Report to

AGEA

Comparative Costs of Electricity Generation Technologies

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1 INTRODUCTION

The Australian Geothermal Energy Association (AGEA) has sought data from MMA on the predicted costs of a range of generation technologies likely to be operating in the Australian market up to 2030 and beyond utilising its own and globally credible data bases.[1] AGEA has sought cost predictions for the years 2020 and 2030 from the technologies utilising the following energy sources:

1. Geothermal:
    a. Hot Rocks (with enhanced geothermal systems)
    b. Projects utilising the heat from hot sedimentary rocks (i.e. as in Victoria).
    c. Direct heat projects (displacing the need for electricity from fossil fuels in the same units of energy).
    d. Hydrothermal projects (global average).
2. Wind projects
3. Biomass projects
4. Solar water heaters (SWH) (displacing the need for electricity from fossil fuels in the same units of energy)
5. Solar thermal projects
6. Solar photovoltaic concentrator projects
7. Roof top photovoltaic
8. Conventional supercritical coal fired boiler
9. Gas incorporating CPRS
10. Clean coal with CCS

As part of the cost structure, it was assumed that generating options had to pay for their carbon footprint using emission prices are per the CPRS -5 scenario modelled by the Federal Treasury.

AGEA has sought this data to assist in informing its representations to government as part of the various policy development processes currently underway in the climate change and energy policy areas. The results indicate that geothermal is likely to be a highly competitive form of generation in an environment where low emission generation is required. This conclusion rests on the technology being successfully demonstrated, with the major limiting factor being the optimisation of transmission network costs to allow this resource to be effectively exploited.

[1] Data sourced from IEA, US Department of Energy and REN 21. IGCC and CCGT data from Gas Turbine World

2 COST BREAKDOWN

Table 2-1: Cost breakdown for hot dry rock geothermal technologies, $/MWh levelised cost

Year	2020		2030	
Technology type	HR	HSR	EGS	HSR
Capital - drilling	43	42	41	39
Capital - other equipment	27	27	26	26
Capital - transmission connection only	8	7	8	8
Operating and maintenance	13	11	13	10
MLF	8	5	8	5
	99	92	95	88

Note: In mid 2008 dollar terms. Calculated using a WACC of 10.2%. Transmission connection costs only included. MLF is the marginal loss factor used to get a regional reference node price (the basis for pricing in each state in the NEM). MLFs are based on losses ranging from 3% to 10%, with higher losses applying to technologies likely to be located in remote regions. HR = hot granitic rocks (with EGS); HSR = hot sedimentary rocks.

3 COMPARATIVE ANALYSIS

Table 3-1: Comparison of long run marginal costs of generation technologies, $/MWh, mid 2008 dollar terms

	2020	2030
Coal Options		
Supercritical coal (dry-cooling)	97	117
IGCC	99	110
IGCC with CC	101	98
Supercritical coal with oxyfiring and CC	107	109
Post-combustion capture	149	174
Natural Gas Options		
CCGT - small	97	104
CCGT - large	88	95
Cogeneration	76	80
CCGT with CC	104	102
Renewable Energy Options		
Wind	102	96
Biomass - Steam	110	108
Biomass - Gasification	109	105
Solar Thermal	250	229
Solar Hot Water	157	150
Geothermal – Hydrothermal**	75	72
Geothermal - Hot Rocks (EGS)	99	95
Geothermal - Hot Sedimentary Rocks (HSR)	97	93
Geothermal – Direct Heat*	105	100
Concentrating PV	271	259
Roof Top PV	507	397

Calculated assuming 10.2% discount rate. Calculated at a notional regional reference node in the NEM (a common basis for comparing technology costs in the wholesale market) by assuming marginal loss factors in the range from 3% to 10%, with higher losses applying to technologies likely to be located in remote regions. Assumes carbon prices as per Treasury's CPRS -5 scenario. Capital costs sourced from AGEA, IEA, Sun and Wind Power Journal, Gas Turbine World and US DOE. Assume de-escalation rates for capital as per assumptions used in MMA's analysis of CPRS for Federal Treasury (including the assumption that the supply shortage and material cost factors that increased costs of all generation options dissipates by 2012). Costs do not include transmission costs other than modest connection charges. Costs are accurate to +/- 20% for mature technologies and +/- 50% for immature or as yet developed technologies.

* The direct heat option, on a displaced electricity cost basis, will be competing on a delivered electricity cost basis (not at the regional reference node) as in this table. At the estimated long run marginal costs in this table (which assumes heat loads are located close to the heat source), the delivered energy cost for this technology will be significantly lower than current average retail tariffs for commercial customer classes (currently averaging above $130/MWh) and some less energy intensive (low voltage level) industrial customer classes (where current retail tariffs are above $100/MWh).

** The opportunity for this technology is limited in Australia.