of plant before geothermal supply can compete, possible in the 10 – 20 MW range. In practice, the costs are based on high enthalpy geothermal fields and so they represent the lower estimate of costs.



Source: East Harbour Management Services

Assumed $15/t Carbon tax

Figure 8 – Comparative costs of industrial scale heating types

Source: "Assessment of Possible Renewable Energy Targets – Direct Use: Geothermal" (EECA, 2007)

Thain et al (2006) discussed the costs of geothermal energy when used in timber drying kilns. The report notes that where it is available, geothermal steam can be used as the heating source in drying kilns usually at half the cost of other fuel sources. Further details are presented in Appendix 2.

4.4 Electricity Generation

Geothermal electricity production costs consist of two major components: the initial capital costs (including pre-resource development activities) and operation and maintenance costs during electricity production (GEA – USA, 2005). Appendix 3 presents several Case Studies indicating a range of development and capital costs.

4.4.1 Capital Costs

- **Cost to Develop the Resource**

Costs include all the generating and steamfield plant cost, lease acquisition, permitting, exploration, confirmation, site development and other associated costs such as transmission. Capital costs are site and resource specific. The cost of a specific project is significantly influenced by the resource temperature, depth, chemistry, and permeability.

The resource temperature determines the conversion technology (steam -vs. - binary) as well as the technical efficiency of the generating system.

The project size determines the economies of scale and the project type (i.e. greenfield or expansion) will provide the basis for the extent of exploration, confirmation and infrastructure or construction work needed to build the project.

The typical capital costs of a geothermal electricity plant (whether a steam flash or a binary electricity plant) are identified in **Figure 9**.

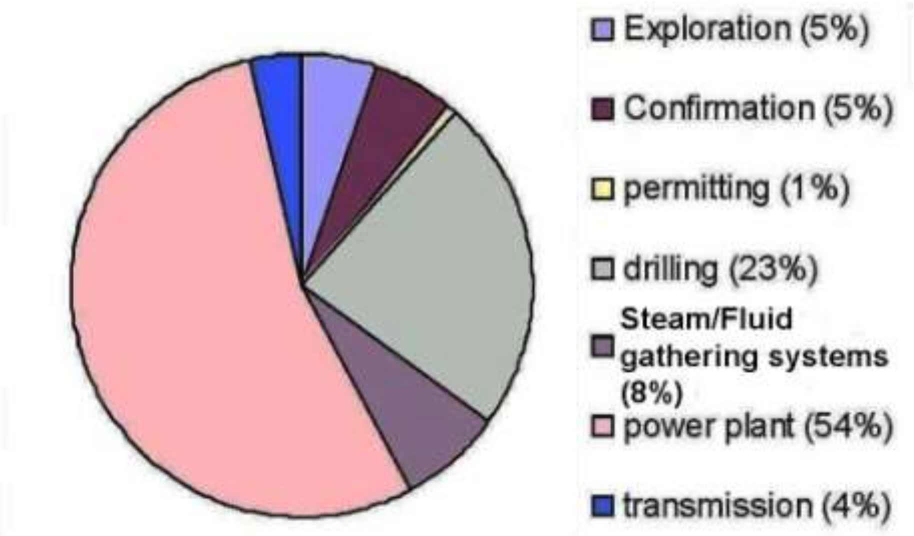


Figure 9 – Typical cost breakdown of a geothermal electricity generation project

The GEA-USA study (2005) broke down the cost components of the initial development phases. The cost components of binary electricity plants from 2005 data are discussed below.

Exploration – Costs associated with the initial development phase to locate a geothermal resource that will provide energy to run a binary electricity plant are shown in **Table 10** .

Sources	Costs (NZ$/kW)
Nielson (1989)	150
EPRI (1996)	180
EPRI (1997)	145-190
GeothermEx (2004)	130-200

Table 10 – Typical exploration costs for binary projects
Source: GEA (2005)

The typical fluid gathering costs for binary electricity projects are shown in **Table 11.**

Sources	Costs (NZ$/kW)
Entingh and McLarty (1997)	140 (field piping: 60 + production pumps: 80)
EPRI (1997)	40
Entingh and McVeigh (2003)	5% of total capital cost
Other US developers	360-570

Table 11 – Fluid gathering costs for binary projects
Source: GEA (2005)

New Zealand-specific estimates on the costs of steam field development for various plant types were developed in SKM, (2009) and are in the range $650 – $790 /kW, particularly for higher temperature resources. Some of the data from the SKM study has been included in Appendix 3.

Transmission – The typical transmission line costs for binary electricity projects are shown in **Table 12**.

Sources	Transmission line cost (In NZ$/km)
Sifford & Beale (1991)	320,000 (58% labour cost & 42% material cost)
Lesser (1993)	301,000 (61% labour cost & 39% material cost)
GeothermEx (2004)	240,000
Developer's interview	310,000 – 400,000

Table 12 – Typical costs of transmission lines for binary plant projects
Source: GEA (2005)

These costs are compared to estimates by SKM (2009) of approximately $4 million for a 20 km heavy duty double circuit 220 kV transmission line (approx $200,000/km). The associated transformer is an additional $2 million and $3 million for 20 and 50 MW developments respectively. Switchyard, substation, consenting and easement costs are not included in these estimates.

The SKM (2009) study (see Appendix 3) puts the *Establishment costs* between $3 million (for a 20 MW development) to $3.5 million (for a 50 MW development).

Commercial Costs - The SKM (2009) study also notes the often overlooked commercial costs associated with developments. These include financing charges (including establishment costs and interest), interest before and during construction, corporate overhead, legal costs, insurances, related costs.

- **Plant Capital Costs**

A World Bank (2007) study documents the capital costs for a 200kW and 20MW binary plant development (**Table 43,** Appendix 3). The study illustrated the relatively high costs of smaller capacity plants and the economies of scale for the binary plant showed that the generation cost becomes cheaper as the unit size increases.

From the GEA – USA (2005) study the typical capital costs of binary electricity generating plants are shown in **Table 13**.

Author/Source	Technology	Capital Cost (NZ$/kW)	Capital Cost range (NZ$/kW)	Inflation adjusted capital costs (NZ$/kW)
Entingh & McVeigh (2003)	Binary	3,430	2,430-3,860	3,520
CEC, RRDR (2003)	Binary	3,250		3.340
CEC, CCCCSEGT (2003)	Binary	3,280		3,360
Owens (2002)	Binary	3,020		3,170
Kutscher (2000)	Binary	3,000		3,290
EPRI (1997)	Binary	3,020		3,550
Average capital cost (Binary)		3,160	2,430-3,860	3,370

Table 13 – Capital costs of binary electricity plant technologies

Source: GEA (2005)

Montana (2009) concluded that given development costs and a specific electricity price, the payback period for their binary plant was 5 years. The analysis indicated a binary plant unit cost of $3,000/kW. The GEA (2005) study also has typical capital costs around $3,000/kW (see **Table 48,** Appendix 3). Kutscher (2001) and Rafferty (2000) also derive a similar unit cost but it is noted that they do not include the resource development costs as identified in Section 4.4.1. Rafferty's study confirms the economies of scale with a 1 MW plant incurring a capital cost of around $2,549 compared to a 100 kW plant incurring costs of $4,140. Resource temperature is also seen to impact on the capital cost with the former resource temperature at 140°C and the latter at 99°C.

EHMS (2008) showed the capital cost for only the electricity generating plant to be $2,700/kW for both a 20 and 50MW development. For plant sizes less than 1MW in capacity, this cost may double. Overall, because binary plant comes in small units there will be little economies of scale in going from say 20MW to 50MW.

Lower temperature resources developed for electricity generation will likely use binary cycle plant. Fluid/steamfield costs, however, will have to be borne by the project and are field specific but will add from NZ$600 to NZ$2,000/kW to the binary cycle generating plant costs.

4.4.2 Operational and Maintenance Costs

Post construction, the O&M costs for both electricity generating plant and fluid gathering systems includes all expenses needed to keep the generating plant system in good working order. They are strongly affected by site and resource characteristics, especially the resource depth and chemistry.

Research shows that the modular design of binary plant facilitates low cost operation and maintenance. The Montana (2009) study indicated annual O&M costs of approximately $35,700 for a 500 kW system equivalent to 1.1c/kWh. The World Bank (2007) study shows 4.3c/kWh for combined fixed and variable O&M costs for a 200 kW binary plant and 2.5 c/kWh for a 20 MW binary plant.

The GEA-USA (2005) study illustrate how O&M costs are broken down into steam, labour, miscellaneous and chemical costs with steam and labour being the most significant (see **Table 50** Appendix 3). Rafferty (2000) indicates annual maintenance costs of $90,000 for a 300 kW plant (see **Table 53**, Appendix 3).

Comprehensive details on plant capital and O&M costs in a New Zealand context come from the SKM (2009) report. Costs have been broken down into generating plant and steam field costs. The total O&M costs for 20 MW and 50 MW plants are shown in **Table 14**.

	20 MW			**50 MW**		
	NZ$ M/y	**NZ$/kWh**	**NZ$/kWe**	**NZ$ M/y**	**NZ$/kWh**	**NZ$/kWe**
Steamfield	0.60	0.004	30	1.50	0.004	30
Generating Plant	1.60	0.010	80	2.40	0.006	50
Total	2.20	0.014	110	3.90	0.010	80

Table 14 – Total geothermal plant O&M costs

These costs are broken down further and presented in **Table 58**, Appendix 3.

The SKM Report (2009) also notes there are additional planned maintenance costs for regular major overhauls, including statutory inspections and they are estimated at NZ$150,000/overhaul for a 20 MW plant and NZ$200,000/overhaul for a 50 MW plant. The frequency of such inspections varies from one plant to another but is generally conducted once every three years.

The report ranks a number of power cycle options in terms of their thermal and financial performance noting that the advantage enjoyed by the binary plant options in terms of thermal performance at low temperature is not translated into a financial advantage.

A 2008 NZGA study indicates that O&M costs are a function of plant size and the cost of makeup well drilling. A 10 MW plant will need the same number of people to operate as a 30 MW plant. The study projected that the specific cost for a binary plant will be about $2,825/kW since its associated field will add about $525 to $1,750/kW. The study also approximated that:

a. For station size >50 MW, the O&M will be equal to $83/kW/year
b. For station size <50 MW, the O&M = $(157 - 3.25P + 0.035P2)/kW/year, where P = station size (MW)

Note that for very small scale developments the O&M costs on a c/kWh basis may increase significantly. They still require a minimum labour input that must be spread over fewer kWh.

4.4.3 Comparison with other Technologies

Geothermal electricity generation compares favourably with a range of other renewable and non-renewable options. Sector experts indicate that geothermal is within the range of other electricity choices when the costs over the lifetime of a plant are considered.

Work undertaken by Concept Consulting (2010) on behalf of Contact Energy reviewed and compared a number of published estimates on the cost of developing new generation projects.

Estimates from the Ministry of Economic Development, the Electricity Commission[6], the New Zealand Government, Meridian Energy and Concept Consulting were considered.

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[6] In November 2010, the Electricity Authority took over most of the Electricity Commission’s responsibilities.

A number of figures from the Concept report are presented to illustrate the report's findings (see **Figure 14** – **Figure 18** in Appendix 3). They overwhelmingly confirm the cost competitiveness of geothermal when compared with wind, gas, coal and hydro. The addition of a carbon charge enhances this competitiveness further.

For conventional geothermal projects that appear feasible production costs are generally estimated to be in the range 6-9 ¢/kWh (Concept Consulting, 2010 and Contact Energy, 2009), making it one of the cheaper energy options. The Concept Report indicates that given current coal technology and a strong likelihood of a carbon charge, break-even prices for greenfield large scale coal fired electricity generating stations are around 7-9 c/kWh or above, and as high as 12 c/kWh depending on the application of a carbon charge. This cost will of course be influenced by movements in fuel costs. Estimates for gas fired electricity generating stations sit around the 7.5–10 c/kWh level with some estimates putting it at around 9–13.5 c/kWh (Contact Energy, 2009). According to the Concept work, wind is sitting at around 9–11 c/kWh. This is further confirmed in Contact Energy information. Hydro, is sitting around 8-11c/kWh.

NZGA and SKM in their revised 2009 study gave a range of prices depending upon the nature of the geothermal field and electricity output. For high temperature fields and a 50MW plant the costs are in the 7 to 11 c/kWh range, for low temperature fields and a 20 MW plant the costs are 10 to 14.5 c/kWh.

5.0 KNOWLEDGE GAPS AND BARRIERS

The use of geothermal energy offers significant potential for the provision of heat and cooling and electricity generation. The relatively low uptake of some technologies generally, and specifically in the case of GHP's in New Zealand, is a result of a range of barriers one of which is the costs associated with the initial development of the resource and the associated technology.

Other barriers to development include limited access to information, low levels of customer awareness and understanding, lack of skilled technology specific experts and installers; issues around ownership and access to geothermal resources, the process to secure and maintain resource consents and other regulatory barriers. These barriers are often cited internationally and are not necessarily unique to New Zealand. Barriers that are more specific to New Zealand and may prove more difficult to overcome include the relatively low population density (limited opportunity therefore for bulk price purchasing to pass on to consumers), New Zealand's relatively mild climate (short heating and cooling seasons) and the lower level of comfort demanded by New Zealand householders relative to some overseas countries.

A 2010 Ministry of Economic Development report presented details on the barriers to the development and use of geothermal resources in New Zealand (direct and indirect geothermal), particularly for emerging technologies. The report discusses ways to reduce the impact of these barriers. The report looks at geothermal energy across a range of technologies: from ground source heat pumps through conventional hydrothermal, to engineered geothermal systems (EGS). The report considers the use of geothermal energy for both electricity generation and direct heat use. The report discusses barriers at each of the following phases: resource study – prospecting, initial site exploration, drilling and reservoir modeling, consenting and operating, and decommissioning.

In its response to the MED report, the Energy Efficiency and Conservation Authority (EECA) noted the need for strategic planning in relation to increasing the use of geothermal energy in New Zealand and bringing the technologies to the market place, the need for more information and greater awareness amongst potential customers, the significant regulatory barriers and an ageing pool of geothermal engineers. EECA also notes New Zealand's potential to build on current knowledge and to exploit it in an international market. Of particular note is the comment that EECA believes "*that on-site, direct use and ground-source heat pump (GSHP) based utilisation of geothermal resources should also be a priority (alongside the development of large scale geothermal to electricity plant).*"

5.1 Geothermal heat pumps (GHPs)

According to literature studies, although GHP technology is already commercially mature its uptake and widespread acceptance in the USA, Europe, New Zealand and other countries has been slow among architectural and engineering firms, mechanical design teams, developers, and building owner/operators .

It is projected that with wider operation of GHP systems, capital costs will lower making it competitive with other heating system alternatives. GHP will then have lower life cycle costs, higher incremental rates of return, and shorter payback periods consequently with more widespread use in the domestic and commercial sectors (buildings, schools, retail buildings, etc.).

Overseas, the GHP system industry is heavily promoted and marketed. Efforts are being made to address a number of constraints and so achieve better economic results and commercial growth for GHP systems in New Zealand.

5.2 Other Direct Heat Uses

The direct use of low enthalpy geothermal heat is limited by a lack of knowledge, experience and skills. Potential investors are unaware of the many direct uses associated with geothermal energy compared to electricity generation. There appears to be a tendency for developers to assume electricity generation is the best utilisation of the resource, where in fact direct heat use may be a better option.

It is through a lack of understanding that potential geothermal use opportunities across New Zealand are going unnoticed. Opportunities for use are potentially more widespread across the country and not, as many believe, just in the known geothermal locations such as Rotorua.

5.3 Electricity Generation

MED's Energy Outlook publication forecasts that geothermal energy is one of the cheapest sources of new electricity generation over the next 20 years. Geothermal capacity from traditional hydrothermal sources could increase to nearly 1,500 MW by 2025 and at current prices this indicates a potential contribution of nearly $1 billion per annum from electricity generated from geothermal energy. The March 2011 quarter edition of the New Zealand Energy Quarterly showed geothermal generation made up just over 13 % of total electricity generation in New Zealand.

Generation plants in New Zealand are a mix of flash and binary electricity plants. The increased use of standalone low enthalpy binary plants could increase the potential geothermal resource for the generation of electricity in New Zealand. That said, as this report has illustrated, the typically small plant size for low enthalpy resources tends to erode the economies of scale making it a more expensive option for standalone electricity generation than for large scale high temperature resources (over 100 MW). The cost of consenting and exploration could be similar to that of a larger plant.

Further, despite being a well established technology, binary electricity plants are still considered new commercial technology and less well known among project financiers. The technological economic information on these plants is limited and not that readily available or accessible to potential investors.

6.0 OTHER CONSIDERATIONS – THE COST POSITIVES OF GEOTHERMAL

In many situations geothermal energy has the potential to meet demand for a range of large and small scale uses at competitive prices. Geothermal has additional attractive attributes not least of which are its inherent flexibility, availability nationwide (at least for heatpumps), environmental benefits (including being carbon-low) and that it is an indigenous/domestic resource.

As a renewable resource, producing low carbon emissions, geothermal is by default favoured by Government policies the world over and the economics will continue to improve with the application of carbon costs across economies.

Resources are widespread and varied as are the means to access them. Significant, untapped and yet-to-be realized resource opportunities exist across New Zealand.

7.0 DISCUSSION

Geothermal resources are numerous in scale and grade. With respect to their use, there are a range of options; some of which are financially attractive now and some that will become so.

This report has presented some information on the direct and indirect use of geothermal resources noting in particular the economics related to the development of low temperature geothermal applications.

New Zealand’s geothermal resources are to a large extent an undiscovered opportunity. Contrary to the general understanding, geothermal resources can be just below the ground making them much more widespread and accessible than people generally understand.

Geothermal resources are used in a wide range of applications from electricity generation to space and water heating in schools, hotels, greenhouse applications, as industrial heat and in homes throughout New Zealand.

The biggest obstacle to their development is the lack of understanding of the ease and the flexibility with which they can be used. In many situations (both large and small applications) engineering consultants and developers alike lack knowledge about the nature of the resource and its advantages to the extent that it is often overlooked at the planning stage.

Irrespective of the scale of the application, for a geothermal resource, the costs are heavily weighted towards early expenditure rather than the ongoing costs of keeping the technology/development running. Considered over the lifetime of the plant or technology, costs become increasingly favourable compared to other conventional alternatives.

With regards to electricity generation the New Zealand story is one of outstanding success. According to the March 2011 quarter of the New Zealand Energy Quarterly, geothermal accounted for just over 13 % of total electricity generation. Key market players have a number of developments in the pipeline which are set to increase generation further. These developers are utilising higher temperature resource opportunities but lower enthalpy options are expected to eventually be required.

Direct use opportunities at the industrial and commercial scale grow albeit slowly. New Zealand has some excellent examples of direct use at the commercial and industrial level including timber drying, heating for aquaculture, horticulture and for use in the diary sector with attractive development economics.

With respect to the use of geothermal at the domestic level, utilization is low and uptake suffers from a lack of awareness about the resource and currently unattractive economics. Uptake levels remain low and so too does the potential for cost reductions associated with bulk buying. Air source heat pumps have in recent times seen significant growth in the residential marketplace. With effective marketing and supporting finance programmes many consumers have opted for this technology as a space heating solution. Research indicates that GHP’s are competitive with the air-to-air heat pump although initial costs are a limiting factor. Typically a GHP makes a good investment in a newly constructed home. Advantages over air source heat pumps for space heating have been noted in particular performance (especially in colder climates) and running costs. GHP’s are suited to heating water as well as space heating.

Overseas, the increased uptake and commercialization of binary electricity plant and geothermal heat pump technologies have resulted in lower capital costs and competition with alternative energy options. It is projected that with increased commercialization and marketing increased growth will be observed leading to further life cycle cost (LCC) savings, and shorter payback periods. These factors alone will ensure that binary plants and geothermal heat pump systems are the technology of choice in countries like USA, Korea, Japan, and China where their technology and utilization is substantially mature.

In New Zealand, both the binary electricity plants and geothermal heat pump markets are still developing. They tend to be a more expensive investment for which increased uptake is expected to bring lower costs making them more competitive with other options later in time.

In terms of direct heating options, these are attractive in the known hot and warm spring areas at a range of development scales from domestic to larger scale. What is becoming clearer is that there are direct heat options outside the traditional areas by taking advantage of the earth’s natural thermal gradient. These latter options will require a critical size for a development to be commercial.

The growth of direct use of geothermal resources can be encouraged with promotion of the positives, explanation of the resources and clear value messages. The heat use potential is significant.

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APPENDIX 1 - TECHNOLOGICAL ECONOMIC CASE STUDIES – DIRECT USE - GEOTHERMAL HEAT PUMPS

A1.1 Overseas Examples

A1.1.1 China (NREL, 2009)

Example focus – a simple life-cycle (LCC) analysis comparing a GHP system and natural gas powered AC.

The NREL (2009) study covered the investment and operational costs of heating systems in Beijing's International Mansions at the Jiaheli Garden (**Table 15**). The total investment cost for a GHP system is slightly lower than air conditioning or boiler heating (fueled by natural gas).

Particulars	GHP system		NG-Powered Central AC and Furnace	
	Unit price (NZ$/m^2)	Total (NZ$M)	Unit price (NZ$/m^2)	Total (NZ$M)
Equipment cost	39	2.7	37.8	2.7
Engineering cost	24	1.6	25.4	1.8
Total investment	63	4.4	63.2	4.4
Operational cost heating	2.3	0.26	5.2	0.5
Operational cost cooling	1.4	0.13	2.5	0.21
Cost of building space required for equipment	431	.07	431	0.16

Table 15 – Investment and operational costs - Beijing heating systems

A simple life-cycle (LCC) analysis made on the two systems showed that the GHP system will have lower life cycle cost (LCC) against the natural gas powered AC. The study concluded that investment cost for GHP system can be recovered in 10 years (**Table 16**).

Particulars	Heating system (In NZ$)	
	GHP system	Natural Gas A/C and furnace
Equipment investment cost	4,357,140	4,428,570
Cost of building space for equipment	64,725	151,030
Total investment cost	4,421,865	4,579,600
Life (years)	15	15
Operational cost of heating	259,080	455,670
Operational cost of cooling	129,110	215,750
Total cost of delivered heat/cold (NZ$/yr)	388,190	671,420
Annual maintenance (1% of capital cost)	44,220	45,800
Annual insurance (0.34% of capital cost)	15,030	15,570
Annual property tax (0.15% of capital cost)	6,630	6,870
NPV	9,142,730	12,265,060
Rank	1	2

Table 16 – LCC analysis for China - Home heating options

A1.1.2 South Korea (Rhee, 2000)

Example focus – LCC of heating technology alternatives; building energy performance simulation.

The study by Rhee (2009) involved a typical 18-story apartment building with 72 household units in Asan City, Korea.

The energy performance of the building was simulated through a computer program ("Energyplus'') and the result was compared with the actual consumption data. Sustainable building technologies were then applied to the building and the energy performances were analysed. The energy consumption data were then converted to CO_2 emissions data by using carbon emission factor of various fuel resources. Afterwards, life cycle cost (LCC) analyses were conducted considering energy cost and environmental cost. The characteristics of sustainable technologies in South Koreas are shown in **Table 17**.

Technology	Applied Location	Energy Serve	Type/Size
1. Geothermal	Underground	Heating/Cooling	Vertical closed circuit type heat pump, 100RT each building
2. Exterior insulation	Exterior wall	Heating/Cooling	THK200mm dry construction type
3. Double envelope system	South window	Heating/Cooling Ventilation	Box-shape double envelope, glazing U-value: 2W/m^{2}K
4. Radiant floor heating/cooling	Existing floor heating coil	Heating Hot water	Refrigerator capacity: 3.6RT/house, COP 3.0
5. Photovoltaic	Roof	Electricity	144 panels (1,584 mm*787mm, 170W each), total area of array: 180m^2
6. Solar thermal	Balcony guard rail (Evacuated tube)	Heating/Cooling	40 houses in upper 10 floors (~18F), 12 m^2 in each house, average radiation: 3,500kcal/m^2.day

Table 17 – Characteristics of heating technologies in Korea

Negative values (-) indicate the reduction of energy consumption when a technology is applied to the building. The increase of electricity consumption in geothermal, solar thermal and double envelope is due to the increased fan and pump operation for the technologies.

The study showed that higher energy savings can be achieved using a geothermal system, followed by a double envelope system, and the other systems. It also indicated that a geothermal system has the best performance in life cycle cost (LCC) saving, followed by double envelope, and then the other systems (**Table 18**).

Particulars	Geothermal	Double envelope	Solar thermal	Exterior insulation	Radiant heating/ cooling	Photovoltaic
Initial cost	-1.23	-0.32	-0.37	-0.28	-0.02	-0.27
Financial incentive	0.78	-	0.19	-	-	0.14
Sub-total	-0.45	-0.32	-0.18	-0.28	-0.02	-0.13
O&M	0.06	-0.21	-0.26	0.01	0.17	-0.03
Energy cost	3.68	1.78	0.96	0.78	0.09	0.03
CO_2 right price	0.47	0.22	0.14	0.10	-	0.01
Sub-total	4.11	1.79	0.84	0.89	0.26	0.01
Total savings	3.66	1.47	0.66	0.61	0.24	-0.12
Rank	1	2	3	4	5	6

Table 18 – LCC analysis of heating technologies (in NZ$M)

Note: 1 won = NZ$0.0012

A1.1.3 Sweden (Lind, 2009)

Example focus – Swedish development and testing of various designs of heat pumps for district heating, including those for private homes.

The Lind (2009) Report addresses the Swedish experience on ground source heat pump technology, which is now one of the most popular types of heating installation for smaller residential buildings in that country.

The development of heat pumps was a result of the oil crisis in the 1970s, when measures were considered to reduce oil demand for heating and increase use of domestic fuels, and research funds were provided by the government.

The projects include the development and testing of various designs of heat pumps for district heating, including those for private homes using well-based designs for ground-source heat pumps. Several public agencies were active supporters of the new technology and this provided the impetus for the successful research and development of heat pumps in Sweden.

Initially, government subsidies were available for heat pump installations and they were credited for the accelerated use of heat pumps for residential and district heating purposes. Later on the subsidies were withdrawn, thereby slowing down the increase in the heat pump market.

NUTEK (the then Swedish National Board for Industrial and Technical Development) also introduced a heat pump technology competition in the 1980s. This scheme focused on ground source heat pumps and increased public awareness and acceptance of this technology. In the 2000s, the government introduced a subsidy for phasing out of oil boilers and this also provided increases in ground source heat pumps installations.

Cost of GSHP[7]

A ground source heat pump has a high installation cost in Sweden (about $3,860 to $15,440/unit). Its running cost, however, is low and they consume less electricity than conventional heating (1 unit of electricity to move 3 or 4 more units of heating). It needs little maintenance due to relatively few moving parts and those parts are usually covered inside a building. It is durable, highly reliable, its borehole carries warranties of 30-50 years and its service life is about 15-20 years.

The components of the capital costs of a GSHP installation are: heat source, vertical or horizontal ground loops (35-40%), heat pump (40%), and installation (20-25%). A GSHP costing about $28,950 to install and supplying a load of 24,000 kWh/yr, can provide fuel savings of about $2,900/yr. This will translate to a payback of about 10 years, which is better than most renewable technologies in Sweden.

It is noted that from January 26 2006 to 31 December 2010, there is special support for owners of single family dwellings, multi-dwelling buildings and other housing premises to convert from direct electric heating to district heating or individual heating systems using heat pumps, solar heating and biofuels. The main catalysts for the increased use of GHP

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[7] Originally in Swedish Kroner (SEK) and converted to NZ $ at 2010 level (1 SEK = NZ$0.193)

installations were the government subsidies and funding for their adoption as heating appliances in Sweden.

A1.1.4 USA

a. *Rafferty -Heat Spring Energy (2008)*

Example focus – Comparative heating costs.

Rafferty (2008) showed that the comparative costs of heating using GSHP and other methods depend on local rates for electricity and other fuels, the efficiency of the device, the type of fuel used and the cost of the fuel.

The commonly used heating fuels/systems are:

1) Fuel oil
2) Propane
3) Natural gas
4) Electric Resistance
5) Air-Source Heat Pump (ASHP)
6) Geothermal Heat Pump (GHP)

The results based on different cases of annual home heating requirements show that GHP offers the lowest annual space heating costs for all fuel technologies (**Table 19**).

Heating technology	**Costs for annual heating requirement (In NZ$)**							
	Case 1	**Case 2**	**Case 3**	**Case 4**	**Case 5**	**Case 6**	**Case 7**	**Rank**
GHP	740	630	510	430	330	240	160	1
ASHP	1,685	1,370	1,100	810	585	430	260	2
Nat gas	1,410	1,240	1,170	870	785	630	410	3
Propane	2,730	2,390	2,240	1,870	1,500	1,210	800	4
Fuel Oil	2,770	2,430	2,270	1,900	1,510	1,230	810	5

Table 19 – Annual space heating costs

The study also compared the energy costs for GHP and conventional HVAC by building and ground-loop types (**Table 20**). The results show that GHP technology will have the highest savings in energy operating costs when installed in retails shops (about 39%) and then in schools (36%). GHP technology will also attain the highest savings (47%) when the ground loop type is installed in horizontal sites.

Particulars	**Building energy costs, (NZ$/m^2/yr)**		
	GHP	**Conventional HVAC**	**Savings**
Weighted Average of:			
Building Type			
All Sites and References	11.4	16.0	29%
Schools	8.4	13.1	36%
Office Buildings	14.1	19.9	29%
Retail	8.3	13.6	39%
Retirement	13.6	19.0	26%
Prisons	17.0	1.7	2%
Gas Station/Convenience Store	128.4	14.7	26%
Ground Loop Type			

Particulars	Building energy costs, (NZ$/m^2/yr)		
Horizontal Sites	6.7	12.4	47%
Vertical Sites	11.7	16.1	27%
Groundwater Sites	11.6	15.0	23%

Table 20 – Energy costs by building and ground-loop type

b. Chiasson studies, Geo-Heat Centre

Examples focus - Three studies following including a school, an LCC comparison of a heat pumps (air and ground source); and greenhouse heating.

1) Lapwai School, Indiana (2006) - The Chiasson (2006) study involved a life-cycle cost analysis of net present value (NPV) of 50-year life-cycle cost and a simple payback approach comparing the HVAC system alternatives Life-cycle costs included capital costs (or initial costs), annual costs (including operating and maintenance costs), and periodic costs (such as replacement costs). The capital cost and energy savings of the GHP system were used to estimate a simple payback period.

Assumptions:

- Annual energy cost escalation rate = 2%
- Annual maintenance cost escalation rate = 2%
- Discount rate = 8%
- Project life = 50 years

The comparisons for HVAC alternatives at Lapwai School are summarized in **Table 21**.

HVAC System	Total Capital cost (NZ$M)	Annual Costs (NZ$)		Periodic Costs (NZ$)	Simple Payback (yrs)	NPV of 50-yr Life-Cycle Cost (NZ$M)
		Energy	Maint.			
1. Rooftops with propane heat and DX cooling)	0.740	37,140	5,000	78,570 (@ Year 17)	-	1.40
2. Geothermal heat pump (open-loop wells)	0.905	11,570	6,710	35,570 (@ Year 20)	9.3	1.10

Table 21 – Comparison of HVAC alternatives for Lapwai School

The life-cycle cost of the GHP system's (NZ$1.10M) is lower than the conventional alternative, propane (NZ$1.40M). Based on the "base case" assumptions, the simple payback period of the GHP systems is estimated to be about 7 years.

A sensitivity analysis was then conducted on the payback period to quantify uncertainty in the GHP system cost estimates. Cost items of the GHP system were varied from -20% to +20% of the base case. The results of the sensitivity analysis are shown in **Figure 10**.

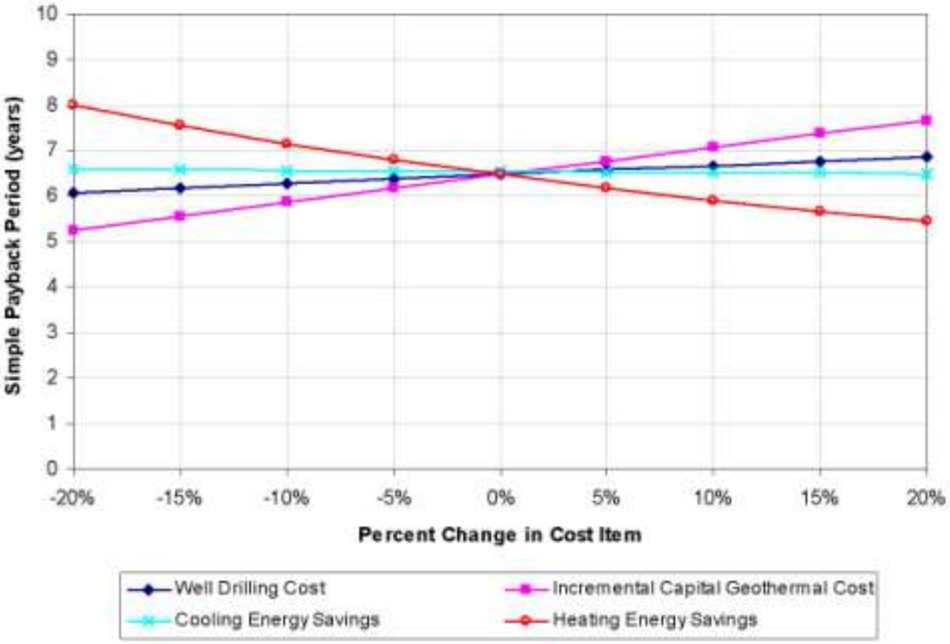


Figure 10 – Sensitivity analysis for GHP system (simple payback period)

The study showed that the most sensitive cost items of the GHP system are the heating energy savings and the incremental GHP system capital costs. The sensitivity of the simple payback period to well drilling cost is less significant and almost insensitive to the cooling energy savings due to the low number of cooling hours.

A 20% change in the heating energy savings or the GHP system incremental capital cost will shorten the payback period by about 1.5 years. A 20% change in the well drilling cost will shorten the payback period by about 6 months.

2) Winnebago, Nebraska - The LCC analysis for Heating Ventilation Air Conditioning (HVAC) systems made in 2006 by Chiasson considered the following:

- Rooftop units with gas heat and direct expansion (DX) cooling (air-cooled condensers)
- Air-source heat pumps
- Geothermal heat pumps (GHPs) approach.

The results are shown in **Table 22**.

HVAC system	Capital cost (NZ$)	Annual costs (NZ$)		Periodic costs (NZ$)	NPV of 30-yr LCC (NZ$)	Rank
		Energy	Maintenance			
1. Geothermal heat pumps (GHP)	230,000	5,570	2,710	42,860 (@ Year 20)	351,430	1
2. Rooftop gas heat and DX cooling	164,285	11,710	6,430	57,140 (@ Year 17)	427,140	2
3. Air-source heat pumps (ASHP)	200,000	9,710	5,860	NZ$71,430 (@ Year 17)	431,430	3

Table 22 – LCC analyses for HVAC systems

Note: Assumptions: Annual energy escalation rate = 2%, Annual maintenance costs escalation rate = 2%, Discount rate = 8%, Project life – 30 years

The GHP system was found to have the lowest life-cycle cost of NZ$351,000 or about 18% lower than the conventional alternatives. The GHP system is more expensive to install but has considerably lower O&M costs than conventional alternatives.

In terms of simple annual cash flows, the study estimated that the GHP system has a payback period of 7 years and 4 years as compared with rooftop gas heat and DX cooling and ASHP, respectively. Neglecting annual maintenance cost and only considering energy savings, the GHP system can have payback period of 11 years and 7 years as compared with rooftop gas heat and DX cooling and ASHP, respectively.

3) Chiasson, "Greenhouse heating" - The Chiasson (2005) study examined the feasibility of greenhouse heating with geothermal heat pump (GHP) systems. Both closed- and open-loop systems are examined at four locations across the U.S. and a net present value analysis was conducted for a 20-year life-cycle for various GHP base-load fractions.

Open-loop GHP systems show more favourable economics than closed-loop systems. At natural gas costs of about 29¢/m^3 it is feasible to install an open-loop system to handle 25-30% of annual greenhouse heating demands. At the natural gas cost of 43¢/m^3, the feasible annual base-load handled by an open-loop system will increase to 60% and then again to 85% if natural gas cost goes up to 57¢/m^3.

At natural gas prices of about 36¢/m^3, it would not be justifiable to heat any portion of a greenhouse with a closed-loop GHP system unless the ground loop could be installed at very low cost of about NZ$23/m). At these rates, it would only be feasible to install a ground loop capable of handling 15-30% of the total annual heating requirements. At a loop installation cost of NZ$47/m, natural gas prices would have to exceed 70¢/m^3 to justify installing a ground loop to handle 15-30% of the total annual heating requirements.

The study showed heating of greenhouses is feasible with closed-loop GHP systems. It is strongly dependent on the natural gas cost and the ground loop installation cost. It will not be economically feasible to heat any portion of a greenhouse using a closed-loop GHP system unless loop installation costs were as low as NZ$19/m to NZ$23/m and natural gas prices exceeded 43¢/m^3. Open loop systems appear to be quite economically feasible above natural gas rates of about 29 ¢/m^3.

c. *Bloomquist (2001)*

Example focus – LCC on several conventional HVAC systems.

The Bloomquist 2001 study on economics of geothermal heat pumps cited a simplified life-cycle cost analyses on the following types of conventional HVAC systems:

1) Geothermal heat pump (Geoexchange),
2) Rooftop DX with gas heating,
3) Air-source heat pump,
4) Water-source (California type) heat pump, with gas boiler and cooling tower
5) Central variable air volume, with chiller, cooling tower and gas perimeter heat, and
6) Four-pipe fan coil unit with electric chiller and gas boiler

The life cycle analyses (LCA) at a discount rate of 6% (without O&M cost escalation and with 2.0% O&M cost escalation) are shown in **Table 23**.

System type	**Cap. cost (NZ\$/m^2)**	**Oprtng. cost (NZ\$/m^2/ yr)**	**Maint. cost (NZ\$/m^2/yr)**	**Simple payback (years)**	**PV of Oprtng. Costs (NZ\$/m^2)**	**PV of Maint. Costs (NZ\$/m^2)**	**Total LCC (NZ\$/ m^2)**	**Rank (Lowest LCC to Highest LCC)**
6.0% Discount Rate, No Operating or Maintenance Cost Escalation, 20-year life								
GHP	143	11.4	1.4	n/a	131	23	297	1
Rooftop DX w/gas	87	18.6	4.3	6	204	54	346	2
ASHP	107	21.4	4.3	3	24	49	399	3
WSHP	190	17.1	2.9	immed.	203	37	431	4
VAV	231	12.9	5.7	immed.	147	43	436	5
Four-Pipe fan coil	244	12.9	5.7	immed.	141	66	450	6
6.0% Discount Rate, 2.0% Operating and Maintenance Cost Escalation, 20-year life								
GHP	143	11.4	1.4	n/a	157	29	329	1
Rooftop DX w/ gas	87	18.6	4.3	6	244	64	396	2
ASHP	107	21.4	4.3	3	290	59	454	3
WSHP	190	17.1	2.9	immed.	243	46	479	4
VAV	231	12.9	5.7	immed.	176	69	476	5
Four-Pipe fan coil	244	12.9	5.7	immed.	169	79	490	6

Table 23 – Life-cycle cost analysis

The capital costs for GHP systems will be lower than water-source heat pumps, central variable air-volume and four-pipe systems. In areas without a well-established infrastructure of GHP drillers and installers, GHP can substantially exceed the NZ\$143/m^2 average.

Even if capital cost increases from NZ\$170 to NZ\$215/m^2, the GHP systems will always be better on a life-cycle cost basis due to the cost benefits derived from O&M savings. Increasing the discount rate reduces the preset value of future GHP operation and maintenance cost benefits while increasing the escalation in operating and maintenance cost increases the present value of those future savings.

Capital and operating costs account for about 90% of the total life-cycle cost of a GHP system, while maintenance represents only 8% of the total. The GHP systems offer the lowest life-cycle cost of all HVAC system types evaluated. The capital cost premium of GHP systems versus ASHP and rooftop units is recovered with the savings in operating and maintenance costs, from 3 to more than 6 years, respectively.

d. Geo-Heat Center in Klamath Falls, Oregon, USA (Higbee, 1998)

Example focus - Analysis of office building heating systems

The Geo-Heat Center in Klamath Falls, Oregon, USA (Higbee, 1998) conducted a simple LCC analysis of the following heating systems that provide heat for a 30,000 ft^2 office building in USA:

i. Electric resistance (ER)
ii. Air-to-air heat pump
iii. Geothermal heat pump (GHP)

The LCC analysis evaluated all the costs and revenues associated with acquisition, construction, and operation over the lifetimes of these heating systems. It did not consider, however, the environmental costs and the carbon costs associated with the fuel used. It also assumed constant fuel prices, materials and maintenance costs.

Assumptions:

1) Annual maintenance cost for both electric resistance and geothermal heat pump = 1% of capital cost
2) Annual maintenance cost for air-to-air heat pump = 1.5% of capital cost
3) Annual insurance for all systems = 0.35% of capital cost
4) Annual property tax for all systems = 0.15% of capital cost
5) At the end of year 10, the compressor for air-to-air heat pump will be replaced and cost will be = 0.42% of capital cost. This will be added to the maintenance cost on the 10th year

The costs details for the heating systems are shown in **Table 24**.

Heating	**Electric Resistance**	**Air-to-Air Heat Pump**	**Geothermal Heat Pump**
Capital cost (NZ$)	226,285	257,140	333,000
Life (y)	15	15	15
Salvage value (NZ$)	0	0	0
Annual electricity requirement (kWh)	263,280	131,840	22,620
Unit cost of electricity (NZ$/kWh)	0.07	0.07	0.07
Electric electricity cost (NZ$)	18,830	9,420	1,615
Annual maintenance (NZ$)	2,260	3,790	3,330
Annual insurance (NZ$)	790	900	1,165
Annual property tax (NZ$)	340	385	500

Table 24 – Heating system cost alternatives

An LCC analysis was conducted for the geothermal heat pump with 15 years lifetime, 8% interest rate compounded annually, and electrical electricity cost of 7¢/kWh. The same LCC analyses were also conducted for electric resistance and air-to-air heat pump (AAHP) systems. A comparison of their LCC is shown in **Table 25**. The GHP system is competitive with AAHP system and much better than the electric resistance system.

Particulars	**Heating System (NZ$)**		
	Air-to-Air Heat Pump	**Geothermal Heat Pump**	**Electric Resistance**
NPV	382,270	390,390	417,090
Rank	1	2	3

Table 25 – LCC analysis of heating systems @ 7¢/kWh

A sensitivity analysis was then conducted to show the effect of increasing the cost of electricity to NZ$0.10/kWh on the LCC for all three systems. The results are shown in **Table 26**.

Particulars	**Heating System (in NZ$)**		
	Geothermal Heat Pump	**Air-to-Air Heat Pump**	**Electric Resistance**

Particulars	Heating System (in NZ$)		
	Geothermal Heat Pump	**Air-to-Air Heat Pump**	**Electric Resistance**
NPV	194,001	203,111	235,973
Rank	1	2	3

Table 26 – LCC analysis of heating systems @ 10¢/kWh

The GHP system has the highest capital cost (NZ$333,000) and the lowest annual electricity requirements for operation (22,620 kWh) among the three heating systems. At initial conditions (i.e. lower electricity cost), the GHP system will not be the first preferred option (it will be the AAHP system. However, if the electric electricity costs increases, the life cycle cost (LCC) of the GHP system will be lower than the other options and it will become more competitive and a better heating option to consider.

A1.2 New Zealand Examples

A1.2.1 BECA heat pump study (2009)

Example focus – comparison of geothermal heat pump and other heating types (residential and commercial example).

The Beca 2009 study compared the geothermal heat pump system as against other heating system alternatives installed in residential healthcare and commercial office buildings.

Residential healthcare building - The capital costs range for space heating/cooling options in a 2 storey residential healthcare building are summarised in **Table 27**.

System Type	Capital cost (NZ$)
Fan Coil Unit System (FCUS)	360,000
Variable Refrigerant Flow (VRF)	410,000
Geothermal Heat Pump (GHP)	480,000

Table 27 – Residential healthcare building - Capital costs

Assumptions:

1) 20 year life for all equipment, except for the outdoor units of the ASHPs
2) ASHP outdoor unit to be replaced by the end of year 15 (at 30% of system capital cost).
3) Maintenance costs = 2.5% of capital for all options.
4) 2% rate of inflation
5) 30% tax rate
6) Costs are in 2008 dollars.

Cost calculations were carried out on an NPV basis and expressed as post tax real. The unit costs for heating and cooling of a residential healthcare building (at 10% Weighted Average Cost of Capital (WACC or the expected return on investment) were calculated and the results are shown in **Table 28**.

Particulars	No CO_2 charge			NZ$25/t CO_2 charge		
	Auckland	Wellington	Christchurch	Auckland	Wellington	Christchurch
GHP	*-480*	*-488*	*-515*	*-482*	*-490*	*-517*
VRF	-425	-430	-461	-427	-432	-464
FCUS	-389	-402	-419	-391	-423	-423

Table 28 – Residential healthcare building - Heating & cooling cost (NPV @NZ$,000)

The GHP system is indicated to offer the lowest energy consumption, but its higher capital cost (NZ$480,000) and the relatively low unit electricity prices for residential healthcare buildings resulted in higher NPVs (higher life cycle cost) than both VRF and FCUS systems. The GHP system is not competitive with the two heating systems options and will need to offer lower costs than the other heating options to be considered as the best alternative.

Commercial office example - The study considered the annual energy of a 900 m^2 floor plate, 3 level commercial office building in Auckland, Wellington and Christchurch to show how the air-source VRF heat pump (ASHP) and geothermal heat pump (GHP) systems can compare in varying climates. The capital costs for the two systems are summarised in **Table 29**.

System Type	Capital cost budget (NZ$)
GHP	$1,000,000
VRF	$860, 000

Table 29 – Commercial office building - Capital costs

Assumptions:

1) 20 year life for all equipment, except for the outdoor units of the ASHPs
2) ASHP outdoor unit to be replaced by the end of year 15 (at 30% of system capital cost).
3) Maintenance costs = 2.5% of capital for all options.

Cost calculations were also done on an NPV basis and expressed as post tax real. The unit costs for heating and cooling of a commercial building (at 10% WACC with or without CO_2 charges are shown in **Table 30**.

Particulars	No CO_2 charge			NZ$25/t CO_2 charge		
	Auckland	Wellington	Christchurch	Auckland	Wellington	Christchurch
GHP	-1,007	-1,010	-1,049	-1,010	-1,013	-1,053
ASHP	-876	-877	-918	-880	-880	-922

Table 30 – Commercial office building - Heating & cooling cost (NPV @NZ$,000)

The GHP system for a commercial building will offer lower energy costs consumption but higher capital cost (NZ$1M) than VRF system (NZ$860,000). These costs, plus the relatively low unit electricity prices in commercial office building will result to higher NPV (higher life cycle cost) for the GHP system as against the ASHP system. The GHP system will not be the favoured option for the commercial building and will also need to have lower costs to be considered as the best alternative.

A1.2.2 Distributed Generation study NZGA-EHMS (2008)

Example focus – GHP's and Distributed Generation; costs of air and ground source heat pumps.

The 2008 study for NZGA by EHMS showed that geothermal heat pumps (GHP) will be uneconomical for small domestic loads unless combined with other domestic loads and with water heating that will give an economy of scale and higher load factor. Larger-scale developments of geothermal heat pumps in schools, retirement homes, buildings, etc. are needed for them to compete with air source heat pumps and other heating options.

It compares the current geothermal heat pump (GHP) and air-sourced heat pump (ASHP) systems available in NZ (**Table 31**). Geothermal heat pumps tend to have a higher capital cost, especially at smaller sizes, as compared with other heating options. However, they have competitive operating costs (electricity costs is minimised by higher coefficient of performance (COP)) and their performance is less affected by the outside temperature as compared with air source heat pumps.

Particulars	**GHP @ heating capacity (kW)**			**Air source HP**
	6 kW	**20 kW**	**726 kW***	**20 kW**
Capital cost (NZ$)	Heat pump - $6-7,500 Ground loop - $2,300 Underfloor/ hot water system - $2,500 Total cost - $12,000	Total cost - $24,000	Total cost - $488,000	Total cost - $19,000
COP	4	5	4.3	3.7

Table 31 – Comparison between GHP and ASHP costs (NPV @NZ$)

Note: COP - Coefficient of Performance

**This size is not available in NZ and the figures are for a Chinese water source heat pump system*

The GHP system at 20kW peak heating capacity has a capital cost of NZ$24,000 and will require 4kW of electric electricity. An ASHP system with the same capacity will cost NZ$19,000 and require 5.5kW of electric electricity. The GHP system will be competitive with the ASHP system at the 20 kW heating capacity level, but will not be an option at the other smaller or higher level applications.

Heating costs from GHPs are competitive with other heating options, especially at larger sizes. Heating costs would be further reduced if load factor is higher or when heat is supplied to a swimming pool.

GHPs are less attractive than pellet burners and air source HP's at an average house load of 6 kW peak heating capacity. For large houses (with water heating, however, GHPs approach the unit cost of ASHPs. Where the price of electricity is high, the better COP of GHP will make it more preferable than all the other options. The generic heating costs for various options are shown in **Table 32**.

Project	**Size**	**Load factor**	**Heating cost**			
			5% WACC*		**10% WACC***	
			No CO_2 cost	**$25/t CO_2 cost**	**No CO_2 cost**	**$25/t CO_2 cost**
	kW	**%**	**c/kWh**	**c/kWh**	**c/kWh**	**c/kWh**
GHP						
Average house	6	10	29	30	40	41
Large house	20	12	16	17	21	22
Commercial	726	29	6	7	8	9

Industrial	726	40	4	5	5	6
School	726	16	8	9	11	12
Blenheim house	18	22	15	16	18	19
Air source HP						
Average house	6	10	14	15	16	17
Large house	20	12	15	16	19	20
Pellet burner						
Average house	6	10	19	19	23	23
Large house	13	12	17	17	20	20
School	1000	16	7	7	8	8
Gas fire						
Average house	6	10	23	24	27	28
Electric resistance heater	6	10	26	27	26	27

Table 32 – Generic heating costs

Note: Includes all capital cost, operating cost, and fuel cost.

For larger commercial loads, economies of scale and the high COP of the GHPs combine to make use of this heating option attractive. The resulting unit cost is below that of a unit of electricity, even without adding the capital cost of the electric heaters

A1.2.3 LCC Analysis - New Zealand

The same LCC analysis conducted by Geo-Heat Center (USA) in the previous section was adopted in the life cycle cost (LCC) analysis of heating systems in New Zealand. There were three sets of data on central heating systems available from the Central Heating New Zealand (2009) costs estimates information sheet (Annex A), the Environment Southland/Nature's Flame (2009) brochure (Annex B), and the Ministry for the Environment (2005) study (Annex C).

The GHP systems were considered under the bigger-sized central heating system category for buildings and other large structures. They are not suitable for comparison with single units or single-detached heating appliances for home applications. The central heating systems are those that are capable of heating an entire home. They heat either water or air which is then used to heat the entire house. For air or geothermal heat, the systems heat a series of ducts in each room, and for water they can use either radiators in each room or pipes built into the floors (underfloor).

The theoretical study was based on a 3 bedroom home with 2 living areas and 1 bathroom, approximately 150 metres of living area (standard house minus garage area). Approximate kW heat demand for the home is 15 kW. The average annual usage consumed is 12,000 kWh. A 30% increase in fuel consumption has been allowed for underfloor systems due to the required longer running periods and downward heat losses). The lifetimes of the heating systems were assumed to be 15 years and the interest rate was set at 5%.

Assumptions:

a. Annual maintenance cost for both electric resistance and geothermal heat pump = 1% of capital cost
b. Annual maintenance cost for air-to-air heat pump = 1.5% of capital cost
c. Annual insurance for all systems = 0.35% of capital cost

d. Annual property tax for all systems = 0.15% of capital cost
e. At the end of year 10, the compressor for air-to-air heat pump will be replaced and cost will be = 0.42% of capital cost. This will be added to the maintenance cost on the 10th year.
f. Initial condition (without CO_2 charges)
g. Carbon charge = NZ$25/t$CO_2$

The results of the LCC analysis are shown in **Table 33**.

Option	1	2	3	4	5	6	7
Fuel/Energy source	**Wood**	**Electricity ASHP**	**Diesel**	**GHP**	**Wood pellets**	**LPG/ Natural gas**	**Coal**
Current conditions, with CO_2 charge	20,544	22,400	31,787	45,708	48,879	57,912	76,774
Rank	1	2	3	4	5	6	7

Table 33 – LCC analysis of domestic central heating options (NPV, $)

Sensitivity analyses were then conducted at 5% and 10% increases in delivered heat cost and CO_2 charges to see possible change in the ranking and the results are shown in **Table 34**. Results show no changes in the preference for GHP system over the other options.

Option	1	2	3	4	5	6	7
Fuel/Energy source	**Wood**	**Electricity ASHP**	**Diesel**	**GHP**	**Wood pellets**	**LPG/ Natural gas**	**Coal**
With 5% increases in delivered heat cost and CO_2 charges	25,662	27,350	36,344	48,098	55,076	72,735	103,051
Rank	1	2	3	4	5	6	7
With 10% increases in delivered heat cost and CO_2 charge	33,393	34,808	43,228	51,710	64,439	95,129	142,749
Rank	1	2	3	4	5	6	7

Table 34 – LCC analysis of domestic central heating options (NPV, $)

Further sensitivity analyses were conducted at 5% and 10% increases in delivered heat cost and CO_2 charges with decreases in the installation costs of the GHP systems. The results are shown in **Table 35**.

Option	GHP-a	GHP-b	GHP-c	GHP-d	GHP-e	GHP-f
Fuel/Energy source	**@ -10% capital cost**	**@ -20% capital cost**	**@ -30% capital cost**	**@ -40% capital cost**	**@ -50% capital cost**	**@ -60% capital cost**
Current conditions, with CO_2 charge	41,772	37,837	33,901	29,966	26,030	22,095
Rank	4	4	4	3	3	2
2. With 5% increases in delivered heat cost and CO_2 charges	44,163	40,227	36,292	32,356	28,421	24,485
Rank	4	4	3	3	3	1
3. With 10% increases in delivered heat cost and CO_2 charge	47,774	43,838	39,903	35,967	32,032	28,096
Rank	4	4	3	3	2	1

Table 35 – LCC analysis of domestic central heating options (NPV, $)

The above sensitivity analysis shows that the GHP system will only be the best option when its capital cost is decreased by as much as 60% (which will be impossible to achieve at current conditions).

Referring back to **Table 34**, it is worth considering the relative differences in price and to consider the value brought by a heating-cooling option that is unobtrusive visually and audibly. Where premiums have been paid for properties because of views or settings, the life cycle premium may be acceptable.

APPENDIX 2 – HEATING OPTIONS

A2.1 Conventional geothermal developments

Example focus – costs associated with traditional geothermal heat options

The 2008 study for NZGA by EHMS illustrate that the exploration and development of geothermal wells involve risks and costs which cannot be fully determined until the well is completed. An existing nearby well(s) can give a fair indication of its quality and performance, especially when good and reliable information is available.

As a ball park figure, domestic and small commercial wells of around 100mm diameter can cost of the order of $110/m, with typical depths (depending on location) being in the range 100 to 500 m for traditional geothermal development areas (e.g. Taupo, Rotorua, Tauranga). Production from these wells is site dependant but is typically enough for the heating needs of several homes and potentially many more. The costs associated with traditional geothermal heat options are shown in **Table 36**.

Application	Capital cost (NZ$ T)	Operating cost ($000)	Unit cost @ 8% WACC (c/kWh)	Unit cost @ 10% WACC (c/kWh)
Average house	9	0.09	15.5	23.2
Large house	14	0.14	10.5	15.4
Hotel	44	0.44	1.6	2.5
School	514	5.14	3.9	5.8

Table 36 – Costs associated with traditional geothermal heat options

The direct use of wells for water and space heating of average to large houses can be considered as an attractive option. Direct heating will also be an option for hotels, schools, and other commercial applications that are located in the thermal regions. Conventional direct heating options are competitive with other heating options, except for average houses where air-source heat pumps are currently preferred.

A2.2 Feasibility study report: Geothermal heat and electricity at Fonterra's Waitoa dairy factory (EHEL, 2009)

Example focus – Low Temperature Geothermal as an alternative to coal.

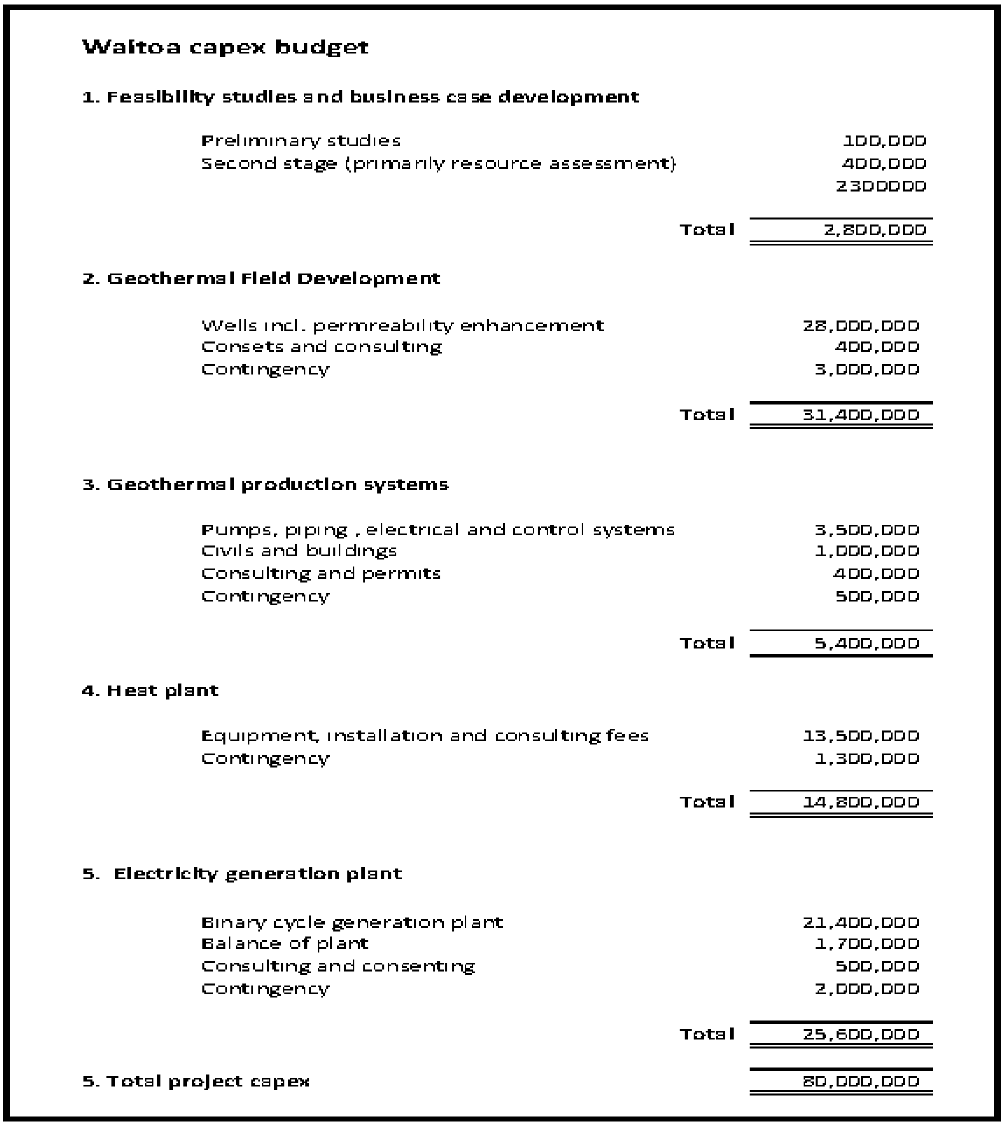
Fonterra's Waitoa milk processing plant is currently supplied with process heat by three coal boilers with a combined capacity of 100 tonnes per hour of steam, and with electricity primarily from the grid. The plant is, however, located in an area with geothermal potential, with surface manifestations to the North, South and East, and above favourable geological conditions for a geothermal resource.

This high level study by East Harbour Energy (2009) presumed at the outset that geothermal heat from such a resource would be economic for process heat supply in conjunction with generation of electricity using binary cycle technology. The study showed that investment in the geothermal systems, and required processing plant modifications should reduce the coal use on the site by more than 90%, while generating up to 8MW of electricity. The investment required for both heat and electricity generation plant is around $80m and this could earn a post tax project return of better than 15% with an NPV around $20m, based on a range of assumptions.

Enhanced geothermal has very low environmental impacts and essentially zero carbon emissions. The project will reduce CO_2 emissions from coal use by around 100,000 tonnes per annum and by a further 20,000 tonnes per annum as a result of the generation of electricity.

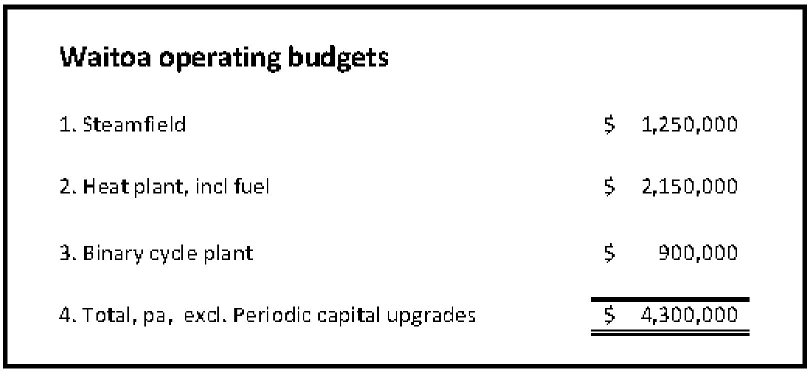
Consenting the project is not expected to be difficult or protracted and risks to Fonterra are low as the geothermal resource will be proven before connection and current energy systems can remain operational or on standby as required.

Table 37 and **Table 38** following illustrate the capex budgets and the operating costs respectively while **Table 39** presents the project financial outcomes.



Waitoa capex budget		
1. Feasibility studies and business case development		
	Preliminary studies	100,000
	Second stage (primarily resource assessment)	400,000
		2300000
	Total	2,800,000
2. Geothermal Field Development		
	Wells incl. permreability enhancement	28,000,000
	Consets and consulting	400,000
	Contingency	3,000,000
	Total	31,400,000
3. Geothermal production systems		
	Pumps, piping , electrical and control systems	3,500,000
	Civils and buildings	1,000,000
	Consulting and permits	400,000
	Contingency	500,000
	Total	5,400,000
4. Heat plant		
	Equipment, installation and consulting fees	13,500,000
	Contingency	1,300,000
	Total	14,800,000
5. Electricity generation plant		
	Binary cycle generation plant	21,400,000
	Balance of plant	1,700,000
	Consulting and consenting	500,000
	Contingency	2,000,000
	Total	25,600,000
5. Total project capex		80,000,000

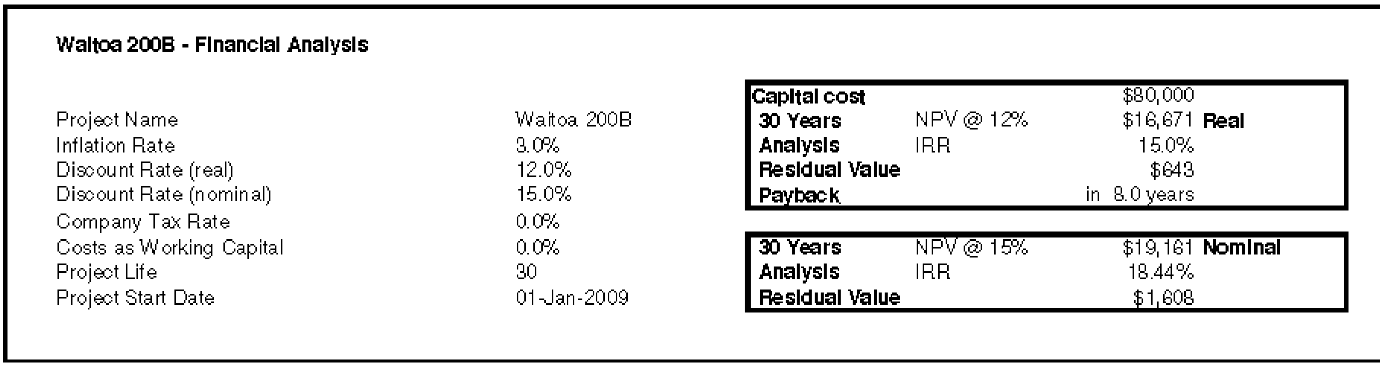
Table 37 – Waitoa Capex Budget



Waitoa operating budgets

1. Steamfield	$ 1,250,000
2. Heat plant, incl fuel	$ 2,150,000
3. Binary cycle plant	$ 900,000
4. Total, pa, excl. Periodic capital upgrades	$ 4,300,000

Table 38 – Waitoa Operating Budget



Waitoa 200B - Financial Analysis

Project Name	Waitoa 200B
Inflation Rate	3.0%
Discount Rate (real)	12.0%
Discount Rate (nominal)	15.0%
Company Tax Rate	0.0%
Costs as Working Capital	0.0%
Project Life	30
Project Start Date	01-Jan-2009

Capital cost		$80,000	
30 Years	NPV @ 12%	$16,671	**Real**
Analysis	IRR	15.0%	
Residual Value		$643	
Payback		in 8.0 years	

30 Years	NPV @ 15%	$19,161	**Nominal**
Analysis	IRR	18.44%	
Residual Value		$1,608	

Table 39 – Waitoa Financial Analysis

The study considered a range of sensitivities with a focus on potential downsides including:

- Capex + 10% and +20%
- Exchange rate US$0.50c
- 10% reduction in heat cost to Fonterra
- 10% reduction in electricity price
- Carbon charge at $10 /tonne carbon
- Gas/coal fuel costs doubled

In none of the above cases did the project return reduce to an IRR below 15% indicating that the project, on the basis of the costs, revenues and assumptions made, is financially robust; remaining attractive under all scenarios considered.

The report notes a number of non-financial benefits to Fonterra from the development of the geothermal resource not least of which is the increased security of electrical supply given the generation on site, the potential for growth in site activities on the basis of green heat supply, and the avoided investment in a new boiler(s) on the site.

This initial high level feasibility study provides a “picture” of potential costs and benefits from a range of options and indicates areas for further consideration. Applying engineering parlance to the study it has “an order of accuracy of +/- 30%”. It is noted, however, that the returns and the sensitivities to a range of assumption changes indicate that despite this order of accuracy, the project is likely to be economic.

A2.3 Direct use of Low Temperature Geothermal Resources in New Zealand

Example focus – Costs of geothermal for timber drying

Thain et al (2006) present comprehensive details of the many uses of direct heat in a range of commercial / industrial uses in New Zealand. Of particular interest is the presentation of the costs to develop timber drying facilities.

The use of kilns to dry timber is the quickest and simplest way to add value to the timber. A timber-drying kiln is a large oven in which the enclosed heated air is circulated to draw moisture from the timber. The heat energy is often supplied by hot water at high pressure and temperature to heat exchanges in the kilns.

The report notes a budget cost to buy and install a single 55 m^3 HT (‘High Temperature’) drying kiln as $800,000 and for a similar sized ACT (‘Accelerated Conventional Temperature’) kiln to be around $610,000. The cost for geothermal production/re-injection wells and pipe work could be of the order of $600,000 for both kiln systems.

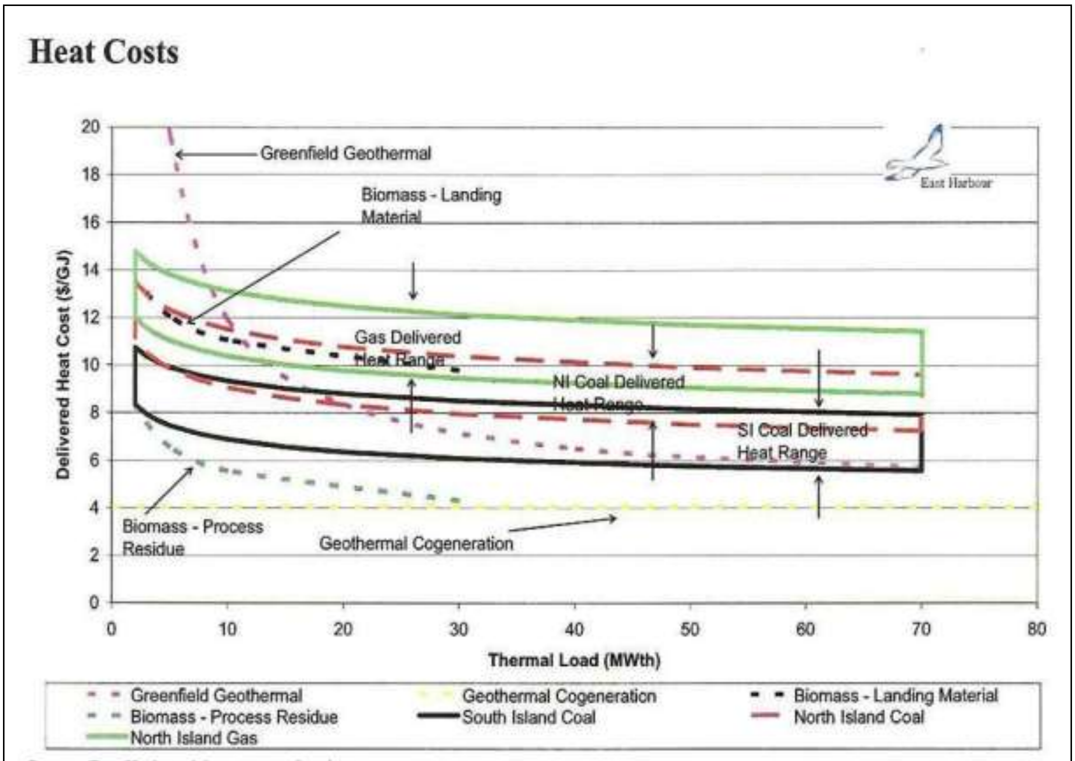
The report estimates the cost of drying timber using geothermal energy to be $518, 000 and $375,000 per year for the HT and ACT kilns respectively. It is noted that this could be further reduced if a suitable cascade geothermal fluid resource was obtained from an electricity plant.

The report goes on to illustrate the benefits of geothermal in the event of the application of a carbon price. Using natural gas as the alternative, it is calculated that application of a $15/tonne carbon tax would add an additional $2.40 to the cost of drying a cubic meter of lumber.

A2.4 NZGA-EHMS (2008)

Example focus - Comparison on the delivered heat cost of various energy sources

The NZGA-EHMS study in 2008 provided a good comparison on the delivered heat cost of various energy sources with two geothermal heat supply options (**Figure 11**). The delivered heat cost is the total heat cost, including fuel costs, annualised boiler and other heat plant costs (for the geothermal development this includes wells, pipes, separators, etc), and operating costs.



Source: East Harbour Management Services

Assumed $15/t Carbon tax

Figure 11 – Comparative costs of industrial scale heating types

Source: (EECA, 2007)

The geothermal options considered are a greenfield option and an option for a heat consumer located beside an electricity station development (cogeneration). The greenfield development is based on a high temperature field with deep wells (1750m deep) of average production. The price set for the geothermal cogeneration option is based on achieving the same revenue per tonne of steam for steam which is directed either to a turbine for generating electricity at the wholesale price, or supplied to a heat user located beside the steam mains.

Analysis was undertaken using a carbon price of NZ$15/t CO_2. The higher cost increases the gas and coal curves and will also have a minor increase in geothermal cogeneration cost due to higher wholesale electricity prices.

A developer located beside any geothermal electricity station requiring steam should be able to negotiate attractive commercial rates, in comparison with the cost of alternatives, for heat supply at almost any scale. For a greenfield development a heat load of about 10 to 20 MWt[8] or greater is required to be clearly competitive with other heat forms. This sort of load can be for large timber kiln operations or large glasshouses.

If there are existing wells or a shallow steam zone located near the plant can significantly reduce the cost of a direct supply of heat and thereby improve the plant economics.

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[8] MWt – MWthermal

APPENDIX 3 - TECHNOLOGICAL ECONOMIC CASE STUDIES – ELECTRICITY GENERATION

This section presents, for reference, a number of case studies on the economics of electricity generation (mainly binary electricity plants). New Zealand and overseas examples are given. Where generic geothermal electricity plants are referred to, they are generally considered to be applicable to both flash steam and binary electricity plant technologies. *(Note: In order to improve comparisons, costs that were originally in US$ and other currencies were converted to NZ$ or NZ¢ at 2010 level i.e. 1 NZ$ = US$0.70).*

A3.1 Overseas Examples

A3.1.1 World Bank (2007)

Example focus – Capital cost of binary electricity plants by key components and by development phase; binary electricity plants generation costs.

A 2007 World Bank study assessed a 200 kW binary plant for mini-grid applications and a larger size (20 MW binary plant) suitable for grid applications. The design assumptions for these binary electricity plants are shown in **Table 40**.

Particulars	Binary plant (Small)	Binary plant (Large)
Capacity	200 kW	20 MW
Capacity factor (%)	70	90
Geothermal reservoir temperatures (°C)	125-170	125-170
Life span (year)*	20	30
Net generated electricity (MWh/year)	1,230	158,000

Table 40 – Design assumptions for binary geothermal electricity plants

Note: Although the plant life span is 20-30 years, well will be depleted and new wells will be drilled much before that time. An allowance for this additional drilling is included in the generating cost estimates.

The project estimated that larger geothermal electricity plants would operate as base-load generators with capacity factors comparable to conventional generation. Smaller plants for mini-grid applications would have lower capacity factors of 30-70%, mainly due to limitations in local demand. The components of capital costs of the large and small binary electricity plants are shown in **Table 41**.

Item	200 kW binary plant (NZ$/kW)	20 MW binary plant NZ$/kW)
Equipment	6,210	2,230
Civil	1,070	290
Engineering	640	440
Erection	2,390	2,900
Total	10,310	5,860

Table 41 – Capital costs of binary electricity plants

The breakdowns of the capital costs for a binary geothermal electricity plant by project development phase are shown in **Table 42**.

Item	200 kW binary plant (NZ$)/kW	% of total	20 MW binary plant (NZ$)/kW	% of total
Exploration	430	4	460	8
Confirmation	570	6	670	10
Main wells	1,140	11	1,010	18
Electricity plant	6,070	59	3,030	52
Others	2,100	20	690	12
Total	10,310	100	5,860	100

Table 42 – Capital costs for binary electricity by project development phase

For the 200 kW binary projects, World Bank set a high contingency cost based on studies that very few projects of this size have been built. They projected that these small projects would be unattractive for commercial firms, thus a public sector entity will most likely be the implementing agency for such systems.

The generating costs for binary electricity plants are shown in **Table 43**. O&M costs are considered as fixed costs since the truly variable costs (e.g. lubricants) are very low. Most of the O&M is in labour for the electricity plant. O&M for binary systems includes replacement of downhole production pumps at three to four year intervals. The economies of scale for the binary plant showed that the generation cost becomes cheaper as the unit size increases.

Item	200 kW binary plant (NZ¢/kWh)	20 MW binary plant (NZ¢/kWh)
Levelised capital cost	18	7.1
Fixed O&M cost	2.9	1.9
Variable O&M cost	1.4	0.6
Total	22.3	9.6

Table 43 – Binary electricity plant generation costs

World Bank stated that it is difficult to predict future prices for binary geothermal electricity systems. Although there have been significant long-term price declines since 1980 (about 20% per year for electricity plants), recent increase in oil prices have driven up the cost of geothermal wells.

A3.1.2 USA

Examples a. – f. focus as follows:

- **a. Cost of new electricity production; comparison with other types of generation.**
- **b. Cost-benefit analysis on modular air-cooled binary cycle electricity plants; 5 year payback period.**
- **c. Comparison with other types of generation; levelised costs of various generation technologies**
- **d. Typical capital costs of binary electricity plants – exploration, permitting, drilling, confirmation, fluid gathering, transmission lines, O&M costs.**
- **e. Costs of various types of small-scale geothermal projects – including plant, field, and well costs, O&M costs and COE costs.**
- **f. Costs for binary type electricity plants and the impact of resource temperature and plant size on capital cost.**

a. ***National Geothermal Collaborative Issue Briefs (2004)*** - The brochure states that new geothermal plants in the USA generate electricity from 7¢/kWh to 11¢/kWh. Once capital costs for the plant are recovered, the price of electricity can decrease to below 7¢/kWh.

The price of geothermal energy is within the range of other electricity choices when the costs over the lifetime of a plant are considered (**Table 44**). In the USA, geothermal electricity plants have the distinct advantage against the other plant options of enjoying tax credits provided by the federal government for their implementations. Geothermal flash steam plants are the best plant options and if the capital and financing costs for binary plants can approach or equate with the costs of geothermal flash steam then it can also be competitive with the other plant options.

Technology	**Geothermal Flash**	**Geothermal Binary**	**Wind**	**Hydro**	**Natural Gas (Combined cycle-Baseload)**	**Turbine (Simple Cycle – Peaking)**
Capital & financing cost	5.00	7.34	4.99	6.60	1.33	9.90
Fixed operating costs	2.04	4.40	2.56	1.60	0.27	3.47
Taxes (credit)	-0.77	-1.30	-0.49	0.41	0.01	0.17
Total fixed costs	6.27	10.44	7.06	8.61	1.61	13.2
Fuel cost	0.17	0.11	0	0	5.47	7.30
Variable O&M costs	0.01	0	0	0	0.34	1.56
Total variable costs	0.18	0.11	0	0	5.81	8.86
Total levelised costs	6.45	10.55	7.06	8.61	7.42	22.06

Table 44 – Cost of New Electricity Production (NZ¢/kWh)

Source: Badr et al. (2003)

Numbers will vary depending on the quality of the renewable resource and the price of natural gas.
Figures for wind do not include the federal production tax credit of 1.8¢/kWh
Levelised costs refer to the cost of electricity that an electricity plant will generate over its lifetime.

Most of the costs associated with geothermal electricity plants are related to resource exploration and plant construction. It is expensive and risky to locate geothermal resources because only one in five wells yields a reservoir suitable for development (the success rate in New Zealand is far higher). Geothermal developers must prove that they have a suitable resource before they can secure the millions of dollars required to develop geothermal resources.

b. ***Montana Department of Environmental Quality (2009)*** - The cost-benefit analysis was conducted by the Montana government on their air-cooled binary cycle electricity plants (Organic Rankine Cycle) which uses water temperatures of less than 177°C for electricity generation. The binary electricity plants are of modular design with small plant investment that can be increased after time. They are relatively easy to design, can be operated automatically and be able to reduce operational costs. They are also well suited for a secondary, or metered, electrical source, which can obtain retail, rather than wholesale, electrical rates.

For this study, the geothermal resource has the following parameters:

1) Water flow = 114 m^3/hr
2) Water temperature = 121°C
3) Effective thermal charge (121°C – 77°C = 44°C)

4) Overall/Predicted plant efficiency = 8.5%
5) Estimated maximum output = 500 kW
6) Unit cost of binary plant = NZ$3,000/kW
7) Total project = cost was calculated to be about NZ$1.5M

At a price of electricity of 17¢/kWh in Montana, 7,000 hours operation/year, average output of 463 kW (@ 93% operational efficiency), and annual operations/maintenance of NZ$35,700, the savings (electrical electricity sales) from the binary plant was estimated to be NZ$290,000. The Montana government estimated the pay back for the binary plant to be about 5 years, which is a relatively good number of years to recover the project investment.

c. ***California Energy Commission, 2007*** - The California Energy Commission (CEC) (GEA web-site, 2010) estimated the levelised cost of electricity (LCOE) for a 50 MW geothermal binary plant (about 13¢/kWh) to be competitive with geothermal dual flash plants (12¢/kWh), wind (14¢/kWh) and advanced nuclear (14¢/kWh). The costs for individual geothermal projects vary significantly based on various costs factors and costs for electricity projects change over time with economic conditions (**Figure 12**).

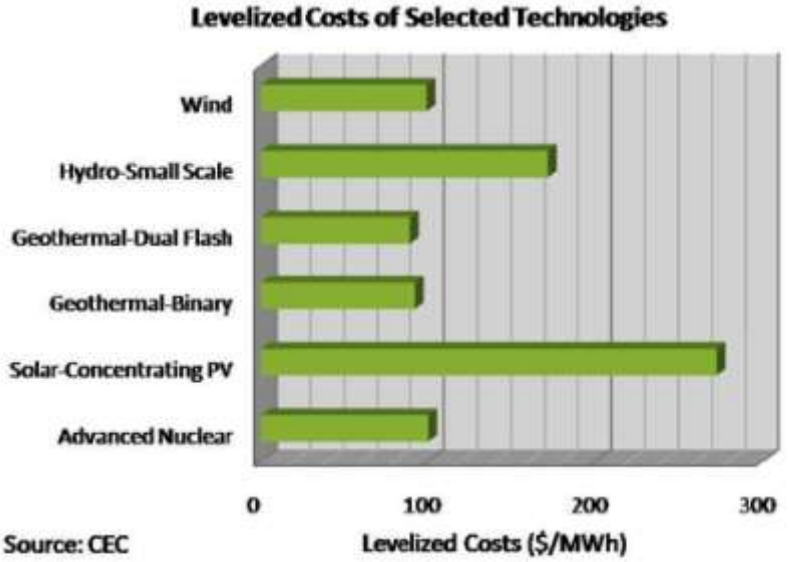

Figure 12 – Levelised costs of selected technologies

The study concluded that the geothermal electricity cost is affected by the local, regional, national, and global competition for commodities such as steel, cement, and construction equipment. Geothermal electricity is competing against other renewable and non-renewable electricity development, building construction, road and infrastructure improvements, and all other projects that use the same commodities and services.

d. ***GEA-USA (2005)*** – The typical capital costs of a geothermal electricity plant (whether a steam flash or a binary electricity plant) are ranked equipment and related installations costs (54%), drilling cost (23%), steam/fluid gathering systems (8%) and a range of other activities (16%) are shown in **Figure 13**.

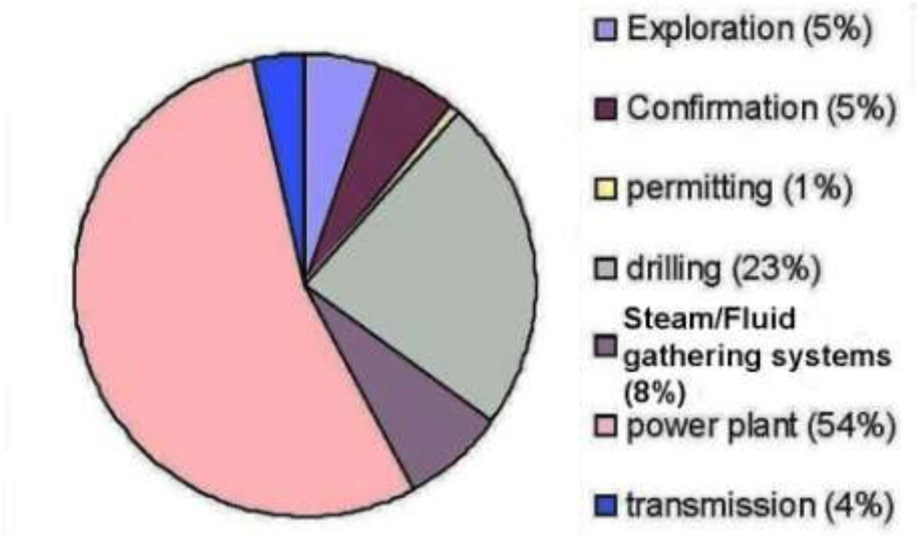

Figure 13 – Typical cost breakdown of a geothermal electricity generation project

The cost components of binary electricity plants are:

Exploration costs – Costs associated with the initial development phase to locate a geothermal resource that will provide sufficient energy to run an electricity plant and produce electricity. This phase starts with prospecting and field analysis and ends with the drilling of the first successful full-size commercial production well. The typical exploration costs for binary electricity projects are shown in **Table 45**.

Sources	Costs (NZ$/kW)
Nielson (1989)	150
EPRI (1996)	180
EPRI (1997)	145-190
GeothermEx (2004)	130-200

Table 45 – Typical exploration costs for binary projects
Source: GEA (2005)

Confirmation costs – typically these costs are about ¼ of the total drilling costs (possibly lower for commercially viable projects since confirmation does not require 25% of injection capacity to be drilled). They may vary widely according to the resource characteristics and drilling success rate. They are related to drilling costs, the site's accessibility and the possible delays due to regulatory or permitting issues or accessibility of drilling rigs.

Permitting costs – costs to ensure compliance with legislative requirements on environmental and construction issues, which vary from one government to another and the type of land ownership type. The permitting process considers potential impacts on the project (e.g. potential archaeological, cultural/religious and biological values at the site, local hydrology, etc). Exploration activities typically require permits from the government, state or local agencies, for discharge of air emissions and waste fluids.

Drilling costs – costs of drilling individual wells and the number of wells drilled. The cost of an individual well is mainly related to the depth and diameter of the well as well as the properties of the rock formation. The average drilling costs for binary electricity plants are shown in **Table 46**.

Sources	Costs (NZ$/kW)
Entingh and McLarty (1997)	460
EPRI (1997)	1,420
GeothermEx (2004)	530-6,430+
Other US developers	860-1,710+ (Average: 1,430)

Table 46 – Average drilling costs for binary electricity projects

Source: GEA (2005)

Fluid gathering costs – These costs depend on the distance from the production and injection wells to the electricity plant, the flowing pressure, chemistry of the produced fluids, and material of pipelines used. The typical fluid gathering costs for binary electricity projects are shown in **Table 47**.

Sources	Costs (NZ$/kW)
Entingh and McLarty (1997)	140 (field piping: 60 + production pumps: 80)
EPRI (1997)	40
Entingh and McVeigh (2003)	5% of total capital cost
Other US developers	360-570

Table 47 – Fluid gathering costs for binary projects

Source: GEA (2005)

Electricity plant costs - According to the GEA 2005 study, the typical capital costs of binary electricity plants are shown in **Table 48**.

Author/Source	Technology	Capital Cost (NZ$/kW)	Capital Cost range (NZ$/kW)	Inflation adjusted capital costs (NZ$/kW)
Entingh & McVeigh (2003)	Binary	3,430	2,430-3,860	3,520
CEC, RRDR (2003)	Binary	3,250		3.340
CEC, CCCCSEGT (2003)	Binary	3,280		3,360
Owens (2002)	Binary	3,020		3,170
Kutscher (2000)	Binary	3,000		3,290
EPRI (1997)	Binary	3,020		3,550
Average capital cost (Binary)		3,160	2,430-3,860	3,370

Table 48 – Capital costs of binary electricity plant technologies

Source: GEA (2005)

Transmission lines costs – These costs are based on the length and capacity of the transmission line, the topography, slope stability, accessibility of the site considered. The typical transmission lines costs for binary electricity projects are shown in **Table 49**.

Sources	Transmission line cost (In NZ$/km)
Sifford & Beale (1991)	320,000 (58% labour cost & 42% material cost)
Lesser (1993)	301,000 (61% labour cost & 39% material cost)
GeothermEx (2004)	240,000
Developer's interview	310,000 – 400,000

Table 49 – Typical costs of transmission lines for binary plant projects

Source: GEA (2005)

Operating (O&M) costs – Their components are shown in **Table 50**.

Cost category	% of total O&M expenses
Labour	8 - 32 %
Steam	42 - 74 %
Chemical	1 - 15 %
Other/Miscellaneous	6 - 41 %

Table 50 – Components of operating cost of geothermal electricity plants
Source: GEA (2005)

e. ***National Renewable Energy Laboratory (NREL) (2001)*** - The NREL study reported on the construction of small-scale (300 kW to 1 MW) geothermal electricity plants such as Organic Rankine Cycle (ORC) and Kalina Cycle System (KCS), and a small Low Pressure Flash Plant (LPFP) for greenhouses in the Western USA. The costs for these projects are summarized in **Table 51**.

Plant type/ Plant name/Location	MW	Unit cost (NZ$/kW)	Total cost (NZ$M)
Organic Rankine cycle, Empire Energy, Empire, NV	1	3,000	3.7
Kalina (KCS-34) , Exergy-AmeriCulture, Cotton City, NM	1	3,700	4.9
Low-pressure flash plant greenhouse, Milgro-Newcastle, Newcastle, UT	0.750	3,600	3.7

Table 51 – Costs of small-scale geothermal projects

The projected costs of electricity (COEs) (with and without NREL shares) for Organic Rankine Cycle and Kalina Cycle Systems (from 6.3¢/kWh to 12.6¢/kWh) are competitive with those of the low-pressure flash plant (from 5.9¢/kWh to 8.9¢/kWh) (**Table 52**).

Plant type	Plant cost (NZ$/kW)	Field cost (NZ$/kW)	Well cost (NZ$/kW)	Total Project cost (NZ$/kW)	Annual O&M cost (NZ$/kW)	COE w/ cost share (NZ$/kWh)	COE w/out cost share (NZ$/kWh)
ORC	3,000	370	0	3,710	110	.074	.126
KCS	3,710	270	40	4,860	100	.063	.091
LPFP*	3,570	240	480	4,860	40	.059	.089

Table 52 – Projected costs of small-scale geothermal projects
*Note: * A new production well is required for the Milgro-Newcastle plant*

f. ***Geo Heat Center (2000)*** - The 2000 study by Rafferty stated that the costs for binary type electricity plants using air cooling for the condenser is affected by the impact of resource temperature and plant size on capital cost. A 1-MW plant using a 140°C resource incurs a capital cost of about NZ$2,540, while a 100-kW plant using a 99°C resource has a capital cost of NZS$4,140. They do not, however, include resource development (exploration, production and injection wells or pumps). The relevant parameters for a binary plant are shown in **Table 53**.

Particulars	Values
Resource temperature	121°C
Net capacity	300 kW
Production well depth	305 m
Injection well depth	198 m
Capacity factor	0.80
Service life	30 yrs
Total capital cost (wells and plant)	$1.83 M
Annual maintenance costs	$90,000/yr

Cost of produced electricity	15¢/kWh

Table 53 – Electricity production from binary electricity plant (in NZ$)

They concluded that for most applications, binary electricity plants will be successful and more competitive with other sources of electricity if resource temperature is greater than 104°C, plant sizes are greater than 500 kW and direct sales are considered primarily to a utility.

A3.2 New Zealand Examples

A3.2.1 MED (2009)

Example focus – General electricity model for the cost of new generation.

The Ministry of Economic Development (MED) website is a good source of reference material for New Zealand electricity generation analysis. In particular, the *Interactive electricity model: cost of new generation* (MED, 2009). The model shows the assumed cost of new generation projects, and the sensitivity of these cost to certain key assumptions.

An illustrative list comparing representative electricity plant options are shown in **Table 54**.

Project	Type	MW	GW pa	Capital cost $M	Variable O&M S/MWh	Fixed O&M $/kW	LRMC $/MWh
Tauhara Stage 2	Geo (Steam)	240	1787	1189	0	95	86.35
Tauhara Stage 1	Geo (Binary)	23	171	114	0	95	86.36
Hauauru	Wind	540	1892	1416	16	0	98.36
Clutha River	Hydro	340	1489	1360	0	0	106.42
Glenbrook	Coal	400	2628	961	9	40	109.32
Kawerau	BioCog	30	210	85	10	60	110.20
Otahuhu C	CCGT	400	2803	561	4.25	50	129.48
Mohikinui	Gas Cog	85	596	78	6.4	40	158.06
OCGT 2	Gas Pkr	200	438	245	25	50	262.59
OCGT NI 1	Diesel Pkr	150	66	151	4.25	40	665.59

Table 54 – New projects ranked from lowest to highest LRMC

Currently, both geothermal steam flash and binary electricity plants offers the lowest LRMC (at about $86.4/MWh) among the electricity plant options and can provide the cheapest electricity requirements for New Zealand.

A.3.2.2 NZGA-SKM (2009)

Example focus – Factors that influence capital costs of geothermal plants; various electricity cycles for geothermal energy generation; components of a geothermal project; character of the resource; cost parameters.

A 2009 report by NZGA and SKM studied the following electricity cycles that can be used for geothermal energy generation:

a. Single flash steam Rankine cycle direct contact condensing plant
b. Double flash steam Rankine cycle direct contact condensing plant
c. Organic Rankine cycle (ORC) binary electricity plant, and
d. Hybrid steam-binary cycle plant.

The choice of these cycles had been affected by an assumption of a high enthalpy resource whereas binary cycle technology is most appropriate for low enthalpy resources. The capital cost of a geothermal electricity project is affected by the size of the project, the energy conversion process used, the size and number of individual generating units, resource conditions, and the character of the geothermal field. The character of the field affects the size and type of electricity plant.

The electricity tariff dictates the range of generation technologies where it is feasible for application. Although it is common overseas to use lower temperature resources and pumped wells, in New Zealand, current and reasonably foreseeable future prices are such that low temperature geothermal energy is unlikely to be competitive in the medium term.

The key components of a geothermal electricity project are as follows:

a. the geothermal field or resource and the wells that tap it;
b. the fluid collection and disposal system that take geothermal fluids from the wells, conditions them, delivers them to the electricity plant, and takes the waste fluids for disposal;
c. the electricity plant (within the electricity plant fence); and
d. the electricity transmission system (to deliver electricity to the interconnection point).

The character of a geothermal resource/field is dictated by the following factors:

a. the area of the field (km^2)
b. the degree of recharge
c. the electricity potential of the field (MW) (i.e. energy reserves or field capacity)
d. the typical (e.g. average) flow of individual wells (in kg/s or t/h)
e. the energy content of the fluids (in kJ/kg or MJ/t), and
f. the chemical nature of the fluids (which includes non condensable gases, silica content, scaling and corroding potential, and toxicity).

The cost parameters of geothermal electricity plants are:

1. *Establishment costs* – They range from NZ$ 3M (for a 20 MW development) to NZ$3.5M (for a 50 MW development). The costs include:

a. Permitting
a. Land acquisition
b. Geoscientific/Environmental
c. Well testing
d. Civil works and infrastructure
e. Site operations, and
f. Pre-feasibility/Feasibility reports.

2. *Drilling Costs* – They depend on the depth and size of wells to be drilled, the capability of the rig, the number of holes to be drilled (allows rig mobilisation cost to be shared over a number of wells), topography and site access, and the drilling conditions encountered.

The estimated drilling costs in New Zealand are shown in **Table 55**. The costs have increased considerably over the last few years and upward movement in the cost of drilling rigs and drilling equipment are expected to continue.

Well drilling operation	**Estimated total cost t (NZ$M)**	**Estimated total cost (at E/R 0.70) US$M**	**Local content %**	**Local cost component NZ$M**	**Overseas cost component (at US$M**
Production well work over existing	0.3 - 1.0	0.2 - 0.7	50%	0.2 - 0.5	0.1 - 0.4
Production well (1,500m)	3.2	2.2	40%	1.3	1.3
Production well (2,500m)	5.2	3.6	40%	2.1	2.2
Reinjection well (2,000m)	4.2	2.9	40%	1.7	1.8

Table 55 – Estimated Geothermal Drilling Costs in New Zealand (2007) (in NZ$)*
*exclusive of rig mobilization and demobilization costs

3. *Steamfield development costs* – They consist of:

a. *Steamfield piping* - This includes two phase piping, steam and brine piping and reinjection pumps to take geothermal fluid from the production wells to the electricity plant, and dispose of waste fluids to reinjection wells.

b. *Steamfield plant* – This includes line valves and instrumentation, and steam / water production separators and brine pumps depending on development options.

c. *Site civil works* – These include preparation of site roading, separator station foundations, well pads and multi well cellars.

The steamfield development requirements are assumed to be the same for the single flash, hybrid steam + binary and the pure ORC options, as they involve the same piping layout and control systems and a single separation in each case. The estimated steamfield development costs for various options are given in **Table 56**.

Item	**Description**	**Cost of steamfield system, (in NZ$ M)**				**Overseas Cost %**	**NZ Cost %**
		50 MWe		**20 MWe**			
		SF, GCCU, ORC	**Dual flash steam**	**SF, GCCU, ORC**	**Dual flash steam**		
1	Preliminaries & General	2.8	3.3	1.5	1.8	0	100
2	Civil/Structural works	9.70	11.4	5.3	6.2	0	100
3	Mechanical works	14.8	17.5	6.2	7.4	40	60
4	Control & Instrumentation	0.5	0.6	0.2	0.3	80	20
5	Electrical work	0.5	0.5	0.2	0.2	0	100
6	Miscellaneous	1.0	1.0	0.6	0.6	10	90
7	Engineering and Design	3.2	4.0	1.8	2.2	20	80
	Total estimated EPC cost	32.5	38.3	15.8	18.7		
	NZ$/kWe gross electricity	650	770	790	940		
	NZ$ cost	25.4	29.9	12.7	15.0		
	Overseas cost	7.1	8.4	3.1	3.7		
	%NZ$ cost	78	78	80	80		

Item	Description	Cost of steamfield system, (in NZ$ M)				Overseas Cost %	NZ Cost %
		50 MWe		20 MWe			
		SF, GCCU, ORC	Dual flash steam	SF, GCCU, ORC	Dual flash steam		
	%Overseas cost	22	22	20	20		

Table 56 – Estimated steamfield development costs (in NZ$)

4. *Electricity plant costs* – These are affected by current competition among suppliers, order status, commodity prices, the commercial terms and/or scope of supply, and the particular project contract interfaces for geothermal fluid supply and/or electricity export. It is usually difficult to give a precise price for a geothermal electricity plant in advance of tendering.

Plant size is a significant cost factor, usually higher for single unit condensing steam turbines and lesser for ORC plants which are typically modular. Other factors are the optimisation of condenser pressure (and attendant effects on cooling system operation), means of gas extraction, and the use of standard (modular) electricity units. There will be possible variation in electricity plant prices depending on the choice of supplier, whether it is from Japan, USA, Italy, France, Israel, Germany, etc., and the choice of electricity cycle.

The electricity plant, including major spare parts can be supplied under an engineer, procure and construct (EPC) contract. This is a contract arrangement in which a contractor assumes total responsibility for the design, procurement, construction and commissioning of the electricity plant. It is normally based on a fixed contract sum and specifies a time for project completion. The contractor commits to the contract and posts a performance guarantee, beyond which liquidated damages may be claimed and reflecting the value of the loss that the owner faces due to the late completion or the off-guarantee performance. The damages include items such as the cost of financing, penalty costs the owner may be charged for performance shortfall under its electricity sales agreement (if any), additional charges for engineering supervision and the like.

The estimated costs for ORC electricity plant and hybrid steam + binary cycle plant under EPC contracts are shown in **Table 57**.

Plant size (MW)	Estimated total cost NZ$/kW	Estimated total cost US$/kW	Local cost component NZ$ M	Overseas cost component US$ M
20 (+steamfield piping	3,350	2,350	13.4	37.6
50 (+steamfield piping	3,350	2,350	33.5	94.0
20 (electricity plant)	2,700	1,890	10.8	30.2
50 (electricity plant)	2,700	1,890	27.0	75.6

Table 57 – Estimated Costs for ORC Electricity Plant (2007)

5. *Transmission interconnection costs* - The geothermal electricity plant is assumed to be located in the vicinity of the national 220 kV transmission network. The cost of a 20 km heavy duty double circuit 220 kV transmission line is estimated at NZ$ 4M and the associated transformer an additional $2M and $3M for the 20 and 50 MW developments respectively. Switchyard, substation, consenting and easement costs are not included in these estimates.

6. *Operating and maintenance costs* - They include costs for:

a. *Electricity plant O&M costs* - Geothermal electricity plants typically incur about 50 to 100 NZ$/kW, which translates to total O&M costs of about 1 ¢/kWh.

b. *Steamfield O&M costs* - It will be about $20/yr/kW (gross) of steamfield plant capacity, equating to about $400,000/yr for a 20 MW plant and $1,000,000/yr for a 50 MW plant. These include fixed costs for operating personnel, planned and unplanned maintenance on the wells and the fluid collection and disposal systems, and routine down well measurements for production field activities. They do not include make-up and replacement well ("M&R") drilling, testing, and connection to maintain geothermal fluid and energy supply to the electricity plant at the level required to maintain full turbine loading.

The estimated breakdown for electricity plant O&M costs for a size range of 20 to 50 MW is shown in **Table 58**.

Particulars	20 MW	50 MW
Gross capacity factor, %	95	95
Gross generation, GWh/yr	166.44	416.1
Fixed costs		
Labour & mgmt, NZ$ M/yr	1.25	1.8
Variable costs		
Materials, NZ$ M/yr	.05	.15
Planned maintenance (major overhauls)		
Cycle period, yr	2	2
Labour/cycle , NZ$ M	.20	.30
Materials/cycle, NZ$ M	.05	.125
Unplanned maintenance		
Labour, NZ$ M/yr	.05	.075
Materials, NZ$ M/yr	.10	.20
Fixed costs		
NZ$M/yr	1.25	1.8
NZ$/kWe	60	40
Variable costs		
NZ$M/yr	.325	.638
NZ$/kWh	.0020	.0015
Total electricity plant, NZ$ M/yr	1.575	2.438
O&M Costs		
NZ$/kWh	.010	.006
NZ$/kWe	80	50

Table 58 – Breakdown of Geothermal Electricity Plant O&M Costs

The total O&M costs for 20 MW and 50 MW plants are shown in **Table 59**.

	20 MW			50 MW		
	NZ$ M/y	NZ$/kWh	NZ$/kWe	NZ$ M/y	NZ$/kWh	NZ$/kWe
Steamfield	.60	0.004	30	1.50	0.004	30
Electricity Plant	1.60	0.010	80	2.40	0.006	50

Total	2.20	0.014	110	3.90	0.010	80

Table 59 – Total geothermal electricity plant project O&M costs

There are also additional planned maintenance costs for regular major overhauls, including statutory inspections and they are estimated at NZ$150,000/overhaul for a 20 MW plant and NZ$200,000/overhaul for a 50 MW plant. The frequency of such inspections varies from one plant to another but is generally conducted once every three years.

7. *Commercial costs* - Commercial costs associated with developments also need to be included in costing a geothermal project. These include financing charges (including establishment costs and interest), interest during construction, corporate overhead, legal costs, insurances, related costs.

The above costs are sensitive to:

a. *Drilling success* - Drilling success is key to the entire project development economics. If the resource is well understood, and conditions are favourable, drilling success rates of 70% or more can be achieved (including exploration wells), resulting in lower total drilling costs for a given size of project.

   In New Zealand, success rates by private sector developers are generally higher due to considerable Crown legacy conducted earlier in exploration drilling and resource proving that lessened risks for the private sector.

b. *Climatic factors* - New Zealand’s mild climate is reasonably favourable for: low cooling water temperatures and high vacuum in the turbine condenser for condensing steam plant, good night time and winter time cooling for ORC electricity plant but with less efficient summer time cooling.

c. *Site specific factors (Terrain and access)* - Most of New Zealand’s geothermal fields are located in relatively subdued volcanic terrain, which do not require much effort and expense to build access roads, and undertake extensive ground levelling and earthworks.

d. *Plant capacity factor* - Electricity delivered at the grid connection point is affected by plant net capacity (gross capacity less internal electricity consumption), scheduled outages, and unscheduled outages. Gross capacity is affected by plant degradation (e.g. due to scale build-up or turbine blade erosion). Some of this degradation is recoverable and some is unrecoverable. Scheduled outages are normally related to maintenance. Geothermal electricity plants are generally reliable once early experience is gained specific to the resource, steamfield and electricity plant configuration.

The study concludes that the plants can be compared in terms of:

1. *Gross thermal performance* (thermal energy delivered divided by electrical energy produced), whereby at:

    - *High temperature*[9]*:* ORC < Single Flash < Hybrid < Double flash

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[9] ‘<’ means ‘uses more thermal energy per unit of gross electricity produced than’.

- *Low temperature:* Single Flash < Double Flash < ORC < Hybrid

2. *Financial performance* which is the plant specific capital cost (the capital cost divided by the gross plant capacity), and the 'real' levelised electricity tariff (required to achieve a specified after tax internal rate of return), with certain assumptions made in regard to taxation and inflation. It is equal to the present (discounted) value of the before tax income stream divided by the present (discounted) value of the generation stream.

   For low temperature plants (20 MW)

   - *Specific capital cost:* Single flash < Double flash = Hybrid < ORC
   - *Electricity tariff*[10]*:*Single flash < Double flash < Hybrid < ORC [Range 10-14.5 NZ¢/kWh real]

   For high temperature plants (50 MW)

   - *Specific capital cost:* Single flash < Double flash = Hybrid < ORC
   - *Electricity tariff:* Single flash < Double flash = Hybrid < ORC [Range 7-11 NZ¢/kWh real]

The ranking of the electricity cycle options in terms of thermal performance (gross) is 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 translated into a financial advantage. The binary plant options have higher plant parasitic loads which decrease their net thermal performance and their respective revenue streams. Although binary electricity plants have similar specific steam consumptions to double flash plants at low temperature, this is not enough to give them a levelised tariff advantage.

It is generally considered that the differences between the binary and steam flash electricity plants are few. It is projected that innovative approaches to equipment marketing and financing can favour one technology over the other, as evidenced by the market success of ORC and hybrid plants in New Zealand over the years.

The ORC plant may not be the preferred option due its relatively high specific cost. The hybrid steam + binary option reduces specific cost considerably by placing a relatively low cost non-condensing turbine, with relatively high electricity output, upstream of the higher cost ORC equipment and this achieves a much better specific capital cost performance.

A3.2.3 NZGA (2008)

Example focus – Development costs

The NZGA–EHMS (2008) study states that economies of scale are applicable for geothermal electricity generation in New Zealand. The current specific cost of a greenfield 25 MW

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[10] Based on 100% equity, 30% corporate tax rate, 8% straight line depreciation, 10% real after tax internal rate of return, zero inflation.

station/steamfield is NZ$3,200/kW while for a 50 MW station/steamfield it will be NZ$3,000/kW.

Fluid/Steamfield costs make up about 1/3 of the total capital costs of geothermal electricity development and are less than other countries due largely to the relatively lower cost of well drilling

If lower temperature resources are to be developed for electricity, the best technology will be the binary cycle plant. Full fluid/steamfield costs, however, will have to be borne by the plant and field specific but will add from NZ$600 to NZ$2,000/kW to the binary cycle plant costs.

The O&M cost is a function of plant size and the cost of makeup well drilling. A 10 MW plant will need the same of number of people to operate a 30 MW plant. It is projected that the specific cost for a binary plant will be about NZ$2,825/kW since its associated field will add about NZ$525 to NZ$1,750/kW. It is also approximated that:

c. For station size >50 MW, the O&M will be equal to NZ$83/kW/year
d. For station size <50 MW, the O&M =NZ $(157 - 3.25P + 0.035P^2)/kW/year, where P = station size (MW).

A3.2.4 Concept Consulting (2010)

Example Focus – A comparison of the benefits of the Tauhara Stage II geothermal development cf other generation options.

A 2010 study commissioned by Contact Energy from Concept Consulting presents a review of published estimates of the cost of developing new generation projects, including geothermal developments. The study assessed the expected benefits of the Tauhara Stage II Geothermal Development. The assessment was based on a reference scenario, involving the construction of a geothermal electricity station with a generating capacity of approximately 250 MW. The information in the study has been used to derive estimates of the cost of electricity from new generation sources, expressed as the electricity price required for the new generation project to breakeven (otherwise known as long run marginal cost, or LRMC, projections).

The Concept report noted several organisations that have published estimates of the costs of developing new generation projects including the following:

- the Ministry of Economic Development (in Energy Outlook to 2030 published in September 2006),
- the New Zealand Government (in the New Zealand Energy Strategy to 2050 published in October 2007),
- the Electricity Commission[11] (in the Statement of Opportunities released in August 2008),
- Meridian Energy (in Options, Choices, Decisions 2009 Update) and,
- Electricity Technical Advisory Group and the Ministry of Economic Development (in Improving Market Performance – Volume one: Discussion Paper (August 2009).

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[11] In November 2010, the Electricity Authority took over most of the Electricity Commission's responsibilities.

These estimates differ slightly in the basis of preparation, Concept has sought to standardise their presentation in some areas. The key differences and amendments are:

- the Electricity Commission's[12] published estimates offer a range of gas prices, HVDC charges and carbon values. Concept has assumed a carbon value of $7/GJ for gas, $40/MW for HVDC charges and $30/tonne CO_2e, and applied Electricity Commission estimates for all other variables;

- the MED Energy Outlook estimates have been converted from capacity based estimates to energy based estimates. To achieve this, geothermal, gas and coal plant are assumed to achieve 90% plant factors, and hydro and wind are assumed to achieve 42% plant factors; and

- the Meridian estimates, as well as the MED/Concept estimates, are presented at a higher level of aggregation than the preceding estimates. Both sets of estimates are based on a $25/tonne CO_2e, gas at $7/GJ and coal at $4/GJ. The Meridian estimates are based on tier 1 wind development sites of 100MW, large hydro development, geothermal expansion, and exclude HVDC charges.

The results are shown in **Figure** , **Figure 15**, **Figure 16**, **Figure 17** and **Figure 18** following. The figures are taken directly from the Concept report.

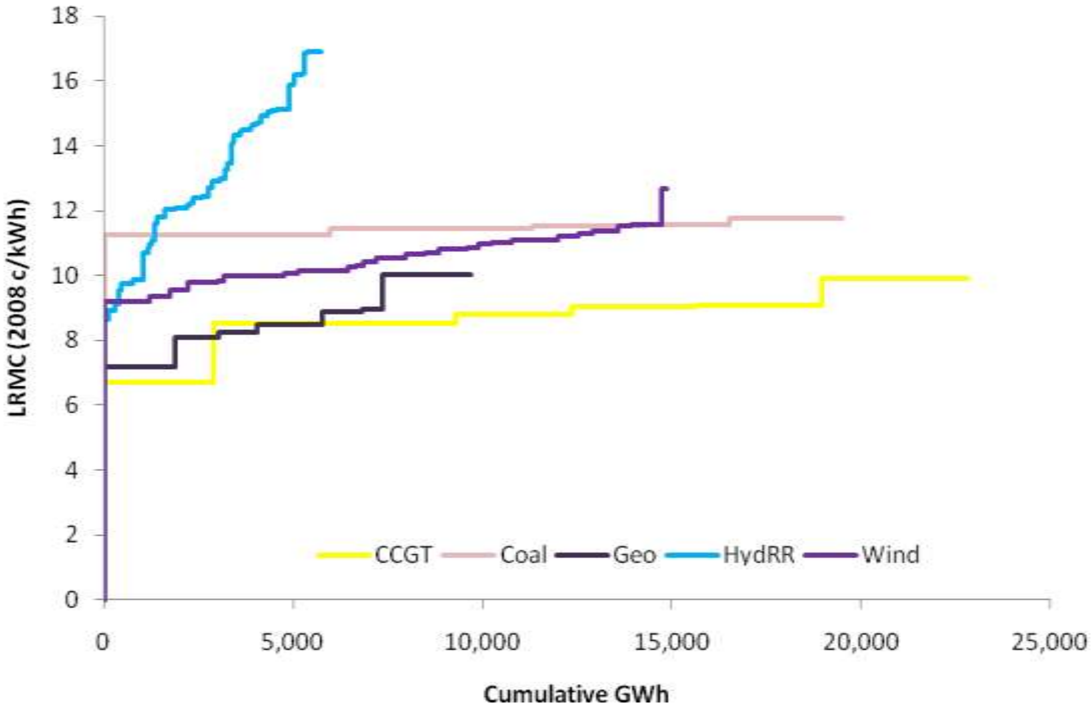

Figure 14 – Costs of Developing New Generation Projects (Derived from Electricity Commission estimates (with $30/t CO_2, $7/GJ gas, $40/MW HVDC charge))

Original Source: Electricity Commission website, with Concept estimates for carbon price, gas cost and HVDC charge

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[12] The New Zealand Electricity Commission was replaced by the Electricity Authority in 2010. Many Electricity Commission functions or Programmes are now undertaken by EECA.

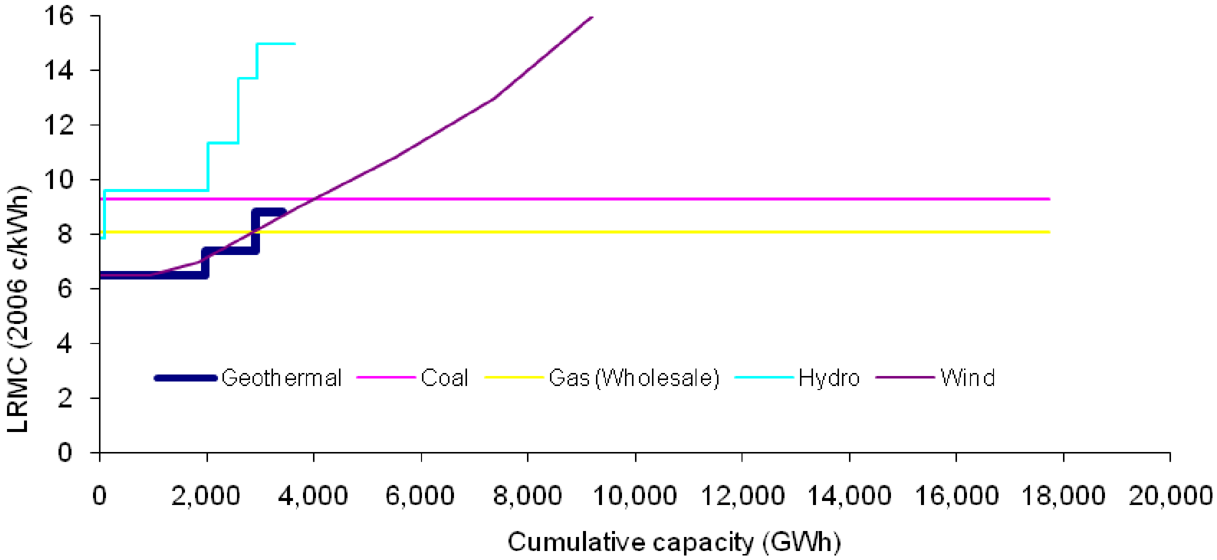


Figure 15 – Costs of Developing New Generation Projects (Derived from Ministry of Economic Development Energy Outlook estimates)

Original Source: MED, with Concept estimate for plant load factors

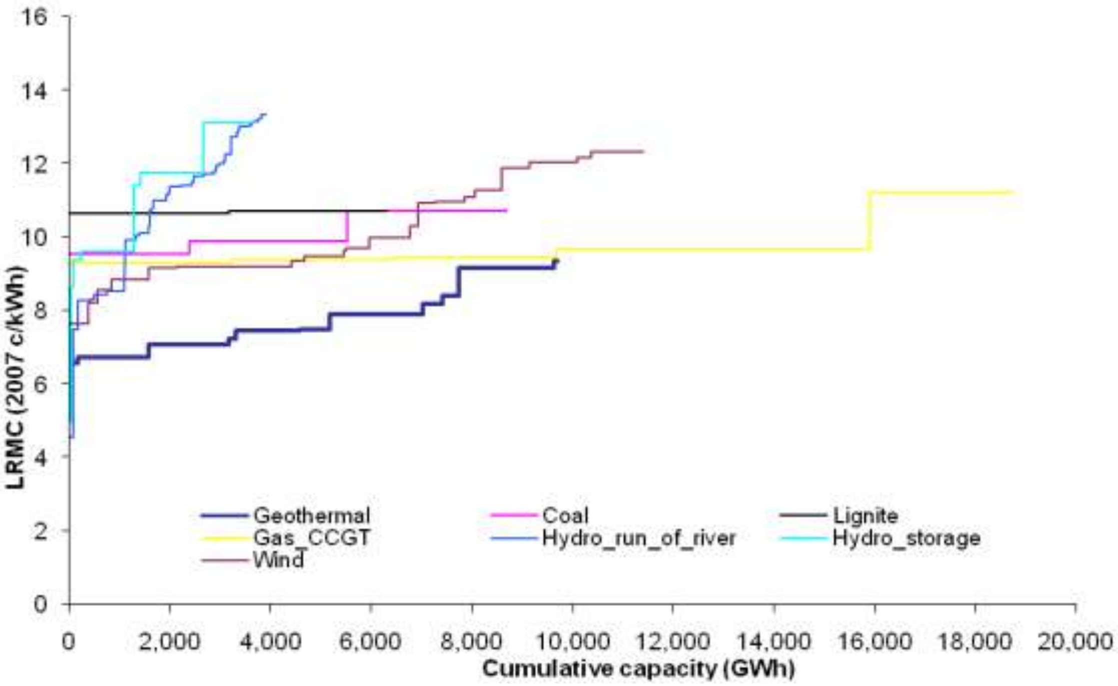


Figure 16 – Costs of Developing New Generation Projects (Derived from New Zealand Government Energy Strategy to 2050 estimates)

Original Source: New Zealand Government

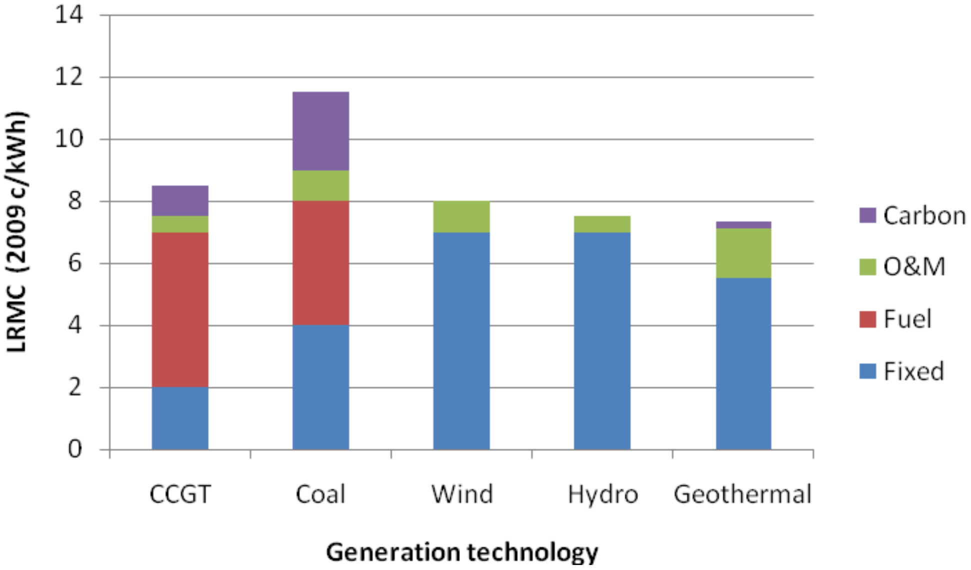


Figure 17 – Costs of Developing New Generation Projects (Derived from Meridian Energy estimates)
Original Source: Meridian Energy

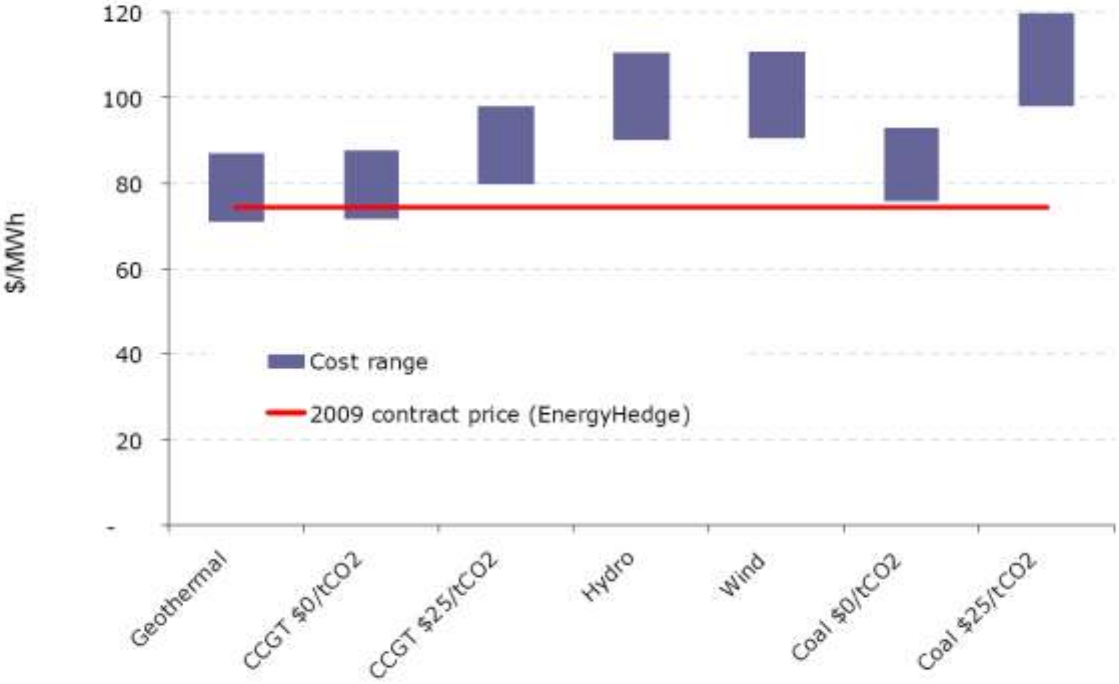


Figure 18 – Costs of Developing New Generation Projects (MED/Concept estimates)
Original Source: MED Concept Report

The report notes that while each organisation has its own view about the costs and quantities available for the various generation types, observations can be made that are relevant to the Tauhara Stage II development in particular and similar geothermal developments generally. These are:

- all organisations (Electricity Commission, MED, NZ Government, Meridian and Concept) consider that new geothermal supply is among the most cost effective options available in New Zealand;
- significant volumes (2,000+ GWh/yr) of new geothermal supply are estimated to be available, before increasingly high cost sites are required; and
- new geothermal supply is one of the few alternatives that is projected to be viable at prices close to current levels.

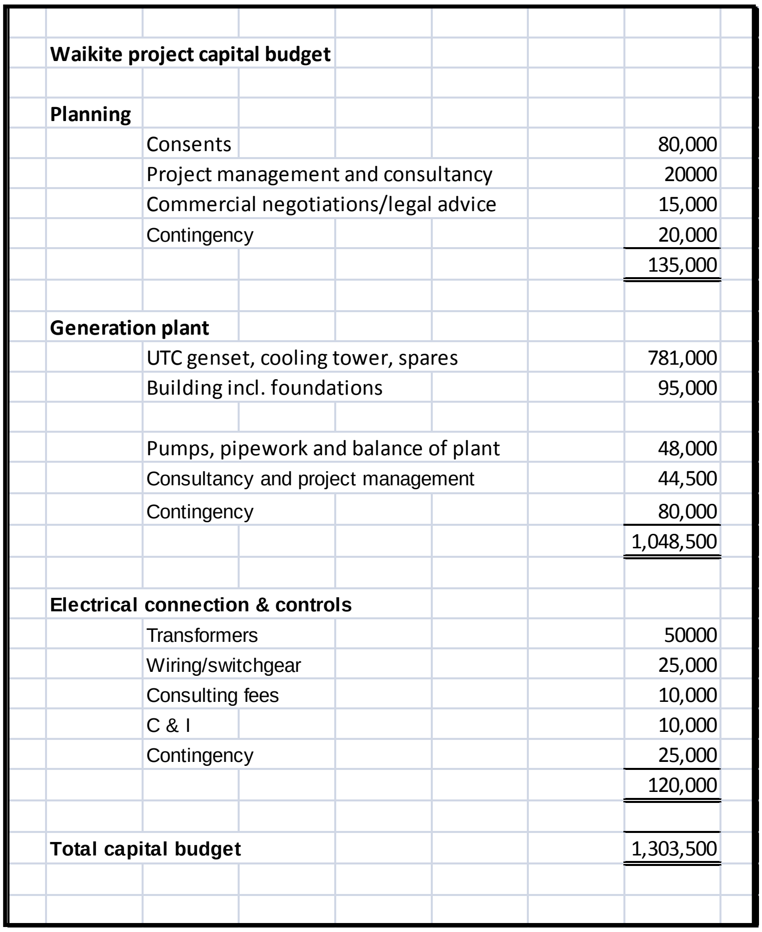
A3.2.5 EHEL (2009)

Example Focus – Small scale binary plant with minimal development costs.

The Waikite Valley Thermal Pools were established in 1972 to provide a geothermal bathing experience beside the Te Manaroa Springs, the largest boiling spring in New Zealand. The land owners (Rotorua District Council) have consents to take 3,000m^3/day of thermal water from adjacent smaller springs and to discharge the water, with these consents expiring in December 2016.

This EHEL study investigated if new "lower cost" United Technologies (UTC) binary cycle units offered an opportunity to economically generate electricity from low-temperature geothermal resources where the cost of supplying the hot geothermal water to the plant was minimal. Waikite met the criteria with the hot water take already consented, and available at no cost. This study was conceived as a potential commercial opportunity and an example that could potentially be replicated elsewhere in the central North Island.

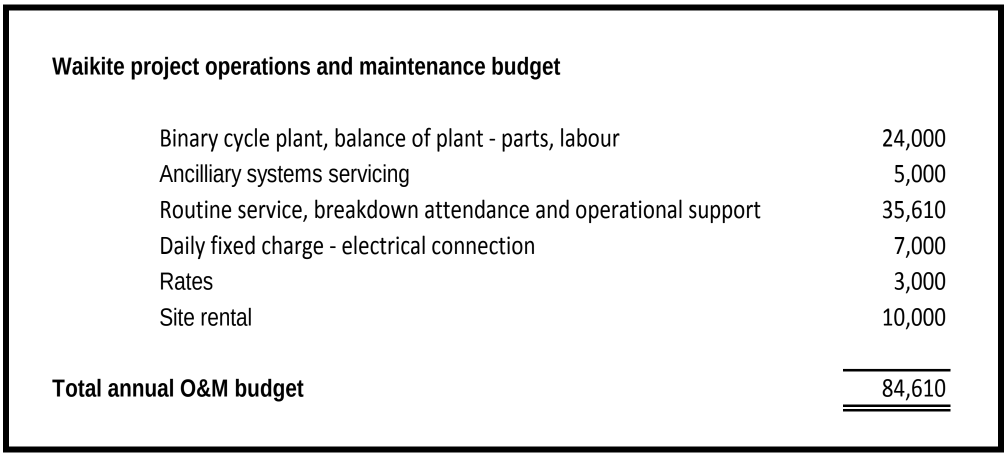
The capital costs for the project are presented in **Table 60**. They are based on budget prices for the UTC model binary cycle plant and the cooling towers, and East Harbour's previous work for balance of plant, civil works and buildings, with some check prices from suppliers.



Waikite project capital budget		
Planning		
	Consents	80,000
	Project management and consultancy	20000
	Commercial negotiations/legal advice	15,000
	Contingency	20,000
		135,000
Generation plant		
	UTC genset, cooling tower, spares	781,000
	Building incl. foundations	95,000
	Pumps, pipework and balance of plant	48,000
	Consultancy and project management	44,500
	Contingency	80,000
		1,048,500
Electrical connection & controls		
	Transformers	50000
	Wiring/switchgear	25,000
	Consulting fees	10,000
	C & I	10,000
	Contingency	25,000
		120,000
Total capital budget		1,303,500

Table 60 – Waikite Project capital budget

Operating costs were based on a quotation from UTC (with East Harbour's interpretation). Nominal land lease costs were included in the financial model with potential to be converted into an equity position in the ownership company, and land requirements were noted as small. **Table 61** presents the project operations and maintenance budget.



Waikite project operations and maintenance budget		
	Binary cycle plant, balance of plant - parts, labour	24,000
	Ancilliary systems servicing	5,000
	Routine service, breakdown attendance and operational support	35,610
	Daily fixed charge - electrical connection	7,000
	Rates	3,000
	Site rental	10,000
Total annual O&M budget		84,610

Table 61 – Waikite annual operations and maintenance budget

Revenues included in the calculations were those from the sale of electricity. It was assumed that the net generation of 219kW was available for export and sale with a load factor of 92%.

Estimated costs and revenues indicate the project showed a nominal IRR of 9.3%, but a negative NPV of $480,000. Clearly this does not meet the criteria for a commercial project with the revenues insufficient to cover the very high capital costs in relation to output; around $5,900/MW. This indicates a levelised generation cost of around 16c/kWh to provide a "commercial" return.

This initial feasibility study was carried out at high level: on the basis of estimated costs and budget quotations for major equipment items. It provided a "picture" of potential costs and benefits for the project and indicated areas for further consideration in terms of improving project outcomes, at this and other sites with similar resources.

Despite the project not being economic, at another site with more favourable conditions for such a development, the business proposition may be much closer to economic, depending on the assumptions made.

APPENDIX 4 - TECHNOLOGICAL ECONOMIC EVALUATION TOOLS

The sound economic evaluation of an electricity project (including a binary plant or geothermal heat pump) during pre-feasibility and feasibility analysis is a fundamental requirement to secure capital finance and plan ongoing operational and maintenance costs. Owens (2002) documented the typical economic evaluation techniques for appraisal and selection of electricity projects are as follows:

- Time Value of Money (TVM) analysis
- Cost-Benefit Analysis (CBA)
  - Benefit-Cost Ratio (BCR) Analysis
  - Net Present Value (NPV) or Discounted Cash Flow Analysis
  - Internal Rate of Return (IRR) Analysis
  - Least Cost Planning Analysis
  - Payback Period Analysis
  - Sensitivity Analysis
- Levelised Cost of Energy (LCOE) analysis
- Life-Cycle Cost (LCC) analysis
- Weighted Average Cost of Capital (WACC) analysis

A4.1 Time Value of Money (TVM) analysis

The value of money is correlated to time. The investments aim to set aside a sum of money for the present in expectation of receiving a sum of money in the future. Using the discounted cash flow[13] approach, and assigning a value to the cost of capital, the cash flow in the early years of the project will have greater value at the present time than in the later years of the project.

The discount rate[14] is very important for project analysis. The selection of a discount rate usually depends on the opportunity cost of capital (i.e. the foregone production or potential return when capital is invested in one project than in another project).

The equation for calculating the discount factor is as follows:

$$\text{Discount factor} \quad = \quad \frac{1}{(1+i)^n}$$

where:

i = the interest rate or cost of capital
n = years from project implementation

Investments are measured by the consumers' implicit discount rates. They require a high rate of return on investment which indicates high risk. Investments may appear risky to the consumer if there are lack of information and there are uncertainties in the project.

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[13] DCF - A valuation method used to estimate the attractiveness of an investment opportunity.

[14] Discount Rate - The interest rate charged to borrow short-term funds directly from a Bank.

In financial theory, the time value of money is projected to increase with greater risk and uncertainty. If the internal rate of return of the project is not equal to or better than this discount factor, then the project should not be undertaken.

A4.2 Cost-Benefit Analysis (CBA)

The CBA process is typically used by project developers to evaluate the desirability of the project. It analyzes the cost effectiveness of different alternatives and whether the benefits outweigh the costs. The costs and benefits of the project are evaluated in terms of the user's willingness to pay for them (benefits) or willingness to pay to avoid them (costs). Inputs are typically measured in terms of opportunity costs, i.e. the value in their best alternative use.

The process involves monetary value of initial and ongoing expenses vs. expected return. It puts all relevant costs and benefits on an equal footing. A discount rate is chosen, and then used to compute all relevant future costs and benefits in present-value terms. The discount rate that is usually used for present-value calculations is an interest rate taken from the prevailing financial markets.

The CBA differs between countries, and between sectors (e.g. energy, transport, etc.). The main differences include the types of impacts such as costs and benefits within appraisals, the extent to which impacts are expressed in monetary terms, and differences in the discount rate between countries. The CBA analytical tools used to assess the financial and economic viability of a proposed project investment are as follows:

A4.2.1 Benefit-Cost Ratio (BCR) Analysis

BCR is the ratio between discounted total benefits and costs. It is given by the following formula:

$$\text{BCR} = \frac{\text{Sum of present value values of benefits (cash inflows)}}{\text{Sum of present values of costs (cash outflows)}}$$

$$\text{Ex. BCR} = \frac{120}{100} = 1.2{:}1.$$

A proposed development will tend to be acceptable if the ratio has a value of 1 or greater. Among mutually exclusive projects, the rule is to choose the project with the highest benefit-cost ratio. BCR is especially sensitive to the choice of the discount rate, and can provide incorrect analysis if the size or scale of the various projects being compared is great.

A4.2.2 Net Present Value (NPV) or Discounted Cash Flow Analysis

This approach uses the time value of money to convert the stream of annual cash flow generated by the project to a single value at a chosen discount rate. It also allows one to incorporate income tax implications and other cash flows that may vary from year to year. The NPV method takes a spread of cash flow over a period of time and discounts the cash flow to yield the cumulative present value.

When comparing alternative investment opportunities, the NPV is a useful tool. The project with the highest cumulative NPV is the most attractive one. NPV, however, should not be used to compare projects with unequal time spans.

NPV measures the present value of money exclusive of inflation. For example: the value of all dollars received from 1993 through 1999 would be worth less than having those same dollars in 1993. This is due to the interest that could be gained by investing that money in 1993.

NZ$ (1993) = $\frac{\$(1999)}{(1+f)^n}$

Where:

n = number of years (1999-1993 = 6)
f = annual interest rate, 1993-1999

The Real (inflation-corrected) interest or discount rate (r) is:

$(1 + r)(1+f) = 1 + r_n$
$r_n = r + f * r + f$

A4.2.3 Internal Rate of Return (IRR) Analysis

The Internal Rate of Return Analysis (IRR) is an approach similar to NPV. While the NPV determines today‘s values of future cash flow at a given discount rate, the IRR approach determines the discount rate (or interest rate) at which the cumulative net present value of the project is equal to zero. This means that the cumulative NPV of all project costs would exactly equal the cumulative NPV of all project benefits if both are discounted at the internal rate of return.

IRR is the discount rate (r) at which the net present value (NPV) of present and future cash flows equal zero.

P = 0 = $\sum \frac{F_n}{(1+r)^n}$

Where:

P = NPV of present cash flow
F_n = NPV of future cash flow, at year n
Then solve (by iteration) for IRR.

For uniform annual savings (D) over n years resulting from a present capital expenditure (CC):

$$P = 0 = CC - \frac{D}{CRF_{n,irr}} \text{ or } CRF_{n,irr} = \frac{D}{CC}$$

Where $CRF = [1-(1+r)^{-t}]$

Capital Recovery Factor (CRF) is the ratio between the uniform annual savings and the present value of the cash flow stream. This is the minimum value of savings, which makes the investment cost effective.

The computed Financial Internal Rate of Return (FIRR) is compared to the company‘s actual cost of capital. If the FIRR exceeds the company‘s cost of capital, the project is considered to be financially attractive. The higher the IRR compared to the cost of capital, the more attractive the project.

For projects financed in whole or in part by the public sector, the discounted cash flow may need to be adjusted to account for social benefits or economic distortions such as taxes and subsidies, economic premium for foreign exchange earnings that accrue from the project or employment benefits. The resulting statistic would be the economic internal rate of return (EIRR) and would be compared with the country’s social opportunity cost of capital. If the EIRR exceeds the social opportunity cost of capital the project would provide economic benefits to the society.

A4.2.4 Least Cost Planning Analysis

The Least Cost Planning (LCP) Analysis method determines the most efficient way (the least cost) of performing a given task to reach a specified objective or set of benefits measured in terms other than money.

The examination of alternatives might entail different technologies or systems and needs calculation of all costs, capital and recurrent, to achieve the objective, apply economic adjustments and discount the resulting stream of costs for each alternative examined. The one with the lowest NPV would be the one most efficient (least cost).

A4.2.5 Payback Period Analysis

Payback Period Analysis is the easiest and most basic measure of the financial attractiveness of a project is the simple payback period. The payback period reflects the length of time required for the project‘s cumulative revenues to return its investment through the annual (non-discounted) cash flow. A more attractive investment is one with a shorter payback period.

A simple payback (SPB) formula (shown below) is the time required for the sum of the cash flows from the annual savings to cover the initial cost (without discounting). This is an indicator of liquidity and risk.

$$SPB = \frac{CC}{D} = \frac{CAPITALCOST}{ANNUALSAVINGS}$$

A4.2.6 Sensitivity Analysis

Sensitivity Analysis is used to test the key variables in the cash flow and so determine the sensitivity of the project‘s NPV to changes in these variables. It is useful to test a variable in the cash flow that appears to offer significant risk or probability of occurring. The analysis becomes another useful tool when combined with others to improve the decision making process.

A4.3 Levelised Cost of Energy (LCOE) analysis

The LCOE analysis, also known as Levelised Energy Cost (LEC) analysis, is the cost of generating energy (e.g. electricity) for a particular energy system. It is an economic assessment of all the costs involved in the energy-generating system costs over its lifetime, including initial investment, operations and maintenance, cost of fuel, cost of capital.

An NPV is calculated whereby for the value of the LCOE chosen, the NPV of the project becomes zero. The LCOE is the minimum price at which energy must be sold for an energy project to break even.

LCOE is defined as follows:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

Where:

LCOE = Average lifetime levelised cost of energy
I_t = Investment expenditures in the year t
M_t = Operations and maintenance expenditures in the year t
F_t = Fuel expenditures in the year t
E_t = Electricity generation in the year t
R = Discount rate
N = Life of the system

Typically, LCOEs are calculated over 20 to 40 year lifetimes, and are given in the units of currency per kilowatt-hour (e.g. NZ$/kWh) or per megawatt-hour (NZ$/MWh).

When comparing LCOEs for alternative systems, it is important to define the boundaries of the 'system' and the costs that are included in it, whether for transmission lines and distribution systems, R&D, tax, environmental impact studies, costs of impacts on public health and environmental damage, or costs of government subsidies. The discount rate is also important as it depends on the cost of capital, the balance between debt-financing and equity-financing, and assessment of the financial risk.

A4.4 Life-Cycle Cost (LCC) analysis

This analysis evaluates all the annual costs and revenues associated with the acquisition, construction, operation and maintenance during the lifetime of the project. All recurring costs (those that occur every year over the span of the study period) are expressed as annual expenses incurred at the end of each year. Onetime costs (costs that do not occur every year over the span of the study period) are incurred at the end of the year in which they occur.

The present value of future one-time cost is defined as follows:

$$PV = A_t x \frac{1}{(1+d)^t}$$

Where:

PV = Present value
A_t = Amount of onetime cost at a time t
D = Real discount rate
t = Time (expressed as number of years)

To determine the present value of future recurring costs, the following formula is used:

$$PV = A_0 x \frac{(1+d)^t - 1}{Dx(1+d)^t}$$

Where:

PV = Present value
A_0 = Amount of recurring cost
D = Real discount rate
t = Time (expressed as number of years)

These values are summed-up by year and discounted back to time zero at some interest rate to arrive at a net present value (NPV). This process is repeated for each alternative and the alternatives are then compared, based on NPV or equivalent annual cost.

During LCC analysis, sensitivity analysis is performed from various parameters or variables to determine their effect on the feasibility of the project. The results are then evaluated to determine the effects of changing particular economic parameters and other financing scenarios on the outcome of the project.

The LCC analysis can also be used to evaluate the environmental performance of processes and products (inclusive of services) from "cradle to grave" and to identify potential cost savings. It identifies the material, energy and waste flows of a product over its entire life-cycle so that the environmental impacts can be determined. The LCA analysis can help the industry to identify changes to operations, including product design, which can lead to both environmental benefits and to cost savings.

A4.5 Weighted Average Cost of Capital (WACC) analysis

This determines the rate (or a discount rate, in %) that a company is expected to pay to debt holders (cost of debt) and shareholders (cost of equity) to finance its assets. It is also the minimum return that a company must earn on existing asset base to satisfy its creditors, owners, and other providers of capital.

Companies raise money from a number of sources, such as common equity, preferred equity, straight debt, convertible debt, exchangeable debt, warrants, options, pension liabilities, executive stock options, governmental subsidies, etc.. Different securities are expected to generate different returns. WACC is calculated by taking into account the relative weights of each component of the capital structure - debt and equity, and is used to see if the investment is worthwhile to undertake.

The discount rate is effectively a desired return or the return that an investor would expect to receive on some other typical proposal of equal risk. The New Zealand Treasury uses a 10% discount rate whenever there is no other agreed sector discount rate (New Zealand Treasury, 2005).

For financial analysis at the level of the organisation – not for national analysis of net benefit – the Department Capital Charge rate (7.5% in 2006/07) is used. The WACC is used for non-departmental projects (Crown Entities and State Owned Enterprises) or in unusual case where using the standard rate is inappropriate due to an abnormal amount of risk.

The formula for WACC is:

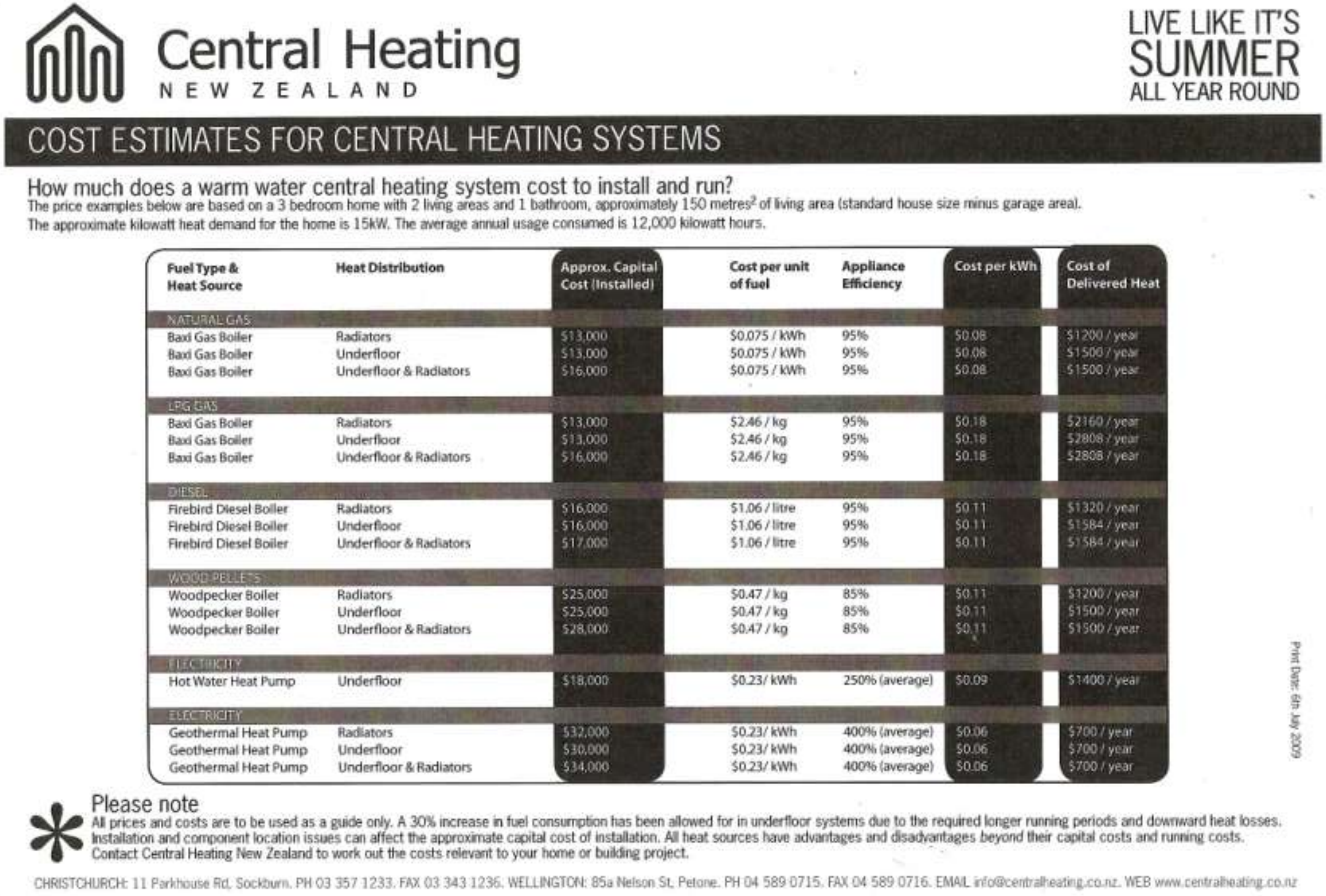
$$WACC = D \times \left(Costofdebt \right) + \left(1 - D \right) x \left(Costofequity \right)$$

Where:

D = %age of debt finance (in market value terms)
Cost of debt = (interest rate payable for the project) x (1 – corporate tax rate)
Cost of equity = {(risk free rate of return) x (1- tax rate of investor) + (equity beta) x (market risk premium)] + (1 – corporate tax rate)
Interest rate payable by government departments = risk free rate plus a premium of 1%.
Tax rate of the investor = assumed to be 0.28 (28%) in the past.
Values for the asset beta may be obtained from observed equity betas for listed companies

Estimates of the market risk premium in New Zealand have commonly ranged between 5% and 9%.

ANNEXES



Central Heating
NEW ZEALAND

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COST ESTIMATES FOR CENTRAL HEATING SYSTEMS

How much does a warm water central heating system cost to install and run?

The price examples below are based on a 3 bedroom home with 2 living areas and 1 bathroom, approximately 150 metres² of living area (standard house size minus garage area).
The approximate kilowatt heat demand for the home is 15kW. The average annual usage consumed is 12,000 kilowatt hours.

Fuel Type & Heat Source	Heat Distribution	Approx. Capital Cost (Installed)	Cost per unit of fuel	Appliance Efficiency	Cost per kWh	Cost of Delivered Heat
NATURAL GAS						
Baxi Gas Boiler	Radiators	$13,000	$0.075 / kWh	95%	$0.08	$1200 / year
Baxi Gas Boiler	Underfloor	$13,000	$0.075 / kWh	95%	$0.08	$1500 / year
Baxi Gas Boiler	Underfloor & Radiators	$16,000	$0.075 / kWh	95%	$0.08	$1500 / year
LPG GAS						
Baxi Gas Boiler	Radiators	$13,000	$2.46 / kg	95%	$0.18	$2160 / year
Baxi Gas Boiler	Underfloor	$13,000	$2.46 / kg	95%	$0.18	$2808 / year
Baxi Gas Boiler	Underfloor & Radiators	$16,000	$2.46 / kg	95%	$0.18	$2808 / year
DIESEL						
Firebird Diesel Boiler	Radiators	$16,000	$1.06 / litre	95%	$0.11	$1320 / year
Firebird Diesel Boiler	Underfloor	$16,000	$1.06 / litre	95%	$0.11	$1584 / year
Firebird Diesel Boiler	Underfloor & Radiators	$17,000	$1.06 / litre	95%	$0.11	$1584 / year
WOOD PELLETS						
Woodpecker Boiler	Radiators	$25,000	$0.47 / kg	85%	$0.11	$1200 / year
Woodpecker Boiler	Underfloor	$25,000	$0.47 / kg	85%	$0.11	$1500 / year
Woodpecker Boiler	Underfloor & Radiators	$28,000	$0.47 / kg	85%	$0.11	$1500 / year
ELECTRICITY						
Hot Water Heat Pump	Underfloor	$18,000	$0.23/ kWh	250% (average)	$0.09	$1400 / year
ELECTRICITY						
Geothermal Heat Pump	Radiators	$32,000	$0.23/ kWh	400% (average)	$0.06	$700 / year
Geothermal Heat Pump	Underfloor	$30,000	$0.23/ kWh	400% (average)	$0.06	$700 / year
Geothermal Heat Pump	Underfloor & Radiators	$34,000	$0.23/ kWh	400% (average)	$0.06	$700 / year

Print Date: 6th July 2009

Please note

All prices and costs are to be used as a guide only. A 30% increase in fuel consumption has been allowed for in underfloor systems due to the required longer running periods and downward heat losses. Installation and component location issues can affect the approximate capital cost of installation. All heat sources have advantages and disadvantages beyond their capital costs and running costs. Contact Central Heating New Zealand to work out the costs relevant to your home or building project.

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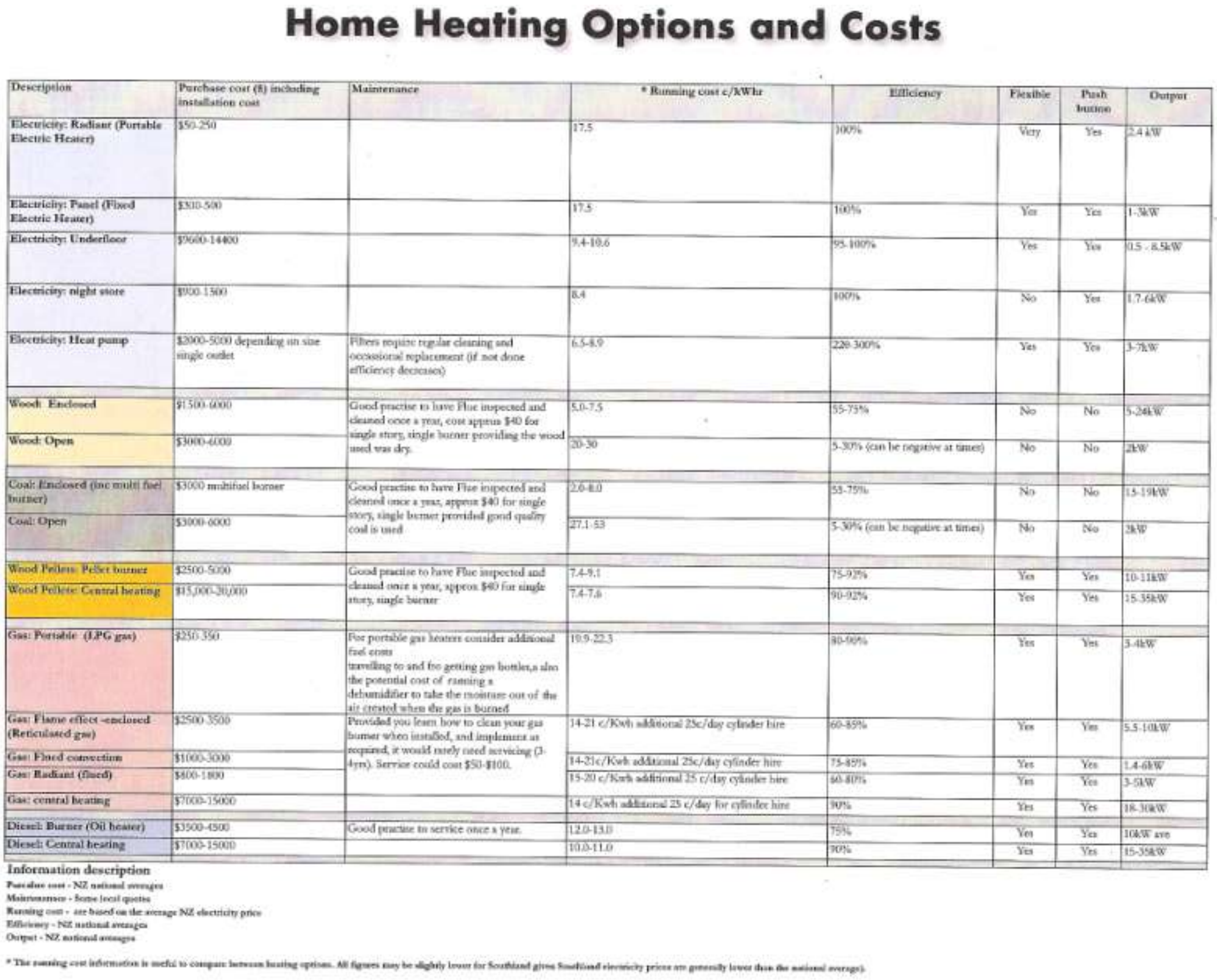
Annex A – Cost estimates for central heating systems – Central Heating NZ



Home Heating Options and Costs

Description	Purchase cost ($) including installation cost	Maintenance	* Running cost c/kWhr	Efficiency	Flexible	Push button	Output
Electricity: Radiant (Portable Electric Heater)	$50-250		17.5	100%	Very	Yes	2.4 kW
Electricity: Panel (Fixed Electric Heater)	$300-500		17.5	100%	Yes	Yes	1-3kW
Electricity: Underfloor	$9600-14400		9.4-10.6	95-100%	Yes	Yes	0.5 - 8.5kW
Electricity: night store	$900-1500		8.4	100%	No	Yes	1.7-6kW
Electricity: Heat pump	$2000-5000 depending on size single outlet	Filters require regular cleaning and occasional replacement (if not done efficiency decreases)	6.5-8.9	220-300%	Yes	Yes	3-7kW
Wood: Enclosed	$1500-6000	Good practise to have Flue inspected and cleaned once a year, cost approx $40 for single story, single burner providing the wood used was dry.	5.0-7.5	55-75%	No	No	5-24kW
Wood: Open	$3000-6000		20-30	5-30% (can be negative at times)	No	No	2kW
Coal: Enclosed (inc multi fuel burner)	$3000 multifuel burner	Good practise to have Flue inspected and cleaned once a year, approx $40 for single story, single burner provided good quality coal is used	2.0-8.0	55-75%	No	No	15-19kW
Coal: Open	$3000-6000		27.1-53	5-30% (can be negative at times)	No	No	3kW
Wood Pellets: Pellet burner	$2500-5000	Good practise to have Flue inspected and cleaned once a year, approx $40 for single story, single burner	7.4-9.1	75-92%	Yes	Yes	10-11kW
Wood Pellets: Central heating	$15,000-20,000		7.4-7.6	90-92%	Yes	Yes	15-35kW
Gas: Portable (LPG gas)	$250-350	For portable gas heaters consider additional fuel costs travelling to and fro getting gas bottles,s also the potential cost of running a dehumidifier to take the moisture out of the air created when the gas is burned	10.9-22.3	80-90%	Yes	Yes	3-4kW
Gas: Flame effect -enclosed (Reticulated gas)	$2500-3500	Provided you learn how to clean your gas burner when installed, and implement as required, it would rarely need servicing (3-4yrs). Service could cost $50-$100.	14-21 c/Kwh additional 25c/day cylinder hire	60-85%	Yes	Yes	5.5-10kW
Gas: Fixed convection	$1000-3000		14-21c/Kwh additional 25c/day cylinder hire	75-85%	Yes	Yes	1.4-6kW
Gas: Radiant (fixed)	$800-1800		15-20 c/Kwh additional 25 c/day cylinder hire	60-80%	Yes	Yes	3-5kW
Gas: central heating	$7000-15000		14 c/Kwh additional 25 c/day for cylinder hire	90%	Yes	Yes	18-30kW
Diesel: Burner (Oil heater)	$3500-4500	Good practise to service once a year.	12.0-13.0	75%	Yes	Yes	10kW ave
Diesel: Central heating	$7000-15000		10.0-11.0	90%	Yes	Yes	15-35kW

Information description

Purchase cost - NZ national averages
Maintenance - Some local quotes
Running cost - are based on the average NZ electricity price
Efficiency - NZ national averages
Output - NZ national averages

* The running cost information is useful to compare between heating options. All figures may be slightly lower for Southland given Southland electricity prices are generally lower than the national average).

Annex B – Home heating options & costs – Environment Southland & Nature's Flame

Annex C – Domestic central heating options and costs – New Zealand

Domestic central heating options

Option	1	2	3	4	5	6	7	7a	7b	7c	7d	7e	7f
Particulars	Electricity ASHP	Wood	Coal (open-fire)	Wood pellets	LPG/ Natural gas	Diesel	GHP	GHP @ 10% cost	GHP @ 20% cost	GHP @ 30% cost	GHP @ 40% cost	GHP @ 50% cost	GHP @ 60% cost
Capital cost (Purchase & Installation), $	8,000	6,000	6,000	28,000	16,000	17,000	34,000	30,600	27,200	23,800	20,400	17,000	13,600
Life (years)	15	15	15	15	15	15	15	15	15	15	15	15	15
Salvage value	0	0	0	0	0	0	0	0	0	0	0	0	0
Output, kW	10	24	3	35	30	35	15	15	15	15	15	15	15
kW demand for the house	15	15	15	15	15	15	15	15	15	15	15	15	15
Equivalent annual operation, hours	1,200	500	4,800	343	400	343	800	800	800	800	800	800	800
Equivalent annual operation, days	50	21	200	14	17	14	33	33	33	33	33	33	33
Annual consumption, kWh	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000	12,000
Running cost, $/kWh	0.1	0.1	0.55	0.125	0.21	0.09	0.051	0.051	0.051	0.051	0.051	0.051	0.051
CO_2 gas emissions (mg/MJ)	0	102,000	118,000	80,200	55,300	80,200	0	0	0	0	0	0	0
CO_2 cost ($/t$CO_2$)	25	25	25	25	25	25	25	25	25	25	25	25	25
Carbon Charge ($)	0	0	127	0	60	87	0	0	0	0	0	0	0
Fixed connection charge, $/day	0.639	0	0	0	0	0	0	0	0	0	0	0	0
Bottled gas, delivered, $/kWh	0	0	0	0	0	0	0	0	0	0	0	0	0
Cylinder hire, $/day	0	0	0	0	0	0	0	0	0	0	0	0	0
Reticulated natural gas. $/kWh	0	0	0	0	1200	0	0	0	0	0	0	0	0
Connection charge, $/day	32	0	0	0	15	0	0	0	0	0	0	0	0
Cost of delivered heat ($/yr)	1,264	1,200	6,600	1,500	3,735	1,080	612	612	612	612	612	612	612
Annual maintenance (1% of capital cost)	80	60	60	280	160	170	340	306	272	238	204	170	136
Annual insurance (0.35% of capital cost)	28	21	21	98	56	60	119	107	95	83	71	60	48
Annual property tax (0.15% of capital cos	12	9	9	42	24	26	51	46	41	36	31	26	20
Compressor replacement - end-of-year 1	34	0	0	0	0	0	0	0	0	0	0	0	0

Note: 1) For A-to-A HP, maintenance cost = 1.5% of capital cost and compressor replacement - end-of-year 10 = 0.42% of capital cost. Based on a 3 bedroom home with 2 living areas and 1 bathroom, approximately 150 m2 of living area (standard house minus annual usage consumed is 12000 kWh. A 30% increase in fuel consumption has been allowed for in underfloor systems due to the required longer running periods and downward heat losses.

Sources: MfE (2005), Central Heating NZ (2009), Nature's Flame (2009)