What will make EGS geothermal energy a viable Australian renewable energy option?

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There are good reasons to expect the Australian geothermal sector to be able to provide zero-emission electricity for the country at an affordable cost, once certain technical challenges are overcome. This paper presents cost estimates for geothermal electricity using the present technology and identifies the areas where technical improvements are anticipated in the next couple of years and how they should influence that cost.

The present proven cost of EGS geothermal electricity is too high to be commercially feasible but is expected to come down to parity with gas-fired electricity provided successful outcomes are achieved in some of the current research programs in Australia and elsewhere.

Challenges for the Australian geothermal energy sector

While Australia is not known as a traditional geothermal energy country, high radiogenic heat production within large sections of the Australian continental crust offers a significant geothermal power potential (McLaren et al., 2003). There has been considerable interest in recent years toward realising at least part of this potential. In fact, according to the Australian Geothermal Implementing Agreement Annual Report, more than AU$450 million have been spent on studies, geophysical surveys, drilling, reservoir stimulation and flow tests in the geothermal energy area in 2002 to 2009 (Goldstein 2009).

In spite of this effort, the only geothermal power plant in the country is still the Birdsville geothermal power station, which owes its existence to a combination of local factors which may be difficult to be repeated elsewhere.

After Birdsville, the early commercial geothermal projects in Australia targeted Engineered Geothermal Systems (EGS) also known as Hot Dry Rock (HDR) resources (Chopra, 2005). Currently, two companies have such projects at advanced levels of development: Geodynamics Cooper Basin and Petratherm Paralana projects.

In recent years, a new form of geothermal play has attracted commercial attention in Australia. The term Hot Sedimentary Aquifers (HSA) is used to refer to those resources located in sedimentary basins insulated by an impermeable layer at the top and heated by the basement rock underneath. The underlying heat source for Australian HSA is radiogenic rather than magmatic, although there may be exceptions (see, for example Uysal et al, 2011).

In both HSA and EGS, the two essentials for a commercially viable operation are the flow rate and the temperature. The latter is relatively easier to achieve. There are good scientific tools to predict the temperature and to target the location of the high temperature resource. Consequently, there have not been many recent failures to find these temperatures after drilling to the target locations. A flow rate high enough to enable viable power generation however has been more elusive to achieve.

In a recent workshop in the United States (Renner 2011), the following areas were identified for improvement before EGS becomes commercially viable in USA:

- 20% reduction in drilling costs;
- Increasing the production flow rate to 80 kg/s; and
- 20% improvement in conversion efficiency.

In this paper, an estimate is presented for what the cost of geothermal electricity could be in Australia for a high-temperature EGS resource using the state-of-the-art EGS technology and what improvements are required to make it commercially viable.

To represent the state-of-the-art, the Geothermal Electricity Technology Evaluation Model (GETEM) will be used. This is an economics/performance spreadsheet model developed by the US Department of Energy Geothermal Technologies Program to assess power generation costs and the potential for technology improvements to impact those generation costs. The GETEM Version 2009-A15 was used. This was the most recent GETEM model before the beta version of a new version was released at the GTP Review in Maryland in June 2011.

At what price is the geothermal electricity commercially viable? The answer of course depends on a number of variables including future incentives for renewable electricity and a possible carbon tax regime. A rigorous analysis of these factors is beyond the scope of this paper. Therefore, quite arbitrarily, the cost of electricity from a Combined Cycle Gas Plant (CCGT) including a carbon tax of $30/tonne of CO_2 was set as a commercially viable aspirational cost target for the geothermal electricity. A past study by Energy Supply Association of Australia (ESAA) provides this cost as 8.5 ¢/kWh, based on a discount rate of 10% (IEA 2010).

The Case Study

The present cost of geothermal electricity is calculated for a hypothetical geothermal resource as defined in Table 1.

Table 1. Case Study Definition

Brine temperature	250 °C
Well depth	4500 m
Reservoir type	EGS
Power plant	State-of-the-art binary plant with air-cooled condensers

The State of the Art

Drilling Costs

GETEM has three cost curves for drilling geothermal wells. These high, medium, and low cost curves were worked out by Sandia. The lower cost wells are more likely to have been drilled in "softer" formations, and experienced few troubles. The high cost wells are more likely to have been drilled in harder formations, or had more troubles, or both.

For the state-of-the-art cost calculations, it is assumed that the geothermal well costs will follow the high cost curve option. For a 4500-m deep EGS well, the cost calculated using the high-cost curve is US$22.3m in 2008 US dollars.

Production Flow Rates

The limited experience with EGS makes it difficult to select a production flow rate as the state of the art. In the only Australian EGS project that produced brine flow at the surface, Geodynamics reported the flow rate from Habanero #2 to be in excess of 25 kg/s, with lower flow rates achieved in 2009 during the closed-loop circulation tests. In this paper, I will assume 30 kg/s as the present achievable production flow rate. This is higher than what has actually been experienced but is justifiable as the state-of-the-art production flow rate for the purpose of the present analysis (this agrees with Petty 2010).

Binary Plant

The power conversion efficiency in GETEM is represented by specifying the net kilowatts produced per unit brine flow rate. The power generation efficiency in GETEM is represented by a parameter called brine effectiveness with the units of kW per kg/s (or kJ/kg) of the geothermal fluid. I used a brine effectiveness of 90 kJ/kg and 10% for parasitic losses. The cycle efficiency is based on the steam cycle shown in Figure 1. The upper figure shows the block diagram of a binary plant with preheater (PRE), evaporator(EVA), and superheater(SUP) for steam, which is expanded through a turbine (TUR) and condensed in a condenser(CON) and pumped back to the turbine inlet pressure in a pump (PUM). The lower figure is the cycle plotted on a temperature-entropy (T-s) diagram. The numbers on the T-s diagram correspond to the positions in the upper figure, e.g. 1 and 2 are before and after the pump. The calculations are based upon steam properties from the NIST property database REFPROP (NIST, 2011).

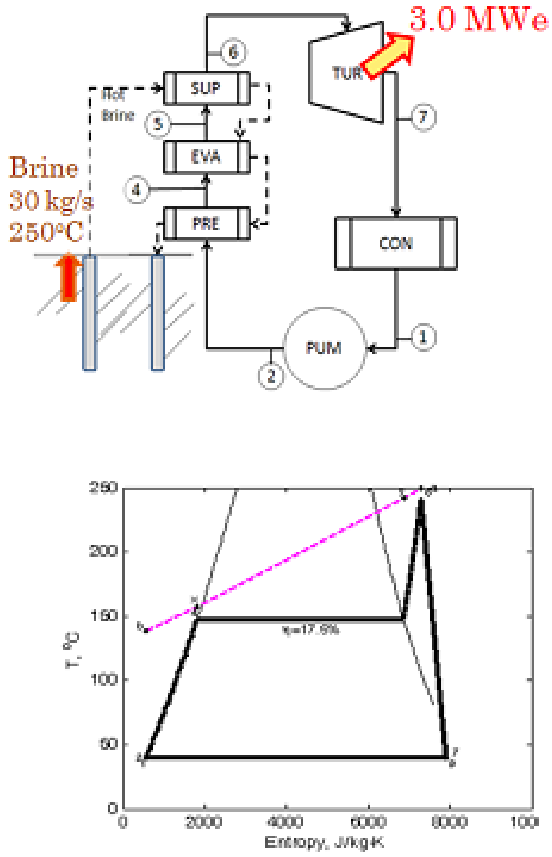

Figure 1. Steam cycle representative of state-of-the-art for geothermal brine at 250°C.

I assumed a heat exchanger pinch point difference of 10 °C (which is a heat exchanger design constraint and refers to the minimum temperature difference between the brine and the cycle fluid). The net power generation (not including the brine circulation pumping) is 3000 kWe for a brine flow rate of 30 kg/s, corresponding to a brine effectiveness of 100 kW/(kg-s). Assuming air-cooled condensers and about 10% for the fan parasitic losses, the net brine effectiveness is 90 kW/(kg-s), which is the number I used in GETEM to represent the state of the art EGS power generation. The plant costs are calculated as $2488/kWe using the default curves embedded in GETEM.

Other Costs

Other cost entries used to calculated the levelised cost of electricity (LCoE) were assumed to be 10% for the cost of the capital and 3 ¢/kWh for annual operations and maintenance. This is composed of 2 ¢/kWh for the power plant and 1 ¢/kWh for the field (including the production pumps). These are the suggested default values by GETEM adapted from hydrothermal data, which I adopted in this analysis. There is not enough EGS experience to suggest different values.

The LCoE

The levelised cost of electricity using the above assumptions were calculated by GETEM as 26.9 ¢/kWh. The breakdown of this cost is given in Figure 2.

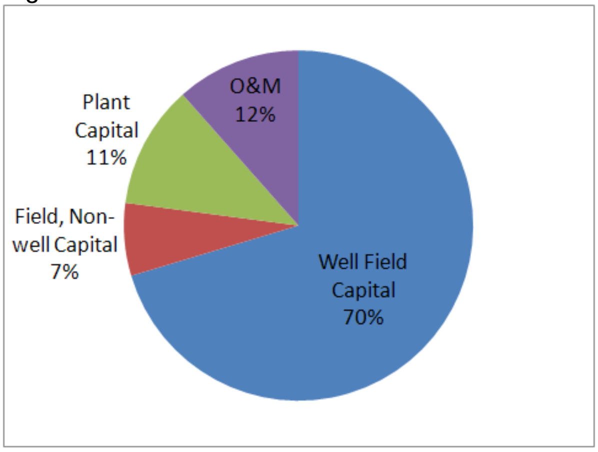

Figure 2. State-of-the-art LCOE components

I created this pie chart by using the results from GETEM. The O&M share has already been explained. The other components in Figure 2 correspond to the cost of the capital for the well field, other field investment and the power plant.

Future Improvements

The effect of the following technology improvements on the LCoE has been calculated using GETEM:

- Drilling Cost
  - Cheaper wells (Medium-Cost curve)
- Power Conversion
  - Supercritical cycles
  - Natural Draft Dry Cooling Towers
- Production flow rate
  - Double the flow
  - Triple the flow

The results are summarised in Figure 3.

All of the above technology improvements are targets of ongoing research projects. it can be expected to see significant progress towards these aims in the next two years and achieve the targets in less than five years. The power plant projects are well-advanced in QGECE and other places in the world. We expect to have supercritical power cycles available for commercial use in the next few years. Similar expectations apply to natural draft dry cooling towers. The aim of cheaper wells is a common subject for several DOE-funded projects in United States. Progress is expected but it is difficult to see how quickly this would occur and at what scale. The flow rate issue is probably the most critical aim. Based on the author's own observations, the issue is similar to what faced the coal seam gas industry 15 years ago in terms of low permeability of the seam and low gas flow rates and it took about 8-10 years for that industry to develop commercial tools to increase flow rates to acceptable levels. A similar time scale may apply here.

Conclusions

The present proven cost of EGS geothermal electricity is 26.9 ¢/kWh but this is expected to come down to as low as 8.5 ¢/kWh provided successful outcomes are achieved in some of the current research programs in Australia and elsewhere, which are targeting the technology improvements considered in Figure 3.

Finally, the focus in this paper has been on EGS. More experience with HSA is needed to carry out similar calculations.

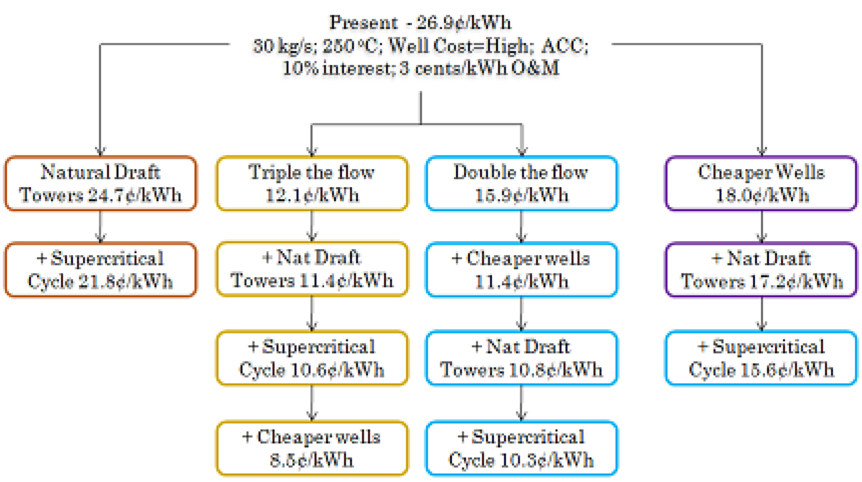

Figure 3. Expected cost reductions by future technology improvements

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