Report to

Australian Geothermal Energy Association

Installed capacity and generation from geothermal sources by 2020

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McLennan Magasanik Associates Pty Ltd
242 Ferrars Street
South Melbourne Vic 3205

Tel: (03) 9699 3977
Fax: (03) 9690 9881
Email: mma@mmassociates.com.au
Website: www.mmassociates.com.au

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GLOSSARY AND ABBREVIATIONS

Abbreviation	Definition
˚C	Degrees Celsius
AGEA	Australian Geothermal Energy Association
AGEG	Australian Geothermal Energy Group
ASX	Australian Stock Exchange
Blind reservoir	A reservoir that has no expression on the earth's surface
Capacity factor	Actual annual generation divided by potential annual generation
Commercial stage	Producing and selling electricity on a commercial scale
Demonstration stage	Typically involves a number of holes/wells and a sizeable generator which is run for long enough to show, if successful, that the project is commercially viable
DKIS	Darwin Katherine Interconnected System
DRET	Department of Resources, Energy and Tourism
EGS	Engineered geothermal system, one from which recoverability has been increased, for example, by artificial fracturing
ETS	Emissions trading scheme
F	Financial year when preceding a year, for example, F2008, which refers to the year from 1 July 2007 to 30 June 2008
GEL	Geothermal exploration licence
GELA	Geothermal exploration licence application
Geothermal	Geothermal energy takes the form of rocks and/or water at elevated temperatures within the earth's crust. The word geothermal is used in this report as a shorthand term for geothermal energy and, sometimes, electricity produced from geothermal energy.
GEP	Geothermal exploration permit areas in Victoria
GER Act	Geothermal Energy Resources Act 2005 of Victoria
HSA	Hot sedimentary aquifers
HDR	Hot dry rocks, a body of rock(s) at elevated temperatures but which needs water from an external source to be circulated for the energy to be extracted
Heat flow	The flow of heat, in this report through rocks, typically quoted in Watts per square metre
HEWI	Heat exchanger within insulator

Abbreviation	Definition
HFR	Hot fractured rocks, a body of hot rocks which has fractures that can be stimulated to enhance the recovery of energy
HR	Hot rocks, hot dry rocks (HDR) and/or hot fractured rocks (HFR)
HTST	High temperature solar thermal
IGCC	Integrated gasification combined cycle
k	Kilo or 1,000
km	Kilometre
kW	Kilowatt
LMRC	Long run marginal cost
m	Metre
M	Mega or 1,000,000
MMA	McLennan Magasanik Associates
MRET	Mandatory Renewable Energy Target
MT	Magneto telluric
MW	Megawatt
MWe	Megawatt electrical
MWh	Megawatt hour
NA	Not applicable
NEM	National Electricity Market
O&M	Operations and maintenance
P	Probability
PIRSA	Primary Industry and Resources South Australia
Play	A general term covering all aspects of reserve and resource investigation and development
Proof of concept stage	Typically involves a number of geothermal holes/wells and energy extraction by means of water circulation, with or without small scale electricity generation
PV	Photovoltaic
R&D	Research and development
REC	Renewable Energy Certificate
SAHFA	South Australian heat flow anomaly
SEDA	Sustainable Energy Development Authority, now Department of Energy and Water of New South Wales
Slimline	A drill hole with a diameter of less than 125 mm
SWIS	South West Interconnected System

Abbreviation	Definition
W	Watt
WACC	Weighted average cost of capital
WEM	West Australian Electricity Market
Yr	Year

PREFACE

This preface has been prepared by the Chief Executive of the Australian Geothermal Energy Association.

The Australian Geothermal Energy Association (AGEA) commissioned McLennan Magasanik Associates Pty Ltd (MMA) to independently assess the business development plans of Australia's geothermal energy companies in order to estimate how much electricity generation capacity the Australian geothermal industry expects to deploy by 2020 and at what price. AGEA sought this independent assessment to inform its submissions to the various policy development processes currently underway across all Australian governments that address the climate change and energy demand challenges.

The Australian geothermal energy industry is currently undertaking an extensive work program across three areas of research and development activity through to project deployment. The industry is predominantly focussed on producing electricity from Enhanced Geothermal Systems (EGS) or Hot Fractured Rocks (HFR) technology where the underground reservoir or heat exchanger is artificially created or enhanced by fracture stimulation techniques. The industry is also undertaking exploration and project development activity in more traditional geothermal or hydrothermal projects where hot underground reservoirs are utilised as heat exchangers for electricity production. A number of companies and research projects are also focussing on the development of systems that exploit the direct heat use for energy efficiency applications. This report addresses the potential output for electricity generation from geothermal energy.

While the Australian geothermal industry is an emerging industry, it is well down the track with exploration activities to find geological structures with optimum temperatures and flow rates to produce competitively priced energy. It is well established that Australia has a globally significant resource relatively close to the earth's surface and that Australia is developing a global leadership position in the technical capability to exploit this resource.

The quantification of the potential for viable generation, presented in this report, is based on information provided by AGEA member companies and other companies operating in the sector who were invited to participate. MMA has used its independent expertise to assess the information provided and has estimated uncertainty limits that are detailed in this report.

The Rudd Government was elected in 2007 with a policy platform that included a commitment to a National Emissions Trading Scheme (ETS), a 20% Renewable Energy Target Scheme by 2020 (RET) and a $500m Renewable Energy Fund (REF). The REF included a dedicated allocation of $50m to a Geothermal Energy Drilling Fund (GEDF). At the time of writing, work on the design of these programs is well underway and is being informed by a range of studies and modelling exercises including the Garnaut Review.

There is strong interest across all Australian governments in the potential of the Australian geothermal energy industry to assist in meeting future emissions reduction targets in recognition that geothermal energy is emissions free, baseload and makes an important contribution to long term energy security goals. The Commonwealth and state governments have a good knowledge base on the industry, its progress, capabilities and its challenges through active participation in the Australian Geothermal Energy Group (AGEG), AGEA's sister organisation. The AGEG's focus is on addressing the technical challenges facing the industry including those that contribute to reducing project costs. The AGEG membership also includes the geothermal companies and all academic and research institutions currently involved in the industry. In order to further support the industry and build on these capabilities and overcome the barriers, The Commonwealth commenced work on the Geothermal Industry Development Framework (GIDF) to address the major policy challenges. COAG has also commissioned the development of Geothermal Energy Technology Road Map for COAG to assist industry in addressing the technology challenges. Industry is working collaboratively with government on these projects.

AGEA's views of the key findings of the report include:

- The emerging Australian Geothermal Energy Industry can be expected to provide at least 1,000 MW and potentially up to 2,200 MW of base-load capacity by 2020 into the National Electricity Market;
- That capacity potentially represents up to 40% of the Federal Government's 2020 Renewable Energy target of 45,000 GWh - the equivalent of the output of up to 6,000 MW of wind farms;
- An estimated $12b would be invested to develop 2,200 MW of installed capacity;
- The cost of generating electricity from geothermal resources is expected to move rapidly down the cost curve through to 2020 – through learning, experience and economies of scale outcomes commencing at around $120 /MWh at small scale (10 MW to 50 MW) and decreasing to around $80/MWh at large scale (300 MW or greater) by 2020;
- That price is expected to be lowest cost of any form of renewable energy; and
- Most of the capacity is expected to come from developments in SA with other states increasing their contribution toward the end of the 2020 period.

This report highlights that the Australian geothermal energy industry has a potentially significant contribution to solving Australia's long term climate change challenges. Delivery to market challenges are being considered through other processes but the demonstrated potential of the industry to deliver the low cost, large scale base-load benefits of geothermal generation warrants serious consideration.

Further work on the benefits of accelerating the development of geothermal energy and the associated economic, social and environmental impacts and export potential will be undertaken in consultation with key government policy reform processes. These include but are not limited to the ETS, the RET scheme, the Australian Electricity Market Commission (AEMC) review of transmission systems capability to deliver the Expanded

RET for the National Electricity Market (NEM), and the utilisation of the Infrastructure Fund.

Susan Jeanes
Chief Executive, Australian Geothermal Energy Association

EXECUTIVE SUMMARY

The Australian Geothermal Energy Association (AGEA) commissioned McLennan Magasanik Associates Pty Ltd (MMA) to prepare this report to address the question of how much capacity the Australian geothermal industry is expected to deploy by 2020. The purpose of the assignment is to assist AGEA to present its case to the Australian, state and territory governments.

At this writing, the industry is evolving rapidly, but it is not capable of deploying any capacity. While it is established that there are resources at sufficiently high temperatures to generate electricity, it has not been demonstrated that these can be the basis of ***viable*** generation. It is also clear that there is the ***potential*** for viable generation on a large scale. The quantification of the potential for viable generation, presented in this report, is based on information provided by AGEA member companies. MMA has estimated some aspects of the information and has estimated, albeit crudely, uncertainty limits.

Figure 1 shows the high correlation between anticipated cumulative installed capacity and estimated cumulative investment between the present and 2020. The investments are shown in 2008 dollars. After 2012, assuming that the results of the pilot and demonstration plants are encouraging, investment and installed capacity rises rapidly, reaching a cumulative installed capacity of 2,200 MW, for a total investment of $12 billion. The level of uncertainty during the pilot and demonstration stages has implications for sources of funds and government policy.

Figure 1 – Cumulative MW installed and cumulative investment

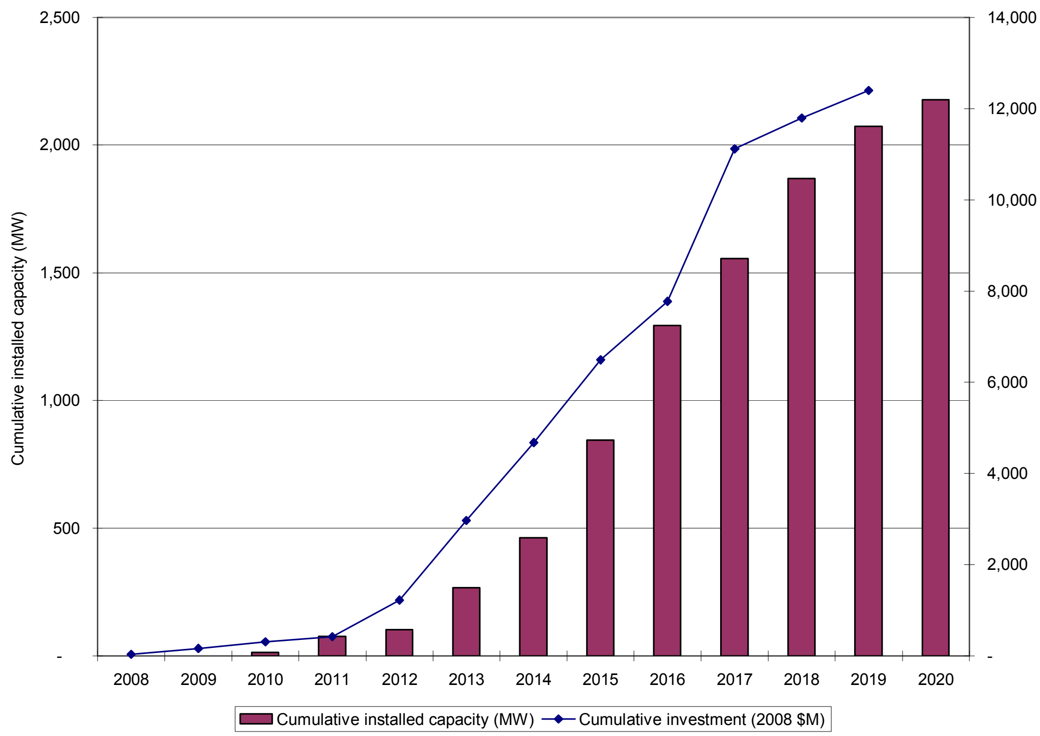
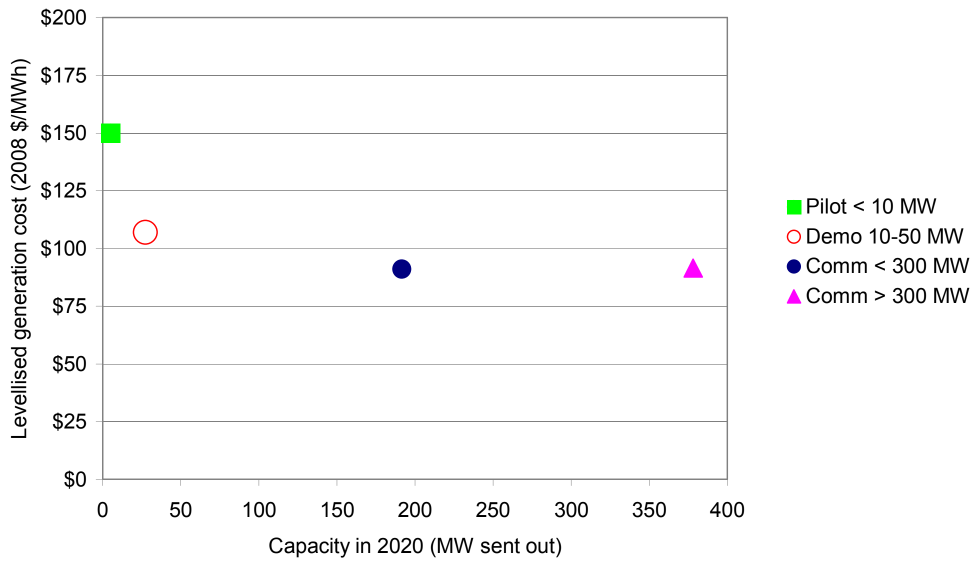


Figure 2 shows the results of our analysis of the levellised generation cost versus the sent out capacity of the proponents in 2020, categorised by us into the stages of pilot, demonstration and commercial, based on installed capacity and the participants' business plans.[1] It shows that pilot plants of less than 10 MW will have a cost of about $150/MWh. Demonstration plants in the 10-50 MW range will have a generation cost of about $105/MWh, and commercial plants both below 300 MW, and above 300 MW, will have a similar generation cost of about $90/MWh. Taken together, the data in this graph shows the rapid reduction in costs anticipated in the transition from very small pilot plants to larger demonstration plants, and the additional reduction in costs anticipated in the transition to commercial scale.

1 The basis of this division is discussed in the section titled *Stages of development* on page 8.

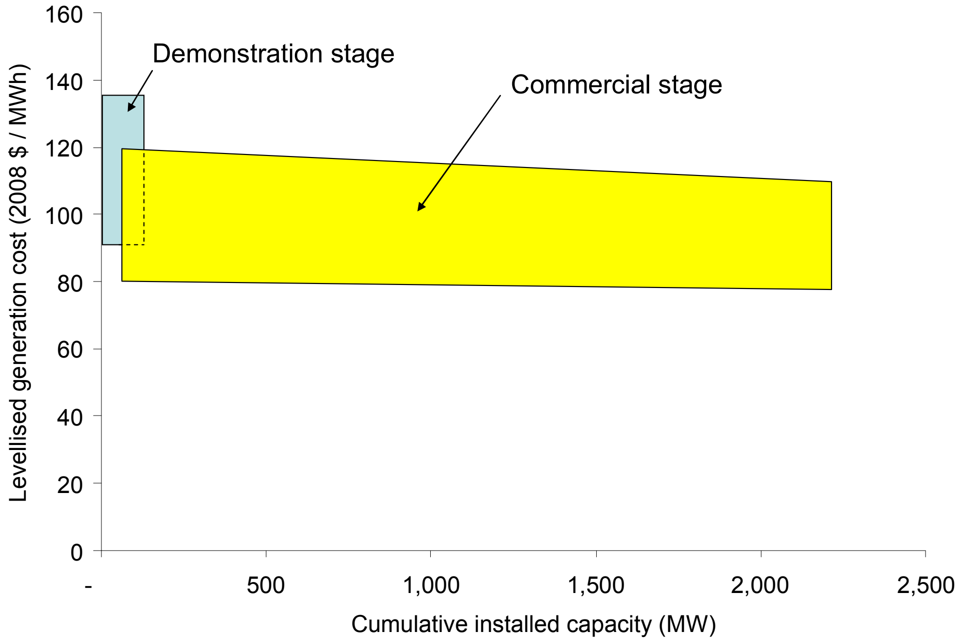
Figure 2 – Levellised generation cost by capacity sent out



The data in Figure 2 appear to show insignificant economies of scale above 200 MW. Economies of scale may however, be realised as projects are implemented.

The participants in this study spoke about the level of uncertainty around the data we have used to calculate the levellised costs. We have, however, determined the uncertainties ourselves in Figure 3, which shows the upper and lower bounds of this uncertainty for demonstration and commercial stages against cumulative installed capacity. Viewed in this way, demonstration projects could range from $90/MWh to $135/MWh. The commercial stage overlaps with the demonstration stage to some extent because of the different business plans. When the commercial installed capacity is small, the range is wider, approximately $80/MWh to $120/MWh. While the lower boundary remains constant as the cumulative capacity increases, the upper boundary declines slightly. This implies that the level of uncertainty is expected to narrow over time. Companies with costs in the lower part of this range will be able to compete successfully under MRET or a carbon tax regime. Companies in the upper part of this range will not. As a result, it is difficult to predict the viable installed capacity in 2020. However, if we assume that half of the study respondents *that provided data* will deliver electricity at the lower part of this cost range, then an effective installed capacity of 1,000 MW will be achieved by those companies.

Figure 3 – Levellised generation costs by cumulative installed capacity



Because none of the proponents have yet reached the demonstration stage, and the uncertainties discussed earlier, it is not possible to nominate which parts of Australia are likely to produce generation from geothermal sources. There appears to be potential for generation in all of the states of Australia and the Northern Territory.

1 INTRODUCTION

1.1 Introduction

The Australian Geothermal Energy Association (AGEA) commissioned McLennan Magasanik Associates Pty Ltd (MMA) to prepare this report to analyse how much capacity the Australian geothermal industry is expected to deploy by 2020. At present, the industry is yet to deploy any capacity. While it has been established that there are resources at sufficiently high temperatures to generate electricity on a large scale, it has not yet been established that these can form the basis of *commercially viable* generation. Realisation of this potential is contingent upon several key factors which are discussed in this report.

1.2 Viable generation

By viable generation we mean generation at a cost that is competitive:

- until 2020, with other forms of generation based on renewable energy, but not necessarily with fossil fuel based generation
- with all other types of generation after a carbon emissions trading scheme (ETS) provides the ***only*** support for zero emission generation, such as generation based on geothermal energy.

The purpose of the assignment is to enable AGEA to present its case to the Australian, state and territory governments, as they move to develop and implement policies to address the growth of emissions from the energy sector. The Australian government has allocated substantial funds for geothermal drilling because the geothermal sector is seen as a possible major contributor to zero emission electricity generation. The contribution it may make by 2020 needs to be assessed on a realistic basis.

The quantification of the potential for viable generation, presented in this report, is based on information provided by AGEA member companies. Proponents provided information on their geothermal resources and business development plans, during workshops, interviews and through self-completion workbooks. Blank copies of these workbooks are included as appendices to this report. MMA has estimated some aspects of the information and has estimated, albeit crudely, uncertainty limits.

1.3 Background

The Australian Government has recently proposed to expand the Mandatory Renewable Energy Target (MRET) to 45,000 GWh by 2020. Currently, wind is the only mature renewable technology available at large scale and it is currently in a position to capture a major part of this target.[2] The inherently base-load nature of geothermal is a major advantage but it needs to overcome developmental and cost reduction barriers to realise its potential to become a major contributor to zero emissions generation.[3]

There are currently over thirty Australian geothermal energy companies actively involved in various stages of the development of the technology. Even the most advanced company is only now about to conduct closed loop circulation tests to reach the proof of concept stage. This required the successful completion of (at least) two wells. A few other companies are expected to commence deep drilling programs within the next twelve months, while most of the other companies are progressing through more preliminary stages of project development. The stages of project development are discussed in the section titled *Stages of development* on page 9.

The final step in the development chain for geothermal energy is to deliver electricity, on a fully commercial basis, to an end user or into the grid, which in the eastern states means selling into the National Electricity Market (NEM). This poses a number of challenges to geothermal companies, which are not experienced in registering as a generator with the National Electricity Market Management Company (NEMMCO), arranging physical connection to transmission systems, arranging a connection contract and negotiating sales contracts.

The Australian Government is engaged in an interactive process with the industry which led to the preparation of the Australian Geothermal Industry Development Framework and the Geothermal Energy Technology Road Map. The latter was commissioned by the Australian Government to enhance its understanding of what is required for the geothermal industry to make a timely and major contribution. Therefore, the Australian Government has a good knowledge base, but acknowledged that it is yet to fully understand the implications of the industry's roll out and electricity generation capability over time.

1.4 Scope of this report

This report describes the results of the first phase of this assignment. It covers:

- an assessment of the expected capacity and output of electricity from geothermal sources by 2020
- the results of meetings with representatives of relevant government departments
- information collected during workshops with industry proponents

2 The Australian Government has not yet determined the path from the present MRET target to the 45,000 GWh in 2020. Nor has it yet agreed with the state governments how the latters' schemes will be subsumed into a single national scheme.

3 Due to variations in ambient temperatures, geothermal energy based generation is subject to diurnal and seasonal variation. There are ways to dampen this and, in any case, the variation is quite small compared to wind or solar energy based generation on a daily basis.

- information collected during interviews with industry proponents in Adelaide, Melbourne and Brisbane
- information provided by proponents who completed workbooks on their projects
- information collected from published and grey literature sources such as press releases, company reports and websites.

The second phase of this assignment, if it proceeds, will include an analysis of costs of different renewable energy technologies, including geothermal, on a comparative basis.

2 STAGES OF DEVELOPMENT

2.1 Purpose of this section

The purpose of this section is to discuss the stages of development as this provides the context for the information provided by the various geothermal companies. Current electricity prices are too low for geothermal to be viable in its pilot and demonstration stages. In the following section, we first define what we mean by viable generation.

2.2 Achieving viable generation

It is necessary to define *viable* generation before the potential for installed capacity can be calculated. In order to attract the required investment, there must be an expectation that geothermal generation will be viable. Viable geothermal generation is generation that is cost competitive and in which revenues exceed costs by a margin deemed to be sufficient by providers of capital. For present purposes, we have assumed that margins will be sufficient if geothermal generation is competitive, that is, if it has costs as low or lower than:

- other forms of generation based on renewable sources of energy, but not necessarily lower than fossil fuel based generation, while an MRET scheme applies
- all other types of generation, when a carbon emissions trading scheme (ETS) provides the ***only*** support for low emission generation, such as generation based on geothermal energy.

Some factors influencing the viability of geothermal generation include:

- The build-up path to the 45,000 GWh target is yet to be determined. Whether or not an MRET will apply beyond 2020 is also not yet determined. In order for geothermal energy to make a significant contribution during the period to 2020 the path must be such that a substantial proportion of the target is still available when the potential commercial geothermal generation projects are ready for commitment.
- The implicit assumption underlying the preceding dot point is that carbon taxes and, hence, electricity prices will not be sufficient to support geothermal generation until after 2020. Whether or not this will be the case depends upon the design of the ETS which will not be finalised until late this year, or later. Even then, it may not be straightforward to predict its impact on electricity prices.
- Investors in geothermal energy electricity generation will need to be confident that the combination of MRET and ETS will result in revenues, over a prolonged period, sufficient to justify the required investments. The expected cost of $4,000/kW of installed sent-out capacity is likely to require a project life of at least twenty years over which the revenues would be earned.

2.3 Stages of development

There are a number of stages of development a company must go through successfully, in respect of any given resource that it wishes to exploit, in order to establish commercially viable generation. In summary, the stages are:

- securing a tenement that is likely to be suitable and evaluating it, preferably before applying for it and before doing any physical work
- proof of concept
- pilot and / or demonstration scale generation
- commercial scale generation.

We discuss each stage in turn.

2.3.1 Securing and evaluating a tenement

Securing a tenement typically requires the proponent to bid in some form of auction. Interest in a tenement is usually encouraged by the results of previous drilling for minerals or petroleum, which may have recorded data on temperature or heat flow measurements that indicate its potential. This drilling may vary in depth, and in some cases can be quite shallow.

> *"For the exploration stage you can rely on existing holes or new holes for raw data on heat flows."*[4]

2.3.2 Proof of concept

The proof of concept stage shows that a heat source is available, and that a flow can be established from an injection well to a production well. It is not necessary to generate electricity in the proof of concept stage.

> *"For the proof of concept stage, you need a first deep well into the heat source and fracturing, followed by a second hole and pumping water to demonstrate connectivity. If the water doesn't flow, you've done your dough …You might drive a 1.5 MW genset for six months to show its not going to stop … but it does not produce any meaningful power."*

2.3.3 Pilot and / or demonstration stage

The boundary between a pilot stage and a demonstration stage varies from play to play, with some skipping the pilot stage completely and installing a larger turbine as their first generation plant. For the purposes of this study, we have assumed that a genset of 10 MW or less represents a pilot stage, and a genset up to 50 MW represents a demonstration stage.

> *"The demonstration stage needs a good number of holes, for example, nine, and a big genset, for example, 50 MW."*

[4] Comments provided by participants in the study are shown in italics.

2.3.4 Commercial stage

We have assumed that any installation with more than 50 MW represents the commercial stage of development of the play. The data provided by proponents show that they typically expect to keep drilling new areas and installing turbines for a number of years during the commercial stage, steadily building up capacity.

2.4 Development stages

The proponents face a significant escalation of scale, complexity and risk as they move through the development stages from securing a tenement to managing a commercial power station.

The work of securing and evaluating a tenement could be entirely office-based if stratigraphical and thermal data are available for thermal resource modelling. These may be available from previous drilling for minerals or petroleum. The cost of securing the tenement and determining whether a heat anomaly exists is likely to be in the hundreds of thousands of dollars, and the time required is likely to be between one and two years.

By definition, the proof of concept stage requires fieldwork for drilling and fracturing for the circulation testing. The cost is likely to be in terms of millions of dollars, and the risks are proportionally higher. The proponents do not expect to carry out these specialist activities in-house, and will rely on services provided by third parties.

By the time the demonstration stage has been reached, with its multiple wells, earthworks, and the installation of pumping and generating plant, the complexity and costs are likely to have increased by at least another order of magnitude.

In some respects, the commercial stage may represent a scaling up from the demonstration stage, but this will further increase the complexity and costs, and the timescale will be different. Where each of the earlier stages could be completed in one or two years, the timescale for the commercial stage is expected to be between 20 and 50 years. Proponents expect that the risks will decline in the commercial stage, and expect to bring more activities in-house. For example, several of the proponents expect to purchase drilling rigs during their commercial stage because continuous work will then be available within their own tenements.

3 KEY RESULTS

The key results are described under the headings of:

- Definition of long run marginal costs (LRMC) and methodology
- Information used for assessment
- Key findings
- Conclusions.

3.1 Definition of LRMC and methodology

The key analytical output of this assignment is the calculation of the long run marginal cost of generation for each of the participating companies.

3.1.1 Definition

There are a number of ways of approaching the calculation of marginal cost but there is no dispute as to the theoretical definition. The Wikipedia states:

> *"In economics and finance, **marginal cost** is the change in total cost that arises when the quantity produced changes by one unit. In general terms, marginal cost at each level of production includes **any** additional costs required to produce the next unit."*[5]

The electricity industry, and many others, departs from such a theoretical definition as the costs that are germane are those required for an investment in new plant. A plant, in the case of the electricity industry, produces not one, but many units of electricity over any period of time that is of practical interest. The expected costs of geothermal generation, in comparison with other means of generation, will determine its viability. The comparison to be made is new plant versus new plant, requiring significant investment, on the basis of long run marginal cost.

3.1.2 Methodology

The methodology which is applicable in the present context is simple in concept although there is much detail involved. The following steps were followed in calculating the LRMC of generation for the geothermal companies.

- All costs and benefits were estimated on a year-by-year basis over the project life.
- Each year's net costs, or benefits, were then discounted to a reference year. This yielded the net present value (NPV) of costs/benefits. The reference year is often the one preceding the year during which the first capital expenditure is to take place.

5 Source: http://en.wikipedia.org/wiki/Marginal_cost. Last accessed: 1 August 2008.

- Each year's generation output, which is the major, but not necessarily the only benefit, was estimated and then discounted to the same reference year, yielding the net present generation quantity (NPGQ). Two of the reasons for discounting the output are:
  - Output in a given future year does not have as much utility as current output and there is a risk that it will not materialise. Discounting all outputs to the reference year makes them comparable.
  - On a practical level, if the outputs are not discounted, the LRMC value is clearly too low – so low that no investments would be justified if the electricity prices were similar to such a low LRMC value.
- The ratio of NPV to NPGQ is the long run marginal cost.

There are many parameters that enter into the calculation of costs and benefits. They take on different values depending upon the type of plant, its location and various influences. We discuss the important ones in Section 3.1.3.

3.1.3 The parameters

There are various parameters which enter into the calculation of LRMC. They are all subject to some degree of uncertainty and this exposes providers of debt and equity capital to risk. Perceived risk influences the value of one of the important parameters: discount rate. Uncertainty also affects the comparison of LRMC of one investment with another. This section includes a discussion of parameters that pertain to generation based on fossil fuels, as geothermal generation will be competing with these as well as with other renewable generation.

3.1.3.1 Project life

For present purposes, as discussed above, the LRMC is the cost of producing all of the output of a plant over its lifetime. We note that there are different lifetimes depending on the technology and design of plant being used, lifetimes also change with the interests of the given party calculating the LRMC. For example, the provider of debt capital may assume a shorter life than the provider of equity capital. The technical lifetime may be different again, and subject to revision from time to time, as might be the economic life. We are concerned with the initially expected project life, at the time an investment decision is taken.

3.1.3.2 Fuel cost, heat rate and carbon costs

We have grouped the discussion of these three parameters together as they pertain to all fossil fuel based generation.

3.1.3.3 Fuel cost

The two fossil fuels of importance are natural gas and coal. Coal will remain relatively low cost to mine and process, for the foreseeable future, but its use will become considerably more expensive when carbon emission costs are imposed. While coal export prices will likely remain high, the coal-based electricity generation plants that will be built and/or continue to operate will be competitive in base load operation. In 2020, such plants will almost certainly account for a substantial proportion of base load plant. See Section 5.3.

Natural gas will be subject to increasing prices and carbon costs, but to a lesser degree than coal.

Heat rates are well understood and are expected to continue to improve with further technological development. They are subject to deterioration as a plant ages.

3.1.3.4 Carbon costs

It is now virtually certain that fossil fuel generation will have to sustain costs associated with emitting or capturing and storing carbon dioxide (carbon for short). These costs are likely to be significant, although they are still uncertain and will remain so for some considerable time. In the case of emitting carbon, the price of emission certificates is uncertain. In the case of carbon capture and storage (CCS), the major uncertainties are those pertaining to its transmission to the storage site and the cost of the storage facilities; no major storage site has yet been identified as being technically and economically feasible *and* available for the purpose.

3.1.3.5 Renewable Energy Certificates

The new Australian Government has adopted a mandatory target of 45,000 GWh of renewable energy, that is, electricity from renewable sources (or some specified equivalents) by 2020. There are currently a number of somewhat overlapping renewable energy schemes and it will not be clear for some time how they will be incorporated into one national scheme.

In view of the above, any renewable energy generator faces significant uncertainty in estimating the revenue it can expect from selling the associated certificates.

3.1.3.6 Outage rate and estimating plant output

Depending upon the type of plant, there will be differing bodies of experience and, hence, accuracy of estimates of planned and unplanned outages. Plants based on new technologies usually have a relatively high outage rate until sufficient experience is accumulated to reduce it to relatively low levels. Some technologies, even with a large body of experience, will inherently have a higher outage rate than others. For example, integrated gasification combined cycle (IGCC) would be expected to have a higher outage rate than conventional coal or geothermal.

Plant output depends on outage rates but also on other factors. Maximum expected sent out energy generation over a given time period for a given plant depends upon:

- the technical condition of the plant – this affects capacity and efficiency
- expected ambient conditions - in the case of geothermal and other technologies, ambient conditions have a significant effect on capacity and may also affect efficiency

- parasitic load – all types of plant, including geothermal, have auxiliary equipment that itself uses some of the plant's output.[6]

3.1.3.7 Capital costs

Capital costs have become quite difficult to estimate over recent years. Not only have they escalated at a high rate, but forecasting future escalation rates is very difficult. This contributes to the uncertainty in estimates. Uncertainties are, leaving escalation rates aside, greater for new technologies than for established ones. They are also greater for technologies for which a relatively greater proportion of expenditure is required for imported equipment, as opposed to domestically sourced materials and equipment. This is due primarily to uncertainties in exchange rate forecasting.

Meeting the project schedule, or otherwise, usually has a bearing on capital costs. Delayed completion or commissioning also delays the commencement of the revenue stream. Risks of delays are higher for new technologies than for established ones.

Transmission or grid connection costs may be significant in some instances. This is the case for some wind farms and would be the case for some geothermal projects.

As technologies mature, the uncertainties and risks discussed in this section diminish, and the capital costs themselves come down.

3.1.3.8 Discount and interest rates

Interest rates enter into the calculation of LRMC if it is assumed that debt capital is used. Discount rates are used whether or not any debt capital is used. Interest rates that may apply to any given project are a function of rates generally and the risk of lending perceived by those providing the debt finance. The discount rate should reflect the opportunity cost of the capital provided by the investors, that is, providers of equity capital, and the risk they perceive. We note, however, that the providers of debt capital, will also use a discount rate in evaluating a project and it may differ from the rate used by the investors. Risk is the main influence on discount rates.

3.1.4 Note on uncertainty

An estimated or calculated LRMC is usually presented as a single number, with two or more significant figures. In general, the range of uncertainty may well be in the tens of dollars per MWh, particularly for new technologies, but often also for *new* plants, even if they use established technologies. When comparing LRMCs, the ranges of uncertainty are important. The question is not whether any two LRMCs are different but whether they are ***significantly*** different.

[6] A near exception is photovoltaic plant. Nonetheless, inverters, control systems and the like use some electricity.

3.2 Information used for assessment

The analysis to estimate the likely installed capacity and electricity sent out from geothermal sources relies on the information provided by proponents about their current state of knowledge and their business plans. The main data collection instrument for this section of the report was the financial parameter workbook, which is included in *Appendix 4, Timeframe and financial parameters,* on page 79. Each company which participated in this study was consulted a number of times in this process, because the questions became more specific as the study evolved. The final step in the consultation process was to send a copy of our analysis of each proponent's results to them for review. This enabled us to cross-check the results of our analysis against the in-house analyses of the participants.

Given the difficulty of answering questions about potential activities up to twelve years in the future, we thank the participants for their co-operation throughout this consultation process.

The data which proved to be of most relevance in the analysis included:

- gross installed capacity, by year to 2020
- gross capacity sent out, by year to 2020
- drilling costs, by year to 2020
- surface equipment costs, by year to 2020
- the year in which exploration started
- the year the power plant will be commissioned
- fixed operating costs, by year to 2020
- variable operating costs, by year to 2020.

Several participants also provided figures for:

- the length, year of commissioning and capital cost of the transmission line
- transmission costs
- the cost of connecting to the transmission line.

However, as the majority of the participants were not able to provide this information with a reasonable degree of confidence, we have not included this information in the report.

3.3 Key findings

Following the review of the data by the participants, we divided each participant's projections into pilot, demonstration and commercial stages, depending on the volume of installed capacity and the proponent's business plan. The pilot stage typically covered up to 10 MW of installed capacity and, as a result, a number of the proponents were not deemed to have a pilot stage, because their first generator exceeded this threshold.

In general, the commercial stage was deemed to begin after 50 MW were installed, but in some business plans it was more appropriate to set the lower threshold at 20 MW. As a result, some of the following graphs show overlapping stages.

Figure 4 shows the high correlation between cumulative installed capacity and cumulative investment between the present and 2020. The investments are shown in 2008 dollars. It also shows that both investment and installed capacity rise slowly until 2012, by which time a number of pilot and demonstration plants will be operating. After 2012, assuming that the results of the pilot and demonstration plants are encouraging, investment and installed capacity rises rapidly, reaching a cumulative installed capacity of 2,200 MW in 2020, for a total investment of $12 billion.

Figure 4 – Cumulative MW installed and cumulative investment

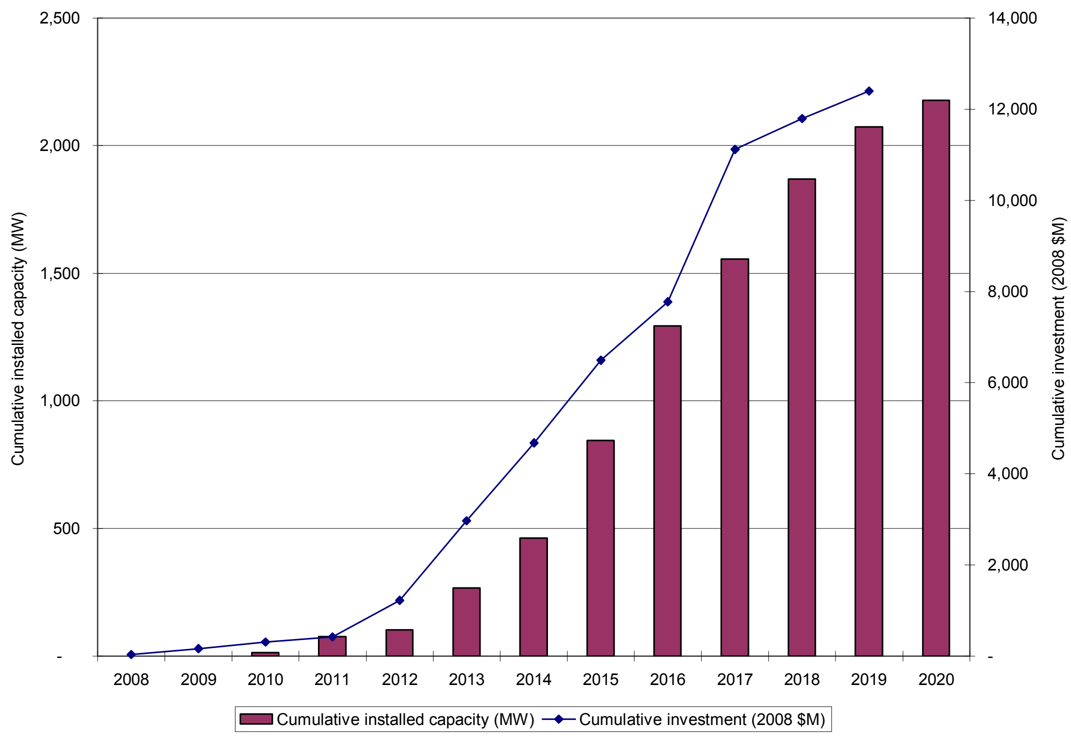
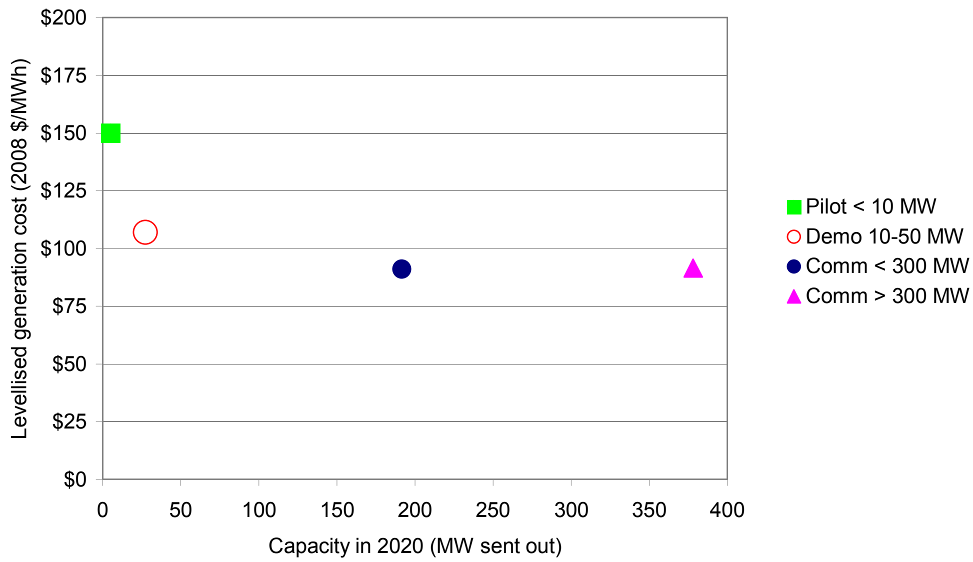


Figure 5 shows the results of our analysis of the levellised generation cost versus the sent out capacity of the proponents in 2020, divided into stages. It shows that pilot plants of less than 10 MW will have a cost of about $150/MWh. Demonstration plants in the 10-50 MW range will have a generation cost of about $105/MWh, and commercial plants both below 300 MW, and above 300 MW, will have a similar generation cost of about $90/MWh. Based on the data provided by participants, they do not anticipate economies of scale above the 300 MW threshold. Taken together, the data in this graph shows the rapid reduction in costs anticipated in the transition from very small pilot plants to larger demonstration plants, and the additional reduction in costs anticipated in the transition to commercial scale.

Figure 5 – Levellised generation cost by capacity sent out



The data in Figure 5 appear to show insignificant economies of scale above 200 MW. Economies of scale may however, be realised as projects are implemented.

Figure 6 shows the typical stages of pilot, demonstration and commercial plants, and the estimated average levellised generation cost per MWh in 2008 dollars. The estimated costs are about $150, $105 and $90 respectively, showing the expected effects of scale.

Figure 6 – Levellised generation cost by stage

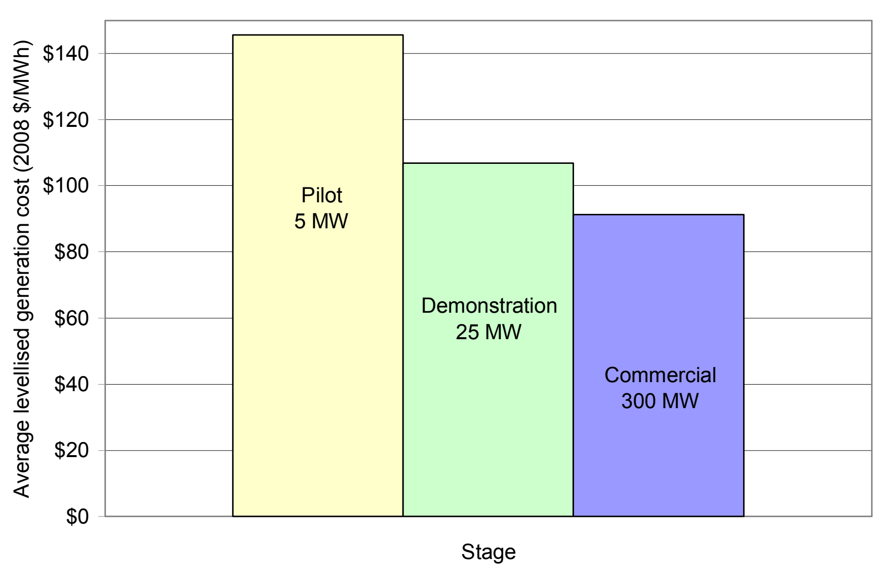
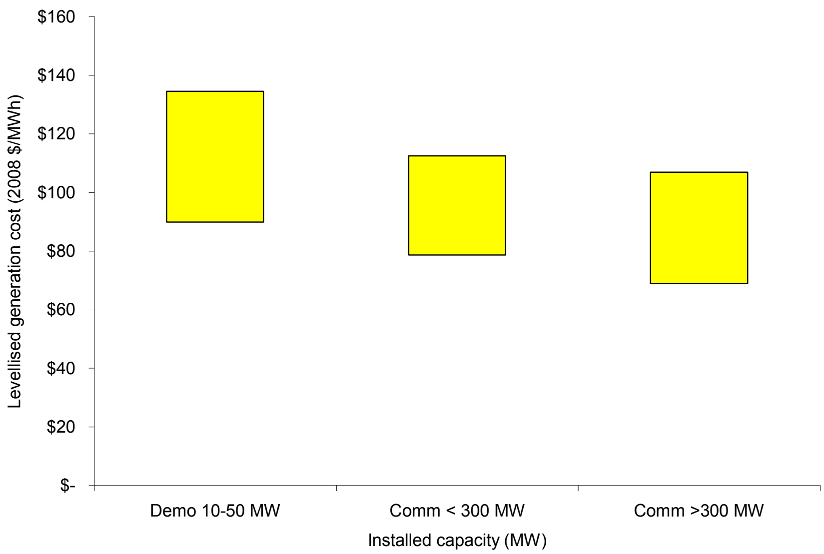


Figure 7 presents the data in a slightly different way, illustrating the margin of uncertainty around the point estimates for the demonstration and commercial stages shown in Figure

5, and splitting the commercial stage into those with less than 300 MW installed capacity and those with greater than 300 MW of installed capacity.

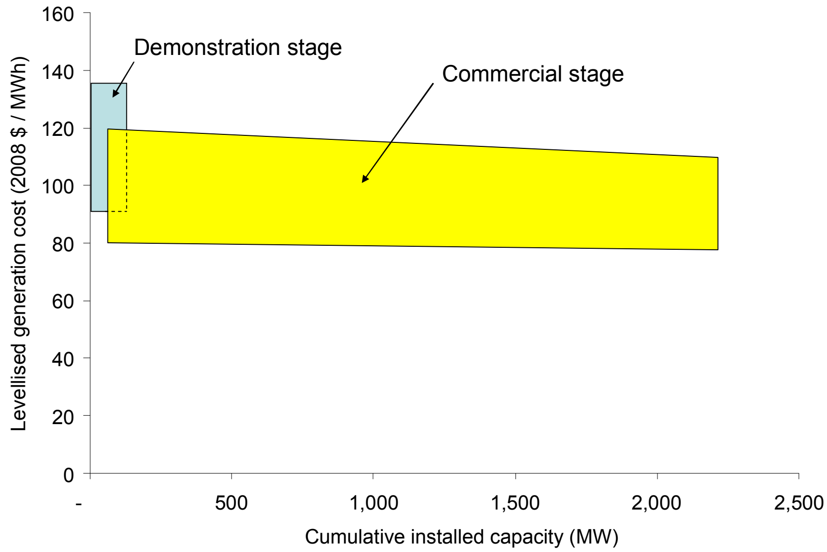
Viewed in this way, the cost in the demonstration phase ranges from $90 to $135/MWh, from $80 to $110/MWh for a proponent with less than 300 MW in the commercial stage, and from $70 to $110/MWh for a proponent with more than 300 MW in the commercial stage. Note that while the average cost is the same above and below 300MW, as shown in Figure 5, the envelope of costs is slightly lower.

Figure 7 – Levellised generation cost by installed capacity



The participants in this study spoke about the level of uncertainty around the data we have used to calculate the levellised costs. We have, however, determined the uncertainties ourselves in Figure 8, which shows the upper and lower bounds of this uncertainty for demonstration and commercial stages against cumulative installed capacity. Viewed in this way, demonstration projects could range from $90/MWh to $135/MWh. The commercial stage overlaps with the demonstration stage to some extent because of the different business plans. When the commercial installed capacity is small, the range is wider, approximately $80/MWh to $120/MWh. While the lower boundary did not change as the cumulative capacity increased, the upper boundary did decline slightly. This implies that the level of uncertainty is expected to narrow over time. Companies with costs in the lower part of this range will be able to compete successfully under MRET or a carbon tax regime. Companies in the upper part of this range will not. As a result, it is difficult to predict the viable installed capacity in 2020. However, if we assume that half of the participants will deliver electricity to an end-user at the lower part of this cost range, then an effective installed capacity of 1,000MW is achievable for them. This ignores the potential contribution of companies that did not participate in this study.

Figure 8 – Levellised generation costs by cumulative installed capacity



This discussion illustrates why companies find it difficult to attract funding to move through the pilot and demonstration stages. It is only after these stages are complete that a proponent will be able to narrow the range of uncertainty sufficiently to assess whether it can build a commercially viable generator.

Generation from geothermal energy offers a number of benefits, one of which is the public benefit of generation from a source which results in lower greenhouse emissions than fossil-fuelled generation. However, no Australian company has yet generated from a non-volcanic geothermal source, so the proponents do not have Australian precedents from which to learn.[7] While a considerable amount of private sector funding has been made available to date, the private sector alone is unlikely to be able to provide the level of funding for the commercial stage indicated in Figure 4 until there are some pilot and demonstration plants operating.

The early high risk stages will rely on funds from equity and short-term investors. The pilot and demonstration stages will require larger sources of funds, which are likely to come via joint venture partners or farm in partners. By the commercial stage, debt and longer-term investors are expected to be the main sources of funds. Based on our interviews with the participants, the stage where they are most likely to experience difficulties are the pilot and the demonstration stages, where the risks remain high and the capital requirements can exceed $100 million just for drilling and, if the drilling is successful, the additional cost of construction for the surface plant can be significant.

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[7] The Soultz project in France began to generate from a non-volcanic site using a 1.5 MW plant in June 2008. (Source: http://www.soultz .net/version-en.htm. Last accessed: 7 August 2008)
We understand that a company has generated by circulating water through a non-volcanic source at Landou in Germany. (Source: http://www.dw-world.de/dw/article/0,2144,3255490,00.html. Last accessed: 7 August 2008)

3.4 Conclusions

This study has analysed the potential installed capacity and generation from geothermal sources by 2020. While the different elements of the technology such as drilling, fracturing, pumping, generating and reinjecting are all proven, the combination has not yet been proven commercially in Australia. A wide band of uncertainty affects the proponents' cost projections.

Successful progression through the pre-commercial stages may result in over 2,000 MW of commercial geothermal capacity operating in base load mode by 2020. It would likely result in at least 1,000 MW. Successful early stages of commercial capacity will lead to commitments for additional commercial capacity well before 2020.

4 ANALYSIS METHODOLOGY

This section describes:

- Data used in the model of the long run marginal cost (LRMC) of generation
- Companies which did not participate in the study
- Transmission loss factors
- Nearest point on the grid
- Regulatory issues identified by participants.

4.1 Data used in the model of the cost of generation

Using the data provided in the workbooks completed by proponents of geothermal projects, we modelled the cost of generation and transmission for each project. The projects were divided into pilot, demonstration and commercial stages based on the size of the installed capacity and the proponent's business plan. Some proponents plan to start at what we term the demonstration stage rather than at the pilot stage, although the distinction is arbitrary.

The generation model calculated the levellised cost of generation for each stage from yearly data on the electrical energy sent out, the total capital cost of the system and its operating costs. Note that by using sent out capacity, the models do not include energy used on site, of which the largest component was for pumping. Pumping loads estimated by proponents varied widely, and added more uncertainty to the analysis.

The generation model assumed a high capacity factor of 95% for geothermal plant. This capacity factor acknowledges the potential for geothermal to supply baseload, compared to wind, which has a typical capacity factor of 30%.

The transmission model calculated the levellised transmission cost from analogous data. Transmission companies will want a connection agreement for 20 years. This is the standard for the industry, and applies to all forms of generation, not just renewables. This and the effects of discounting for revenue, mean that the value of energy sold after 20 years has little effect on the long run marginal cost of generation. However, there is a mismatch between the expected life of 50 years for transmission assets and 25 years for a producing geothermal well. While not explicitly considered in this analysis, it is likely that a manager of a geothermal field will continue to drill new wells as old wells become depleted, and move the surface plant as required. As one participant noted, they will become managers of a *"walking well farm"*. We note that on a discounted basis, using a discount factor of 10%, the transmission tariff based on 25 years would be only 10% more than for 50 years. The transmission tariff, furthermore, will almost certainly be less than 20% of the cost of generation and usually less than 10%. The 25 year difference would result in a less than two percent difference in delivered unit electricity costs.

In combination, these two models gave the total cost of delivering electricity to either an end-user or a NEM connection point.

A number of assumptions were incorporated into the models and these are summarised in Table 1.

Table 1 – Assumptions for the financial model

Parameters	Units	Pilot	Demonstration	Commercial
Real Pre-tax WACC	%	12.5%	11.5%	10.2%
Plant life	Years	25	25	25

4.2 Companies which did not participate in the study

Several companies declined to participate in the study, citing intellectual property issues. In aggregate, these companies predicted that they would have in the order of 1,000 MW of installed capacity by 2020. However, as we have no data on their financial parameters or business plans, this potential generation was not considered in the analysis.

4.3 Transmission loss factors

Expected loss factors between the generator and the connection point where the output would be delivered to the transmission line ranged from negligible to 5%. The proponents seem to have assumed that connection points are close, perhaps not realising it will probably be at a substation, rather than directly to the transmission line.

Loss factors between the connection point and either the end user or the grid are summarised in Table 2. Most of the responses lay in the 1% to 10% range.

Table 2 – Loss factors between connection point and end user or grid

Expected transmission loss factor between the connection point and the end user (%)[8]	Frequency	Percentage of responses
Negligible	5	20%
1%	4	16%
5%	5	20%
10%	3	12%
12%	1	4%
25%	1	4%
Minimal – end user 20km away – may not connect to grid	1	4%
Not applicable	2	8%
Don't know	3	12%
Total	26	

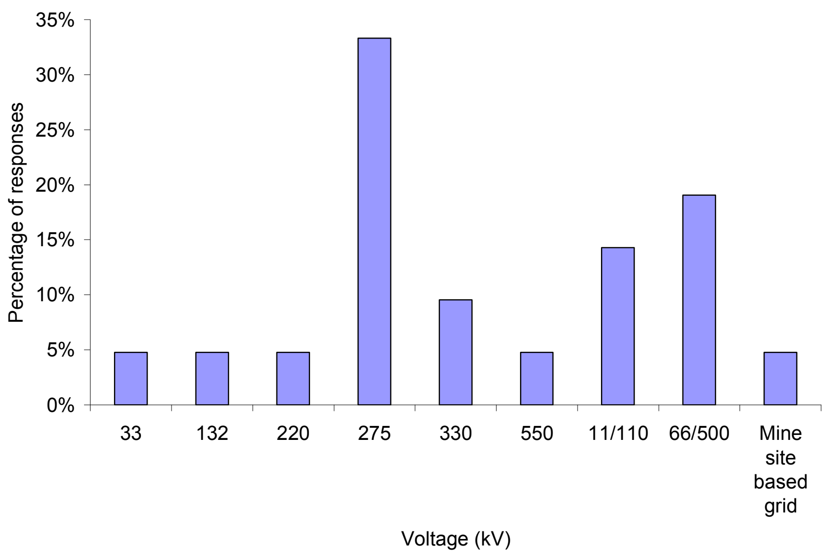
8 The grid can also be considered as an end user.

4.4 Nearest point on the grid

Figure 9 shows the voltage of the nearest point on the grid to the proposed geothermal power station. While it shows a wide range of voltages, the most commonly nominated voltage was 275 kV. The distance to the grid varied from 10 km to 600 km, with most falling in the 10 km to 100 km range.

One participant noted that "*South Australia is the most poorly connected state in the NEM.*" Another participant foreshadowed the need to augment the transmission system between South Australia and Victoria in order to export electricity generated from geothermal sources to the eastern states of the NEM.

Figure 9 – Voltage of the nearest grid



4.5 Regulatory issues identified by participants

Regulatory issues relating to carbon pricing and water were the most frequently cited issues that could affect the viability of proponents' projects. However, there were a number of regulatory issues that affected proponents, with most being cited only once. The issues cited were:

- price of carbon, carbon trading, emissions trading and MRET (3 mentions)
- water legislation and trading (3 mentions)
- government funding (2 mentions)
- NEM rules (1 mention)
- transmission asset regulatory test (1 mention)
- Aboriginal heritage (1 mention)
- environmental legislation and regulation (1 mention)

- state planning authority (1 mention)
- laws relating to engineered geothermal systems (1 mention)
- royalty rules (1 mention)
- tax (1 mention).

The following quotes illustrate the carbon issue and the general regulatory issue.

> *"On carbon value and MRET policies, a scheme which allows carbon value to be captured by wind initially will negatively impact on project economics - especially for large scale developments, but the full impact is dependent upon what the relationship between black and green pricing is, as well as the presence (or not) of carbon value. Carbon value is guaranteed to impact the project 100% as it is guaranteed to affect revenue –the question is by how much. … On carbon, its absence would put expansion at risk - so would not impact on the pilot but the limiting case of no MRET and limited flow through to black pricing would have a 100% probability the project would not be viable, as we would not get past the first expansion stage."*
>
> *"I believe that the geothermal industry will be marginal for some time unless they are very large projects. Consequently, delays and cost blow-outs due to jumping regulatory hurdles cause projects to be uneconomic or too high risk."*

The probabilities that these issues would make projects unviable were rated as:

- none / not applicable (3 mentions)
- low (3 mentions)
- don't know / too early to say / difficult to predict interactions of factors (2 mentions)
- moderate (1 mention)
- high (1 mention).

5 AUSTRALIA'S ELECTRICITY MARKET CHARACTERISTICS

This section describes the electricity markets of Australia and how they may accommodate the sale of electricity from geothermal sources.

Australia's electricity markets comprise a number of large grid based systems, isolated power supply systems supplying remote towns and mining operations, plus stand alone generation systems supplying remote tourist operations, homesteads and small towns.

The principal grids are the National Electricity Market (NEM), the South West Interconnected System (SWIS) and the Darwin Katherine Interconnected System (DKIS). Smaller, but still important potential markets for geothermal power generation include the Alice Springs-Tennant Creek system in the Northern Territory, the Mount Isa grid in Queensland and the Pilbara System in Western Australia. Remote mining operations may also offer prospects for geothermal, but the short life of the mines (typically less than the life of the geothermal plant) acts as a major barrier for geothermal technology in this market. Loads at remote homesteads and communities are generally too small to be suited to geothermal technologies.

Fossil fuel is the dominant form of electricity generation in Australia, as shown in Table 3. Coal-fired generation is dominant in most of the mainland states and contributes 75% of the total generation in Australia. Natural gas contributes 14%, and renewable energy contributes only 9%, with most of this coming from hydro-electric generation. Wind and other forms of renewable energy currently contribute less than 2%, with geothermal not supplying to Australian grids at all.

Despite numerous support measures, including mandating the purchase of up to 9,500 GWh of generation in the original MRET, the proportion of renewable generation has fallen from 10.5% in F1997 to 9.4% in F2007. High electricity growth rates over the past decade have been mainly met by increased natural gas fired generation and brown coal generation. Ongoing drought has also limited the contribution from hydro-electric systems. The expanded MRET target is discussed in the following sections.

Fossil fuels dominate electricity production due to the low cost and maturity of these generation technologies. Nonetheless, there could be an increasing role for renewable energy, as long as it can become competitive. Electricity demand is projected to grow by between 1.7% and 2.1% per annum over the period to 2050. The need to curb emissions of carbon dioxide also is expected to favour renewable energy generation.

Geothermal energy is produced continuously and as such is ideally suited to displace base load sources with high carbon emissions in a carbon constrained world.

Table 3 – Generation by technology and fuel type (GWh)

	Qld	NSW	Vic	Tas	SA	WA	NT	Aust
Black Coal - Steam Turbine	44,121	63,484	0	0	4,991	8,430	0	121,025
Brown Coal - Steam Turbine	0	0	44,975	0	0	0	0	44,975
Gas - OCGT	3,615	1,274	2,088	2,046	411	6,990	1,581	18,006
Gas - CCGT	629	0	0	0	751	1,769	490	3,639
Gas - Cogeneration	0	513	0	0	1,267	3,553	0	5,334
Gas - Steam Turbine	0	0	567	0	1,512	2,664	0	4,743
Liquid Fuels - OCGT	20	0	0	0	0	1,413	988	2,421
Liquid fuel - Steam	0	0	0	0	1	0	0	1
Hydro	632	5,198	730	10,531	0	0	0	17,092
Wind	42	50	249	479	963	66	0	1,849
Biomass	711	517	94	289	46	143	0	1,801
Geothermal	0	0	0	0	0	0	0	0
Solar Thermal/PV	0	0	0	0	0	0	0	1

Source: MMA analysis from Electricity Supply Association of Australia (2007), WA Independent Market Operator (2007), Verve Energy (2007) and NEMMCO (2007)

5.1 Institutional arrangements

Electricity markets comprise a number of components, with different institutional arrangements governing each component. A wholesale market has now been established for most of the major grid systems, including the National Electricity Market (NEM), the West Australian Electricity Market (WEM) and the Northern Territory market. Transactions occur on spot exchange in most of these markets, but long term contracts and hedges are still the dominant form of transactions between generators and retailers of electricity. Market rules have been established to govern the operation of these spot markets.

Ancillary service markets have also been established in most states on a user pays basis to help equalise supply and demand at all times.

Trading in the spot market is an inherently risky business, resulting in the development of a range of financial instruments to manage the risks. However, the markets for financial instruments have not been liquid.[9] An increasing concentration of generation and a trend to vertical integration (combined generation-retail entities) has also reduced the effectiveness of these instruments.

[9] Electricity Reform Implementation Group. 2007. *Energy reform: the way forward*, report to the Council of Australian Governments, Canberra.

These arrangements have a number of important implications for the development of geothermal power generation:

- Participants in the market need large financial reserves to back up their contractual arrangements. A geothermal plant experiencing an outage during the crucial peak demand period will need to purchase electricity from the spot market to meet its operator's contractual obligations.

- Retailers are reluctant to enter into long term contracts with new generators, with the longest terms generally being 10 years, although there are a few 15 year contracts.

- Selling power into spot markets normally provides lower revenue than if the output can be contracted. The uncertainty of revenue also increases business risk and increases the financial costs. The inability to contract the power reduces the profitability and increases the risk of the business.

- Retailers are increasingly buying or building their own generators, which acts as a substitute for the long term contracts.

Therefore, it is likely that the market environment will be very difficult for small technology development companies to operate in. Small companies developing geothermal technologies will need to develop strategic relationships with large generating companies or retailers to help manage the risks involved.

Transmission systems are generally highly regulated because they are natural monopolies with high barriers to entry and large economies of scale. Prices for transmission services are determined by a national regulator on a revenue cap basis. Until now, customers generally paid for network services on a user pays basis, but there is an increasing trend for generators to pay some more of the share of network costs. Currently, generators only pay for connection costs, but there is a trend towards requiring new generators pay for a portion of deep connection costs in proportion to the benefits received by them in relation to upgrades of the network system.

A number of issues will affect the uptake of renewable energy generation, including geothermal. First, there is a lack of information on the potential resource available for each renewable energy technology. Some general information is available on wind resources, biomass resources and solar isolation levels, however, this information is imprecise and the social, environmental and economic constraints of using these resources are not well understood.[10] This affects the potential uptake of geothermal generation in two ways: directly, as there is only a partial understanding of the thermal resource and its proximity to load centres; and indirectly, as there is a lack of knowledge on the renewable resources that would compete with geothermal.

[10] Ministerial Council on Energy Standing Committee of Officials Renewable and Distributed Generation Working Group. 2006. *Impediments to the uptake of renewable and distributed generation*.

Secondly, there is also limited understanding of business opportunities and the risks of investing in renewable energy serving competitive electricity markets. Many of the developers lack the financial skills and knowledge to manage the risks of trading electricity on spot markets. On the other hand, investors have little confidence in the veracity of claims about non-conventional technologies, although ongoing implementation of standards and accreditation systems can improve confidence in them.

Thirdly, the development of some renewable energy sources is hindered by underdeveloped and inconsistent rights to the resource. This issue is unlikely to impact on HTST generation, but will impact on many of its competitors, such as geothermal generation. Project approval can also be onerous and expensive, often requiring the same level of effort for small scale projects as for large scale projects, as is typical for many renewable energy projects. While this confers significant economies of scale for large scale projects, it imposes costs on the pilot and demonstration stages of geothermal projects.

The fourth, and perhaps the most critical near term issue, has to do with network pricing and provision. Detailed consideration of these issues is beyond the scope of this report.

5.2 Role of renewable generation

Renewable generation currently plays a limited role in Australia's electricity markets. Renewable energy generation has grown, but its share of total generation has declined. Although wind and other forms of new renewable generation have grown, hydro-electric generation has fallen as a result of the prolonged drought. Growth in renewable generation has been mainly through government support measures including:

- Australian and state government imposed mandatory targets for the purchase of renewable generation.
    - The Australian Government's MRET scheme came into operation in 2001 and mandated the generation of 9,500 GWh of renewable generation from 2010. Victoria, Queensland, NSW and Western Australia have also imposed their own targets, tallying up to around 27,000 GWh of mandated renewable generation by 2020. However, the recent election of the ALP to the Australian Government means that these State schemes are likely to be replaced by a single expanded MRET target of 45,000 GWh of new renewable generation by 2020, as shown in Table 4. The expanded national target will subsume the various state-based targets.
    - When added to pre-existing generation, a MRET target of 45,000 GWh of new renewable generation will give a total level of renewable generation of 60,000 GWh in 2020, or about 20% of total electricity demand by then. To achieve a share of this, geothermal will have to compete with other renewable technologies, notably wind which is a mature, established technology.
- Green Power schemes, which grew by 25% over the last year as more people become concerned about climate change, and now comprise around 1,500 GWh of generation.

- The Renewable Energy Development Initiative and Renewable Energy Equity Fund, which have been used to develop and commercialise novel renewable energy technologies.
- The Renewable Remote Power Generator Program, which has provided subsidies for off-grid renewable generation.
- The Photovoltaic Rebate Program, which has provided subsidies for solar powered generation.
- The Low Emission Technology Development Fund, which has funded some demonstration projects for low emission technologies, including a 150 MW photovoltaic (PV) concentrator plant. The new Australian Government has promised to establish another $500 million fund to further demonstrate and develop new renewable energy technologies.

Table 4 – Renewable energy targets, assuming linear increases to 2020 (GWh)[11]

Year	Current MRET target	Expanded MRET target (including current state based schemes)
2010	9,500	9,500
2011	9,500	13,050
2012	9,500	16,600
2013	9,500	20,150
2014	9,500	23,700
2015	9,500	27,250
2016	9,500	30,800
2017	9,500	34,350
2018	9,500	37,900
2019	9,500	41,450
2020	9,500	45,000

An additional option is for geothermal plant output to be sold on the Green Power markets.

Green Power is a product developed by electricity retailers comprising electricity sourced from accredited renewable generation. The high cost of renewable generation relative to conventional generation results in Green Power being sold at a premium of a few cents per kilowatt hour.

Green Power schemes can be either of two types:

- Consumption-based schemes, in which a premium is charged on the price paid by consumers on some or all of the electricity consumed. An example is Energy

11 We have assumed in this table that the targets will increase by the same amount each year.

Australia's Pure Energy Scheme, which allows consumers to nominate a percentage of their electricity (25%, 50%, 75% or 100%) to come from renewable sources.

- Contribution-based schemes, in which consumers contribute to a fund administered by a retailer to support renewable energy generation.

For the calendar year 2007, there were over 724,000 Australian customers who had opted for Green Power from their retailer, and a total of 1,137 GWh of Green Power was purchased. Green Power has had an impact on encouraging development in renewable energy, and in 2007 it contributed to renewable energy sales above the MRET target.

Green Power schemes originated in New South Wales through the work of the Sustainable Energy Development Authority (SEDA). SEDA had taken on the role of accrediting Green Power generators and auditing retailers to ensure that all Green Power sold is actually generated by an accredited generator. The functions of SEDA are now undertaken by the NSW Department of Water and Energy.

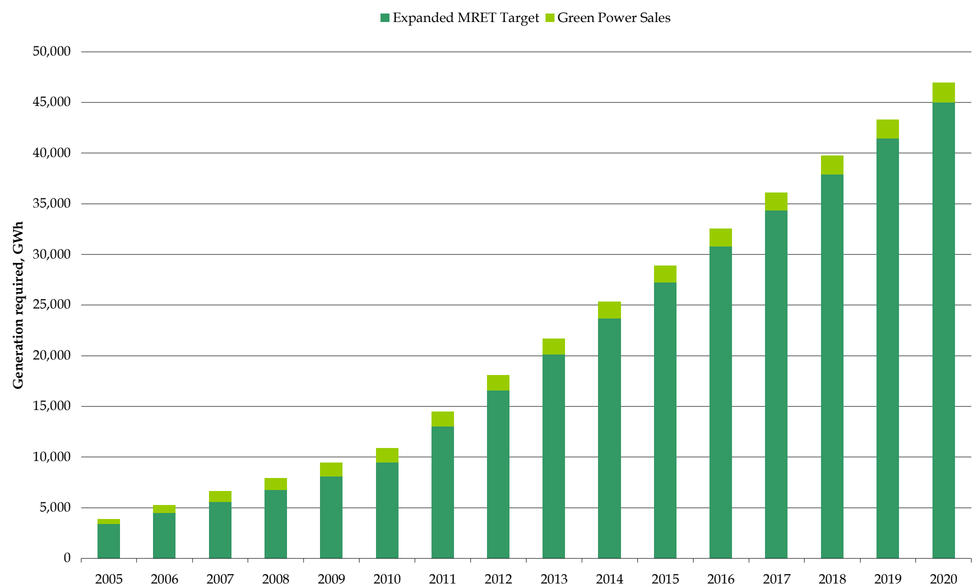
The introduction of the REC scheme has complicated the Green Power scheme and there was considerable uncertainty as to whether generation could be accredited for both, and therefore gain two additional revenue streams. This confusion has been resolved through new Green Power accreditation rules that essentially mean that renewable generation may be either used for RECs or sold as Green Power, but not both. The decision a generator must make, therefore, is whether there is more value in the RECs or from Green Power sales.

It is difficult to predict the market outlook for Green Power as it is a voluntary scheme and is entirely dependent on consumer demand. Although sales under Green Power have been growing strongly in recent years, the volumes of renewable energy are still small compared to other schemes such as MRET.

Growing concern about the environment and climate change may encourage more consumers to purchase Green Power. For example, the South Australian Government has recently announced that it will purchase 20% of its energy needs from Green Power. This will result in a reduction of the government's greenhouse gas emissions by 107,741 tonnes per year. Assuming an emission intensity coefficient of 0.9 t CO_2e/MWh for electricity consumption, the Green Power purchase for the South Australian Government is 120 GWh.

The forecast market for renewable generation under the expanded MRET scheme and under Green Power sales is shown in Figure 10.

Figure 10 – Renewable generation required to meet expanded MRET target and Green Power sales



Despite the considerable investments in renewable energy under government programs, very little of the investment has gone to geothermal technologies. Only a small proportion of projects have received funding, and that has mainly been in the form of R&D grants. To date, geothermal has not been able to exploit the potential market under MRET or any other deployment support program. This probably reflects its stage of development, a negative attitude towards the technology, and cost reductions achieved in more mature technologies such as wind generation.

Despite the support from government programs, renewable energy generation is still more expensive than fossil fuel generation options. It is only in stand-alone electricity supply systems that renewable generation has been able to compete with fossil fuel alternatives, and only when small scale systems using PV or wind have been used. To date, there has been no single renewable energy project in Australia of the scale that is envisaged for geothermal generation.

5.3 Role and benefits of geothermal power

Geothermal power production is controllable and has a lower short-run marginal cost of production.[12] If the high capital cost can be recovered in a carbon constrained world, due to higher energy prices, geothermal generation will be developed and operated as a base load resource. This will displace coal fired generation when it is exposed to a high carbon cost above $20/tCO_2e. Large amounts of wind power are problematic due to the hour to hour and day to day variability of output which does not correspond to the pattern of

[12] Short-run marginal costs are the costs incurred only as a consequence of plant operating. They exclude, therefore, capital and fixed operating costs. As there are no fuel costs and, in future, will be no carbon costs, this provides a significant advantage to geothermal, solar and wind technologies.

electricity demand. Typically the minimum demand for electricity is at least half the peak demand and about 70% of the electricity consumption is base load and is required continuously. Therefore, there is unlikely to be a technical limit on the amount of geothermal power that can be absorbed into the grid. There only remains an economic limit that depends on its cost and reliability. To the extent that geothermal power may have slightly higher short-run marginal costs than wind power, some of it might be displaced into intermediate duty if and when there were large amounts of wind and geothermal power developed in some regions, such as South Australia. However, the prospect for any displacement of geothermal power seems a long way off in the future and would only occur after substantial development of geothermal power. The NEM is well able to absorb geothermal power on a spot or contract basis, provided that transmission capacity is provided in a timely manner, consistent with supply and demand requirements on a local and regional basis.

There is a high concentration of potential wind and geothermal projects in South Australia. It is likely that for the full potential of renewable generation to be realised in the long term, the net flow of electricity will need to be outward from South Australia, rather than inwards as is now the case. It will, furthermore, likely exceed the capacity of the current interconnections. The remoteness of some projects raises additional issues. The current regulatory regime, if not modified, is not conducive to the development of remote projects, as they are treated individually even if the first project in a given region facilitates subsequent projects.

6 BACKGROUND INFORMATION ON GEOTHERMAL TENEMENTS

This section provides background information on the geothermal tenements of the companies which participated in this study, under the headings of:

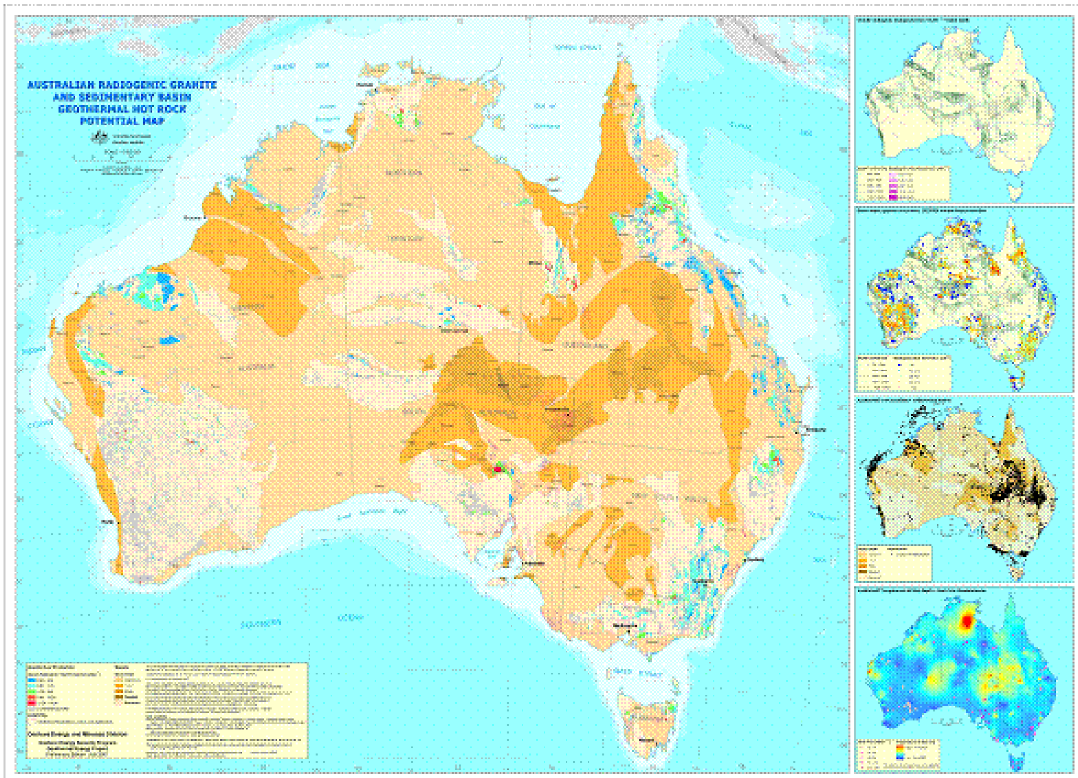
- The tenements
- Number of existing wells and planned drilling
- Models of development
- Water requirements
- Experience in managing similar projects
- Gaps in intellectual property
- Sources of finance to data and for the next five years.

6.1 The tenements

The tenements are scattered across Australia, which reflects the widespread potential for geothermal energy, as shown in the map prepared by Geoscience Australia in Figure 11.[13]

[13] Budd, A.R. 2007. *Australian radiogenic granite and sedimentary basin geothermal hot rock potential map (preliminary edition)* 1:5 000 000 scale, Geoscience Australia, Canberra

Figure 11 – Map of hot rock potential



The tenements ranged in size from less than 100 km² to almost 20,000 km², with an average size of 1,900 km².

For the 38 tenements for which data was provided, the participants held exploration licences for 79% of them, and an additional 5% had been named as the preferred tenderer subject to the Native Title process.

For the same 38 tenements, exploration results were available for fourteen tenements (37%), partial results were available for four (11%) and no exploration data was available for 20 (53%).

The proponents had applied for and held retention licences in only two tenements, but several noted that their tenements could be held for up to 10 years without renewal.

Table 5 shows the responses to the question about whether or not the geothermal resource had been modelled. It shows that in 27 (73%) of the tenements, no modelling had occurred. Some level of modelling had occurred for nine (24%) of the tenements. Only two of the respondents had conducted stimulation or fracture testing.

Table 5 – Modelling of the thermal resource

Has the geothermal play been modelled?	Number	% of tenements
No	27	73%
Yes	9	24%
In progress	1	3%
Total	37	

The quality of the data held for 40 tenements is described in Table 6. Reserve definition at P50 was anticipated by the end of 2008 in one tenement, at probable reserve for four tenements, and a third had a number of wells, two dimensional seismic data and historic fluid information. Twenty-three others had inferred, exploratory or desk-top quality data, indicating that they were in the early stages of defining the extractable geothermal energy. No response was provided for a further 11 tenements, suggesting that no data were available for them.

Table 6 – Level of information by tenement

What level of information is held for this tenement?	Number	Percentage of tenements
P50 Reserves (by end 2008)	1	3%
Probable reserve	4	10%
11 wells, 50km 2D seismic data, historic fluid information	1	3%
Inferred resource	2	5%
Exploration results	11	28%
Preliminary desk top work	10	25%
No response	11	28%
Total	40	

6.2 Number of existing wells and planned drilling

Table 7 summarises the responses to the questions about the number of existing wells from which geothermal data were available in each tenement and their deepest depth. Two had deep wells over 4,000 metres, six had wells 3,000 metre or deeper, and two had wells of 2,000 metres.

Table 7 – Number of existing wells and deepest depth

Number of wells from which geothermal data is available	Greatest depth (m)
2 deep wells	4,400
1 deep well	4,300
56	3,500
27	3,500
7	3,500
6	3,500
Numerous wells	3,500
11	3,000
2 x 2,000 m, plus 6 x shallow minerals wells	2,000
2	2,000
1 well into heat source	1,935
1	1,809
13	913
3	812
7	750
3	400

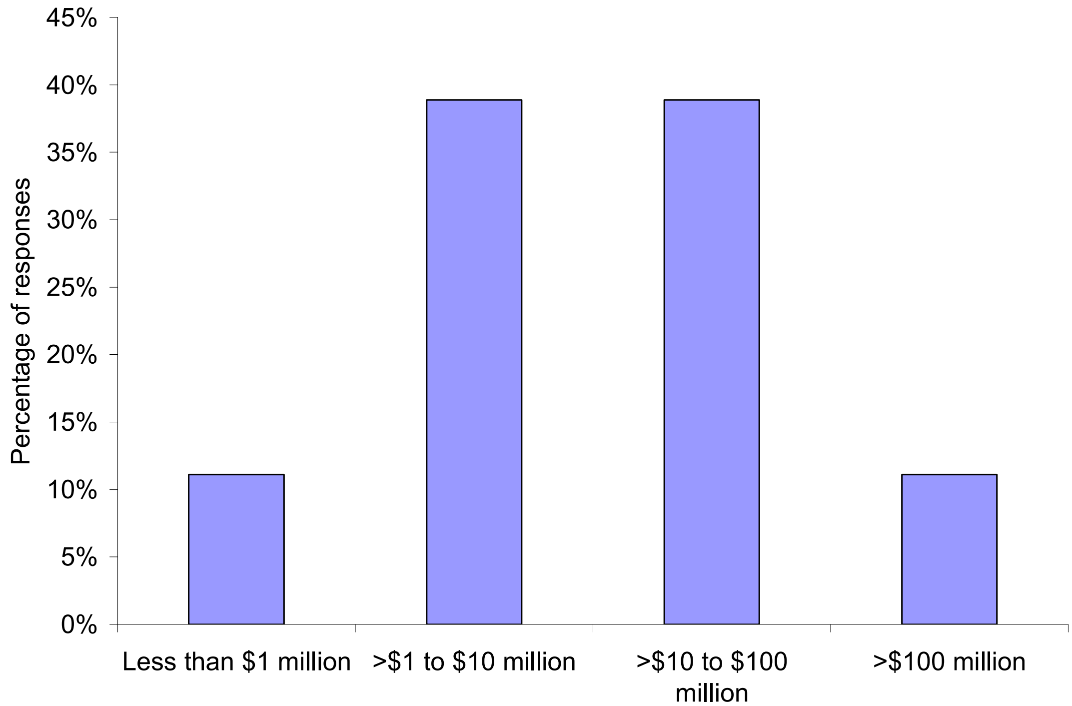
Table 8 summarises the number of proposed wells, and the maximum depth of the proposed wells. Based on these responses, 149 holes are planned and the total length of just the proposed deepest hole in each case represents a cumulative depth in excess of 48,000 metres. The total aggregate depth will be many times this figure.

Table 8 – Number of planned wells and deepest depth

How many wells do you expect to drill by the end of 2010?	What is the maximum proposed depth of these wells? (m)
27	deep
20	5,700
1	5,000
2	5,000
7	5,000
25	5,000
1	4,000
4	4,000
2	3,500
1	3,500
7	3,000
1	2,000
1	2,000
2	1,500
40	1,500
2	500
3	500
5	300

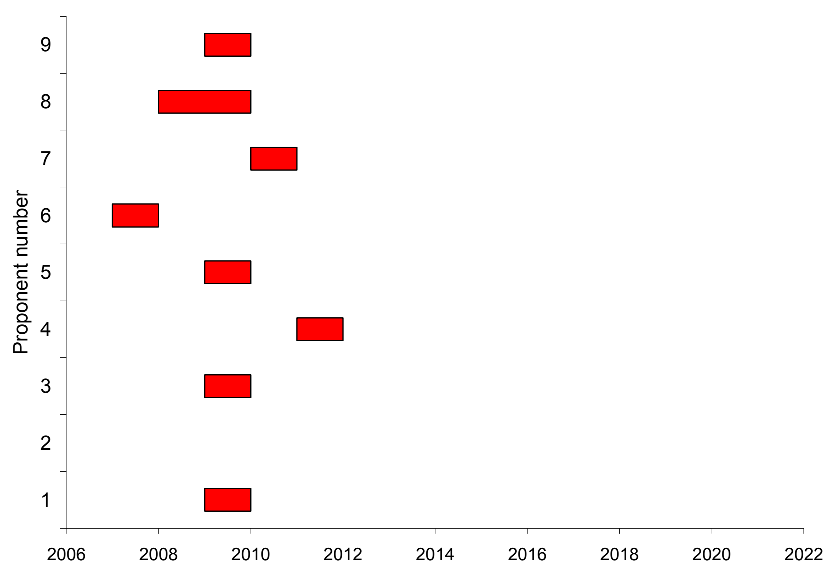
Figure 12 shows the distribution of respondents' answer to the question about the expected expenditure on drilling all of their proposed additional wells. The results are shown on a log scale because of the range between the highest and lowest estimates of expenditure. The median expected expenditure was $10 million, and the average expected expenditure was $28 million, which illustrates the effects of several very high estimates of expected expenditure, which in turn were affected by plans to drill more and deeper wells. The anticipated total expenditure on drilling was $500 million.

Figure 12 – Anticipated expenditure on drilling wells



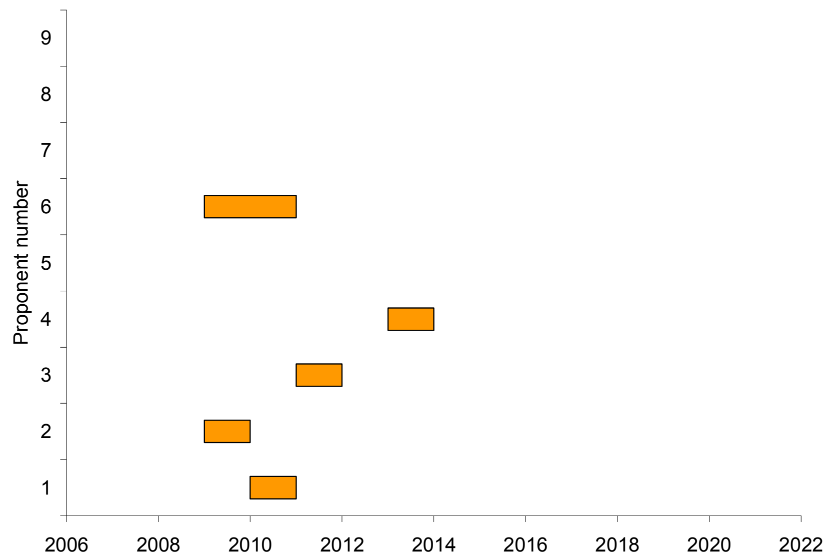
The following three figures show three waves of drilling, which are roughly synchronised. The first wave, for the proof of concept drilling, falls mostly between 2008 and 2012, as shown in Figure 13.

Figure 13 – Timing of proof of concept stage drilling



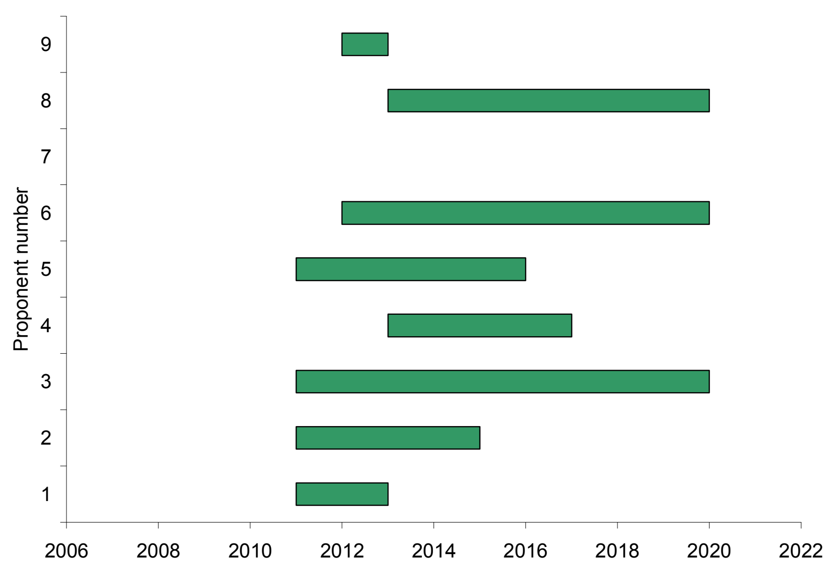
The second wave, of drilling for the demonstration stage ,falls mainly between 2009 and 2014, as shown in Figure 14.

Figure 14 – Timing of demonstration stage drilling



The third wave, for commercial stage drilling, falls between 2011 and 2020, as shown in Figure 15.

Figure 15 – Timing of commercial stage drilling



Combining the data on expected starting and finishing dates for the three stages shows clearly that the proponents will be synchronising their competition for drilling rigs and other development services providers. It also shows that they will be moving into the commercial production stage at about the same time, with the potential to oversupply the electricity market. Opinion about competition over drilling rigs was mixed, as illustrated by the following comments.

> *"Availability of rigs is a preoccupation [and government money has been offered for drilling], but availability is not an issue."*

> *"The shortage of land based rigs has peaked. They will be more available now and in the future."*

Other participants felt that there was a shortage of smaller rigs for the exploratory stage because of competition with the development of coal seam methane.

Figure 16 – Timing of all three stages

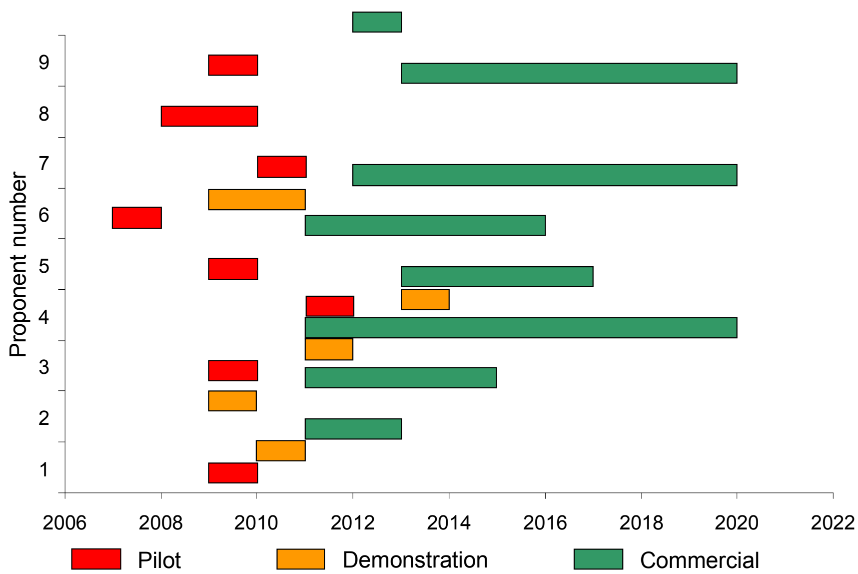


Table 9 summarises the details of the drilling programs for proof of concept, demonstration and commercial stages. The average number of holes for proof of concept was two, rising to seven for demonstration, and rising to 67 for the commercial stage. The diameter of the holes was effectively the same for all three stages, at around 190 mm. The depths, power of rigs, and distance drilled per day were also similar, at around 4,500 metres, 2,000 kW and 80 metres per day respectively. The respondents expected to require two rigs for the demonstration stage, and four rigs in the commercial stage. The cost of drilling rose from $27 million for proof of concept, to $91 million for demonstration, to $640 million for the commercial stage.

Table 9 – Details of drilling programs

Average of:	Number of holes	Diameter of holes (mm)	Depth (metres)	Power of rig (kW)	Metres per day	Number of rigs	Cost ($ million)
Proof of concept	2	195	4,425	1,762	71		27
Demonstration	7	185	4,500	2,058	85	2	91
Commercial	67	185	4,500	1,838	76	4	640

Given the magnitude of the expected level of drilling activity, the answers to the question about what arrangements have been made for drilling rigs come as a surprise. No arrangements had been made for 70% of the tenements, as shown in Table 10. Arrangements had been made to drill at least one well for 19% of the tenements, a consortium was being arranged which would cover another 8% of the tenements, and 3% were covered by a drill owned by the proponent.

Table 10 – Arrangements for drilling

What arrangements have been made for drilling rigs?	Percentage of tenements (N=37)
None	70%
Have made arrangements (for at least one well)	19%
Negotiating consortium with other companies	8%
Have own drill, plus option of second rig	3%

6.3 Models of development

Most proponents stressed that there were a range of models for geothermal development, ranging from very deep, very hot plays to less deep, lower temperature plays. Most felt that one company with a very deep, very hot play had captured the attention of politicians, the media and the share market, to the detriment of other types of plays which did not face the same R&D, financial and distance hurdles.

> *"There is a perception that Australia is hot dry rocks … therefore you don't attract investors like normal [volcanic] geothermal projects."*

> *"[Brokers] do not understand that wet rocks are different to dry rocks."*

> *"The rest of Australia will be dormant for some time … because you can't raise money."*

> *"Scepticism is needed of the folk law that has been built up by corporate, government and bureaucratic effort."*

6.4 Water requirements

All of the proponents believed that water was available within their tenement for use as a transfer medium to bring heat to the surface.

Estimates of the volume of water that they would need during the commercial stage were provided for three tenements, and their estimates ranged from 630 megalitres per year to 8,900 mealtimes per year. Scaling problems were anticipated in three of the tenements, and the proponents were not sure if scaling would be a problem in a number of other tenements.

No problems were anticipated with the discharge of used water because it was to be reinjected in closed loop systems.

6.5 Experience in managing similar projects

A background in minerals development was the most commonly mentioned experience cited by proponents (in-house, seven mentions, via joint venture partner, one mention), as shown in Table 11. Four proponents mentioned experience in volcanic geothermal projects and two with a non-volcanic geothermal play. Two proponents mentioned experience in energy and one mentioned electricity generation. These results suggest that while the proponents tend to have strong backgrounds in minerals exploration and development, they have less experience in generating and selling electricity.

Table 11 – Expertise in managing similar projects

Experience	In-house (mentions)	Via joint venture partner (mentions)	Total (mentions)
Exploration, drilling, mineral development, extraction	7	1	8
Volcanic geothermal	4	0	4
Non-volcanic geothermal	2	0	2
Energy	2	1	3
Electricity generation	0	1	1
Electricity retailing	1	0	1

6.6 Gaps in intellectual property

The participants mentioned the following gaps in the intellectual property that they will require:

- reservoir engineering and fracture stimulation (3 mentions)
- electricity generator construction and operation (1 mention)
- wear on pipe work and casings (scaling and corrosion) (1 mention)
- pumps (1 mention)
- licensing Kalina cycle turbine technology (1 mention).

6.7 Sources of finance to date and for the next five years

Participants mentioned the sources of finance shown in Table 12. Private equity was the most commonly mentioned source of finance to date (7 mentions), followed by government grants (3 mentions). In contrast, the expected sources of finance for the next five years were dominated by joint ventures (8 mentions), equity raising via the ASX (5 mentions) and debt (4 mentions).

Table 12 – Sources of finance

Source of finance	To date (mentions)	Next five years (mentions)
Private equity	7	3
Government grants	3	3
Joint venture partner	1	8
Equity raising via ASX	2	5
Institutional investors	0	1
Debt	0	4

7 UNCERTAINTIES AND IMPEDIMENTS

This section summarises the uncertainties and impediments that were described by participants under the headings of:

- Uncertainties of an immature industry
- Uncertainties surrounding legislation
- Uncertainties surrounding connection costs
- Uncertainties surrounding drilling activities.

7.1 Uncertainties of an immature industry

The following quotes illustrate the uncertainties which participants spoke about.

> *"It is an immature industry that does not have an open file technical record."*
>
> *"[The geothermal] industry is seven years old … not a lot of experience yet."*
>
> *"The petroleum industry is taking a defensive position in geothermal and will play gas off against geothermal."*
>
> *"If you were predicting coal seam methane ten years ago, how much would you have predicted? Not very much. The idea was novel and the resource was unknown."*
>
> *"There's not much data … the rest is hypotheses until you collect some facts."*

7.2 Uncertainties surrounding regulation and legislation

Several participants described perceived difficulties with regulation, as illustrated by the following comment.

> *"The biggest problem is the bureaucracy created overnight for geothermal … it takes six months to get permission under the geothermal acts in South Australia … which is something we do every day for minerals [plays]. Victoria is the worst of all places to work. … [To drill a] geothermal hole to 500 m … you have to lodge copious documents to get permission from all sorts of people … Under the mining act, one bit of paper [is all that is required] for five year's work … [bureaucracy] kills everything and blows the cost out."*

The uncertainties surrounding legislation are summarised in this section under the headings:

- Queensland
- South Australia
- Western Australia
- Northern Territory

- Ministerial Council on Energy.

7.2.1 Queensland

Queensland has a Geothermal Exploration Act and is preparing a Geothermal Act to cover geothermal energy production.[14] The first Exploration Permit was announced on 1 May 2008. It was awarded to Granite Power Ltd for a permit to explore in the Gladstone area. Two other companies, KUTh Exploration Pty Ltd and Clean Energy Australasia Pty Ltd had commenced the native title process, the final step before the granting of their exploration permits.

On 21 May 2008, the Queensland Mines and Energy Minister announced the preferred tenders for eleven additional exploration areas.[15] The tenders will have to undertake a native title process before exploration permits can be granted.

Queensland appears to be the only jurisdiction that has questioned whether geothermal was covered by the concept of mining in existing legislation. As a result, there has been some concern among proponents about the application of native title.

As acknowledged by the Minister for Mines and Energy of Queensland, there has been some uncertainty about the application of the federal Native Title Act to geothermal exploration in Queensland.[16] However, the Queensland government has raised the issue with the federal government in the hope of finding a nationally consistent interpretation.

Queensland has no geothermal production legislation yet, and it is probably more than a year away.

7.2.2 South Australia

While some proponents were critical of the legislative and regulatory framework in South Australia, as illustrated in the following quotes, a representative of a company which facilitates licensing described South Australia as *"much easier to go through [than Queensland], so fantastic to work with."*

> *"State governments are only interested in collecting taxes … [more geothermal exploration licence applications which means more revenue] … In South Australia, they say they have so many GELs, but it doesn't mean anything, just collecting fees."*

> *"The block sizes [in South Australia] are so small, therefore you have multiple application fees … therefore there is no prospecting in unknown areas. Sometimes the feature [of interest] covers a bigger area than the exploration unit, and you need to drill further afield to model the resource."*

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14 Minister for Mines and Energy, Queensland. 2008. *First geothermal permit issued in Queensland*. Press release. Source: http://www.cabinet.qld.gov.au/MMS/StatementDisplaySingle.aspx?id=57830. Last accessed: 2 May 2008.

15 Minister for Mines and Energy, Queensland. 2008. *Preferred tenders for geothermal exploration areas announced*. Media release, 21 May 2008.

16 Minister for Mines and Energy, Queensland. 2008. *First geothermal permit issued in Queensland*. Press release. Source: http://www.cabinet.qld.gov.au/MMS/StatementDisplaySingle.aspx?id=57830. Last accessed: 2 May 2008.

7.2.3 Western Australia

Only one comment was received about working in Western Australia, and it concerned the size of the exploration tenements and the fees.

> *"The application fee for a 10' by 10' block is $4,000. Therefore unless you know exactly where you want, it would cost $400,000 to apply for a reasonable area."*[17]

7.2.4 Northern Territory

The Northern Territory does not have legislation covering geothermal energy yet, but it is expected soon.

7.2.5 Ministerial Council on Energy

The primary clearing house for inter-jurisdictional issues is the Ministerial Council on Energy. Its mandate does not currently include geothermal energy, but it could be extended to cover it.

7.2.6 Uncertainties surrounding generation

While the above ground generation infrastructure is mature technology, there has been little experience in operating turbines in Australia in the conditions that are anticipated, that is, extremely high ambient temperatures in summer and high dust levels at times.

7.2.7 Uncertainties surrounding connection costs

Uncertainties surrounding connection costs are influenced by:

- lengthy time requirements
- voltage, distance and type of connection point
- output of the generator
- regulated costs of providing a connection point
- unregulated costs of providing a line from the generator to the connection point
- the expected life of the generator.

Each of these points is discussed in the following paragraphs.

The process of connecting a generator to the transmission network is time consuming, typically taking up to three years. Part of this process is the negotiation for the easement which can take several years. Until the easement is arranged, the constructor cannot begin work, although planning and other preparations can occur.

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[17] Geothermal resource exploration permits in Western Australia are for areas up to 160 graticular blocks, and one graticulat block is 80 km^2. This is smaller than the 400 graticular blocks covered by a petroleum exploration permit. Source: http://www.parliament.wa.gov.au/hansard/hans35.nsf/(Lookup+by+Page)/20071608074215b?opendocument. Last accessed: 4 August 2008.

The cost of connection to the network is variable, depending on the voltage, type of connection and the distance to a suitable connection point. Some geothermal proponents have expressed a hope that they can use a connection method called a T-connection, which is popular with generators because it requires less engineering and results in lower costs. While a T-connection can be beneficial in some areas because it reinforces the supply to the network, it creates complexity for the transmission network manager, and may not necessarily be the preferred option. They are only suitable for aggregate generation levels up to about 400 MW on the grid above 220 kV. Larger scale requires dedicated switching and multiple circuits to manage the sudden disconnection of generation from the loss of one transmission element.

For small generators in the 1 MW to 3 MW range, it may be feasible to connect to a 33 kV or 66 kV distribution line at relatively low cost.

Information provided by Powerlink suggests that the cost of connecting a generator of less than 50 MW to the high voltage transmission system is likely to be uneconomic. However, the increase in cost from a 50 MW connection to a 100 MW connection is small. Therefore there are advantages for proponents who can develop a significant concentration of output in one location.

Because the first connection to network will be for the exclusive benefit of the first generator, it is likely to be sized accordingly with little capacity to be upgraded. This will reduce the capital cost and have the second order effect of keeping competitors out. Although Powerlink includes a clause in its agreements that triggers discussions if a third party seeks access, there is no obligation on either Powerlink or the first generator to facilitate access for the third party.

In view of the potential size of the renewable energy market and the fact that any one player will be a small part of it, optimisation of transmission connections over longer distances to produce lower costs for current and potential new entrants in a locality has the potential to yield competitive advantage of greater value than that obtained by keeping out some local competitors. Having to contribute to the initial cost of a scheme is itself a barrier to entry that can be reduced by co-ordinated planning and sharing of new transmission resources to achieve economies of scale.

Powerlink also emphasised that there are two elements to the connection of a new geothermal generator. The first element is the provision of a connection to the network at a suitable substation, which is priced under the National Electricity Rules. The second element is the line between the substation and the generator, which is not regulated, and must be paid for by the proponent. For some geothermal generators, these lines may be hundreds of kilometres long. These unregulated lines can be built by any organisation, but the network service provider has no obligation to build or maintain them.

High voltage network assets have an economic working life of 50 to 60 years, over which the initial capital cost is recouped. If a proponent's geothermal generator has a much shorter life expectancy, for example 15 years, then the sunk capital cost has to be recouped over a much shorter period.

7.2.8 Uncertainties surrounding drilling activities

Uncertainties surrounding drilling activities include:

- Availability of small rigs and crews for exploratory drilling
- Availability of suitable large rigs and crews for deep drilling
- Time required for drilling
- Cost of drilling.

7.2.8.1 Availability of small rigs and crews for exploratory drilling

Proponents were concerned about the availability of small rigs capable of drilling down to several hundred metres for exploratory work on rock types and heat flow rates. In particular, they expressed concern that coal seam methane work was likely to compete with their needs.

7.2.8.2 Availability of suitable large rigs and crews for deep drilling

As discussed in the section 6.2 titled *Number of existing wells and planned drilling* on page 35, proponents were aware that their plays were likely to be requiring large rigs for several years and that their periods of peak requirements were likely to coincide. However, the long-term effect of this is unclear. It could result in higher costs because of competition for drilling rigs and crews to operate them. On the other hand, it could result in the construction of drilling rigs designed specifically for geothermal work, which could reduce drilling costs. In addition, the large number of holes anticipated by proponents could mean that rigs could be contracted to work in one area for a longer period of time, reducing the time taken to erect and dismantle rigs as they move to new sites.

7.2.8.3 Time required for drilling

Recently published data on the depth of holes and time required to drill them shows that there is a large degree of uncertainty surrounding the time required for drilling and the rate of drilling per day.[18]

Figure 17 shows the depth of drilling and the number of days taken for 43 holes. Note that deeper wells, where more powerful and larger drilling rigs are used, tended to cover more metres per day than shallower holes. The R^2, which describes the proportion of the variance of this distribution that is explained by the linear regression, is only 0.1, indicating that only 10% of the variance is explained.

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[18] Primary Industry and Resources South Australia. 2007. Tenement activity – petroleum and geothermal. *MESA journal.* Number 46. Source: http://www.pir.sa.gov.au/__data/assets/pdf_file/0011/58925/MJ46_tenement_activity_petroleum_geothermal.pdf. Last accessed: 2 May 2008.

Figure 17 – Depth of drilling and days taken

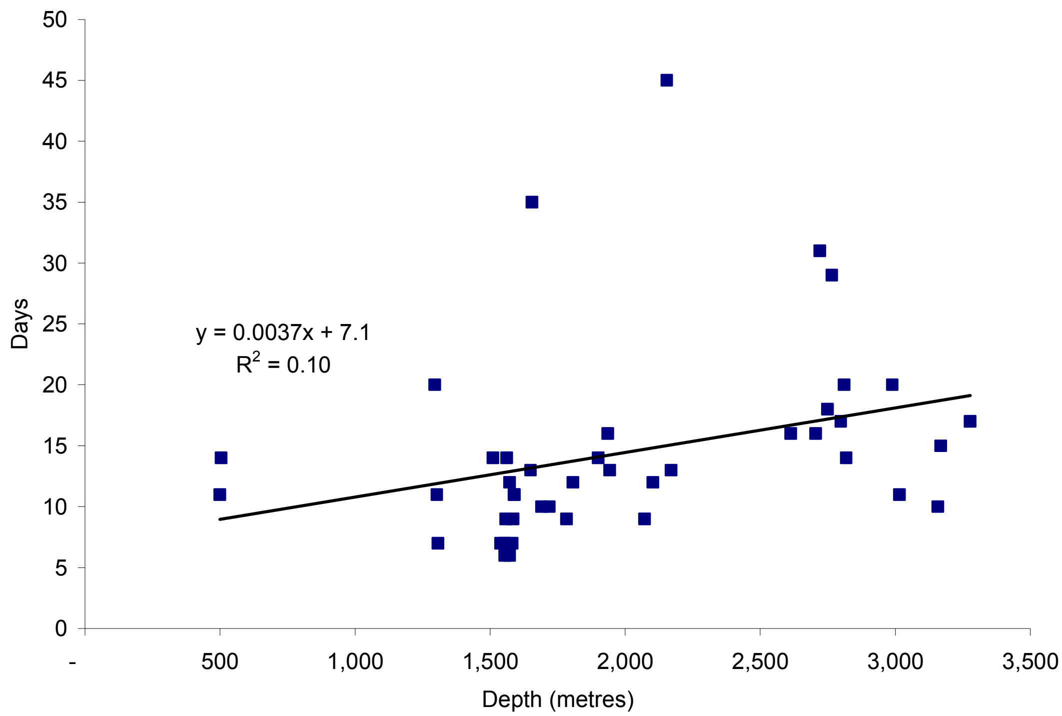
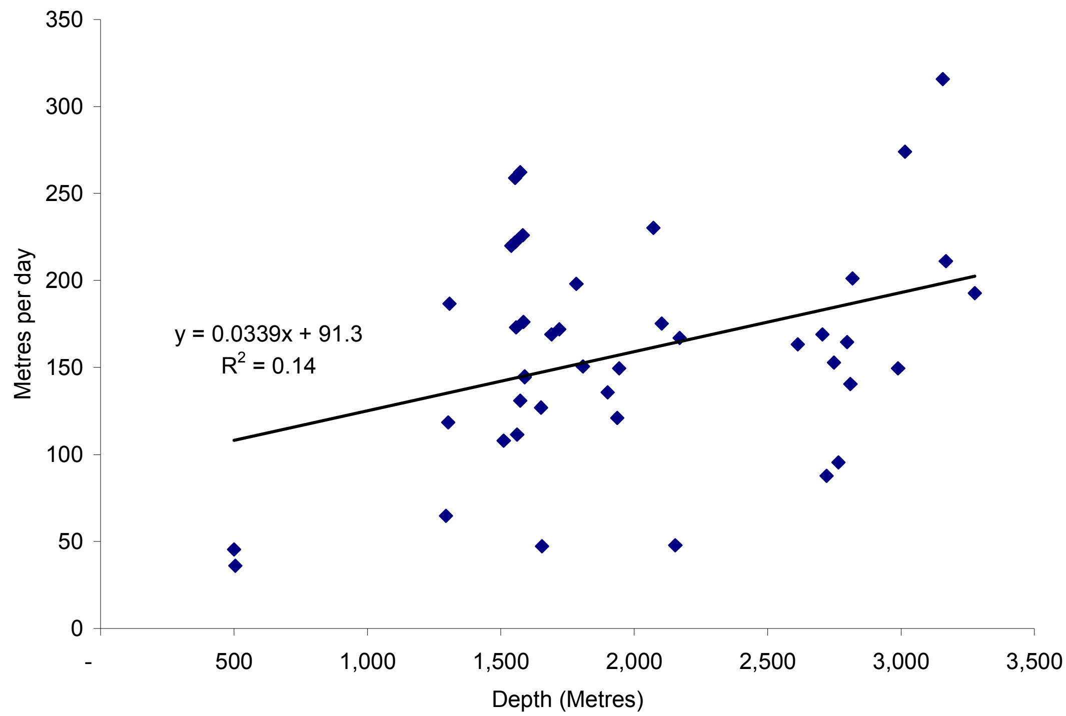


Figure 18 shows the metres drilled per day by the depth of drilling. While this figure does show that the more powerful drilling rigs used for deeper drilling can average more metres per day, there is a high level of variance in the distribution. The R^2 shows that only 14% of the variance is explained by the linear regression. Taken together, the data for the number of days and the metres per day show that there is a large degree of uncertainty in forecasting the speed at which proponents will be able to sink shallow exploratory and deeper proof of concept, demonstration and production holes.

Figure 18 – Depth of drilling by metres per day



7.2.8.4 Cost of drilling

The cost of drilling is an issue for the proponents who are searching for higher temperatures at deeper depths. One proponent suggested that the cost of drilling to 4,500 metres was four times the cost of drilling to 3,000 metres. While it was technically feasible to drill to these depths, or even deeper, the oil and gas industry was not geared up to provide drilling to these depths as a routine service.

Figure 19 shows the cumulative cost of drilling up to the proof of concept stage, using data from a presentation by Barry Goldstein of PIRSA.[19] The range between minimum and maximum estimates of costs is very large compared to the minimum estimates.

The Australian Geothermal Energy Group is currently compiling recent historical information on geothermal drilling costs.[20] This will provide data which will allow better estimates of drilling costs, which will reduce the level of uncertainty surrounding estimates for future drilling.

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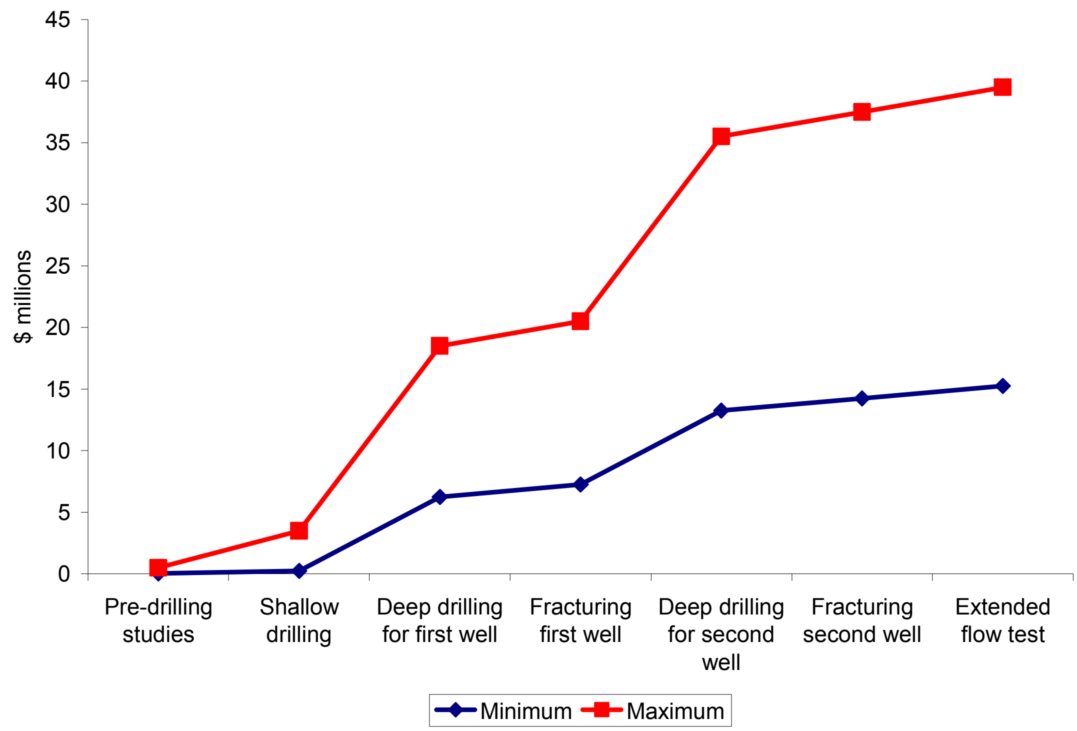
[19] Goldstein, B. 2007. Australia's energy needs - investing for the future, a focus on peak oil and hot rock energy. Source: http://www.asx.com.au/investor/pdf/energy_needs_barry_goldstein_2007.pdf. Last accessed: 28 May 2008.

[20] Source: http://www.pir.sa.gov.au/geothermal/ageg/geothermal_basics/potential_use. Last accessed: 28 May 2008.

Figure 19 – Cost of drilling to proof of concept stage



7.2.9 Uncertainties surrounding connection to the grid

Even the most basic form of connection to high voltage transmission lines, a T connection, is likely to cost $20 million for the transformer, circuit breakers and switchgear. However, this up-front cost can be reduced if the proponent is prepared to use a second-hand transformer. However, the trade-off is the potential for lower reliability, and the knowledge that the transformer will have to be replaced sooner.

A representative of a company which carries out high level feasibility studies for the connection of generators, such as wind farms, to the grid felt that none of the geothermal proponents …

> *"had a real appreciation of the connection issues … the connection process, particularly the delays. The industry needs to get NEMMCO, Electranet and ESCOSA to understand their process in bringing this generation to the grid …[in South Australia], the logical way forward is for the geothermal operators to get together to fund a transmission line that they share. [In Victoria], it is hard to find connection points because of the level of activity. You can use either an existing or a new substation … but it's the distance to the connection point, rather than the distance to the transmission line, that matters.*
>
> *It takes two years to get an offer to connect in New South Wales.*

In more remote areas, the barriers to entry are more substantial because of the uncertainty about long term development plans. The establishment of the National Transmission Planner by AEMC is intended to improve the planning of new network developments that do not depend on a single proponent. This will be very important for geothermal and solar thermal resources in central Australia which will depend on the new high voltage, large capacity transmission lines that would be needed if renewable energy from this area is prospective for large scale development.

7.3 Where will the cost reductions come from?

Generating electricity from geothermal energy requires a marriage of mature and innovative technologies, and this is reflected in the potential for cost reductions in the different components. While the development of underground heat exchangers is innovative, once the hot water reaches the surface, its conversion to electrical energy and the transmission of that energy to the end-users is mature technology.

For convenience, we have grouped the areas of potential cost savings under headings that reflect the life cycle of a geothermal project, that is, exploration, proof of concept, demonstration and commercialisation.

7.3.1 Exploration

Potential areas of cost reductions in the exploration stage include:

- a better knowledge of resources across Australia from work by Geoscience Australia, state geoscience organisations and proponents
- improved data collection and dissemination by some state geoscience agencies
- university courses which focus on geothermal
- improved modelling of heat reservoirs
- refinements in measuring down hole temperatures and heat flows
- slimline drilling of shallow exploration holes.

7.3.2 Proof of concept

Potential areas of cost reductions in the proof of concept stage include:

- greater experience in fracturing
- specialised drillings rigs for geothermal, rather than using rigs optimised for petroleum drilling
- optimisation of bore diameter.

7.3.3 Demonstration

Potential areas of cost reductions in the demonstration stage include:

- greater experience with installing the above ground facilities, including turbines and transmission lines

- greater knowledge of the behaviour of underground heat exchangers
- ability to pump fluids in the range of 180˚ C to 230˚ C
- well design, drilling experience (thus time and cost reductions)
- fracture stimulation techniques in the relevant geological setting.

7.3.4 Experience with installing the above ground facilities

There are a number of companies in Australia with experience in installing the heat exchangers, turbines and electrical equipment, but proponents do not typically have this experience in-house. Proponents expected the cost of installing demonstration scale facilities to improve with experience, and with the evolution of modular demonstration scale plants.

7.3.5 Knowledge of the behaviour of underground heat exchangers

Very little is known about the behaviour of underground heat exchangers or about the long-term effects of stimulating these heat exchangers to increase flow rates. Stimulation, which involves fracturing the rock mass, has been likened to creating 1,000 miniature earthquakes.

Little is know about flow rates over time after stimulation.

One participant in this study had calculated the flow rates that some projects are anticipating, and said that they seemed very high when compared to the flow rates from oil and gas production wells.

7.3.6 Ability to pump water between 180˚ C and 230˚ C

In order to extract energy from Australia's non-volcanic geothermal sources, it will be necessary to pump water down through injection wells, through cracks in the rocks and back up to the surface via a production well.

The drilling technologies and pumps developed for the petroleum industry are effective up to 180˚ C. Above 180˚ C, the elevated temperatures and captivation render these pumps ineffective, although we were told by one proponent that a trial of a pump designed for 200˚ C was scheduled in the EU this year.

Above 230˚ C, a geothermal well will be self-flowing.

Handling fluids in the 180˚ C to 230˚ C range will require an R&D breakthrough.

Pumping constraints are one of the reasons that some proponents are currently targeting rocks that are below 180˚ C.

7.4 Commercialisation

Potential areas of cost reductions in the commercialisation stage include:

- proponents buying their own drilling rigs rather than using drilling services providers
- drilling rigs powered by electric motors from nearby geothermal generators rather than diesel engines (Note that the Lightning rig currently used by Geodynamics is powered by an AC motor)[21]
- achieving economies of scale in long distance transmission, including integration of power transfer requirements with solar thermal resources
- lower cost of capital with increased confidence in the viability of the project.

[21] Wilkinson, R. 2007. *The Australian*. 14 April 2007. Source: http://www.theaustralian.news.com.au/story/0,20867,21475768-12829,00.html. Last accessed: 28 May 2008.

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10 APPENDIX 1, SUMMARY OF RESOURCE AND RESERVE CLASSIFICATION

This appendix is based on the work of the Australian Geothermal Energy Group, Geothermal Code Committee. 2008. *Code for geothermal resources and reserves reporting*. Draft version 2.0, February 2008. Page 26.

	EXPLORATION RESULTS	RESOURCE			RESERVE	
		INFERRED	INDICATED	MEASURED	PROBABLE	PROVEN
COMMERCIALITY	No implications regarding commerciality	Commerciality not yet established. Possibly feasible with current or future technology, prevailing and/or more favourable market conditions			Commercial. Feasible with existing technology and prevailing market conditions	
DEFINITION	Data from exploration that is of material value to resource estimation, but which in itself is insufficient to define a resource category	An area/volume that has enough direct indicators of resource character or dimensions to provide a sound basis for assuming that a body of thermal energy exists, estimating resource temperature and having some indication of extent	A more reliably characterised volume of rock than the Inferred Resource. Sufficient indicators to characterise resource temperature and chemistry, although with few direct measures indicating the extent of resource.	A drilled and tested volume of rock within which well deliverability has been demonstrated, with sufficient indicators to characterise resource temperature and chemistry and with sufficient direct measurements to confirm the continuity of the reservoir	Equivalent to a Inferred Resource for which commercial production for the assumed lifetime of the project can be forecast, or: Equivalent to a Measured Resource for which commercial production for the assumed lifetime of the project cannot be forecast with sufficient confidence to be considered a Proven Reserve	Equivalent to a Measured Resource for which commercial production for the assumed lifetime of the project can be forecast with a high degree of confidence
Correlation with probabilistic estimates					~P50	~P90
UNITS	As appropriate	Thermal Energy in Place (PJ) with assumptions stated	Thermal Energy in Place (PJ) and optionally Recoverable Thermal Energy (PJ), with assumptions stated. May be also reported as assumed electricity generation with assumptions and rate stated (MWe) or GWh in total	Thermal Energy in Place (PJ) and optionally Recoverable Thermal Energy (PJ), with assumptions stated. May be also reported as assumed electricity generation with assumptions and rate stated (MWe) or GWh in total	Thermal Energy in Place (PJ) and Recoverable Thermal Energy (PJ), defined in relation to a stated technology and recovery rate. Electricity generation should be presented as net electrical output (MWe) for a defined period or GWh in total.	Thermal Energy in Place (PJ) and Recoverable Thermal Energy (PJ) defined in relation to a stated technology and recovery rate. Electricity generation should be presented as net electrical output (MWe) for a defined period or GWh in total.

11 APPENDIX 2, REVISED WORKBOOK FOR THE EXPECTED CAPACITY AND ELECTRICAL OUTPUT OF GEOTHERMAL POWER STATIONS IN 2020

11.1.1 Introduction to the revised workbook

Following feedback on the original workbook, we have revised some of the questions to improve their clarity, as follows:

- 14 – this question refers to the number of wells drilled by the END of 2010
- 20 – this question about heat recovery rates has been split into two questions, 20a and 20b
- 25 – this question about the number of proposed wells has been split into two questions, 25a and 25b
- 42, 43, 44 – these questions about the commissioning of the commercial plant have been superseded by questions in the supplementary question module.

The Australian Geothermal Energy Association (AGEA) has commissioned McLennan Magasanik Associates (MMA) to provide an independent analysis of the development plans and forecasts of the capacity and the electricity output of each of the geothermal energy companies. MMA will use this information to estimate the total installed capacity and output by 2020 and the likely cost of electricity delivered from geothermal sources. This information will assist the AGEA to present a credible case when it is seeking support for the development of Australia's geothermal energy industry.

Energy used for purposes other than electricity generation is outside the scope of this assignment.

This workbook is designed to collect information on each company's operations, which MMA will analyse to build up a picture of the potential installed capacity and generation from geothermal sources in 2020.

Any information that you provide will be treated as confidential. The data will be de-identified as early as possible in the analysis.[22] The analysis will aggregate the data in ways that protect your confidential data.

For the sake of clarity, we ask that you use the abbreviations and acronyms listed at the start of this workbook. If you need to use additional abbreviations, please explain their meaning the first time that you use them.

[22] MMA operates under the Market and Social Research Privacy Principles.

We realise that preparing this information will be a time-consuming task. However, the better the quality of the information, the better the final report will be. We thank you in advance for your assistance in helping us build a composite, credible picture of the potential of electricity generation from geothermal sources by 2020.

Susan Jeanes
Chief Executive, Australian Geothermal Energy Association

11.1.2 Data workbook

The format for the data is described in this section. You can complete this document and return it via fax to (03) 9690 9881, or complete the alternative spreadsheet in Microsoft Excel and email it to Kate Brook at MMA at k.brook@mmassociates.com.au.

The data workbook covers information on the tenements held by your company, financial issues, general issues and company details.

If your company has more than three tenements, please duplicate the pages. However, if your company does have more than three tenements, you may find it easier to use the Microsoft Excel version of the workbook.

If an item is not relevant to your company, please mark it NA for Not applicable. Please show dollar amounts in current Australian dollars, that is, 2008 dollars. Please add any additional information that you feel is necessary for us to understand your company's estimates of electrical output.

If you have any questions about the items in the workbook, please contact Jim Stockton on (03) 9674 4718 or via email on j.stockton@mmassociates.com.au.

11.1.3 Tenements

Table 13 – Data workbook

	Tenement identification designation			
1	State			
2	Locality name			
3	Geological province			
4	Area of tenement (hectares)			
5	Has your company applied for an exploration licence for this tenement?			
6	Does your company hold an exploration licence for this tenement?			
7	Does your company have exploration results for this tenement?			
8	Has your company applied for a retention licence for this tenement?			
9	Does your company hold a retention licence for this tenement?			
10	Has the thermal play been modelled?			
11	What level of information is held for this tenement? Is it exploration results, an inferred resource, a probable resource, a proven resource, a probable reserve or a proven reserve?			
12	Number of wells from which geothermal data is available			

	Tenement identification designation			
13	What is the greatest depths of the wells (m)			
14	How many wells do you expect to drill by the end of 2010?			
15	What is the maximum proposed depth of these wells? (m)			
16	What is the expected cost of these wells? ($M)			
17	Has stimulation testing been conducted?			
18	What is the proposed heat recovery technology?			
19	What is the area of proposed heat recovery? (hectares)			
20a	What is the expected flow rate? (litres/minute)			
20b	What is the expected temperature? (°C)			
21	What is the distance from the proposed generator to nearest electricity transmission line? (km)			
22	What is the voltage of nearest transmission line? (V)			
23	What is the expected transmission loss factor between the generator and the transmission line? (%)			

	Tenement identification designation			
24	What is the expected transmission loss factor between the connection point and the end user? (%) (The grid can also be an end user)			
	Demonstration phase			
25a	How many injection wells are proposed in the demonstration phase for this tenement?			
25b	How many extraction wells are proposed in the demonstration phase for this tenement?			
26	What are the proposed depths of these demonstration wells?			
27	What arrangements have been made for drilling rigs?			
28	What is the anticipated cost of drilling for the demonstration phase? ($ 2008)			
29	What is the proposed methodology for conversion to electrical energy in the demonstration phase? [23]			
30	What is the total installed capacity of the demonstration modules?			

[23] Likely conversion technologies include non-condensing steam turbines which vent to the atmosphere, condensing steam turbines, binary or Rankine cycle plants, the Kalina system, combined cycle plants, hybrid plants and thermo-electrical systems. For further information on these technologies, see the report titled *Geothermal industry development framework. workshop 1 issues paper* by Sinclair Knight Mertz. Source: http://www.pir.sa.gov.au/__data/assets/pdf_file/0018/60408/LawlessAGEG_DP_GeothermalResourcesDefinition_2007.pdf.

	Tenement identification designation			
31	When will the first module of the demonstration plant be commissioned?			
32	When will the last module of the demonstration plant be commissioned?			
33	How many modules are planned in the demonstration phase?			
34	What is the expected net electrical output per year in the demonstration phase? (MWh/yr)			
35	What is the anticipated cost of generation during the demonstration phase? ($/MWh)			
36	What arrangements do you expect to make for transmission to a user or the grid?			
	Commercial phase			
37	How many wells are proposed in the commercial phase for this tenement?			
38	What are the proposed depths of these commercial wells?			
39	What arrangements have been made for drilling rigs?			
40	What is the anticipated cost of drilling for the commercial phase? ($ 2008)			

	Tenement identification designation			
41	What is the proposed methodology for conversion to electrical energy in the commercial phase?			
42	Deleted			
43	Deleted			
44	Deleted			
45	How many modules are planned in the commercial phase?			
46	What is the expected net electrical output per year in the commercial phase? (MWh/yr)			
47	What is the anticipated long run marginal cost of generation during the commercial phase? ($/MWh)			
48	What arrangements do you expect to make for transmission to a user or the grid?			
49	What is the anticipated long run marginal cost of transmission during the commercial phase? ($/MWh)			
50	Do you have any prospects for further installed capacity beyond the first commercial phase at this tenement?			
51	Please describe what you plan to do after 2020?			

11.1.4 Financial issues

Please describe the assumptions that your company is using for the following financial parameters.

Table 14 – Financial assumptions

	Parameter	Units	Assumption
1	Size of the commercial development generator modules	MW	
2	Life expectancy of commercial generator	Years	
3	Capacity factor of generator	%	
4	Real pre-tax WACC	%	
5	Capital cost of drilling in 2008 dollars	$/kW	
6	Capital cost of generation in 2008 dollars	$/kW	
7	Capital cost of transmission in 2008 dollars	$/kW	
8	Interest during construction	%	
9	Capital cost reduction (per year from 2008)	%	
10	O&M fixed costs in 2008 dollars	$/MW	
11	O&M variable costs in 2008 dollars	$/MWh	
12	Transmission costs in 2008 dollars	$/MWh	

11.1.5 General issues

1. Please describe your company's experience in managing similar projects.

2. Please describe the aspects of your company's project for which your company does not currently have access to the required intellectual property.

3. How has your company arranged financing to date?

4. How does your company propose to arrange financing in the next five years?

5. Does your company foresee any regulatory issues that could affect the viability of your project?

6. What is the probability that these regulatory issues will affect your project?

7. What is the probability that these regulatory issues will make your project not viable?

11.1.6 Company details

Please provide the following information on your company.

Table 15 – Company details

1	**Name of company**	
2	Company address	
3	Name of contact person	
4	Contact person's job title	
5	Contact person's telephone number	
6	Contact person's mobile telephone number	
7	Contact person's email address	

Thank you for providing this information. Please return your workbook to MMA by fax to (03) 9690 9881 or via email to

k.brook@mmassociates.com.au.

12 APPENDIX 3, SUPPLEMENTARY QUESTIONS ON WATER AND DRILLING FOR GEOTHERMAL POWER

12.1.1 Introduction to the supplement

The Australian Geothermal Energy Association (AGEA) has commissioned McLennan Magasanik Associates (MMA) to provide an independent analysis of the development plans and forecasts of the capacity and the electricity output of each of the geothermal energy companies. During discussions with companies, a number of new topics were raised and these have been synthesised in this supplement to the workbook.

As described for the main workbook, any information that you provide will be treated as confidential. The data will be de-identified as early as possible in the analysis.[24] The analysis will aggregate the data in ways that protect your confidential data.

Susan Jeanes
Chief Executive, Australian Geothermal Energy Association

12.1.2 Data workbook supplement

If your company has more than three tenements, please duplicate the pages or you may prefer to use the Microsoft Excel version of the workbook.

If an item is not relevant to your company, please mark it NA for Not applicable. Please show dollar amounts in current Australian dollars, that is, 2008 dollars. Please add any additional information that you feel is necessary for us to understand your company's activities.

If you have any questions about the items in the workbook, please contact Jim Stockton on (03) 9674 4718 or via email on j.stockton@mmassociates.com.au.

[24] MMA operates under the Market and Social Research Privacy Principles.

12.1.3 Water

Table 16 – Water

	Tenement identification designation			
1	Is water available for use as the medium to transfer heat from the reservoir to the surface?			
2	How much additional water will be required per year during the commercial phase? (ML/year)			
3	Will the water quality cause problems such as scaling or corrosion?			
4	Are there likely to be any problems with discharged water, such as pollution or contamination?			

12.1.4 Drilling in the proof of concept phase

The proof of concept stage typically involves a number of holes and a sizeable generator which is run for long enough to show that the project is commercially viable.

Table 17 – Drilling in the proof of concept phase

	Tenement identification designation			

5	When do you expect to start drilling for the proof of concept phase?			
6	When do you expect to finish all drilling for the proof of concept phase?			
7	How many holes do you expect to drill in the proof of concept phase?			
8	What will be the diameter of the holes in the proof of concept phase?			
9	What is the maximum expected depth of the holes in the proof of concept phase?			
10	How powerful is the drilling rig that you plan to use in the proof of concept phase? (specify horsepower or kW)			
11	On average, how many metres per day do you expect to drill in the proof of concept phase?			
12	What is the total anticipated cost of drilling during the proof of concept phase?			

12.1.5 Drilling in the demonstration phase

The demonstration phase typically involves a number of holes and a sizeable generator which is run for long enough to show that the project is commercially viable.

Table 18 – Drilling in the demonstration phase

	Tenement identification designation			
13	When do you expect to start drilling for the demonstration phase?			
14	When do you expect to finish drilling for the demonstration phase?			
15	How many holes do you expect to drill in the demonstration phase?			
16	What will be the diameter of the holes in the demonstration phase?			
17	What is the maximum expected depth of the holes in the demonstration phase?			
18	How powerful is the drilling rig that you plan to use in the demonstration phase? (specify horsepower or kW)			

19	On average, how many metres per day do you expect to drill in the demonstration phase?			
20	How many drilling rigs do you plan to employ in the demonstration phase?			
21	What is the total anticipated cost of drilling during the demonstration phase?			

12.1.6 Drilling for the commercial phase

This phase involves producing and selling electricity on a commercial scale.

Table 19 – Drilling in the commercial phase

	Tenement identification designation			
22	When do you expect to start drilling for the commercial phase?			
23	When do you expect to finish drilling for the commercial phase?			
24	How many holes do you expect to drill for the commercial phase?			

25	What will be the diameter of the holes for the commercial phase?			
26	What is the maximum expected depth of the holes for the commercial phase?			
27	How powerful is the drilling rig that you plan to use for the commercial phase? (specify horsepower or kW)			
28	On average, how many metres per day do you expect to drill in the preparations for the commercial phase?			
29	How many drilling rigs do you plan to employ in the commercial phase?			
30	What is the total anticipated cost of drilling during the commercial phase?			

12.1.7 Company details

Please provide the following details of your company.

Table 20 – Company details

1	Name of company	
2	Contact name	
3	Telephone	
4	Email	

Thank you for providing this information. Please return your workbook to MMA by fax to (03) 9690 9881 or via email to k.brook@mmassociates.com.au

13 APPENDIX 4, TIMEFRAME AND FINANCIAL PARAMETERS

13.1.1 Workbook for the expected capacity and electrical output of geothermal power stations in 2020

Please complete this spreadsheet in Microsoft Excel and email it to Kate Brook at MMA at k.brook@mmassociates.com.au

The different sheets in the data workbook cover information on financial parameters and company details.

Please ensure that all sheets are completed.

A glossary of terms is included in the sheets to the far right of the workbook.

If an item is not relevant to your company, please mark it NA for Not applicable.

Please show dollar amounts in current Australian dollars, that is, mid-2008 dollars.

Please add any additional information that you feel is necessary for us to understand your company's estimates of electrical output.

If you have any questions about the items in the workbook, please contact Daniel Magasanik on (03) 9674 4723 or via email on d.magasanik@mmassociates.com.au, or Jim Stockton on (03) 9674 4718 or via email on j.stockton@mmassociates.com.au.

No	**Parameters**	**Units**													
	Calendar year		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
1	Proof of concept phase														
1a	*Start of proof of concept phase*	Year													
1b	*End of proof of concept phase*	Year													
2	Commissioning year of first demonstration plant	Year													
3	Capacity (Please specify type of plant and module capacity in the 'notes' column)														
3a	*Gross capacity*	MW													
3b	*Sent-out capacity*	MW													
4	Capacity factor	%													
5	Degradation of capacity over time	% / year													
6	Availability	%													
7	Total capital cost	$million													
7a	*Drilling cost*	$million													
7b	*Capital cost of surface equipment*	$million													
8	Total transmission costs	$million													

No	Parameters	Units													
	Calendar year		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
8a	*Cost of transmission line to grid (Please specify distance and location of connection point into the grid in the 'notes' column)*	$million													
8b	*Connection cost*	$million													
9	Plant operating costs on a sent-out basis														
9a	*Fixed operating costs*	$/MW													
9b	*Variable operating costs*	$/MWh													

14 APPENDIX 5, METHODOLOGY

We contacted 22 companies which have an interest in geothermal energy. Two to these companies were developing direct heat applications and one was surrendering its tenement, so they have been excluded from the study. Two more companies said that they were not sufficiently advanced to provide reasonable data. Seven companies did not provide data; based on our discussions with them, only one appeared to be likely to be generating electricity by 2015. Therefore, we conclude that out of the eleven companies that were approached and are likely to be generating by 2015, ten (91%) provided data. Table 21 summaries the results.

Table 21 – Response rate

Category	Full sample N=22	Likely to be generating by 2015 N=11
Provided data	10	10
Minor players or not advanced enough	2	
No data provided	7	1
Direct heat applications	2	
Surrendering tenements	1	

This response rate identified fewer companies than expected, but it does provide a snapshot of the geothermal industry in 2008. There are a couple of relatively advanced players, a couple of moderately advanced players, and a number of start-up companies. In the words of the company that was surrendering its exploration tenement, *"It is not an industry that can be monetised quickly"*. This company was returning to its core business of oil and gas exploration. All the participants in this study agreed that investing in geothermal energy was a long term investment.

14.1 The sample

Ten companies completed workbooks covering 40 tenements in the states shown in Table 22. South Australia and New South Wales dominated in terms of the number of tenements, but there were some from every jurisdiction except the Northern Territory and the ACT.

Table 22 – Location of tenements

State	Number	% of tenements
NSW	10	25%
Qld	5	13%
SA	13	33%
Tas, Vic, WA	12	30%
Total	36	

The most commonly named location was in or adjacent to the Cooper Basin.