

## The Development of a Basic Cost and Performance Estimator for Geothermal Power Plants

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### **Abstract**

This report describes the development of a Microsoft Excel spreadsheet spread-sheet that can be used to estimate cost and performance of geothermal power plants in an Australian context. Power plant specifications, performance and itemised costs reported in the Next Generation Geothermal Power Plants (NGGPP) study [1, 2] are reviewed and analysed in the Australian Context (Section 4). The estimator uses the NGGPP data, which was determined at site-specific conditions, to predict cost and performance of plants at variable scale, geofluid temperature and ambient temperature. The procedures used in the estimator are explained in Section 5.

### **1 Introduction**

The Australian Geothermal Energy Group has identified a need for a basic cost-estimator to estimate the likely performance of power plant and of the capital cost of the plant required for power generation in an Australian context. While a number of tools have been, or are being, developed internationally, these do not take into account the local environmental and economic conditions in Australia. For example, the MIT model [3, 4] estimates power output solely from the temperature of the geo-fluid, and so does not take into account ambient temperature or the anticipated need to use air-cooling for the condenser in an Australian context. Likewise, while the US DOE is developing its own more detailed cost estimator [6, 7], this is not yet available and will necessarily be developed for the US context. Furthermore, while significant information is now available from which to estimate costs [1, 2], these have not yet been developed into a simple tool that can be used by the Australian geothermal sector to obtain a reasonable preliminary estimate of plant performance and capital costs. The present report aims to meet this need.

There are, of course, a wide range of technologies that have been, or are being, developed to extract energy from geothermal resources [5]. These include both stand-alone geothermal systems and hybrid approaches. However, only a few of these options are commercially available. Furthermore, the optimal system will necessarily depend on a wide range of locally specific conditions, of which geofluid temperature is only one. These are best developed on a case-by-case basis with specific expertise beyond what is possible from a simple cost-estimator. Furthermore, any more advanced option would need to use established systems as a key point of reference. For this reason, the present system aims to develop the cost estimator only for two representative systems of greatest commercial relevance to presently-available stand-alone geothermal power generation in Australia.

## 2 Scope

The scope of the present cost-estimator is limited to the consideration of equipment within the power block of a geothermal project. The two systems chosen on which to base the development of the cost estimator are the double flash steam and organic Rankine cycle (ORC) power plants. These are the best established technologies that are also of widest relevance to the expected temperature ranges of 130 – 300 °C being considered for Australian projects. At the lower end of this temperature range, single stage systems may be competitive, and at the upper end three-stage flash systems may become viable and ORC's become ineffective. Nevertheless, these two cycles are well suited to the present aim of providing broadly representative technologies as a reference for a basic cost-estimator.

Since the majority of Australian geothermal sites will not have sufficient water available to utilise it for cooling, only air-cooled plants are investigated. Additionally, most Australian geothermal projects will be based on Hot Rock reservoirs, in which levels of non-condensable gas (NCG) and H<sub>2</sub>S are expected to be low relative to those found in hydrothermal reservoirs. Therefore the scope of the present cost and performance estimates consider only geofluids containing not more than 0.2 % NCG and negligible H<sub>2</sub>S.

## 3 GETEM and the NGGPP study

The U.S. Department of Energy (DOE) has developed a spreadsheet model named GETEM (Geothermal Electricity Technologies Evaluation Model) to estimate how specific technology improvements may affect the cost of geothermal electricity, thus allowing prioritisation of research efforts [3]. At the time of writing, this model is not available to the public. However, the model developers have stated that a primary source of information was the Next Generation Geothermal Power Plants (NGGPP) study [1, 2], which

“..provides the only firm estimates - in the public domain - of the cost and performance of U.S. geothermal power systems and their main components in the early 1990s.” [2]

The NGGPP study provides detailed data on the cost and performance of conventional flash steam and binary cycles, as well as advanced cycles such as the Kalina cycle, for specific US sites. The principal investigators were from companies involved in the design and construction of geothermal power plants, and in the production of geothermal power plant equipment. The study based its estimates on plants producing 50 MWe net power for transmission to the grid. Figure 1 shows estimates for the specific cost of geothermal projects (in 1995 US\$/kW) versus geofluid temperature. Estimates for projects using double-flash, ORC and Kalina Cycle plants are shown. While these estimates were developed for specific hydrothermal reservoirs so that they are therefore not generally applicable, they nevertheless indicate how the choice of power plant affects the cost of power at a given geofluid temperature. Some notable observations are:

- ORC and Kalina Cycle plants are advantageous at temperatures less than 200 °C, while double-flash plants are advantageous at higher temperatures.
- The specific cost of projects using ORC power plants is approximately the same regardless of whether air-cooling or water-cooling is used.
- Kalina Cycle 11 is advantageous relative to an ORC for temperatures of 150 °C and less.
- Costs are not characterised by smooth trends since the estimates were based on real geothermal sites. Extra costs associated with non-condensable gas removal and H<sub>2</sub>S abatement lead to anomalous overall costs, eg. at 266 °C and 274 °C.

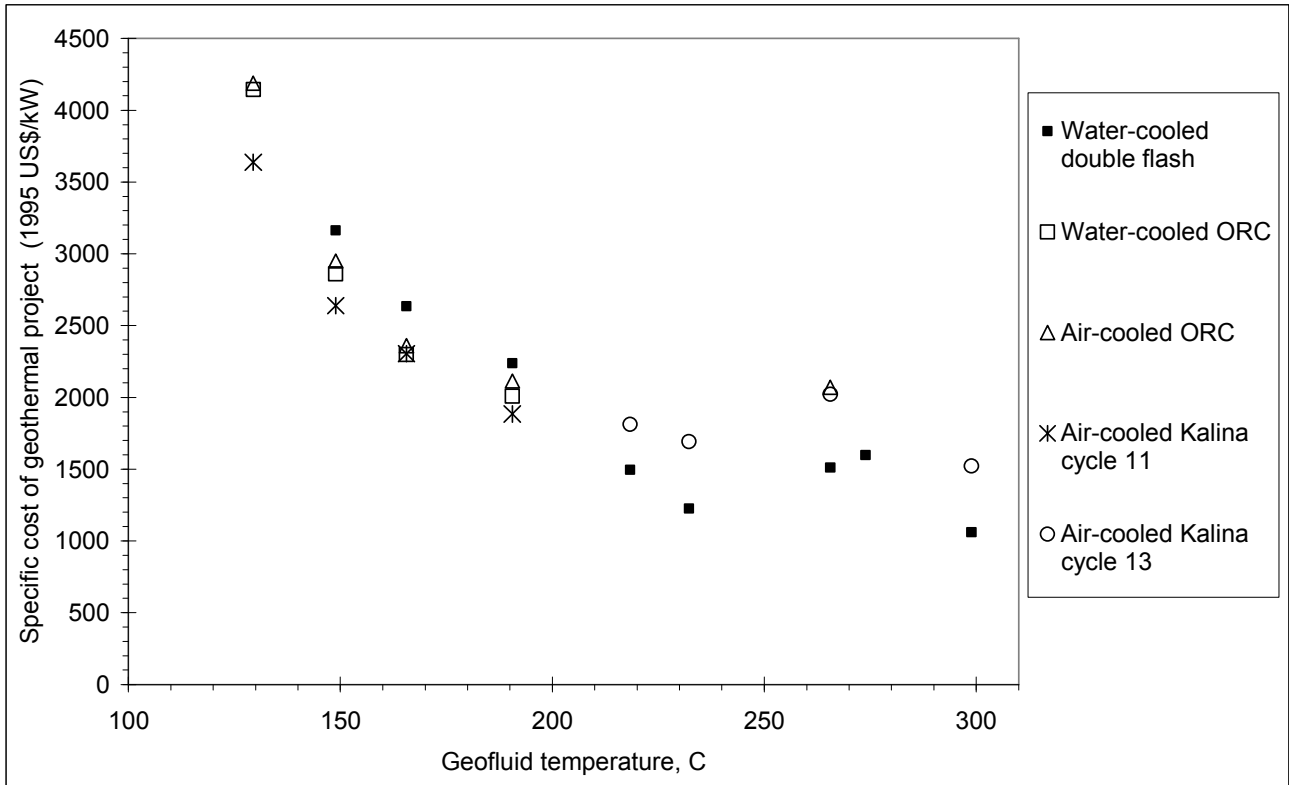


Figure 1: Specific cost of geothermal projects versus geofluid temperature, as estimated in the NGGPP study [1]. Specific cost is determined as the entire cost of the project divided by net power transmitted to the grid, and is shown in 1995 US\$/kW.

#### 4 Analysis of NGGPP data

As the NGGPP study contains detailed and recent cost information available in the public domain, we have extracted relevant data from that study in order to provide estimates of power block costs and efficiencies for Australian geothermal projects. We define the power block of a geothermal project as comprising all equipment required for converting heat in the geofluid to electrical power. Geofluid pumps are deemed to be outside of the power block. This is because the parasitic losses associated with underground circulation depend on a wide-range of site-specific, geological parameters that are beyond the scope of the present investigation.

Flows of mass and energy associated with the power block are illustrated in Figure 2. The quantities of particular interest to the present report are:

1. Net power before geofluid pumping,  $P_{NBGP}$  (kW).
2. Geofluid effectiveness (net before geofluid pumping),  $\frac{P_{NBGP}}{\dot{m}_{GF}}$  (kJ/kg).

The net power before geofluid pumping will serve as the basis for power block cost comparisons, while the geofluid effectiveness (before geofluid pumping) is a measure of power block efficiency.

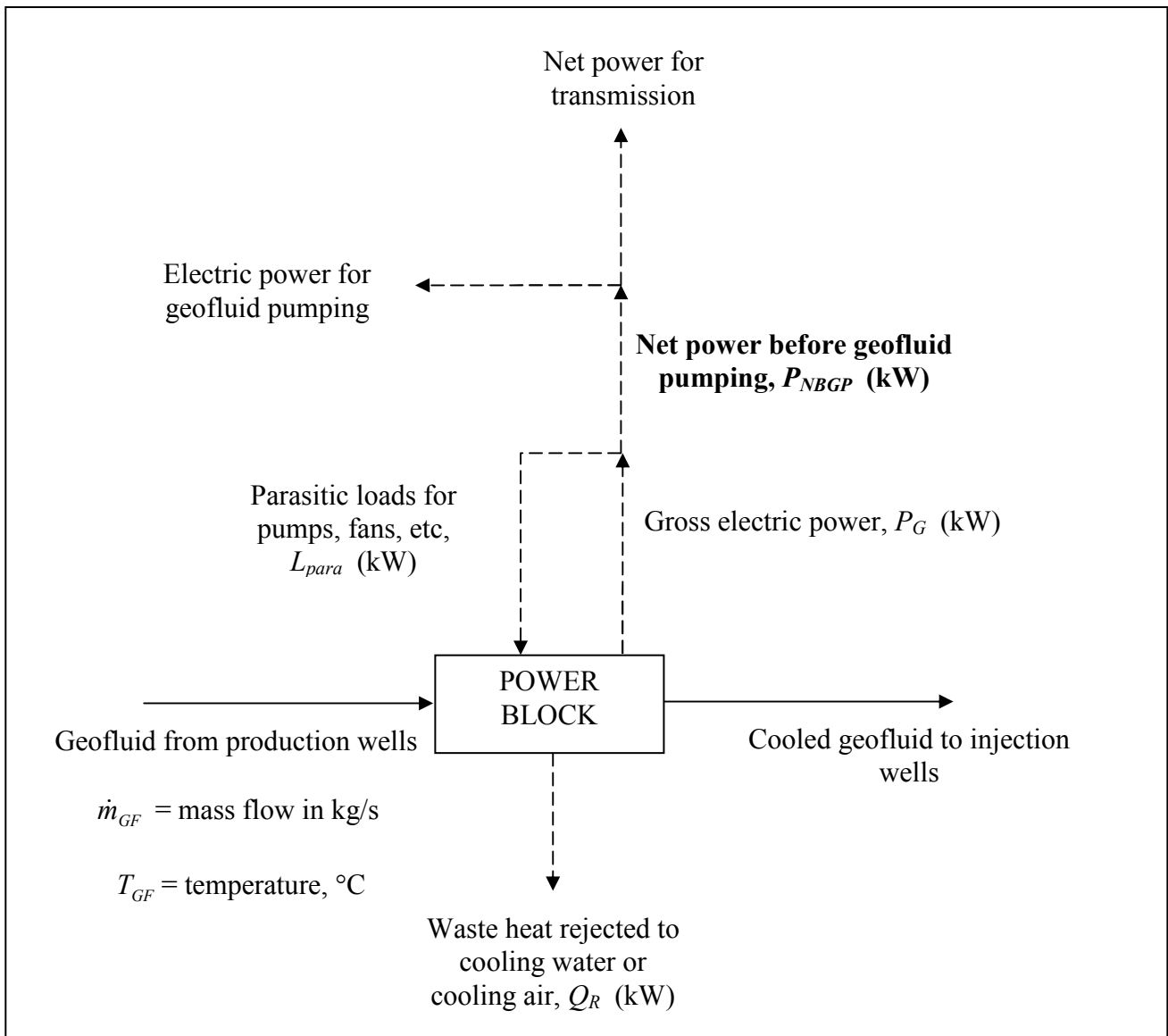


Figure 2: Mass and energy flows associated with the power block.

#### 4.1 Performance

Figure 3 shows NGGPP study data for geofluid effectiveness versus geofluid temperature for air-cooled double flash and ORC plants. The double flash data has been adjusted to represent air-cooled plants by methods that are explained in Section 4.2.1. ORC plants use commercial grade isobutane as the working fluid. It is observed that ORC plants are significantly more efficient than double flash plants over the 129-232 °C temperature range, eg. 23 % more effective at 232 °C. This is mainly due to the higher condensing temperatures employed in the flash plants, which is necessary in order to limit the size of steam turbines to an economic optimum [9].

Figures 4 and 5 show the percentage of gross power consumed by parasitic loads in air-cooled ORC and double flash plants respectively. The ORC plants lose 17-21 % of gross power to parasitic loads, which is significantly greater than the percentage lost by double flash plants over the same range of geofluid temperatures (10-12 %). Most of the difference is attributable to the ORC working fluid pump, which must deliver high pressures, eg. 15 bar increase for geofluids at 129 °C and up to 57

bar for geofluids at 191 °C. The working fluid pump load causes the total parasitic percentage of gross power to increase with geofluid temperature, whereas that for double flash plants decreases.

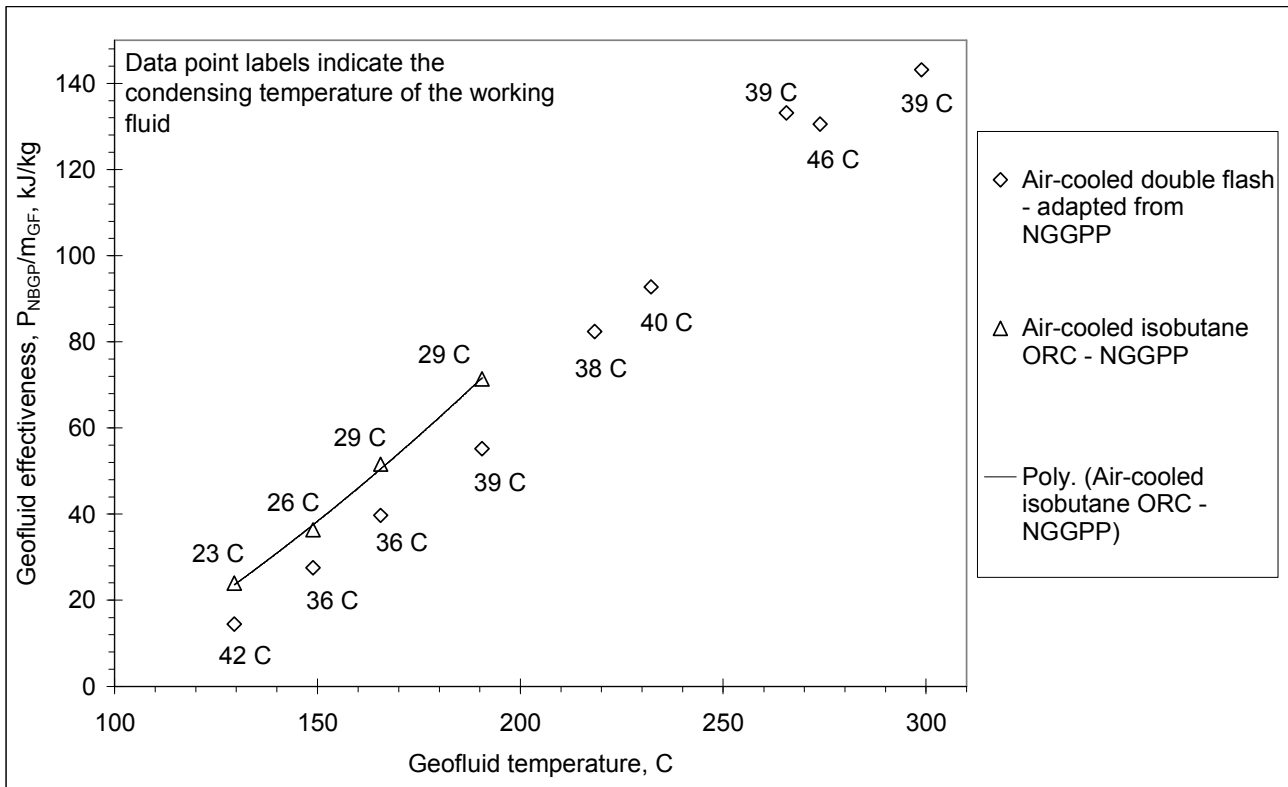


Figure 3: Geofluid effectiveness of air-cooled double flash and ORC plants versus geofluid temperature, adapted from NNGPP study [1].

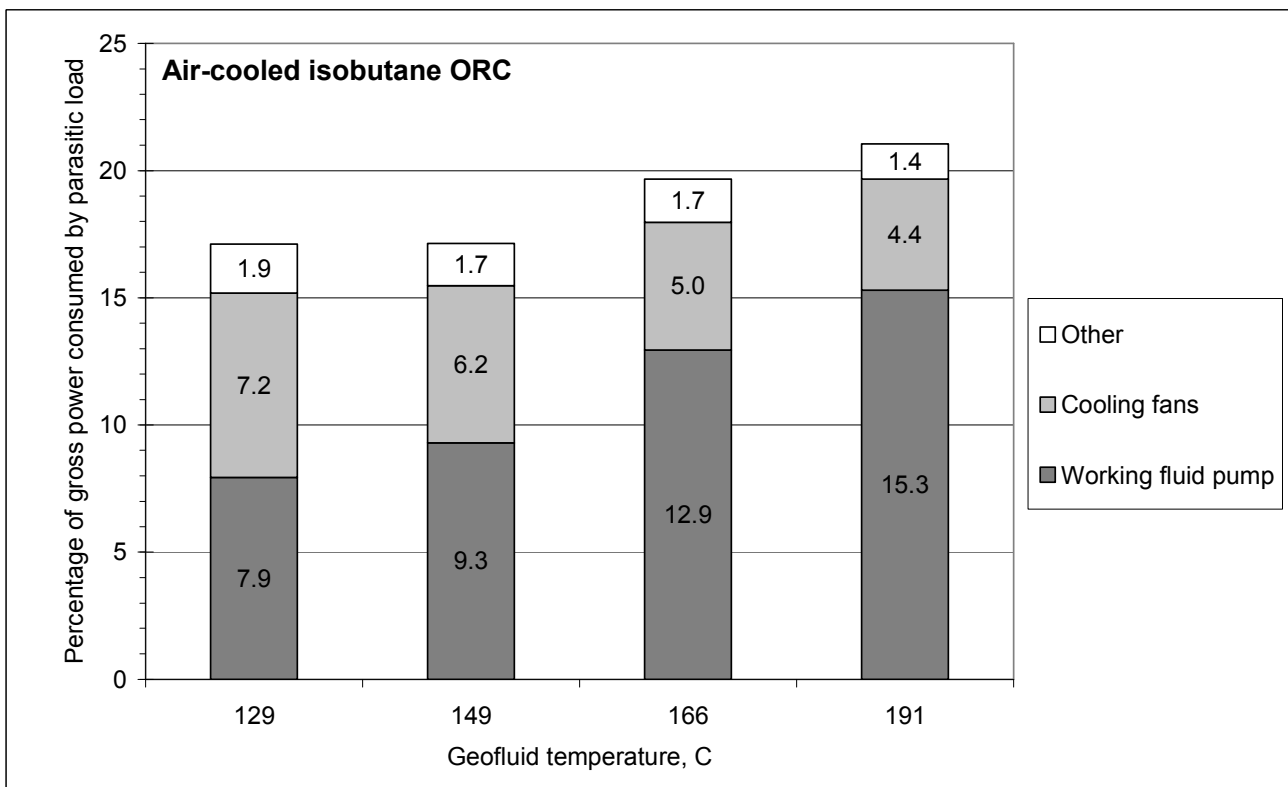


Figure 4: Percentage of gross power consumed by parasitic loads for air-cooled ORC plants in versus geofluid temperature (adapted from NNGPP study [1]).

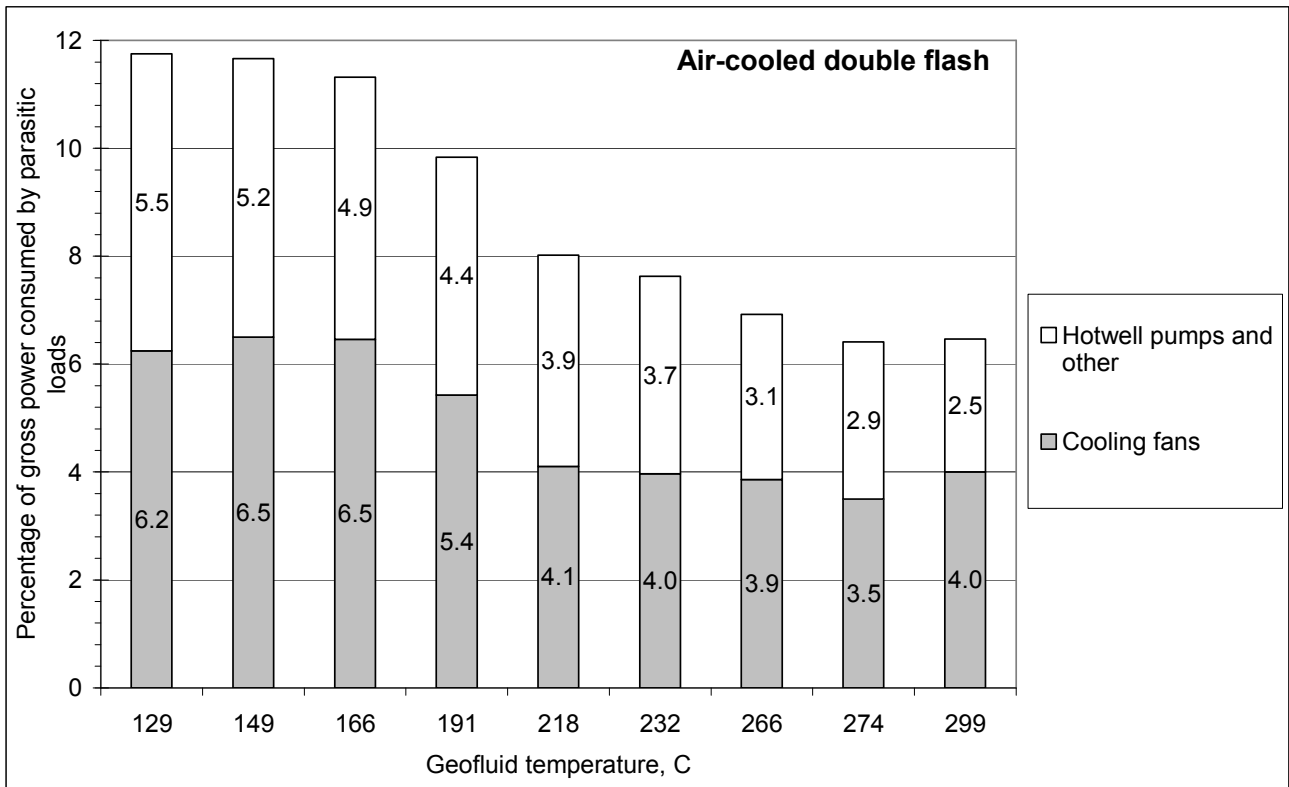


Figure 5: Percentage of gross power consumed by parasitic loads for air-cooled double flash plants versus geofluid temperature (adapted from NGGPP study [1]).

## 4.2 Capital Cost

The total fixed capital investment in the power block can be estimated following the categories of costs listed in Table 1, given by Peters and Timmerhaus [4] for processing plants. In practice, cost factors are commonly used to determine total fixed capital investment. The total purchased (ex-factory) equipment cost for the plant is multiplied by a cost factor,  $f$ , which is formulated based on prior industry experience. The NGGPP study generally used cost factors of 2.53 for double flash plants and of 2.8 for ORC and Kalina Cycle plants.

Table 1: Typical percentages of fixed-capital investment values for direct and indirect cost segments for multipurpose plants [8].

Component	Range, %
<b>Direct costs</b>	
Purchased equipment	15-40
Purchased-equipment installation	6-14
Instrumentation and controls (installed)	2-8
Piping (installed)	3-20
Electrical (installed)	2-10
Buildings (including services)	3-18
Site development	2-5
Service facilities (installed)	8-20
Land	1-2
<b>Indirect costs</b>	
Engineering and supervision	4-21
Construction expense	4-16
Contractor's fees	2-6
Contingency	5-15

The specific purchased cost of power block equipment items is defined in this report as the purchased cost,  $E_i$ , divided by the net power before geofluid pumping:

$$\text{Specific purchase cost of item } i = \frac{E_i}{P_{NBGP}}$$

The specific purchased costs of air-cooled ORC and double flash plant components, as estimated from the NGGPP study [1], are shown in 6 and 7 respectively. The similarly estimated percentages of total purchased cost shown in Figures 8 and 9. Figure 10 shows on a single graph the cost data for both types of plant to facilitate comparison. The highest-cost components in both types of plant are the turbogenerator (turbine and electric generator combination) and air-cooled condenser. The heat exchangers of ORC plants, which transfer heat from the geofluid to the working fluid, are also a significant cost item. Other plant components are 5 % or less of total purchased equipment cost for ORC plants and generally 9-14 % for double flash plants. At 149 °C and 166 °C the double flash plants incur a relatively high cost for non-condensable gas removal, adding 9 % and 4 % to the total equipment cost respectively. The double flash plant for the 300 °C geofluid has a large air-cooling cost due to a relatively high average ambient temperature at the site, ie. 23.4 °C (Salton Sea), compared with 9-12 °C at the other sites represented in Figure 10.

Figure 11 shows that the total specific purchased cost of ORC plants is less than that of double flash plants for geofluid temperatures of less than 191 °C. The following sections will discuss in greater detail the equipment items contributing most to the cost of each type of plant in order to explain this and other trends in Figures 6-10.

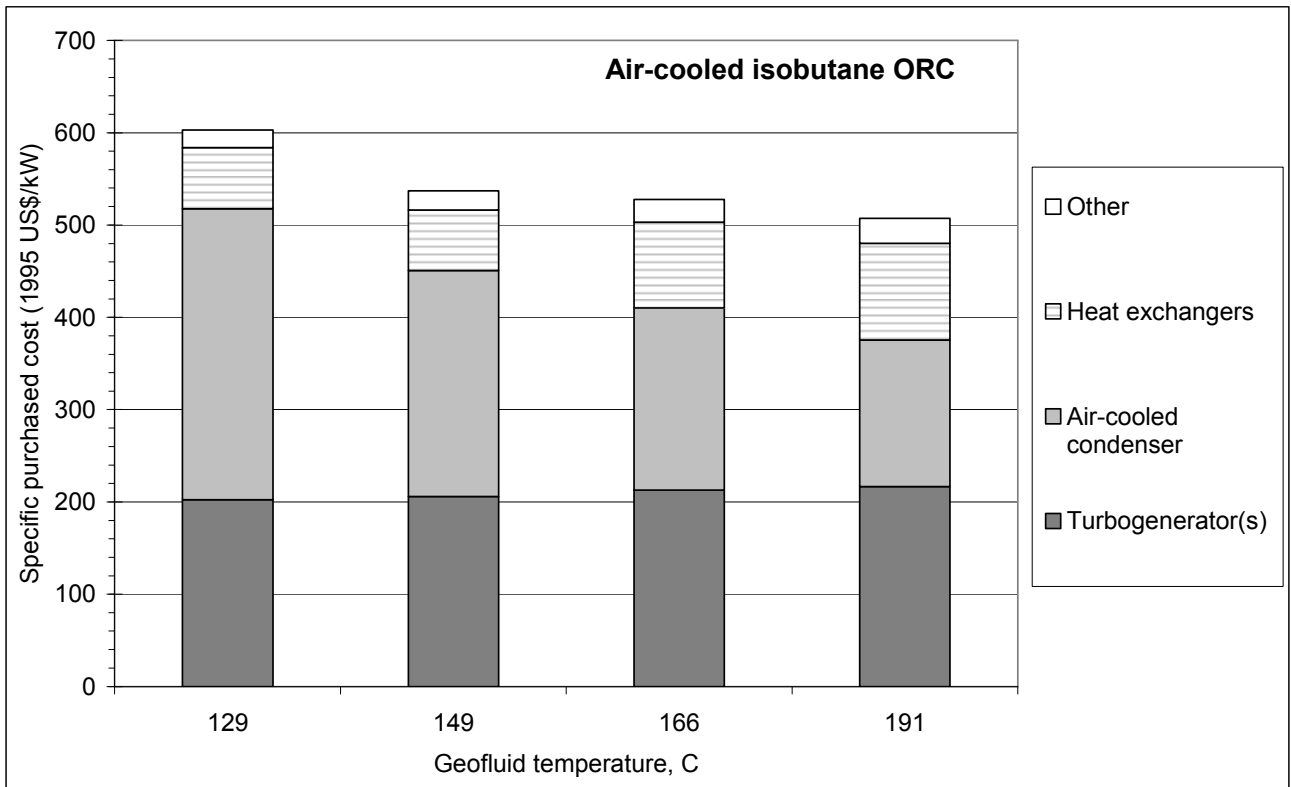


Figure 6: Specific purchased cost of components for air-cooled ORC plants versus geofluid temperature, as estimated from the NNGPP study [1].

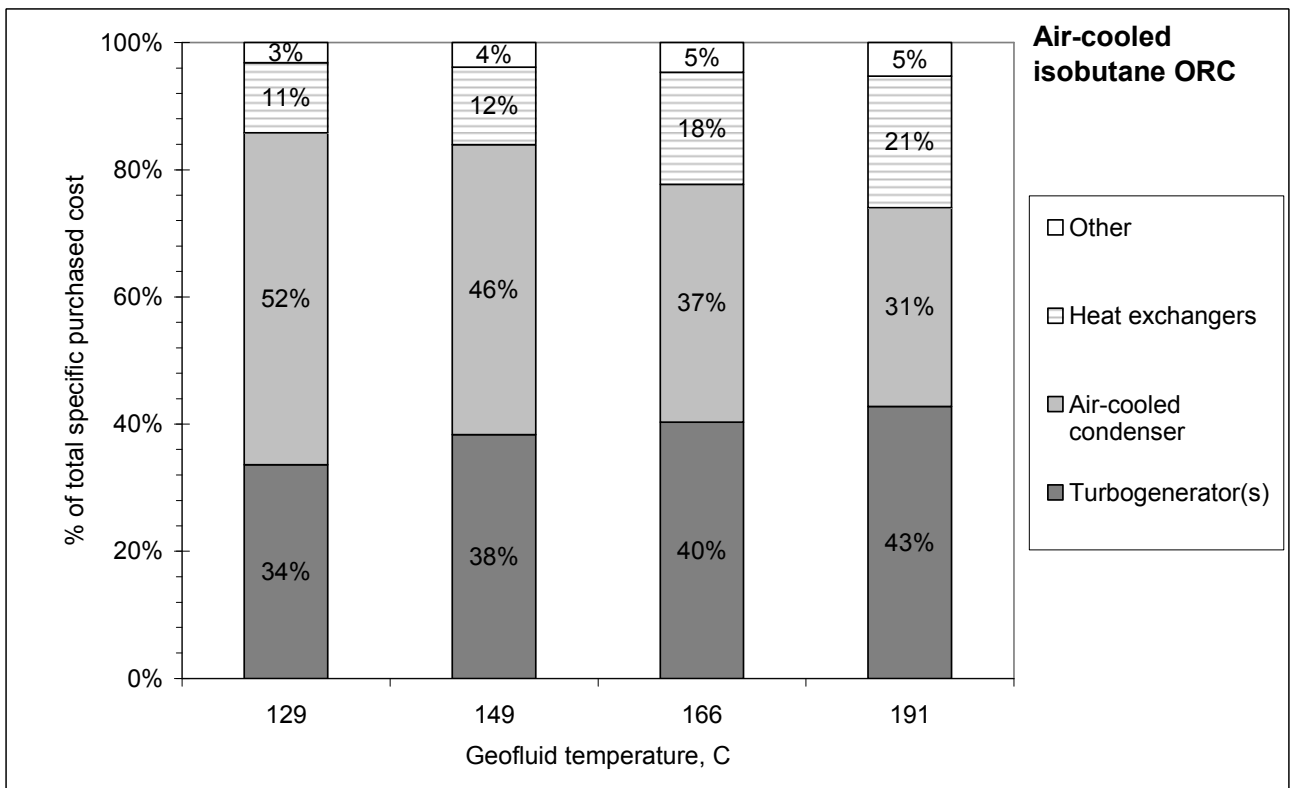


Figure 7: Percentage of total purchased cost for air-cooled ORC plant components versus geofluid temperature, as estimated from the NNGPP study [1].

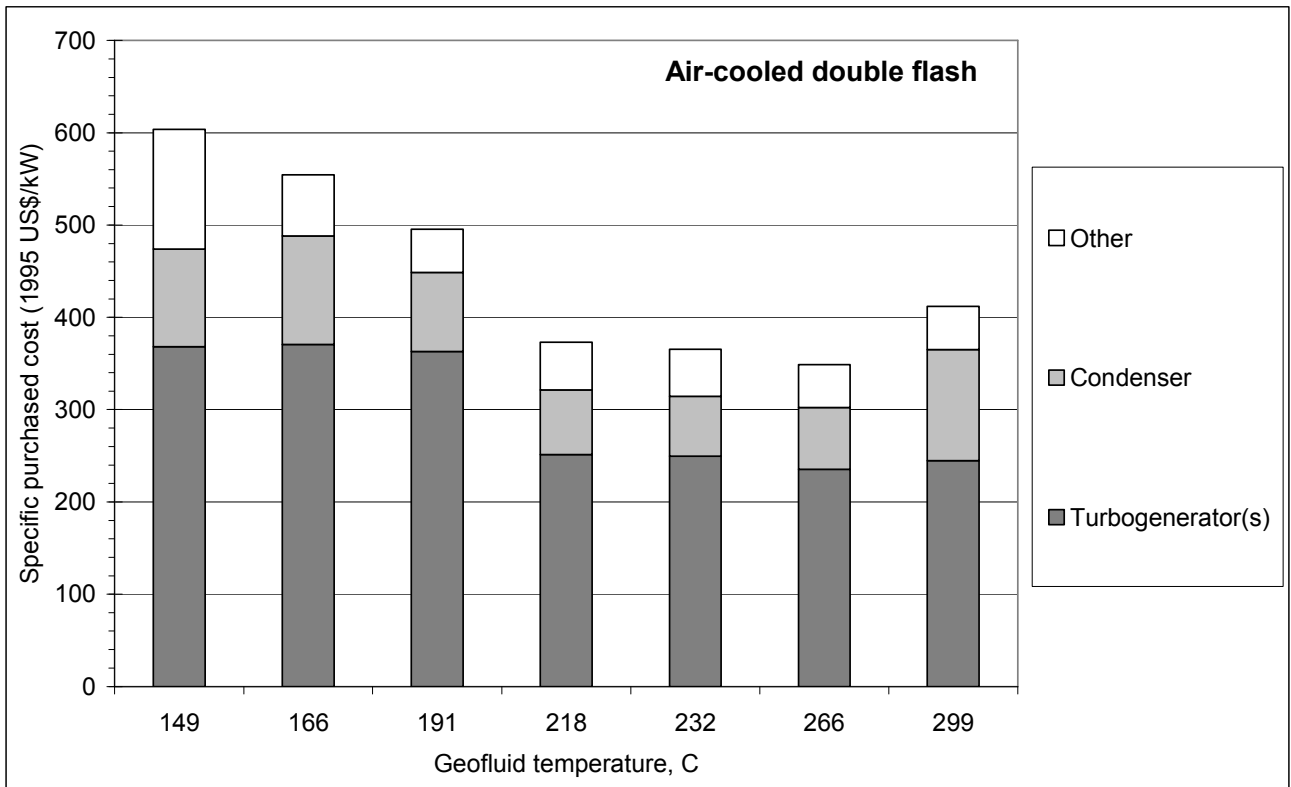


Figure 8: Specific purchased cost of components for air-cooled double flash plants versus geofluid temperature, adapted from NGGPP study [1].

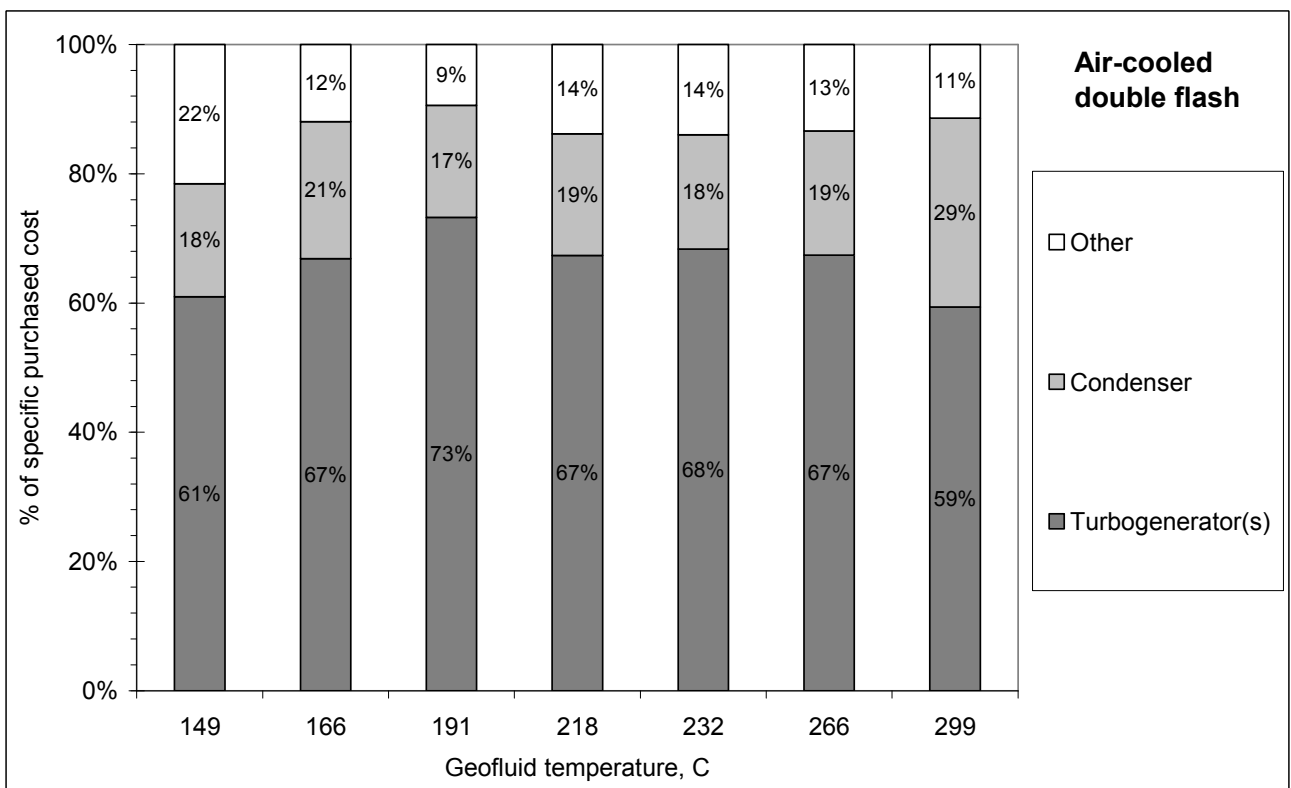


Figure 9: Percentage of total purchased cost for air-cooled double flash plant components versus geofluid temperature, adapted from NGGPP study [1].

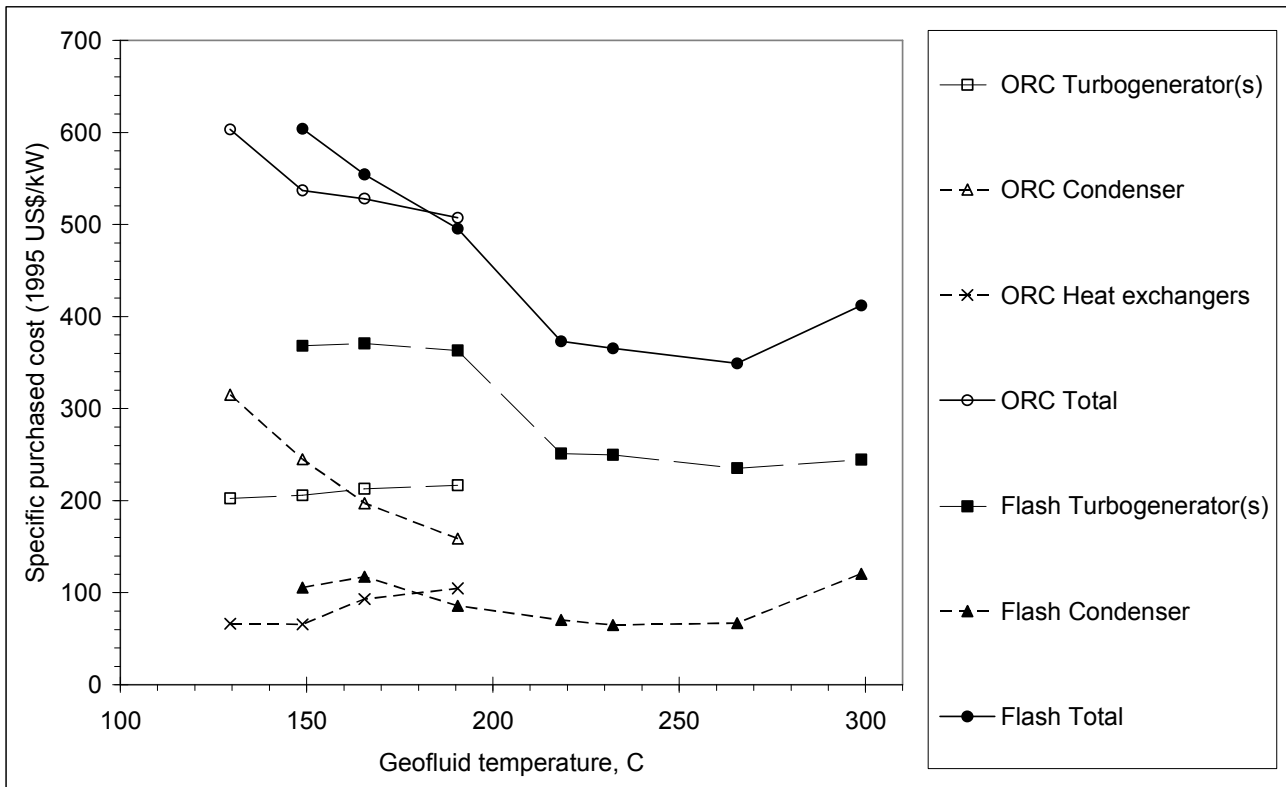


Figure 10: Specific purchased cost of components for air-cooled ORC and double flash plants versus geofluid temperature, adapted from NGGPP study [1].

#### 4.2.1 Air-cooled condensers

Air-cooled condensers consist of finned tubes over which air is forced (or drawn) by fans. It is evident from the NGGPP data for ORC plants [1] that the ratio of fan load to rejected heat was assumed to be fixed at 0.00897. This ratio was used to determine the fan load for air-cooled double flash plants, since the NGGPP study only considered water-cooling for double flash plants.

The relationship governing condenser cost was determined from the NGGPP data for ORC plants. For each geofluid temperature between 129 °C and 191 °C, the bare-tube heat exchange surface area was calculated from the given cycle specifications and reasonable values of assumed heat transfer coefficients. The air-cooled condenser cost as a function of bare-tube area is shown in Figure 11. The power law trend-line was used to determine an air-cooled condenser cost for double flash plants, assuming that the ambient air is heated by 5 K.

Figure 10 shows that the cost of air-cooled condensers is comparatively higher for ORC plants than for double flash plants. This is mainly a result of the smaller temperature difference between air and the condensing fluid in ORC plants, which increases the heat exchange surface area required per unit heat rejected. Another contributing factor is the more favourable heat transfer coefficient assumed for steam condensation ( $800 \text{ W m}^{-2} \text{ K}^{-1}$ ) compared with that for isobutane ( $570 \text{ W m}^{-2} \text{ K}^{-1}$ ).

As geofluid temperature decreases, the cost of condensers for ORC plants increases significantly. This trend is the result of two factors:

1. The thermal efficiency of plants decreases unavoidably, meaning that more waste heat must be rejected per unit of power generated
2. The mean temperature difference between ambient air and the condensing fluid decreases in an effort to achieve optimum efficiency. This causes the cost per unit rejected heat to increase.

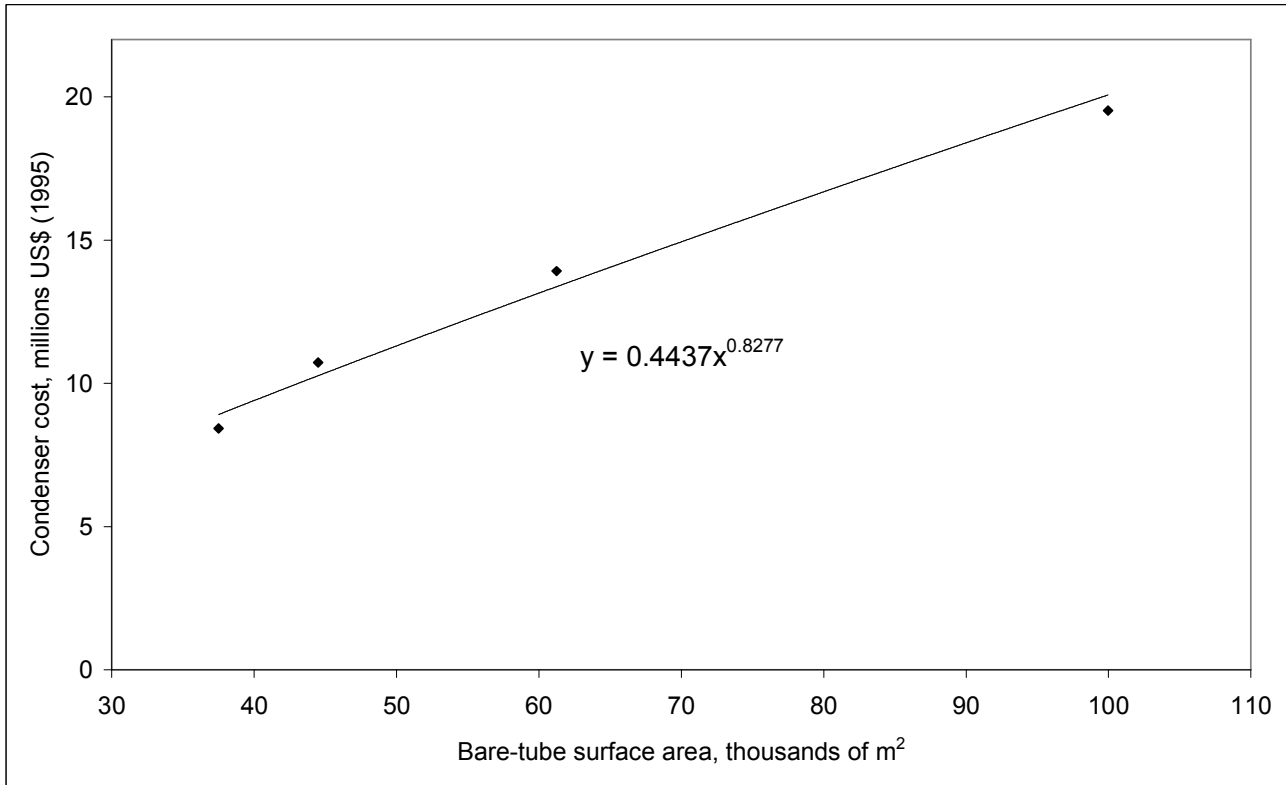


Figure 11: Air-cooled condenser cost for ORC plants in NGGPP study versus estimated bare-tube surface area.

#### 4.2.2 Turbogenerators

The turbogenerator contributes 34-43 % of purchased equipment cost for ORC plants, and 59-73 % for double flash plants. Axial turbines were chosen for both plant types in the NGGPP study [1]. Axial turbine cost is mainly a function of the exhaust stage diameter, as illustrated by a model developed by the Barber-Nichols company [9]:

$$\phi_T = n_e [1 - 0.04(n_e - 1)] f_2 \left[ 30135 n_s f_1 D_p^{2.1} + 16775 D_p^3 + 20720 D_p^2 \right] + 225000 \left( \frac{MWe}{10} \right)^{0.7}$$

where

$\phi_T$  = Total turbogenerator cost, 1976 US\$

$n_e$  = Number of exhaust ends,  $\leq 4$  for tandem configurations on the same shaft

$n_s$  = Number of turbine stages

$f_1$  = Blade tip speed correction factor

$f_2$  = Pressure correction factor

$D_p$  = Last turbine stage pitch diameter (mean of tip and hub diameters), m

$MWe$  = Electric output in MW

The model is applicable for outputs of 1-100 MWe and for  $h^*/D_p$  ratios of 0.03 to 0.11, where  $h^*$  is the blade length of the last turbine stage. The  $(30135n_s f_1 D_p^{2.1})$  term is a stage cost accounting for rotor and stator costs, as well as casing and shaft costs associated the stages. It is a dominant term, such that the overall turbine cost is approximately proportional to  $D_p^{2.1}$ .

The last stage diameter is dependent on the sonic velocity of the working fluid (which cannot be exceeded in the nozzles of the final stage) and the turbine rotational speed, eg. 3000 rpm. The final stage diameter has a practical limit for a particular rotational speed and this limits the power output per exhaust end in the design. The last stage diameter is also affected by the sonic velocity in the working fluid. Eskesen and Kelley [10] state that the sonic velocity in an organic compound is approximately half that in steam, such that the organic turbine of optimum design will either be half the diameter of its steam counterpart or run at half its speed. A detailed explanation of the effect of working fluid on turbine design is beyond the scope of the present report, but is provided by Milora and Tester [9].

Appendix B of the NGGPP study [1] investigated the design and cost of turbogenerators for ORC plants that could be used for various sites through minor modifications and by adding or deleting turbine stages. The purchased cost of a turbogenerator per unit of gross power is shown in Figure 12 as a function of geofluid temperature for ORC and double flash plants. On the basis of gross power, the steam turbines are roughly twice the cost of organic fluid turbines over all geofluid temperatures, a fact that is due to the larger size of steam turbines. It is also apparent that higher geofluid temperatures enable 30-40 % lower cost. The details given in Appendix B show that for organic fluid turbines the reduction in cost is due to the use of a single double-flow turbine driving a single 65 MW generator, instead of two double-flow turbines driving two 32 MW generators. We presume that the costs for steam turbogenerators above 200 °C are significantly lower for the same reason, but this is not explicitly mentioned in the NGGPP report.

We note that the cost data for ORC plants [2] implies a turbogenerator cost of 170 \$/kW (gross power basis) for the 191 °C geofluid, rather than the lower cost of 102 \$/kW indicated in Appendix B of the NGGPP report [1]. If the lower cost turbogenerator configuration were used instead, it would reduce the cost of the power block by 17 %. This fact highlights the sensitivity of power block cost to turbine design and generator costs.

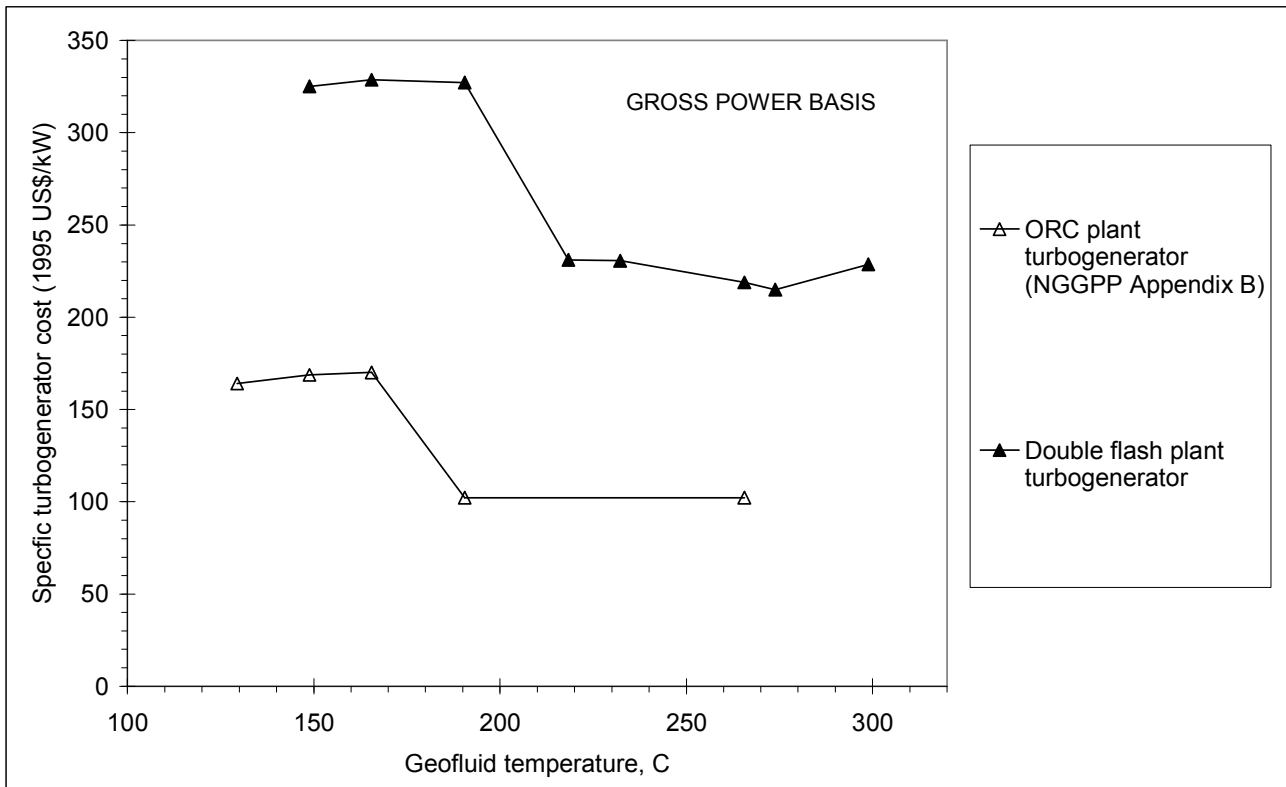


Figure 12: Specific purchased cost of turbogenerators (gross power basis) versus geofluid temperature for ORC and double flash plants, adapted from NGGPP study. ORC data is that of lowest cost reported in Appendix B of the study.

#### 4.2.3 Discussion of cost trends

It is clear that the turbogenerator has a large influence on power block costs. The large size of steam turbines is the primary reason why double flash plants are uneconomic at low geofluid temperatures. Also notable is that turbogenerator cost varies in a “stepwise” manner due to the constraints of turbine design and the availability of generator sizes.

The 191 °C limit to the range of geofluid temperatures for which cost estimates are presented for ORC plants is caused by the limit to the conditions for which sufficient detail is provided by the NGGPP study. The trends in component cost shown in Figure 6 suggest that further reduction in cost is possible as geofluid temperature increases, depending on whether the decrease in condenser cost outweighs increases in the cost of other components. However, verifying this will require more information becoming available.

It is important to note that the cost of the power plant in \$/kW does not determine the most economic choice of power plant. The best choice of plant is that which minimises the levelised cost of electricity after accounting for all project costs, including that of drilling wells, stimulating the reservoir and of operation and maintenance. A particular plant may have a greater cost than its alternatives, but superior efficiency may justify the expense. Hot Rock projects will have high drilling costs and large geofluid pumping loads compared with those based on hydrothermal reservoirs. Therefore, economically optimum power plants for Hot Rock projects are likely to have greater efficiency than those for hydrothermal reservoir projects.

## 5 Cost and performance estimator

The NGGPP data [1] was used to develop a cost and performance estimator in the form of a Microsoft Excel spreadsheet. The estimator aims to provide reasonable cost and performance estimates for air-cooled ORC and double flash power blocks of approximately 50-100 MW power (net before geofluid pumping), accounting for the effect of design ambient temperatures between 10 °C and 25 °C. The methodology employed is described in the following sections.

### 5.1 Choice of plant type

The geofluid temperature range of 129-299 °C is divided into two regions: a low temperature region over which ORC plants are assumed to be economic, and a high temperature region where double flash plants are assumed to be economic. The temperature dividing these regions is an input variable, ranging between 218 °C and 240 °C.

ORC plants can be selected with the option of heat recuperation for geofluids of 191 °C or more. Heat recuperation involves the use of a heat exchanger - the recuperator - to transfer heat from the turbine exhaust gas to the pressurised liquid working fluid. This is done to increase the efficiency of the plant, particularly for geofluids of 190 °C or greater, where the cooled geofluid must be returned to injection wells at a temperature high enough to avoid amorphous silica precipitation. The recuperator is an extra cost item, but its use reduces the size and cost of the condenser. The cost of ORC plants with heat recuperation is determined by applying two adjustment factors to the simple ORC component costs: a factor increasing the heat exchanger cost (1.5), and a factor decreasing condenser cost (0.8). The values of these factors have been estimated based on preliminary process calculations.

### 5.2 Cost estimation

NGGPP study costs are scaled to represent the desired power output. A power-law relationship is used for cost scaling:

$$\frac{E_{i,R2}}{E_{i,R1}} = \left( \frac{R2}{R1} \right)^n$$

where  $E_i$  is the cost of item  $i$ ,  $R$  is the equipment capacity and  $n$  is a scaling exponent less than or equal to 1. The scaling exponents applied are:

Turbogenerator:	1
Air-cooled condenser:	0.8 (implied by NGGPP data)
Other equipment:	0.6

The resulting scaled costs must be adjusted to represent the input geofluid and ambient temperatures. This is achieved by linear interpolation of costs with respect to *exergy*. The exergy of the geofluid (in kJ/kg) is defined as the maximum mechanical work that the geofluid can produce in an energy conversion process operating in a specific ambient environment. Geofluid exergy is calculated in the estimator by reference to the thermodynamic properties of pure water, assuming that the geofluid entering the plant is pure water in the saturated liquid state. The interpolation of data on an exergy basis is equivalent to assuming that geofluids of equal exergy produce power at equal specific cost.

The reliability of this assumption is yet to be assessed by rigorous process calculations, but it is reasonable for the purposes of expedient and simplified cost estimation.

Figure 13 shows specific purchase cost versus exergy data for plants of 70 MW. There are 5 data points for ORC plants that can be obtained from the NGGPP study. Two points are shown at an exergy of 176 kJ/kg – these correspond to the detailed cost data [2], while the third (and lower) cost implied by the turbogenerator costs are shown in Appendix B of the NGGPP report [1]. For interpolation purposes, the average of these costs is used. The average of the data points at 113-134 kJ/kg is used for interpolation, since these points are relatively close to each another. It is important to note that the points for interpolation of ORC costs are invariant with ambient temperature.

For those ORC plants where interpolation of cost-versus-exergy points is impossible, ie. those with geofluid exergies greater than 176 kJ/kg, the cost is assumed to be constant at the value of 176 kJ/kg. We believe this is a conservative approximation, as it is not yet known whether the specific cost of ORC plants decreases continuously with increasing exergy. If the option of using heat recuperation is selected, it is only applied for geofluid exergies greater than 176 kJ/kg.

The double flash points in Figure 13 derive from NGGPP data which has been modified to represent air-cooling rather than water cooling. In doing so, the steam condensing temperature,  $T_{cond}$ , is left unchanged from its value in the NGGPP report, regardless of the assumed ambient temperature. The cost of the air-cooled condenser at a particular exergy value therefore varies with ambient temperature, increasing in cost as the  $T_{cond} - T_{amb}$  temperature difference decreases. Thus, the steps in producing the double flash points for cost interpolation are to determine the modified cost of the NGGPP plant according to ambient temperature, and then to scale that cost to the desired power output. Unlike the ORC costs, the air-cooled double flash costs the estimator determines at a single geofluid exergy will vary with ambient temperature.

The total fixed capital investment in the power block is determined by multiplying the purchased equipment cost by a cost factor of 2.8 for ORC plants and 2.53 for double flash plants, these being the factors used in the NGGPP study [1]. The total fixed capital investment in current Australian dollars is determined using input conversion factors accounting for US inflation from 1995 to present, and for the current US to Australian currency exchange rate. It is noted that this conversion is likely to be conservative, owing to the tendency for technology developments to lead to reduced costs over time. However, no reliable information has been obtained with which to correct for such issues.

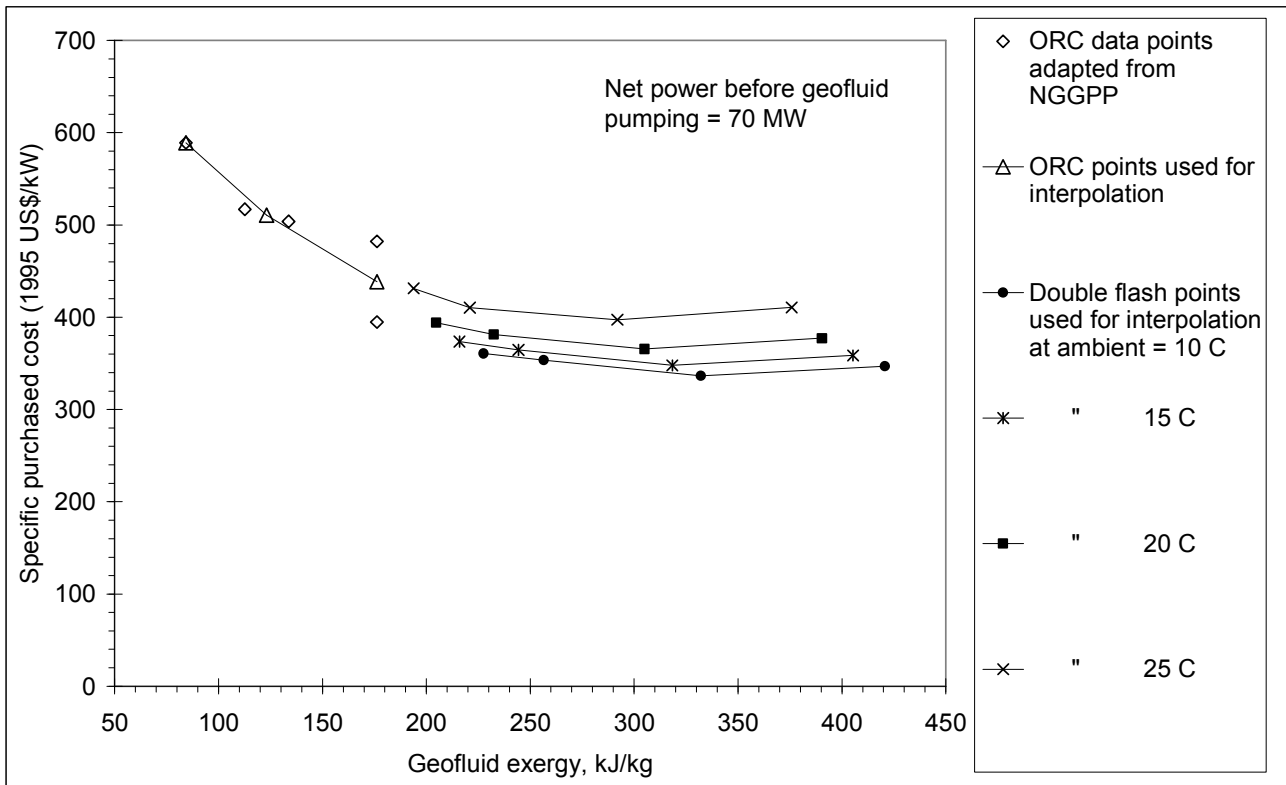


Figure 13: Specific purchase cost versus geofluid exergy for 70 MW plants (net before geofluid pumping).

### 5.3 Performance estimation

Plant performance is estimated by correlation or interpolation of geofluid effectiveness versus exergy data. Figure 14 shows the correlations used for ORC plants and typical data points for double flash plants. The ORC correlations are derived from reported information on the GETEM model [6]. The difference in performance between ORC plants with and without heat recuperation is clear from Figure 14, this difference increasing as exergy increases. The upper exergy limit for ORCs is 273 kJ/kg, corresponding to  $T_{GF} = 240\text{ }^{\circ}\text{C}$  and  $T_{amb} = 10\text{ }^{\circ}\text{C}$ .

The estimated geofluid effectiveness is used to calculate the plant utilisation efficiency (effectiveness divided by exergy), and the geofluid flow required to generate the desired power output. Performance is independent of the scale of plant.

### 5.4 Example

An example of the input parameters to the cost estimator and the predicted results from it, is shown in Figure 15. A macro is used to generate plots of total fixed capital investment and geofluid effectiveness versus geofluid temperature for ambient temperatures between 10 °C and 25 °C. For the input given in Figure 15, these plots are shown in Figures 16 and 17 respectively.

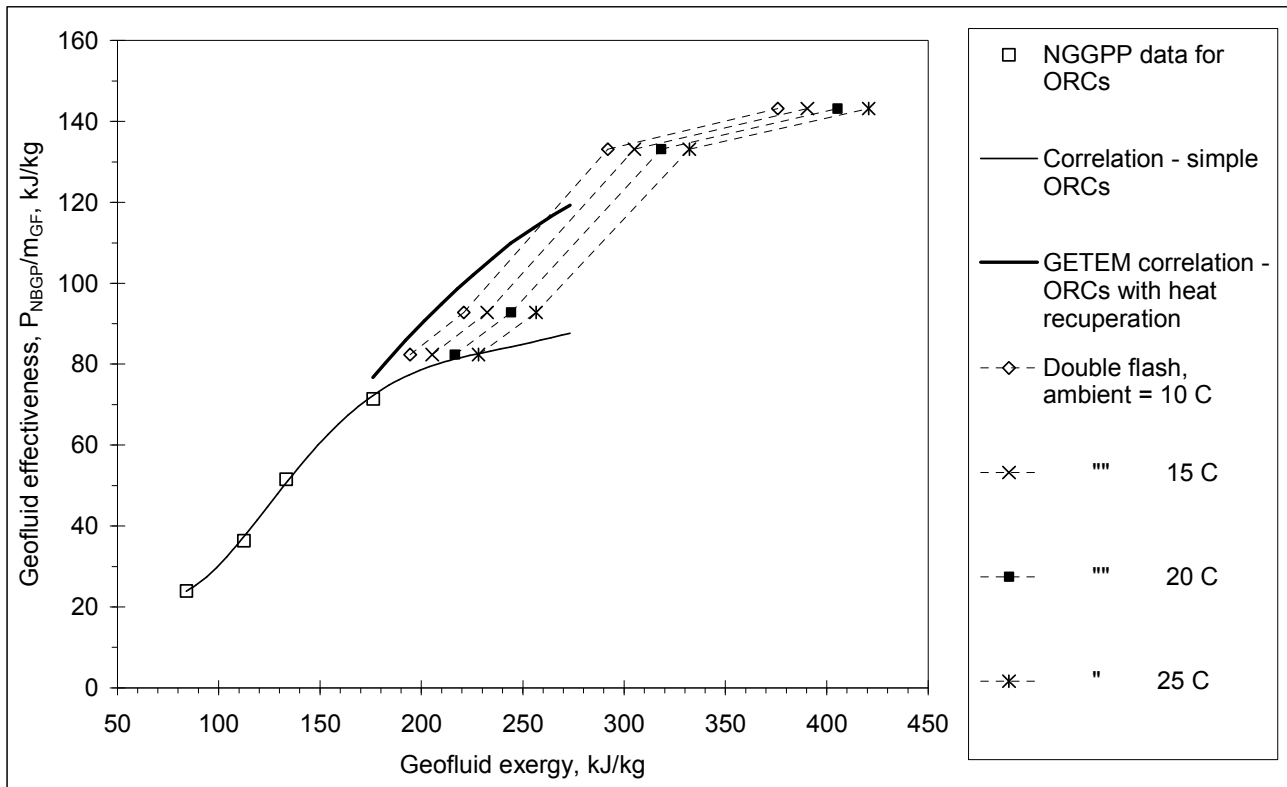


Figure 14: Geofluid effectiveness (net before geofluid pumping) versus geofluid exergy for air-cooled plants.

<b>Cost and performance estimator for air-cooled geothermal power plants</b>			
<b>Inputs</b>			
Geofluid temperature	(129-299 C)	220	C
Design ambient temperature	(10-25 C)	25	C
Power, Net Before Geofluid Pumping (NBGP)	(suggest 50-100)	70	MW
Upper temperature limit for ORCs	(218-240 C)	230	C
Heat recuperation used for ORCs above 190 C?	(y/n)	y	
Heat recuperation factor applied to heat exchanger cost (suggest 1.5)		1.5	
Heat recuperation factor applied to condenser cost (suggest 0.8)		0.8	
US inflation factor, 1995 to present		1.4	
Current USD-AUD exchange rate	1 AUD =	0.9	USD
<b>Results</b>			
Geofluid exergy (must exceed 84.4 kJ/kg)		198	kJ/kg
Plant type		<b>ORC with heat recuperation</b>	
Estimated specific purchased cost of power block		459	US\$/kW (1995)
Total fixed capital investment in power block		140	million AUD (current)
Specific fixed capital cost of power block		1998	AU\$/kW (current)
Geofluid effectiveness, NBGP		89	kJ/kg
Utilisation efficiency, NBGP		45%	
Geofluid flow required		789	kg/s

Figure 15: Example of input and results of the cost and performance estimator.

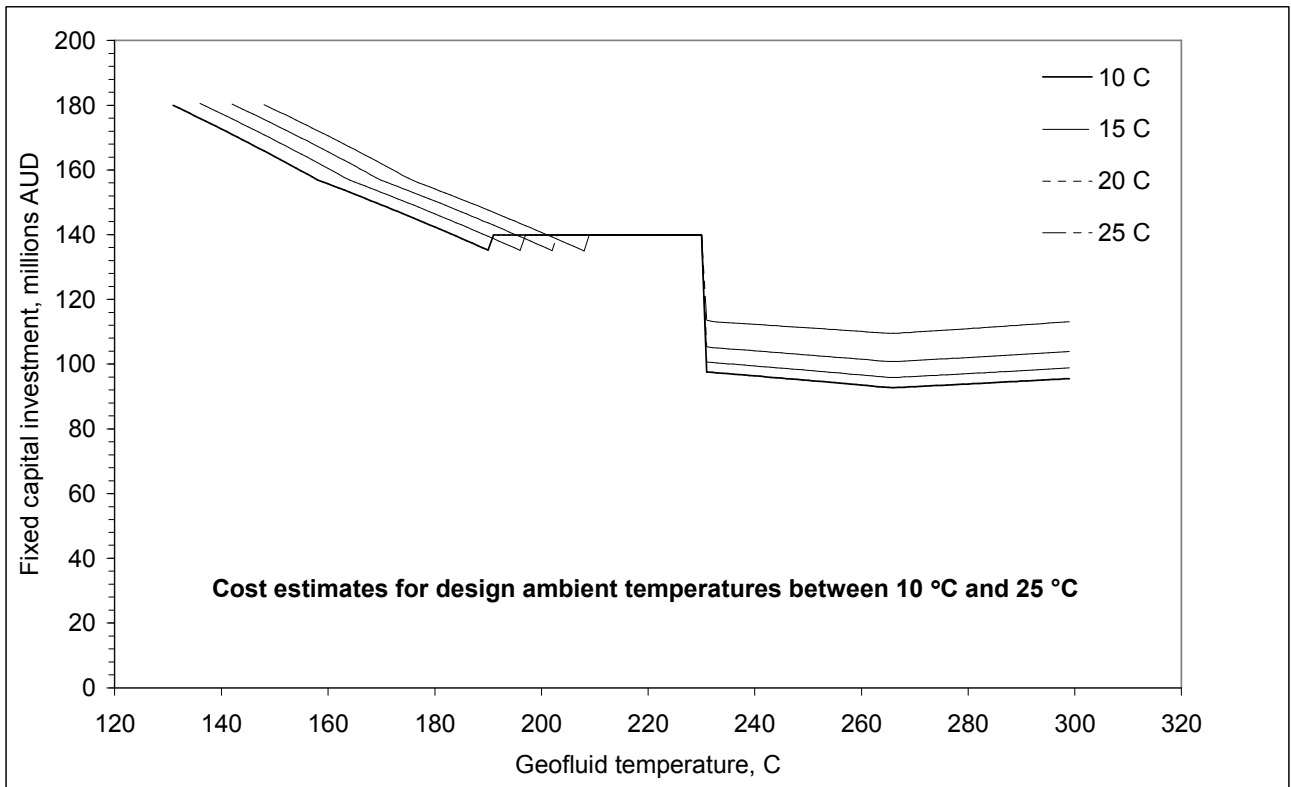


Figure 16: Estimator predictions of total fixed capital investment versus geofluid temperature at ambient temperatures between 10 and 25 °C.

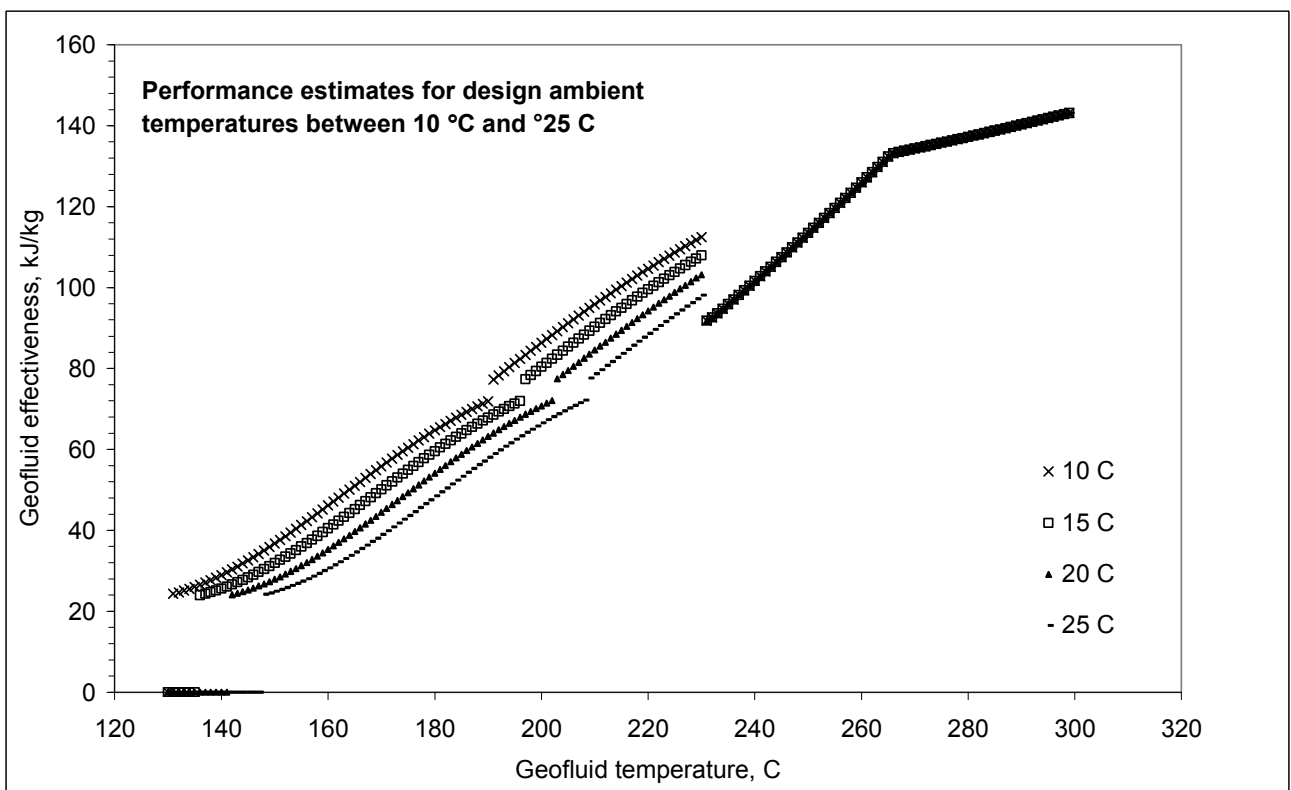


Figure 17: Estimator predictions of total fixed capital investment versus geofluid temperature at ambient temperatures between 10 and 25 °C.

## **5.5 Property calculations**

The properties of water and steam are calculated by Water97\_v13.xla, a Microsoft Excel Add-In which is freely available [11]. The Add-In must be installed in Excel before using the cost and performance estimator.

## **6 Concluding remarks**

A basic cost and performance estimator has been developed for Australian conditions, as described in this report. The estimator accounts for geofluid temperatures and assumes air-cooled condensers, which differentiates from available work based on water-cooled systems. Cost estimates are adapted from existing information for both organic Rankine cycle (ORC) and double-stage flash systems. It is found that ORC systems have lower cost for temperatures below about 190 °C, while double flash plants have lower cost for higher temperatures. This does not necessarily imply lower levelised cost, but can be used to calculate it. While the estimator is based on the best information publicly available, it should be noted that the data was current in 1995, and conversions to the present currency do not account for the positive benefits of advances in technology.

Further work on these models is in progress that is expected to lead to significant improvements in cost estimation capability. In particular, there is insufficient cost data for ORC plants at geofluid temperatures greater than 191 °C, and costs over the range 191-240 °C are probably over-estimated. In ongoing work, process calculations are being developed using the Aspen HYSYS process simulator, and corresponding cost data obtained using Aspen Process Economic Analyzer. This work will additionally provide cost-versus-efficiency relationships at single geofluid temperatures, which are necessary in order to find the minimum levelised cost of electricity.

## **7 Acknowledgements**

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