Australian Government

Australian Renewable Energy Agency

ARENA

LOOKING FORWARD:

BARRIERS, RISKS AND REWARDS OF THE AUSTRALIAN GEOTHERMAL SECTOR TO 2020 AND 2030

Australian Renewable Energy Agency

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Content: Australian Renewable Energy Agency
Coordination, editing and indexing: Australian Renewable Energy Agency

Design: Giraffe VCM
Printing: CanPrint Communications

(Printed publication) : 978-0-9925510-0-1
(PDF online format) : 978-0-9925510-1-8
(Word online format) : 978-0-9925510-2-5

A report provided to the Board of the Australian Renewable Energy Agency by members of the International Geothermal Expert Group

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This version 10 June 2014

Contents

Terms of Reference

The Board of the Australian Renewable Energy Agency (ARENA) is seeking advice on the barriers to, and opportunities for, the development and deployment of geothermal energy in Australia.

To this end, ARENA is establishing an International Geothermal Expert Group to assess Australia's geothermal prospects and present its findings in the form of a written report and briefing to the ARENA Board and a report for public dissemination.

The assessment will comprise the following:

1. Determine whether, over the periods to 2020 and 2030, there are plausible commercialisation pathways for either EGS or HSA geothermal energy to deliver cost competitive utility scale energy to Australia without long-term subsidy and to describe those pathways.
2. Critically evaluate:
   a. the performance of Australia's geothermal energy sector – how effectively has it used the private investment and public funding it has received to date?
   b. opportunities and threats to support a SWOT analysis of Australia's geothermal energy sector, including its size, structure, governance, skills, capabilities (technical and managerial) and finances.
3. Identify:
   a. the main barriers facing pilot/demonstration projects, including technical, physical, economic, institutional and policy
   b. the main barriers to commercialisation
   c. the geothermal industry's capability gaps (including technical, managerial, engineering, scientific), and
   d. key gaps in data (including resource and technology specific performance data), information and knowledge.
4. Include site visits and face to face engagement with stakeholders in Australia.
5. Prepare for the ARENA Board an analysis of risks and rewards for geothermal energy, which will help inform the Board's consideration of how to allocate and prioritise funding for geothermal energy as part of its portfolio approach to supporting renewable energy in Australia.

International Geothermal Expert Group Members

The members of the International Geothermal Expert Group (IGEG) combine extensive experience in geothermal energy, drilling technology and energy economics.

Chair

Quentin Grafton FASSA, Professor of Economics, Crawford School of Public Policy, ANU and former Executive Director of the Australian Bureau of Resources and Energy Economics. He has published extensively in the area of environmental and resource economics including in the world's leading science and economic journals and is the editor or author of more than a dozen books on resources and economics.

Members

Roland N. Horne, Thomas Davies Barrow Professor of Earth Sciences in the Department of Energy Resources Engineering at Stanford University; Director of the Stanford Geothermal Program. Roland is past President of the International Geothermal Association (2010 to 2013) and is recognised for his work in well-test interpretation, production optimisation and tracer analysis of fractured geothermal reservoirs.

Bill Livesay, Drilling Consultant, Black Mountain Technology. Bill was a pioneer of the geothermal industry. He brought to the expert group the unique insights and profound knowledge that he developed over thirty-five years' experience in all aspects of drilling engineering for oil, gas and geothermal resources. Bill passed away on 4 March 2014.

Michal Moore, Distinguished Fellow and Professor of Energy Economics, School of Public Policy, the University of Calgary. Michal formerly served as Chief Economist at the US National Renewable Energy Laboratory and is a former regulator in the energy industry in California.

Susan Petty, President and Chief Technology Officer, AltaRock. Susan has over 34 years of experience in the geothermal industry in electrical and direct-use project economics, optimising of power plants to meet resource conditions, reservoir evaluation, reservoir modelling, well, plant and well-field performance data analysis, well testing and test data analysis.

Consultant

Cameron Huddlestone-Holmes, Geothermal Stream Leader at CSIRO. Cameron leads research at CSIRO that integrates multi-disciplinary capabilities in geoscience and resource engineering, and applies them to develop the technologies and knowledge needed to demonstrate the technical viability of geothermal energy in Australia. Cameron provided professional technical support to the group.

Abbreviations

AETA	Australian Energy Technology Assessment
ARENA	Australian Renewable Energy Agency
AUSTELA	Australian Solar Thermal Energy Association
Bbls	Barrels, a measure of volume (159 Litres)
°C	Degrees Centigrade
cm/s	Centimetres per Second
CRI	Commercial Readiness Index
CRL	Commercial Readiness Level
CSIRO	Commonwealth Scientific and Industrial Research Organisation
Dm	Darcy metres
EGS	Enhanced or Engineered Geothermal System
EOR	Enhanced Oil Recovery
EPC	Engineering, Procurement and Construction
°F	Degrees Fahrenheit
FIT	Feed In Tariff
Ft	Feet
GDP	Geothermal Drilling Program
GETEM	Geothermal Electricity Technology Evaluation Model
GJ	Gigajoule
GW	Gigawatt
GWh	Gigawatt hour
GRI	Geothermal Research Initiative
HSA	Hot Sedimentary Aquifer
HDR	Hot Dry Rock
IGEG	International Geothermal Expert Group
IRR	Internal Rate of Return
kg	Kilogram
kg/s	Kilograms per second
kj/kg	kilojoule per kilogram
km	Kilometres
km^2	square kilometres
km^3	cubic kilometres
kPa/m	Kilopascals per metre
kW	Kilowatt
kWe	Kilowatt electric
kWh	Kilowatt-hour
LCOE	Levelised Cost of Energy
l/s	Litres per second
m	Metres
m^2	square metres
m^3	cubic metres

MPa	Megapascal
MT	Magnetotellurics
MW	Megawatt
MWe	Megawatt electric
MWh	Megawatt-hour
MW_{TH}	Megawatt thermal
NGDS	National Geothermal Data System (USA)
PJ	Petajoule
PJ_{TH}	Petajoule thermal
psi	Pounds per square inch
PTC	Production Tax Credit
REDP	Renewable Energy Demonstration Program
RET	Renewable Energy Target
SAM	System Advisor Model
SWOT	Strengths, Weaknesses, Opportunities and Threats analysis
TRL	Technology Readiness Level
TVD	Total Vertical Depth
TWh	Terrawatt hours
WHP	Wellhead Pressure
W-hr/lb	watthours per pound

Glossary

3-D Seismic	Geophysical method that allows 3-dimensional images of the sub-surface to be constructed by measuring the reflection of seismic energy (waves of elastic energy travelling through rock, comparable to sound waves in air). The seismic energy is created by a controlled seismic energy source (explosives or mechanical vibrations) and detected by an array or receivers.
Binary Cycle	The energy conversion system through which the hot geothermal fluid transfers its heat to a working fluid. The working fluid consists of a low boiling point fluid, such as a hydrocarbon, that is used within the power plant.
Brine	Salty water. Most water found within the earth is salty.
Brine Effectiveness	A measure of the efficiency of a geothermal power plant, defined as the net power produced by the power plant per unit mass of geothermal brine.
Capacity Factor	The ratio of a power plant's actual electrical generation to its maximum possible generation, usually expressed as a percentage.
Casing	Pipe that is lowered into a well and cemented in place to maintain the integrity of the well.
Cenozoic	The Cenozoic Era covers the period of geologic time from 65 million years ago to the present.
Conductive Geothermal System	A geothermal system where the movement of heat through the rock is dominated by conductive processes. Conduction is the movement of heat through a solid material.
Convective Geothermal System	A geothermal system where the movement of heat through the rock is dominated by convective processes. Convection is the movement of heat carried by the movement of fluid.
Darcy Flow	The process governing the flow of fluid through a porous medium
Deep Natural Reservoir	A geothermal reservoir that has naturally high permeability that does not require any significant level of stimulation. This permeability may be within sedimentary layers or aquifers, or in fractures.
Diagenesis	The processes that affect sediment at or near the surface. These processes include compaction, where loose grains of sediments are squeezed together as they are buried, and cementation, where grains of sediments are held together by the deposition of secondary material.
Direct Use Geothermal	Geothermal energy utilised in the form of heat without being transformed into another type of energy. Direct use applications include space heating, food drying, and other industrial processes that use heat.
Dispatchable	Dispatchable power is a form of power supply that is able to follow load.
Downhole	Denotes any equipment, measurements, or activities that are used or occur within a well.
Enhanced/Engineered Geothermal System	A geothermal reservoir that has been engineered to allow extraction of heat from geothermal resources with little permeability through to enhancement of geothermal resources that have marginal permeability.
Flow Rate	The rate at which geothermal fluid is produced from a reservoir through a well or a collection of wells.
Fracture Tortuosity	A measure of the geometric complexity of a fracture. Highly complex fracture geometries are more likely to have higher resistance to flow than less complex geometries.
Heat Pump	A device that moves heat energy to or from a heat sink. A geothermal heat pump uses the earth as the heat sink (a body that can store heat).
Hot Dry Rock	A geothermal energy concept in which the reservoir is confined and fully engineered, including a 'man-made reservoir' in rocks that are essentially impermeable, and therefore 'dry'.
Hot Sedimentary Aquifer	A geothermal reservoir within highly permeable layers of sedimentary rock.
Hydraulic Fracturing	A technique to enhance or create fracture paths for fluid flow within a rock mass by opening existing fractures or the creation of new fractures by the application of high-pressure fluid on the rock.
Hydrostatic Gradient	The change in pressure per unit depth inside the pore space of the earth due to gravity acting on water within that pore space. For freshwater at 20 °C and 100 kPa, this gradient is 9.79 kPa/m; for a brine with a composition similar to sea water, this gradient is 10.45 kPa/m.
Hydrostatic Pressure	The pressure inside the pore space of the earth due to gravity acting on water within that pore space at a given depth.

Injection	Delivery of fluid in to a reservoir via a well.
Levelised Cost of Energy	The minimum cost of energy at which a generator must sell the produced electricity in order to achieve its desired economic return.
Lithological Section	The sequence of rock types found in and above a resource.
Lithology	Description of the physical characteristics of a rock, including colour, texture, grain size, and composition.
Logging	The collection of data from a well using geophysical tools that are lowered into that well.
Magnetotellurics	Geophysical method that allows images of the sub-surface to be constructed using measurements of variations of electrical and magnetic fields at the earth's surface.
Overpressure	Pressures in rock formations that are abnormally high, exceeding the hydrostatic pressure at a given depth.
Packers	A device that can be placed in a well and expanded to seal off sections of the well. Packers may be removable or permanent.
Permeability	A measure of the ability of a rock to allow fluid to flow through it.
Petajoule	The heat energy content of about 37,000 tonnes of black coal or 29 million litres of petroleum.
Pleistocene	The Pleistocene Epoch covers the period of geologic time from about 2,588,000 years ago to 11,700 years ago.
Porosity	The open space within a rock, usually filled with fluid.
Precompetitive Data	Government provided information about the broad geology of a region, often strategically focused on national and state needs, which is then used by private explorers to select areas for more intensive exploration. Pre-competitive information can be used by one explorer without preventing the use of the same information by another explorer.
Production	Extraction of fluid from a reservoir via a well.
Proppant	Fine-grained material that is injected with fracturing fluids to hold fractures open (prop) after a hydraulic fracturing treatment.
Reserve	That portion of a geothermal resource which is deemed to be economically recoverable after the consideration of the geothermal resource parameters and modifying factors which directly affect the likelihood of commercial delivery (e.g. production, economic, marketing, legal, environmental, land access, social and governmental factors).
Reservoir	A sub-surface body of rock having sufficient porosity and permeability to store and transmit fluids. In the geothermal context, a reservoir also contains heat.
Resource	In the geothermal context, a geothermal resource is a geothermal system that exists in such a form, quality and quantity that there are prospects for eventual economic extraction of heat.
Rig Release	The completion of drilling a well, before the drill rig is demobilised.
Sand Back	The method used to isolate parts of a well during hydraulic stimulation or other activities that involve injection of fluid into the well. Sand is placed in the well, restricting the flow of fluid into the portion of the well that is filled with sand. The sand can subsequently be flushed from the well.
Shut In	Closing or sealing a well after an injection or production period.
Skin Effect	Damage to the wall of the well that either increases or decreases the ability of fluid to flow into or out of the well.
Spud	The initiation of drilling a well, after the drill rig has been established on-site.
Stimulation	Any of a range of techniques to increase the natural permeability of the rock. These techniques include hydraulic fracturing, chemical stimulation (including the injection of acids) or temperature cycling.
Tensile Failure	Failure caused by tension (pulling apart or stretching).
Thermal Spallation	The method of drilling that breaks the rock through thermal expansion caused by rapid heating.
Well	Industry term for holes drilled into the earth for the purpose of gathering data or the injection or production of fluids.

Key findings

1. Australia has a large geothermal potential with prospective resources that could be used to generate direct heat or electricity.
2. The Australian geothermal sector, including in research ($25 million) and pre-competitive spending ($30 million), attracted funding of around $900 million since the 1990s, of which about 18 per cent was provided by the public sector.
3. Exploration efforts in the geothermal sector peaked in 2010 with 414 applications for exploration licences – an 83-fold increase from only five applications in 2002.
4. Research employment in the geothermal sector peaked in 2010 and included, at the time, the equivalent of 77 full-time staff and more than 40 post-graduate students.
5. In 2014 the Australian geothermal sector is facing a funding crisis as many private sector investors and partners have decided to exit.
6. A SWOT analysis of the geothermal energy sector identifies its principal strengths as a dispatchable power source with low environmental footprint; its major weaknesses are that it has immature commercial readiness levels and has both highly uncertain and relatively high development costs; its greatest opportunities are in new and off the grid markets; and its primary threats are low demand growth for electricity and continued lower costs of alternative renewable energy sources.
7. The major technical barriers to further development in the Australian geothermal sector are pre-competitive data and methods to increase the likelihood of drilling geothermal wells in a prospective resource, and the methods to enhance the flow rate from reservoirs.
8. The major commercial barriers to further development of the Australian geothermal sector are the small size of the companies holding leases and undertaking demonstration projects, the inability to attract additional private sector funding to finance the commercial development of projects, and the high cost of developments that include drilling costs before a prospective resource can be proven.
9. The major risks to investors in the Australian geothermal sector are the high up-front costs in proving a resource relative to the returns from direct heat use or electricity generation.
10. The costs of drilling are the largest contributor to the overall capital costs of geothermal projects in Australia. Drilling costs have increased rapidly over the last decade, primarily as a result of increases in the price of oil and gas and exploration activity that this has generated. The current high drilling costs, determined by developments in the oil and gas sector, create a barrier to further investment in geothermal energy, especially in high risk and exploration stages of geothermal projects.
11. Utility-scale power generation from geothermal projects is not cost competitive in 2014 and is not expected to be cost competitive in 2020. This is because the levelised cost of energy of enhanced geothermal systems is projected to range from $170 to $300/MWh, while the wholesale price of electricity is expected to be between $50-$100/MWh.
12. Utility-scale power generation from geothermal projects may become cost competitive with fossil fuel dispatchable power generation by 2030, but only with a high carbon price and in a 'least cost' or most favourable scenario for geothermal energy. Under this least-cost scenario in 2030 the levelised cost of energy from enhanced geothermal systems may not be cost competitive with the lowest cost forms of renewable energy (such as wind). Other factors such as base-load power characteristics may increase cost competitiveness of geothermal relative to variable electricity generation sources.
13. The most prospective markets for geothermal energy in Australia out to 2030 are in remote locations that are off the grid and where there are commercial-scale applications for either electricity or direct heat.
14. Direct heat uses in the gas sector, especially in the processing of shale gas, in locations where both gas and proven geothermal resources are co-located offer the most likely cost-competitive, commercial-scale market for geothermal energy in the next decade.
15. Looking forward, three options are provided to the ARENA Board in terms of how it may wish to allocate and prioritise its funding for geothermal energy:
    a. A *Resume* option that represents a continuation of the existing ARENA programs. In the view of the IGEG this approach has, to date, not yet put the geothermal sector on a path to delivering cost competitive utility energy generation.
    b. A *Reconsider* option that readjusts the current funding allocated to the sector in ways that will improve reporting standards, allow for a rebalancing in terms of how funds are spent and ensure more stringent standards, but with lower funding levels. This option also includes the possibility of providing no further funding to the sector.
    c. A *Reboot* option that restarts the funding by ARENA in ways that promote innovation and assist the geothermal sector towards a more cost-competitive path and with a strong emphasis on research and development in both finding (other than drilling) and flowing the resource.

INTRODUCTION

1.1 Background

In convening the International Geothermal Expert Group (IGEG) the Board of the Australian Renewable Energy Agency (ARENA) has sought expert and independent advice, informed by stakeholder input, on the barriers and opportunities for the deployment of geothermal energy in Australia out to 2020 and 2030, and whether there are clear commercialisation pathways that do not involve long-term subsidies. This report, authored by the IGEG, details the findings and the options formally provided by the IGEG to the ARENA Board. Based on the formal advice of the IGEG, previous consultations with stakeholders and past studies undertaken by the former Department of Resources, Energy and Tourism (the *Geothermal Industry Development Framework* and *Australian Geothermal Industry Technology Roadmap* released in 2008) and the Australian Centre for Renewable Energy (*Australia's geothermal industry: pathways for development* and *ACRE Geothermal Directions* released in 2011), the ARENA Board will decide on the appropriate level and type of future funding and support for the Australian geothermal industry.

To arrive at its final advice and options to the ARENA Board, the IGEG has actively engaged and encouraged inputs from all stakeholders in the Australian geothermal industry. This included two sets of stakeholder meetings with visits to Brisbane, Adelaide and Sydney in October 2013 and to Brisbane, Adelaide and Canberra in February 2014. In the 2013 meetings all stakeholders were provided with the opportunity to meet with the IGEG on a one-on-one basis and were also given the opportunity to provide a formal submission to the IGEG to inform its deliberations. In February 2014, the IGEG invited stakeholders to comment on a presentation of initial findings, particularly in terms of the strengths, weaknesses, opportunities and threats (SWOT) facing the geothermal sector and its technological and commercial readiness levels. Stakeholders were once again invited to provide written submissions to IGEG. Details of the stakeholder engagement process, who met with the IGEG and the submissions provided to the IGEG, are summarised in Annex B of this report.

1.2 Scope of work

The scope of work undertaken by the IGEG complies with the Terms of Reference that were provided to it by the ARENA Board. The IGEG was asked to determine, and describe where relevant, whether there are plausible commercialisation pathways out to 2020 and 2030, without long-term subsidy, for the Australian geothermal sector to deliver cost-competitive and utility-scale energy. In forming its determination, the IGEG was asked to:

1. Critically evaluate the performance of the geothermal sector in terms of how effectively it had used private and public funding to date and to provide a SWOT analysis of the sector.
2. Identify the main barriers facing geothermal pilot and demonstration projects (technical, physical, economic, institutional and policy), the main barriers to commercialisation in the geothermal sector, and key gaps in data, information and knowledge.

1.3 Overview of the report

This main report and two supplementary reports (*Geothermal Energy in Australia*, *Australian Electricity Market Analysis Report to 2020 and 2030*) represent the complete evidence, advice and options that the IGEG has provided to the ARENA Board. The main report consists of nine chapters that, combined with the supplementary material and reports, respond to the terms of reference of the study.

Chapter 2 provides an overview or summary of the Australian geothermal sector and represents the IGEG's assessment of the information contained in a report prepared by CSIRO on the request of the IGEG. The supplementary report, *Geothermal Energy in Australia*, has been released simultaneously with the IGEG's main report. Included in Chapter 2 is an analysis of direct-heat uses of geothermal energy, which is drawn from a report prepared for ARENA by Evans and Peck entitled *Competitive Role of Geothermal Energy near Hydrocarbon Fields*.

Chapter 3 is a SWOT analysis of the current state of the Australian geothermal sector. An earlier version of the SWOT was presented to, and discussed with, stakeholders in February 2014.

Chapter 4 provides an overview of international geothermal activities and places the Australian geothermal sector into the context of global developments.

Chapter 5 applies an assessment of commercial readiness levels of the sub-components of the Australian geothermal sector to describe what developments would first be necessary for the sector to become commercially viable without long-term subsidies. The chapter also provides a guide to the risks and uncertainty facing the sector. Further details on the commercial readiness levels for the sector are provided in Annex C.

Chapter 6 presents the IGEG's assessment of the information presented in a report developed by CSIRO entitled *Australian Electricity Market Analysis Report to 2020 and 2030* on the request of the IGEG. The chapter describes the relevant features of the Australian energy sector and synthesises the most recent projections of the levelised cost of energy (LCOE) of key renewable and fossil fuel electricity generation sources. The findings and projections in this chapter provide a useful comparison to the levelised cost of energy generation for geothermal power calculated by the IGEG for 2020 and 2030.

Chapter 7 summarises the critical barriers for the sector in finding conductive geothermal resources, flowing and realising the resources through reservoir enhancement, and financing these developments.

Chapter 8 provides the IGEG perspective on the costs, risks and rewards facing the geothermal sector in terms of both direct-heat use and electricity generation. The risk/reward projections to 2020 and 2030 were developed in consultation with CSIRO, based on Australian data on drilling and well costs using the System Advisor Model (SAM) software developed by the United States National Renewable Energy Laboratory (NREL). All assumptions and parameters used by the IGEG in its calculations as well as the method of calculation are detailed in Annex A of the report.

Chapter 9 concludes with a summary of views and a presentation of three options (Resume, Reconsider and Reboot) provided by the IGEG to the ARENA Board, based on the submissions from stakeholders and its own analyses and judgements.

GEOTHERMAL ENERGY IN AUSTRALIA

This chapter presents the IGEG's response to item 2(a) of the Terms of Reference provided by the ARENA Board. It draws on the information contained in a report prepared by CSIRO, other reference sources and stakeholder inputs.

On the request of the IGEG, CSIRO was commissioned to prepare an in-depth report on geothermal energy in Australia. The report, authored by Dr Cameron Huddlestone-Holmes, and entitled *Geothermal Energy in Australia* is a supplementary document that accompanies the main report of the IGEG.

2.1 Geological context – Australia's geothermal resources

Geothermal energy is, simply, the utilisable heat from the earth. Beneficial use of this heat is achieved by bringing the heat to the surface in a fluid (steam or water). This fluid may occur naturally in the sub-surface reservoir or it may have to be introduced into the system via injection from the surface. In general, temperatures increase with depth in almost all geological settings. Thus, at sufficient depth, there is potential for geothermal energy use in almost any accessible terrestrial location. To be commercially viable, however, the cost of extracting and using geothermal energy must be less than the price that energy receives.

The key technical components of geothermal systems that determine the costs of development are the sub-surface temperatures and flow rates of water, steam or other vectors that transfer the underground energy to the surface. A preferred geothermal energy resource has a desirable combination of flow rates and temperature and these are determined by the geological setting of the resource. Most global geothermal resources currently exploited for power generation are convective hydrothermal systems (where the heat is carried upwards by fluids) that are found in geological settings that are in regions of active tectonics and volcanism along plate boundaries. These 'conventional' systems have high temperatures at shallow depths (<3,000 m), due to high heat flows caused by hot fluids moving upwards through rocks with high natural permeability.

Globally, there is growing activity in developing geothermal resources outside of geologically active locations where accessible energy is provided by conductive heat flow. Conductive heat flow occurs when heat moves, but without the movement of the material or fluids within that material. These resources tend to have lower thermal gradients than conventional convection dominated resources and require deeper drilling to reach sufficiently high temperatures.

The Australian continent lies entirely within the Indo-Australian tectonic plate. As a result of its tectonic setting, it does not have the convective heat flow regimes that typify the majority of geothermal provinces globally. Instead, Australia's geothermal resource is characterised by conductive processes.

Geothermal resource types in Australia can be categorised into three categories:

- *Shallow Direct-use* resources, typically in the 500 m to 1500 m depth range, which target aquifers with high permeability and with low to moderate temperatures for direct use applications.
- *Deep Natural reservoir* resources that are typically greater than 1500 m deep and target sedimentary or fractured aquifers, with high natural permeability for direct use or electricity generation.
- *Enhanced Geothermal Systems* (EGS) resources where the reservoir needs to have its permeability increased via the stimulation of existing structures or the creation of new ones, for either direct use or electricity generation.

2.2 Technology context – conductive geothermal resources

A compilation of Australian geothermal resources, based on data reported by 10 publicly listed geothermal companies as at December 2012, placed the size of the resource at 440,570 PJ_{th} of recoverable heat. This is equivalent to about 16 billion tonnes of black coal. Despite this estimate, the size of the Australian geothermal resource remains highly uncertain because of the lack of data about temperature at depth. Estimates suggest that the geothermal energy resource in Australia is potentially very large, but unless these heat resources can be extracted in ways that provide a commercial return they will not be utilised for energy generation.

2.3 History of the geothermal sector in Australia

Before the mid-1990s, the limited geothermal energy activity in Australia was primarily focused on direct-use applications of hot groundwater. Early commercial geothermal energy systems accessed warm water from sedimentary aquifers, primarily for direct use applications. For example, in Portland, Victoria, a district heating system was used to heat building space and the municipal swimming pool from 1983 to 2004. A system also operated in Taralgon, Victoria, in the 1950s supplying 68 °C process water for paper manufacturing from two 600 m deep wells.

The Great Artesian Basin that extends from Queensland to north-west New South Wales and northern South Australia has been exploited for water for drinking and agriculture for over 100 years. Thousands of bores have been drilled into the basin with many extending past 1000 m in depth with water temperatures of up to 110 °C. This hot water has been used for therapeutic baths and provided heat for Australia's first two geothermal power plants. The Mulka geothermal power

plant was developed in 1986 in northern South Australia as a trial plant, funded by state and federal governments. The plant had a rating of 20 kWe and ran for three years. The Birdsville geothermal power plant in south-west Queensland, Australia's only operating geothermal power plant, was also built as an experimental plant funded by state and federal governments. The plant uses hot water from the town bore and has an output of 80 kWe net with a capacity factor of more than 95 per cent. It currently supplies about one third of Birdsville's electricity needs.

Following a study commissioned by the Energy Research and Development Corporation (Somerville et al., 1994), there was a significant increase in interest in geothermal energy. This study examined the potential for Hot Dry Rock (HDR) geothermal energy to make a large-scale contribution to Australia's electricity supply. The report concluded that Australia's HDR resource was 'extremely large'. Activity in the geothermal sector subsequently increased when the New South Wales (in 1998) and South Australian (in 2000) governments enacted legislation to allow for the exploration of geothermal energy resources. The first geothermal exploration lease granted was in the Hunter Valley region of NSW in 1999. The South Australian government awarded its first three geothermal energy leases to three separate consortia in 2001. Two of the leases were near Innamincka (GEL 97 and GEL 98), and the relevant consortia eventually merged with Geodynamics Ltd, the current holder of these leases. Geodynamics Ltd's Innamincka Deeps project is on these leases and Australia's first well into an Enhanced Geothermal System (EGS) resource, Habanero 1, was drilled to a depth of 4421 m on GEL 97 in 2003.

In the early years of this century there was a rapid increase in activity within the geothermal energy sector, primarily driven by private investors. By 2004, there were 24 geothermal exploration leases in South Australia and two in New South Wales. The peak of activity came in 2010, with 414 exploration licences or licence applications covering approximately 472,000 km^2 across all Australian states, and also the Northern Territory.

Over the past decade the geothermal sector has focused on developing resources suitable for electricity generation targeting, and with only a few exceptions, reservoir temperatures over 150 °C. There have been four projects that have drilled to reservoir depths in Australia: Geodynamics Ltd's Innamincka Deeps Project; Petratherm's Paralana Project; Origin Energy Ltd's Innamincka Shallows Project and Panax Ltd's Penola Project. The first two were targeting EGS resources while the second two were targeting natural reservoirs. Only the Innamincka Deeps Project with six wells has progressed beyond a single well. In all cases, the temperatures found were close to expectations. The flow rates, however, have been lower than expected, particularly for the natural reservoirs.

Geodynamics Ltd ran a 1 MWe pilot plant at their Innamincka Deeps Project from April to October 2013. The system ran in standalone mode from June 2013, with availability exceeding 75 per cent. The maximum well head temperature achieved was 215 °C with a flow rate of 19 kg/s. The flow rate was limited by the injection. The plant generated approximately 650 kWe gross, which was able to supply all auxiliary loads. This was achieved after more than a decade of activity around Innamincka. At this site, two of six wells were abandoned, including a catastrophic casing failure in one well only days before hot commissioning of the pilot was due in early 2009 and which caused significant delays to the project.

Exploitation of geothermal resources for direct-use application continues and there are many examples of the hot artesian waters in the Great Artesian Basin being used for therapeutic baths. There are two fish farms that use warm groundwater for aquaculture in Victoria and South Australia and a meat processing plant in Victoria that uses warm groundwater for feedwater for sterilization and hand-washing water. In Perth, there are 11 commercial direct-use geothermal projects producing geothermal fluid from the Yarragadee Aquifer to heat swimming pools.

Geoscience Australia and the various state and territory geological surveys have actively acquired pre-competitive data for the geothermal sector. These data have proven to be important to the development of other earth resources as they decrease the risks and reduce costs of early stages of exploration and, thereby, augment the effectiveness of exploration. The two most significant survey activities have been Geoscience Australia's Onshore Energy Security Program and the Coastal Geothermal Energy Initiative of the Geological Survey of Queensland.

The Australian geothermal energy research sector has grown with the industry and reached a peak of activity around 2010/2011. In August 2010, a group of university, CSIRO and Geoscience Australia researchers joined together to form the Geothermal Research Initiative (GRI) to foster collaboration on research and development for the geothermal energy sector. In 2011, the GRI's eight member institutions had an equivalent of 77 full time staff and more than 40 post-graduate students working on geothermal energy. Nearly all of these researchers have transferred or adapted their knowledge gained in other fields to the geothermal sector.

As the geothermal sector grew through the 2000s, the sector matured with all six states and the Northern Territory enacting legislation to regulate geothermal energy development, the establishment of an industry association and the release of the Australian Geothermal Reporting Code. There have also been several publicly funded studies conducted for the Australian government, or one of its agencies, to provide advice and guidance for the support of geothermal energy in Australia.

Total expenditures on geothermal energy developments and research in Australia since the late 1990s amount to approximately $900 million (in nominal dollars), or over $1 billion in 2014 dollars. State and federal government funding and grants allocated to support geothermal industry activity (excluding research and development and pre-competitive data programs) was $315 million as at the end of the 2013 calendar year. Approximately $76 million of this total has been spent, just over $100 million remains to be spent by recipients, and the remainder has been returned to governments primarily

because project proponents have been unable to secure the matching funds required as a grant condition. In addition to grants, $31 million in tax rebates have been received by the sector. The total amount spent by industry as at the end of 2013 is estimated to be approximately $828 million. Overall, the government contribution has been around 13 per cent of the total expenditure by the Australian geothermal industry.

Funding to the research sector is more difficult to quantify. Major grants, such as for centres of excellence in geothermal research, total between $20 million to $25 million (nominal dollars). The in-kind contributions of the research sector are expected to have at least matched this funding amount. In addition, funding for pre-competitive data programs at Geoscience Australia and the state geological surveys are estimated to have cost some $30 million.

2.4 Current status of the geothermal sector in Australia

The Australian geothermal sector is currently stalled with very little activity underway. A key reason for the current lack of activity is the difficulty in attracting commercial funding to proceed with current and proposed developments and also policy uncertainty in relation to the renewable energy sector.

2.5 Direct-use opportunities

A potential value-add that may make geothermal energy economic in Australia in a shorter time frame than will electric power generation is the direct use of the heat. The rapid uptake of geothermal energy in Germany, for example, is based not only on power generation, but also on direct use of the heat for residential and municipal space heating.

Depths for direct-use wells are typically shallower because the temperatures needed are not as high as those needed for electricity generation. At these shallower depths, it is easier to find or create high permeability reservoirs. A wide variety of uses value-add to geothermal resources in the US, Iceland, Germany and other countries. In Australia, there are some specific opportunities for direct use that would be possible in areas where there is good geothermal potential. Some of these would be off-grid uses, while others would need to be near population centres.

Geothermal heat is used for a wide variety of direct uses including heating for greenhouses, homes and industrial spaces, cooling using absorption chillers, food drying, laundering and dying and for improving efficiency of activated sludge sewage treatment plants. Geothermal hot water in the Perth Basin is also used for heating swimming pools and providing space heating. Some possible future uses include hot water for enhanced oil recovery from shales and desalination. Some examples of uses of geothermal hot water and steam are:

Preheating water for thermal process power generation (coal, gas, biomass)

Example: In the Susanville, California area, a biomass burning plant uses wood waste as the fuel with preheated water from a geothermal resource to get better efficiency.

Preheated water from Concentrated Solar Power (CSP)

Example: ENEL at their Soda Lake, Nevada, plant uses CSP to preheat water for their binary units to boost efficiency and to offset long-term temperature decline of the resource.

Management of waste water from coal-fired generation

Example: the possible use of waste water from coal fired power stations within an EGS as the circulating fluid. The heated water could be used in the boiler to improve efficiency and reduce the amount of coal consumed per MWh.

Heap leach with hot water

Example: Relief Canyon Mine in Nevada uses geothermal water to accelerate heap leaching of gold from crushed ore.

Food drying

Example: Brady's Hot Spring Onion Dehydration Plant – onion dehydration at a Nevada geothermal area involves the use of a continuous operation, belt conveyor using fairly low-temperature hot air from 40 to 105°C using waste heat from a binary geothermal plant.

The most widespread application of geothermal heat is for geothermal heat pumps. They contribute the major part of geothermal heat use in the world. There is considerable potential for geothermal heat pumps to offset electricity demand for space heating and cooling because of the high efficiencies of these systems. While not yet popular in Australia, well established markets exist in Europe, North America and China with growing interest in South Korea, UK and France.

Common direct-use applications are district and space heating, bathing, and the heating of greenhouses. In some regions, geothermal heat is used for snow melting, aquaculture/fish farming or industrial applications. For example, in the Larderello geothermal field in Italy, waste heat from the San Martino power plant is used as a cheap and ecofriendly process heat in a nearby dairy for cheese production. Hot geothermal water is also used to assist in oil recovery. In Australia, direct use projects from geothermal energy include fish farms, geothermal spas, hot baths and swimming pools.

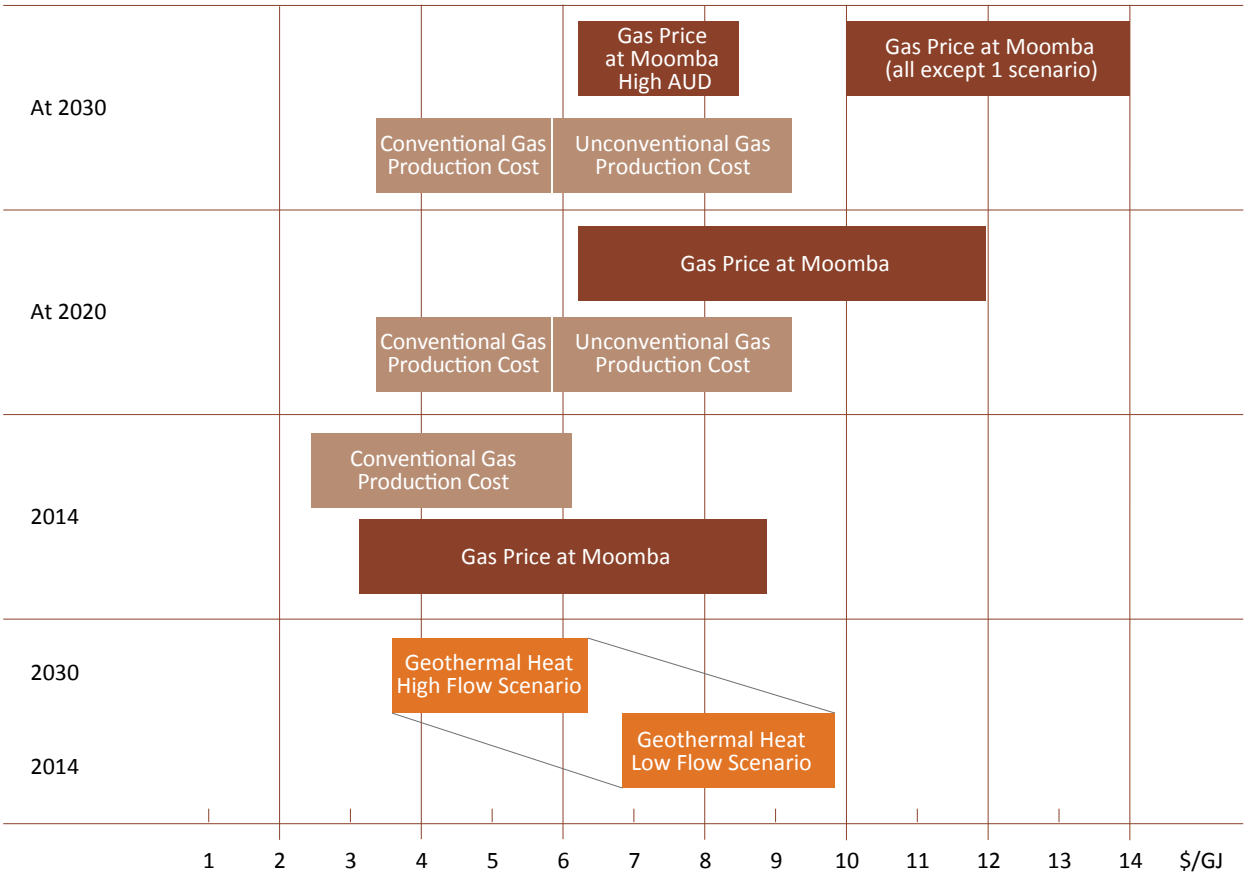
At a large-scale, commercial level there is no direct use project currently operational in Australia, although there are many possible applications in energy intensive sectors such as mining and resource processing. One of the most prospective direct-heat applications is in the oil and gas sector where an identified geothermal resource is co-located with processing and recovery facilities. In particular, natural gas requires processing to remove impurities when it is extracted and prior to transportation through gas pipelines. This generates a parasitic load of about 8 per cent and this is currently supplied by burning the gas itself.

Impurities such as carbon dioxide reduce well productivity and also pose financial risk for firms concerned about changes to imposts based on carbon emissions. Removal of carbon dioxide requires energy, and its reinjection back into wells can also enhance hydrocarbon recovery.

ARENA commissioned Evans and Peck to investigate the market for large-scale commercial use of direct heat from geothermal energy in the Cooper Basin and this study forms part of the evidence base for IGEG's work. The Cooper Basin site was chosen because it has the most developed EGS project in Australia and it is in close proximity to a gas processing facility. The IGEG considered that cost-competitive geothermal energy for direct heat purposes could become commercially viable before 2030. The cost competiveness of geothermal energy for gas processing is highly dependent on: (1) the price for gas received by producers and (2) the cost of producing the gas. Geothermal energy becomes more cost competitive the higher is the gas price and the greater is the cost of producing the gas. This is because higher gas prices encourage greater gas production and, thus, additional processing, while higher costs of gas production make it more attractive to switch to geothermal energy from gas as a fuel source for gas processing.

Based on cost estimates and parameters accepted by the IGEG and developed by Evans and Peck, there are several possible scenarios whereby direct-heat uses of geothermal energy in the Cooper Basin become cost competitive. These findings are summarised in Figure 2.1 where gas prices, gas costs and geothermal costs are listed in terms of dollars per gigajoule (GJ). The relative gas costs (in light brown), gas prices (in dark brown) and geothermal costs (in orange) can be compared over three periods: 2014, 2020 and 2030. The modelling shows that high-flow (and lower cost) geothermal energy is potentially cost competitive with unconventional gas production costs in 2020.

Figure 2.1: Comparison of geothermal heat production cost with gas production price and gas selling price



The expectation is that wholesale gas prices will rise as liquefied natural gas (LNG) exports based on coal-seam gas in Queensland become operational in 2014/15. In anticipation of these exports, and the need to ensure sufficient gas supply, gas has already been contracted from the Cooper Basin at a much higher price than the prevailing netback gas prices at Moomba in the Cooper Basin of between $3-$4/GJ. Should currently high gas prices for LNG continue into the 2020s then the contract and spot LNG netback price will determine the east coast Australia gas prices, and could exceed $6/GJ ex Moomba.

A much higher wholesale gas price will stimulate gas production from conventional wells and possibly from shale gas fields located in the Cooper Basin where a commercial shale gas well has been in operation since 2012. In this scenario of high gas prices, coupled with gas production from relatively high-cost shale gas, geothermal energy can become cost competitive with gas in terms of providing the energy source to meet the parasitic load for gas processing.

The cost competitiveness of geothermal energy for gas processing depends on its costs, which are highly dependent on the flow rate and the cost of production of gas. Using the flow rates obtained at Innamincka by Geodynamics of 40 kg/s, geothermal energy becomes cost competitive with shale gas that costs $6-$7/GJ to extract and which is in the current cost range for shale gas production. While cost competiveness requires geothermal energy to be less than the cost of unconventional gas production, it does not guarantee that gas used for parasitic purposes is actually replaced by geothermal energy. In part, this is because the owners of the gas processing facilities also need to be convinced that geothermal energy is a reliable energy source before they are prepared to retool plants for geothermal energy or to sign long-term contracts.

In summary, at least in the Cooper Basin where there are gas fields that include gas processing facilities and both conventional and unconventional gas resources alongside identified geothermal energy, there is a reasonable possibility of cost-competitive geothermal energy supply for direct-heat purposes. Critical to whether geothermal energy sources in the Cooper Basin will be cost competitive is: (1) the ability to increase the flow rate of geothermal energy from its current level of 40 kg/s to at least 80 kg/s or a rate that has been achieved in enhanced geothermal systems overseas, (2) gas prices ex Moomba of at least $6 to $7/GJ; and (3) Shale gas develops as an important source of gas supply. All of these factors may align between 2020 and 2030. Beyond the Cooper Basin other direct uses are possible, especially off the grid where energy costs can be several multiples of what consumers may pay within the National Electricity Market. Such developments, however, are unlikely without improvements in terms of how to locate suitable geothermal resources without drilling and ways to increase flow rates in enhanced geothermal systems.

AUSTRALIAN GEOTHERMAL ENERGY SECTOR SWOT ANALYSIS

3

3.1 The SWOT framework

A Strengths, Weaknesses, Opportunities and Threats (SWOT) framework is a valuable planning and evaluative tool. A SWOT is not intended to be an exhaustive statement of all positives and negatives, but rather to illustrate existing capacities and future possibilities. A SWOT analysis is particularly beneficial when a technology is not yet developed, a project is under consideration, or when a sector is facing a large degree of uncertainty about its future. This is because it allows for an evaluation of choices that may not otherwise be considered.

The four-dimensional or quadratic structure creates a systematic portrayal of strengths, weaknesses, opportunities, and threats for initiatives such as projects, processes, policies or standards. The general characteristics of each category are illustrated below:

3.2 SWOT of the Australian geothermal sector

In the case of the Australian geothermal sector the IGEG has categorised the SWOT in terms of the issues that the public, policy-makers, developers and financiers must confront.

The SWOT analysis, as constructed, offers a systematic overview of the role and potential of the geothermal industry. It does not offer solutions to policy questions, nor is it a substitute for effective planning and policy processes. In sum, this SWOT analysis represents the learning and research underpinning this report.

The geothermal energy market is unique in its carbon neutral, renewable characteristics. However, it is still bound by an interdependent triangle of policy, technology and economic exchange. The SWOT identifies the major issues and establishes links between them. Thus, it can assist in assuring that interrelationships and forces are accounted for, but it does not replace the necessary value judgments that are the basis of social or economic policy.

STRENGTHS	WEAKNESSES
internal and external comparative advantage	process or product needing improvement
competitive cost characteristics	issues to be avoided
personnel or operating skills	operating cohesion
OPPORTUNITIES	**THREATS**
market niches available	obstacles, hurdles or barriers
emerging trends	more efficient or effective competitors
collaboration	quality standards, changing specifications
	changing technology & early obsolescence
	available and adequate finance

The key issues covered in the framework are colour-coded according to four themes:

1. Policy, social and community issues, jobs and employment
2. Markets, finance and electric system operation
3. Technology and engineering
4. Environmental issues and externalities.

The SWOT quadrangle for the sector, as of June 2014, is provided in Table 3.1. An earlier version of the SWOT was presented to sector stakeholders in February 2014 and was subsequently modified based on their feedback and suggestions.

Table 3.1: SWOT of the Australian geothermal energy sector, 2014

	Positive Attributes	Negative Attributes
Internal Factors, Current Traits	**STRENGTHS**	**WEAKNESSES**
	1. Public support for a made-in-Australia energy source 2. Emerging direct-use sector 3. Experienced and skilled professionals in government agencies, industry, service companies and research organisations	1. Small sector with limited capacity (manpower) 2. Policy inconsistency within the geothermal sector 3. Reliance on petroleum sector for services and labour
	4. Large potential energy source with positive attributes (e.g., dispatchable, base-load power) 5. Well-developed and established national mining and resources sector that can complement/support geothermal sector	4. Unfavourable perception of the returns in the geothermal sector by the finance/investment sector 5. Upfront costs of project development are very high 6. Immature established workflow or exploration tools to de-risk projects prior to drilling 7. Limited track record for geothermal projects in Australian grid 8. Small sector with limited capital
	6. Industry underpinned by existing technology 7. Proof of concept for EGS demonstrated at Innamincka 8. Industry has baseline understanding of Australia's geothermal resources	9. Large uncertainty around necessary resource characteristics for commercial viability 10. Technologies for exploiting the resource are not mature in enhanced geothermal systems 11. Lack of understanding of the distribution of geothermal resources and their characteristics
	9. Carbon neutral	12. Water use 13. Microseismicity potential 14. Distance of transmission connection to grid for some geothermal resources
External Environment; Future Scenarios	**OPPORTUNITIES**	**THREATS**
	1. Public demand for low emissions dispatchable power 2. Development of policy drivers to accelerate reduction of fossil fuel use, nationally and globally 3. Creation of new direct-use market, especially gas sector 4. Opportunity for new off grid market 5. Market drivers that create a favourable environment for geothermal energy development	1. Social licence to operate may be threatened by hydraulic fracturing 2. Falling demand on National Electricity Market 3. Potential loss of established skills and knowledge
	6. Technical breakthroughs reduce the costs of the energy produced from geothermal projects and lower the risks in their development	4. Uncertain market conditions (national energy policy) 5. Market conditions set return on investment at level that is too low to attract investment given the perceived risks in geothermal projects 6. Market perception is that the technology is high risk
	7. Share resources and knowledge with petroleum sector to mutual advantage 8. Create load/dispatchable power source 9. Unconventional gas developments may reduce drilling costs over time	7. Market competition for service providers driving costs up in the short term 8. Technical challenges cannot be solved 9. Other technologies crowd out geothermal energy
	10. Create and capture GHG credits 11. Collaborate on carbon-storage mechanisms	10. Deferral of investments in environmentally benign technologies

Strengths

Nine key strengths of the sector are identified in the SWOT. Its principal strength is that it is a dispatchable power source available 24 hours per day and is carbon neutral.

Geothermal energy in Australia has been developed with, and continues to enjoy, broad public support. It offers promise for generating base-load power that is carbon neutral and can be dispatched regionally and to the urban grid with reliable and consistent characteristics. The sector has already created skilled labour opportunities and the insights gained from Australian research and applied field drilling sites, such as Innamincka, can be exported to other countries. Overall, the geothermal industry has the potential to support and enhance unconventional natural gas operations and could provide power and direct energy support for remote mining operations.

Weaknesses

The sector has 14 identified weaknesses. The more important negatives include the perception of poor returns which is a major barrier to financing further developments, its immature commercial readiness levels, its high development costs, and the large degree of uncertainty over costs and returns.

The sector has faced formidable challenges that have limited or constrained progress and, ultimately, delayed its growth. It is a relatively small sector compared to other, more mature technologies such as combined cycle gas turbines or even photovoltaic installations on rooftops and in remote locations. The initial support from the financial community has waned in the face of limited success in power delivery. Some of the uncertainty in the sector comes from policy inconsistency, but is mainly a result of the very large up-front capital needs for start-up industries, and is further magnified by the fact that the resource characteristics are not well mapped and identified.

Opportunities

Eleven opportunities are provided for the sector. Chief among these is its complementarity in terms of both direct heat and electricity generation as a clean energy source and, thus, it offers a possible means of lowering Australia's carbon footprint. As an immature technology the sector may also be able to lower its costs in ways not available to established technologies and could possibly develop new markets.

Geothermal energy resources represent a significant, and as yet, undeveloped opportunity to enhance the electric grid over time. Over the long term the sector could replace carbon intensive coal generation and add diversity to the generation sector. Future market opportunities include direct-use heat exchange, and a range of EGS developments that would support off-grid and regional energy demands, as well as grid based support for urban load centres. Deep geothermal stimulation and flowing experience might also supplement exploration and development activities in the unconventional gas industry, providing a natural and supportive synergistic sharing of employment, research and financing interests.

Threats

Ten threats have been identified. Arguably, the largest threat facing the sector is market consideration in terms of its costs of energy generation versus alternatives (renewables and fossil fuel) in an energy market where demand is projected to be weak.

Any industry, especially one in its early stages of development and technological improvements, faces threats to successful operation in the marketplace. Geothermal energy relies on deep drilling and stimulation techniques that are alleged to initiate microseismic events and pose risks to aquifer water quality. Inadequate exploration and resource characterization can result in high failure rates for drilling and unrewarding options for investors. While not unique in terms of regulatory oversight of energy systems, these issues represent serious threats to widespread deployment of geothermal technologies. Ultimately, the most serious threats arise from its untested or not-fully-mature technologies, with attendant high capital costs and perception of risk in financial markets. To the extent that geothermal energy fails to attract investment and development interest, the sector will languish and not be able to deliver cost-effective deployment of technology.

INTERNATIONAL GEOTHERMAL ENERGY DEVELOPMENT

This chapter describes the international setting in which Australia's geothermal energy sector operates. International developments provide a valuable context for the barriers facing the Australian geothermal sector and inform the possible options that the ARENA Board may wish to consider in terms of support for the sector. The chapter explains the technical and sector differences in geothermal energy between Australia and overseas and reviews the policies and programs to support the geothermal sector in other countries.

4.1 Convective geothermal resources

4.1.1 Overview, history and current state

Electricity was first generated using geothermal steam in Italy in 1904, and commercial geothermal power generation has been used in Italy since the 1940s. Utility-scale power generation from geothermal energy expanded to New Zealand and the USA in the early 1960s, and has since grown to include 70 countries and regions with geothermal electrical production either in operation or under construction (Matek, GEA, 2013).

There has been a steady expansion of geothermal generation capacity worldwide since the 1970s, with a total increase of installed global capacity between 2005 and 2010 of 1782 MWe (from 8933 to 10,715 MWe) (Bertani, 2010). Figure 4.1, from Bertani (2010), shows the increase in installed capacity and produced electricity from 1950 to 2010, with a projection for installed capacity to 2015. Bertani's projection for 2015 of 18,500 MWe was based on the number of projects under development in 2009, and is not likely to be achieved due to the reduced pace of development following the global economic slowdown that began in late 2008. In April 2012, the world installed capacity was 11,224 MWe (GEA, 2012), and in September 2013 it reached 11,765 MWe (Matek, GEA, 2013). By comparison, Matek, GEA, (2013) projected installed capacity in the sector to be 13,402 MWe worldwide by 2016, as shown in Figure 4.2.

Figure 4.1: World geothermal electricity, installed capacity (MW) and produced electricity (GWh), 1950–2010, from Bertani (2010)

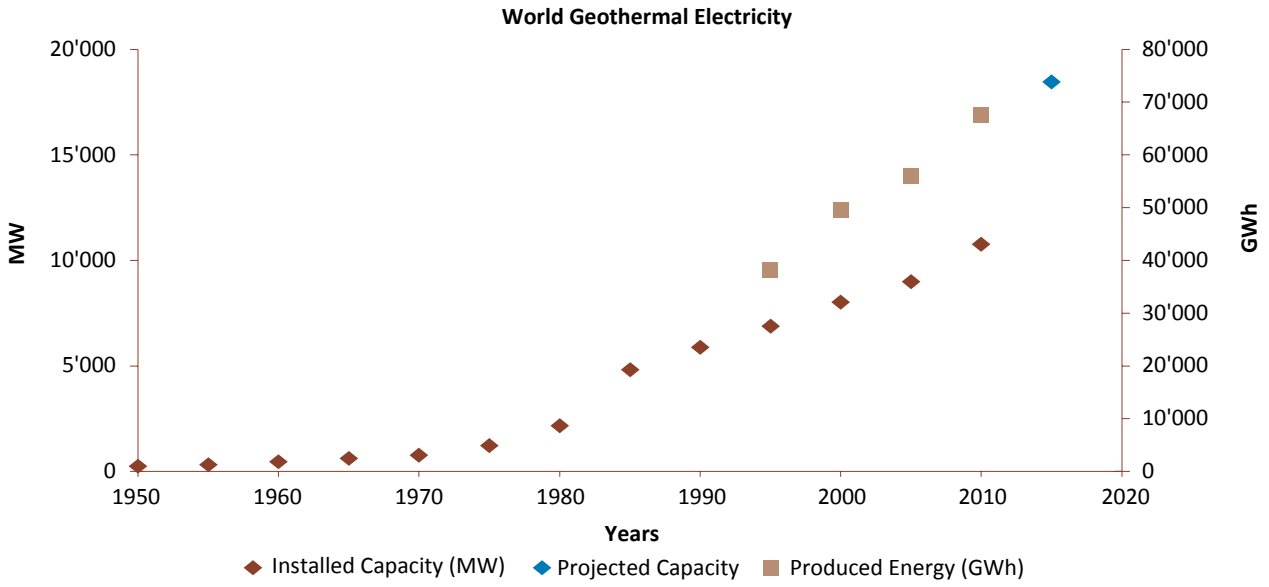
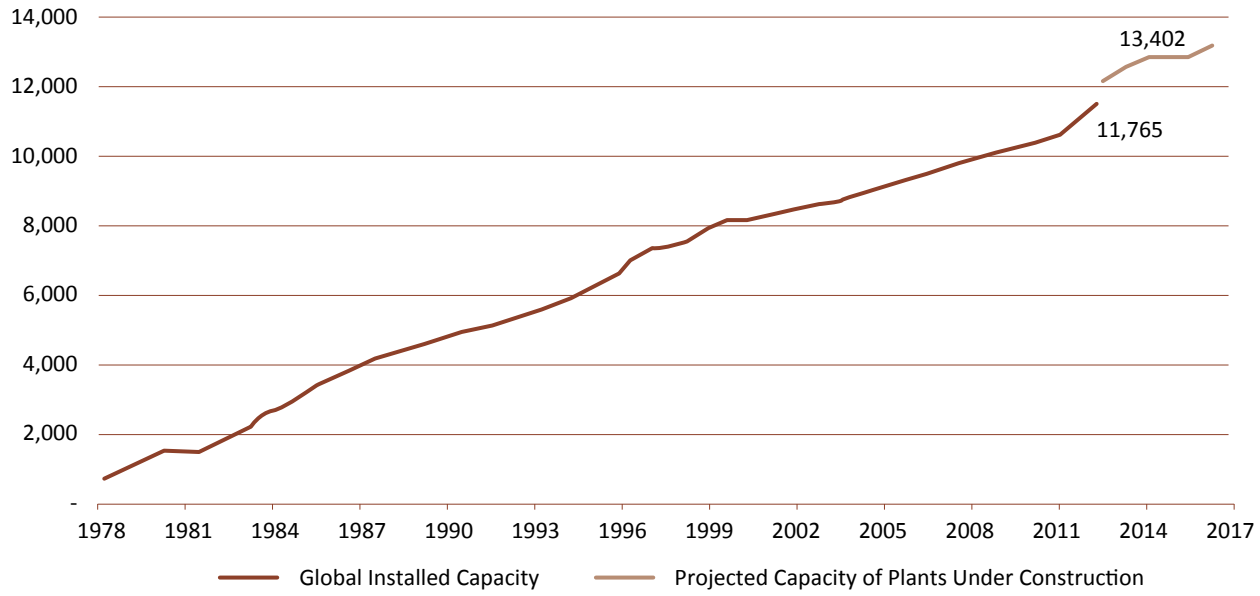


Figure 4.2: World geothermal electricity, installed capacity (MW), 1978–2013, from Matek, GEA (2013)



Currently there are some 12,000 MW of additional capacity of geothermal power in the early stages of development or under construction in 70 countries. Of this, some 1741 MW of geothermal power was under construction as of 2013. In total there are 674 geothermal power projects worldwide that are currently under consideration (Matek, GEA, 2013).

Figures 4.1 and 4.2 show that the expansion of geothermal energy development has shown at least two different phases. Until the late 1970s developments were typically small and few in number. Following that 'gestation' period, worldwide development expanded more or less linearly in a 'steady growth' period. Figure 4.2 shows only the latter period. Although both Figures 4.1 and 4.2 show the worldwide total, developments at a national level have often shown a similar progression from 'gestation to maturity'.

Table 4.1 summarises the mechanisms employed to support geothermal energy in eight countries. It is notable that both Germany and the USA have used a suite of complementary measures to promote the sector's development.

Table 4.1: International support mechanisms for geothermal energy development

	Feed in Tariffs	Risk insurance	Low interest loans/ Loan guarantees	Production tax credits	Direct grants	Mandatory targets	Renewable Energy Certificates
France		✓					
Germany	✓	✓	✓		✓	✓	
Great Britain	✓					✓	
Italy	✓						✓
Japan							✓
Korea					✓		
Switzerland	✓				✓		
USA			✓	✓	✓	✓	✓

4.1.2 Global geothermal resources

Lund and Bertani (2010) have summarised the global resources of electrical and direct-use geothermal energy as reported to the World Geothermal Congress 2010. Table 4.2 shows the capacity and also use of both electricity and direct use in 2010.

Table 4.2 illustrates the dual nature of geothermal energy utilisation. Worldwide there is substantial direct use of geothermal heat for district heating schemes, agricultural and industrial applications, balneology and spas, and tourism.

4.1.3 Conductive and convective resources

Geothermal resources can be divided into two categories, conductive and convective. Convective resources include high-temperature sources of volcanic origin, with naturally flowing geological formations. Examples include what might be called conventional developments, such as Wairakei in New Zealand, or the volcanically heated district heating schemes in Iceland and Turkey. Conductive resources include those in sedimentary formations with largely conductive temperature gradients. Examples would include the district heating systems in the Paris Basin, the enhanced geothermal systems (EGS) in Soultz and in Germany, and most of the resources in Australia.

4.1.4 Geothermal in the USA

The United States is the world's largest producer of geothermal electricity, with an installed capacity of 3093 MW (in 2010). It has also added more electricity capacity since 2006 (520 MW) than any other country (Goldstein and Braccio, 2014). In 2010, the states of California and Nevada both generated about 6 per cent of their electricity from geothermal sources (Table 4.3).

Table 4.2: Total geothermal capacity and use in 2010, from Lund and Bertani (2010)

	Installed power MW	Energy use GWhr/year	Capacity factor	Countries reporting
Electricity	10,715 (MWe)	67,246	0.72	24
Direct use	48,493 (MWt)	117,740	0.28	78

Source: Lund and Bertani (2010, Table 1)

Table 4.3: State renewable electricity profiles 2010 for California and Nevada, from EIA data released March 2012

Generation source	California		Nevada	
	GWhr	%	GWhr	%
Total Electricity Net Generation	**204,126**	**100.0**	**35,146**	**100.0**
Total Renewable Net Generation	**58,881**	**28.8**	**4,444**	**12.6**
Geothermal	12,600	6.2	2,070	5.9
Hydro Conventional	33,431	16.4	2,157	6.1
Solar	769	0.4	217	0.6
Wind	6,079	3.0	-	-
Wood/Wood Waste	3,551	1.7	-	0.0
MSW Biogenic/Landfill Gas	1,812	0.9	-	-
Other Biomass	639	0.3	-	-

Source: http://www.eia.gov/electricity/data/state/annual_generation_state.xls

Geologically, the United States differs markedly from Australia, and has vigorous volcanic and tectonic activity. Nevertheless, there are important similarities in terms of corporate and legislative approaches. Both have market-driven economies, dual federal and regional governments, and an overall reliance on market rather than government control. Although not without government assistance, geothermal development in the United States has been largely in the hands of private companies, financed and supported mostly by private capital.

The US government has supported geothermal development through the use of loan guarantees during the development stages of projects when financial risk is at its highest. In addition, the production tax credit (PTC) of $0.019/kWh has supported projects generating power since its introduction in 2008. State governments have also contributed to growth in the sector by the imposition of renewable portfolio standards (33 per cent by 2020 in California, 25 per cent by 2025 in Nevada).

Geothermal-sourced electricity is among the cheapest in the United States (Table 4.4), and plays an important role in the dispatch of power to meet renewable portfolio standards. This is primarily because of its ability to provide base-load renewable generation to backstop variable renewable sources, such as wind and solar.

Table 4.4: Estimated US average levelised costs (2011$/MWhr) for plants entering service in 2018, from US-EIA (2013)

Plant type	Capacity factor (%)	Levelised capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelised cost
Dispatchable technologies						
Conventional coal	85	65.7	4.1	29.2	1.2	100.1
Advanced coal	85	84.4	6.8	30.7	1.2	123.0
Advanced coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural gas-fired						
Conventional combined cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced combined cycle	87	17.4	2.0	45.0	1.2	65.6
Advanced CC with CCS	87	34.0	4.1	54.1	1.2	93.4
Conventional combustion turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced combustion turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111.0
Non-dispatchable technologies						
Wind	34	70.3	13.1	0.0	3.2	86.6
Wind offshore	37	193.4	55.4	0.0	5.7	221.5
Solar PV[1]	25	130.4	9.9	0.0	4.0	144.3
Solar thermal	20	214.2	41.4	0.0	5.9	261.5
Hydro[2]	52	78.1	4.1	6.1	2.0	90.3

[1] Costs are expressed in terms of net AC power available to the grid for installed capacity

[2] As modelled, hydro is assumed to have seasonal storage so that it can be dispatched within a season but overall operation is limited by resources available by site and season

4.1.5 Geothermal in Germany

Germany has been one of the most active countries in supporting the growth of green energy, in a strategy known as the *Energiewende*. The provision of generous feed-in tariffs for renewable energy of all kinds has made dramatic changes in the overall energy mix of the country during the past decade.

Germany's geothermal resources are primarily conductive and, thus, geologically analogous to the type of geothermal resources in Australia. As of November 2013, there were a total of 26 operating geothermal projects in Germany, out of which six were generating electricity. Of this total, 19 projects provide direct heat, without generating electricity, while four of the projects are combined heat and power, and three are electrical generation only. The total geothermal electrical generation capacity in 2013 was 26.31 MWe (GtV Bundersverband Geothermie, November 2013), as shown in Table 4.5. Another 13 projects are under construction, with an expected capacity of more than 40 MW (Table 4.6).

Importantly, the resources listed in Tables 4.5 and 4.6 include several of the EGS type for which Germany provides an added feed in tariff of €50/MWh to the basic geothermal feed in tariff of €250/MWh. Germany also established the world's first commercial EGS operation at Landau, which has been operating since 2007 without a decline in temperature or output of the plant.

Table 4.5: Deep geothermal projects in operation in Germany, November 2013, from GtV

Project name	State	Type	MWth	MWe	Max temp (°C)	Depth (m)	Flow rate (L/s)	Year commissioned
Arnsberg	North Rhine-Westfalen	Single well	0.35	0	55	2835	5.6	2012
Aschheim, Feldkirchen, Kirchheim	Bayern	Hydrothermal	19	0	55	2630	75	2009
Bruchsal	Baden Wurttemberg	Hydrothermal	5.5	0.55	120	2542	224	2009
Durrnhaar	Bayern	Hydrothermal	0	7	141	3926	130	2013
Erding	Bayern	Hydrothermal	9.7	0	65	2200	55	1998/2008
Garching	Bayern	Hydrothermal	6	0	74	2100	100	2010
Grunwald	Bayern	Hydrothermal	5.3	4**	130	4083	140	2011
Heubach/Gross Umstadt	Hessen	Single well	0.09	0	38	800	0	2012
Insheim	Rheinland Pfalz	Hydrothermal	0	4.8	165	3300	85	2012
Kirchstockach	Bayern	Hydrothermal	0	7	139	3882	130	2013
Landau	Rheinland Pfalz	Hydrothermal	5	3.6	160	3340	70	2007
Munchen-Riem	Bayern	Hydrothermal	10	0	93	2746	75	2004
Neubrandenberg	Mecklenburg Vorpommern	Hydrothermal	3.8	0	53	1267	28	1987
Neuruppin	Brandenburg	Hydrothermal	2.1	0	64	1700	13.9	2007
Neustadt Glewe	Mecklenburg Vorpommern	Hydrothermal	7	0	99	2320	35	1994
Oberhaching-Laufzorn	Bayern	Hydrothermal	40	0	130	3300	138	2011
Poing	Bayern	Hydrothermal	7	0	76	3000	100	2011
Prenzlau	Brandenburg	Single well	0.15	0	108	2790	-	1994
Pullach	Bayern	Hydrothermal	15	0	107	3445	105	2005/2012
Sinbach/Braunau	Bayern	Hydrothermal	8	0	80	1942	80	2001
Straubing	Bayern	Hydrothermal	4.1	0	36	800	45	1999

Project name	State	Type	MWth	MWe	Max temp (°C)	Depth (m)	Flow rate (L/s)	Year commissioned
Unterfohring	Bayern	Hydrothermal	9	0	87	2512	85	2009
Unterhaching	Bayern	Hydrothermal	38	3.36	122	3350	150	2007
Untershleissheim	Bayern	Hydrothermal	28.36	0	79	1960	100	2003
Waldkralberg*	Bayern	Hydrothermal	13.5	-	108	2650	65	2012
Waren	Mecklenburg Vorpommern	Hydrothermal	1.3	0	63	1566	17	1984
TOTALS			**238.25**	**26.31**				

Source: www.geothermie.de/fileadmin/useruploads/wissenswelt/Projekte/Projektliste_Tiefe_Geothermie_Bundesland.pdf

* Power at completion of hot water reticulation network

** Power plant under construction (capacity not included in Totals)

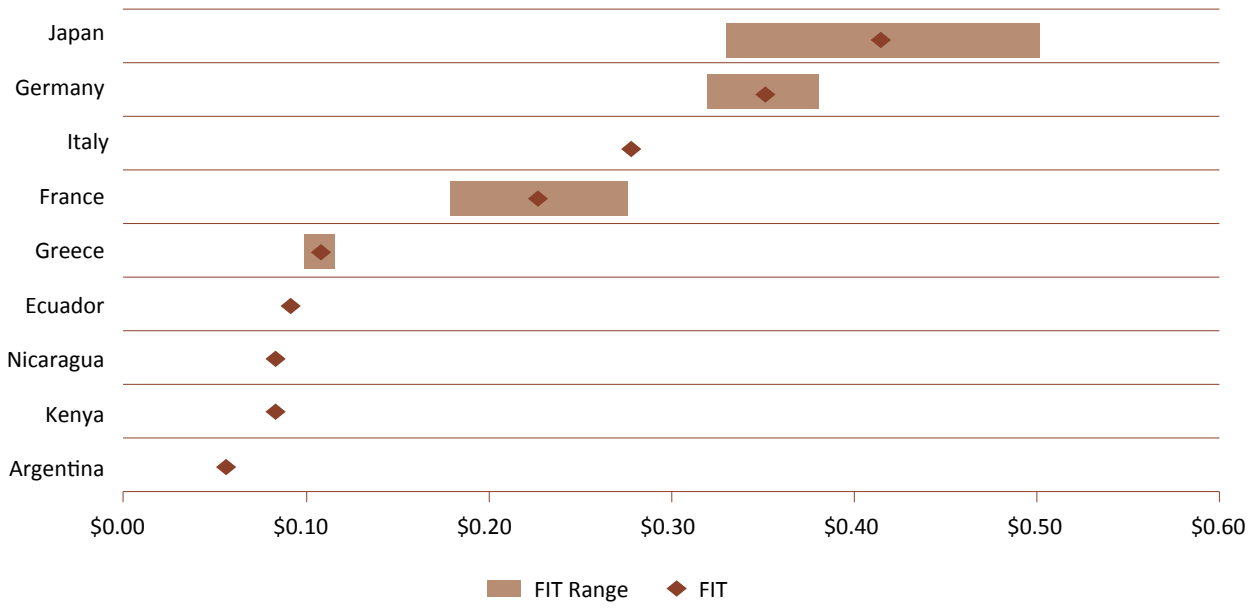
Table 4.6: Deep geothermal projects under construction in Germany, November 2013, from GtV

Project name	State	Type	MWth	MWe	Max temp (°C)	Depth (m)	Flow rate (L/s)	Year commissioned
Aachen, Super C	North Rhine Westfalen	Single well	0.45	0	85	2500	0	-
Altdorf (BY)	Bayern	Hydrothermal	-	-	65	611	90	-
Bruhl	Baden Wurttemberg	Hydrothermal	~ 40	>6	155	3320	>100	2015
Geretsried/ Wolfratshausen	Bayern	Hydrothermal	40	5	145	5200	100	2015
Gross Schonebeck	Brandenburg	EGS	-	-	150	4400	-	-
Hannover	Nedersachsen	EGS	2	0	170	3901	8	-
Ismaning	Bayern	Hydrothermal	7	0	77	1906	85	2011
Kirchweidach	Bayern	Hydrothermal	5	6.6	128	3500	130	2015
Mauerstetten	Bayern	EGS	-	5	130	4000	-	-
Munchen-Freiham	Bayern	Hydrothermal	20	0	90	2700	100	2014
Sauerlach	Bayern	Hydrothermal	4	5	140	4480	110	2013
Taufkirchen/ Oberfaching	Bayern	Hydrothermal	40	5	133	3800	120	2014
Traunreut	Bayern	Hydrothermal	12	4	118	-	130	2014

Source: www.geothermie.de/fileadmin/useruploads/wissenswelt/Projekte/Projektliste_Tiefe_Geothermie_Bundesland.pdf

One of the drivers for the growth of the geothermal energy sector in Germany has been the provision of a feed-in tariff that is among the most generous in the world, as shown in Figure 4.3, from Taylor (2012), Bloomberg Geothermal Market Outlook, as reported in Goldstein and Braccio (2014).

Figure 4.3: Feed-in tariffs in various countries in 2012 (US c/kWh)



Source: Bloomberg Geothermal Market Outlook. https://www.bnef.com/Insight/5296

4.2 Conductive geothermal resources

In a conventional geothermal resource, heat is carried upward from depth along fractures or other permeable conduits and then is contained in a permeable reservoir near the surface where it can be drilled to produce hot water or steam in economic quantities, and then injected back into the reservoir to be reheated. The heat source can be volcanic or it can be the deep heat of the earth, but the depth that needs to be drilled to reach the reservoir and the fact that the resource is permeable without human intervention make the conventional geothermal resource similar to the conventional oil and gas resource. In both cases, a natural system exists and can be drilled into without the need to alter or enhance the system for the exploitation of the resource to be economic.

If conventional geothermal resources are analogous to conventional oil and gas resources, then so are unconventional geothermal resources analogous to unconventional oil and gas resources. The natural system in both cases requires modification or enhancement to be economic.

In oil and gas development, two major methods have been used to improve the economics of extracting the hydrocarbons – enhanced recovery operations, and stimulation.

Enhanced oil recovery (EOR) is typically used to get more oil from a reservoir by adding water or another fluid to the reservoir to both recharge the pressure and sweep the oil from the pore spaces.

Stimulation methods improve the permeability of the reservoir, both near the wellbore and out in the far field away from the well, through hydraulic fracturing, explosive fracturing or chemical treatment. In unconventional geothermal reservoirs enhanced recovery operations are undertaken through injection of cool water and stimulation to improve permeability.

Improvements in multi-zone fracturing technology in unconventional oil and gas, combined with the ability to economically drill horizontal wells, has allowed access to a much larger volume of hydrocarbons located in very tight formation. The result of this technological breakthrough is a complete turn-around in gas and oil production and reserves, making the US a potential exporter of both oil and gas. The situation in very low permeability geothermal heat reservoirs is similar in that it is necessary to stimulate large rock volumes to access the heat. However, a series of open, proppant-filled, tensile fractures, as is typical for oil and gas hydraulic fracturing, cannot access the really large rock volumes needed for high flow rate geothermal heat production. This is because the open fractures created by tensile rock failure could lead to creation of short circuits and too rapid cooling of produced fluid.

While hydraulic fracturing has been used to improve oil and gas production since the 1950s, geothermal stimulation was first used to improve well outcomes in the 1970s. In order for geothermal projects to be economic, large production and injection rates are needed because the energy density of the fluid in all but the hottest wells is low. To allow for the large production and injection volumes, well bores are larger in diameter than in oil and gas wells. Casing is cemented from top to bottom in all strings to prevent thermal expansion or contraction from moving the casing up and down. This makes wells much more expensive than oil and gas wells of the same depth. To make geothermal projects economic, large flow volumes are needed to offset the higher well costs. This means that wells are often pumped, not only increasing completion costs, but increasing the amount of parasitic power needed by the project.

The amount of heat stored in the rock of the earth's crust is truly vast. However, the amount of this heat that can be extracted from conventional geothermal systems is limited because it requires a natural-circulating, high-permeability reservoir. The revolution in oil and gas production from unconventional resources with very low permeability provides encouragement to produce heat cost effectively from unconventional geothermal resources.

4.2.1 History of geothermal well stimulation

Geothermal exploration has always resulted in some unproductive wells. Sometimes wells were drilled that did not intersect with high temperature zones. In other cases, wells were hot, but the permeability was too low for economic production of energy.

In the early 1970s, the US Department of Energy Geothermal Technology Program initiated research and development (R&D) to adapt oil-field hydraulic fracturing methods to improve geothermal wells in conventional fields. The table below shows the projects and their outcomes.

Table 4.7: Cost effectiveness of US Department of Energy geothermal well stimulation experiments (Combs, et al, 2004)

Location	Raft River	East Mesa	Valles Caldera	The Geysers	Beowave
Type of stimulation	Hydrofrac	Hydrofrac	Hydrofrac	Explosive	Chemical
Well name	RRGP-4 & -5	58-30	Baca 23	LF-30	Rossi 21-19
Year of stimulation	1979	1980	1981	1981	1983
Reservoir temperature (^{0}C)	143	177	232	238	197
Approximate well depth (m)	1,740	2,227	1,649	2,691	2,198
Pre-stimulation flow rate (t/hr)	32	42	55	22	127
Post-stimulation flow rate (t/hr)	n/a	90	23	14	n/a
Steam fraction (%)	0	0	30	100	n/a
Dissolved solids (ppm)	1,850	2,200	6,100	0	1,200
Well cost (1983$)	$450,000	$724,000	$1,075,000	$1,132,000	n/a
Well stimulation cost (1983$)	$357,000	$454,000	$400,000	$334,000	n/a
Effective increase in deliverability of well	None	Doubled	Decreased	Decreased	n/a

Later commercial stimulations used these experiments and projects like Rosemanowes in the United Kingdom (UK) and Soultz in Germany have developed a stimulation method that has yielded good results some of the time. The stimulation methods in current practice include:

- large volume injection
- dilute acids-acid activity increased by high temperature
- pump from surface
- sand back to isolate zones at depth
- inject at pressures below tensile failure, and
- temperature contrast between injected water and rock temperature can induce thermal stress cracking, which improves the outcome of stimulation.

4.2.2 History of EGS Projects – Fenton Hill, and activity in Europe and the US

Efforts to use the enormous low to no permeability heat resource, originally termed hot dry rock (HDR), by engineering the reservoir were carried out starting in the mid 1970s and 1980s in the USA, the UK, France, Sweden and the Federal Republic of Germany (Figure 4.4). The earliest projects tried to adapt techniques from oil well stimulation. The assumption was that the rock would undergo tensile failure at high pressures and then be held open by proppants. Mechanical packers would then be used to create a series of these hydraulic fractures as was done in oil and gas, thus forming the heat exchanger surface (Kappelmeyer O. & Rummel F., 1980; Duffield R.B. et al. 1981; Kappelmeyer O. & Jung R., 1987; Takahashi H. et al., 1987; Tenzer, 2002).

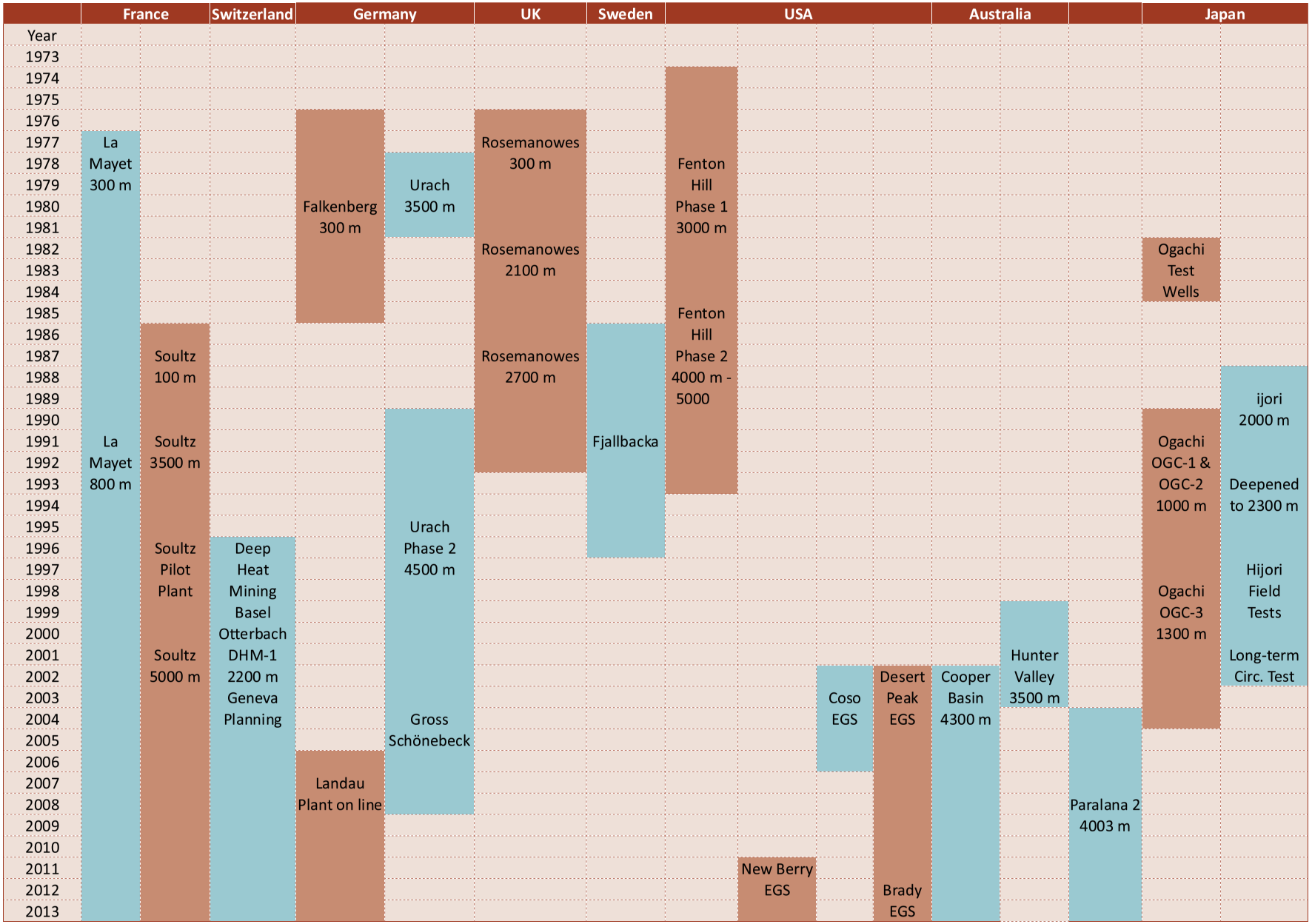
Fenton Hill Project history

The US project at Fenton Hill was the first attempt to make a deep, full-scale HDR reservoir in the world. The site on the edge of the Valles Caldera at the northern end of the Rio Grande rift zone in north central New Mexico was chosen for its heat and rock characteristics, as well as its proximity to the Los Alamos National Laboratory facility, where the project was conceived. The purpose of the project was to develop methods to economically extract energy from HDR systems located in crystalline granitic/ metamorphic basement rock of suitable temperatures.

The R&D program was roughly divided into two major phases. Phase I dealt with field development and associated research on a 3 km deep reservoir with a temperature of about 200°C and started in 1974 and completed in 1980. Phase II with a deeper (5 km), hotter (300°C) reservoir followed in 1979 with the drilling of EE-2. Initially, fracturing methods used in the oil and gas industry were used to create open tensile fractures in the shallow system. This seemed to work well for the Phase I wellbores. Multiple stages were developed with packers in the open-hole section of the injector and vertical fractures established a connection with the production well that had already been drilled.

For the deeper hotter Phase II reservoir, the stress state was not the same at depth so fractures did not grow vertically as they had in the Phase I wells. Instead, fractures grew downward more than upward and at about a 45° angle from vertical and did not intersect the production well that had already been drilled parallel to the injector. Fractures created with high pressures would not stay open on their own and proppants dissolved rapidly at the high temperatures of the reservoir. During injection at high pressures, the fractures were open, but the poor connection to the production well meant that much of the injected fluid did not reach the producer. As a result, the production well was then redrilled to better intersect the seismic cloud. The production well was also stimulated and further testing demonstrated less fluid loss and better heat sweep. Well completion problems that developed when the production well was cooled by injection during stimulation resulted in a casing leak that cooled the production. In addition, very high pressures were needed to keep fractures open since proppants were not viable in the high-temperature, high-pressure environment.

Figure 4.4: Schedule of HDR and EGS projects



Lessons learned at Fenton Hill

- Low permeability crystalline rock can be stimulated to create hydraulically conductive fractures.
- Propped tensile fractures were not an option since all tested proppants dissolved with time. Instead, hydraulic fractures had to be kept open with high pressure and this resulted in large parasitic energy requirements.
- Conventional drilling methods, including directional drilling methods, can be adapted for the harsh environments encountered in reaching zones of rock from about 200 to 300°C, which are hot enough to be suitable for commercial power production.
- The Phase I reservoir was too small. Larger volumes were needed to achieve a commercial size.
- The thermal hydraulic performance of the recirculating Phase I system was successfully modelled and indicated approximately 10,000 m^2 of effective surface area when matched to field data. This is too small by about a factor of 100.
- Techniques using chemical tracers, active and passive acoustic emissions methods and other geophysical logging techniques can be used to map and evaluate the created fractures
- Connection between wells was a crucial step in developing the created reservoir. Connection was easier to establish by drilling into the fractured volume once it was stimulated and mapped.

Rosemanowes Project History

As a result of experiences during Phase I at Fenton Hill, in 1977 the Camborne School of Mines undertook an experimental hot dry rock project located at Rosemanowes Quarry near Penryn in Cornwall, UK, in the Carnmenellis granite. The project was funded by the UK Department of Energy, and by the Commission of European Communities, and was intended as a large-scale rock mechanics experiment addressing some of the issues surrounding the stimulation of adequate fracture networks. Because the temperature was restricted deliberately to below 100˚C, to minimise instrumentation problems, this project was never intended to be a net producer of energy. The site was chosen because mine works in the area allowed rock characterisation to over 1000 m, because of the clearly defined vertical jointing evident in the exposed granite, and because of the heat flow and high temperature gradients, between 30 – 40˚C/km, in the area. The main tectonic regime of the area is strike-slip.

Phase 1 of the project started in 1977, with the drilling of a number of 300 m test wells to test some possible fracture initiation techniques. For Phase 2A of the project, two wells were drilled with a total vertical depth (TVD) of around 2000 m where the temperature was around 80˚C. Both were deviated in the same plane to an angle of 30 degrees from the vertical in the lower sections, and separated by 300 m vertically. The wells were initially stimulated using explosive methods, which did not produce results that were useful for heat sweep. Hydraulic fractures produced a system of fractures that were mapped with microseismic monitoring. As was the case at Fenton Hill, the stress regime was not the same at depth as in the shallow test wells. At Rosemanowes, fractures grew vertically downward rather than upward and the fractures did not intersect the production well.

Phase 2B began in 1983 and entailed the drilling of a third well, RH15, which was drilled underneath the existing wells in order to access the large reservoir already created in Phase 2A. The well was drilled to a TVD of 2600 m and bottom hole temperatures around 100˚C were recorded. Hydraulic stimulation of the well was carried out and circulation began in 1985, with RH12 continuing to be the injection well, and RH15 the primary producer. A series of flow tests were then carried out through September 1986, with rates gradually stepping up. The reservoir was then circulated continuously at various flow rates (typically around 20-25 kg/s) for the next four years.

Temperature drawdown over the period of the long-term flow test caused a downhole temperature loss of about 12 per cent, from 80.5 – 70.5°C. Injection rates through the testing phase varied from 5 l/s to 24 l/s. In the 5 l/s case, the return from the production well was 4 l/s and the wellhead pressure was 4 MPa. In the 24 l/s case, the return from the production well was 15 l/s and the wellhead pressure 10.5 MPa. Flow path analysis shows that a preferential pathway, or short circuit, developed, which allowed cool injected water to return rapidly to the production well.

The experimental work was continued in Phase 3A with further circulation and other tests at Rosemanowes Quarry. Phase 3 involved no further drilling. In the downhole pump test in Phase 2C, lowering the pressure in the production well seemed to close the joint apertures close to the borehole and decrease the permeability. An experiment in Phase 3A placed proppant in the joints near the production borehole, but while the sand proppant was successfully emplaced and significantly reduced the water losses and increased the permeability, it also worsened the short circuiting and lowered the flow temperature into the production borehole even further. Attempts to shut off the short circuit did decrease the cooling, but they also reduced the production rate.

At Rosemanowes, it appears that every action to the reservoir was irreversible. In particular, pumping too hard at too high a pressure caused irreversible rock movements while applying too high a pressure for too long started to drive short circuits, as well as pathways for losses, to the far field.

It was realised that there were probably a whole network of hydraulically activated joints and fractures contributing to the connection between injection and production boreholes, rather than just one or even a series of artificially created hydraulic fractures (Batchelor, 1977). The concept of enhancing these natural fractures and joints resulted in a change of concept from Hot Dry Rock (HDR) to Enhanced Geothermal Systems (EGS).

Lessons learned from Rosemanowes

- The fractures created by hydraulic stimulation, which connect best across the reservoir are not formed through tension, as in the hydraulic fracturing used in oil and gas wells, but instead are created by shearing on pre-existing joint sets.
- Stress fields in crystalline rock are invariably anisotropic, so the natural fractures fail in shear long before jacking takes place. Having sheared, the natural fractures then self-prop and stay open.
- Too high applied pressure can open tensile fractures leading to water loss and/or short circuits.
- There are always critically-oriented natural fractures, so while it is easy to stimulate with lower pressures, it is also very easy to apply too high a pressure.
- The downward growth at Rosemanowes, and that observed at Fenton Hill, are the result of the combination of in situ stress and the temperature and pressure on the rock.
- The prediction of the direction of fracture growth is difficult in the absence of precise data from downhole. Even with near-well-bore data from image logs, the fractures may not grow exactly as predicted. As a result, it is better to create the reservoir first, and then drill into it.
- One way to increase reservoir permeability is to choose areas where there are pre-existing fractures spaced closely in the wellbore and that are oriented so that they will be likely to fail in shear during stimulation.
- Near-well-bore permeability reduction, termed 'skin effect', can increase pressure drop and decrease flow rates. Placing proppants in this near-well-bore area in the injector may require high pressures and flow rates that increase the likelihood of short circuits.
- Probably the most important single lesson from this experiment is that hydro-fracturing and artificial fractures are almost irrelevant. The natural fracture system dominates.
- Natural fractures are pervasive in crystalline rocks at all depths and all locations so far investigated. Even if an artificial fracture is generated, deliberately by hydrofracturing or – more often – accidentally while drilling, it will intersect the natural system within metres and, from there on, the behaviour is dominated by the natural system.
- Over stimulating pre-existing fractures can result in more direct connection from injector to producer than is desired so that cool fluid can 'short-circuit' through the reservoir and cool production.

Research at Rosemanowes and various other sites in the 1980s (Pine R.J. and Batchelor A.S., 1984) confirmed that the creation of new hydraulic fractures was not the dominant process, but that the shearing of natural joints, favourably aligned with the principal stresses of the local stress field, was a more important mechanism to generate flow. These joints fail in shear because the fluid injection reduces the normal stress across them, but at the same time only marginally affects the magnitude of the shear stress. The shearing mechanism allows frictional slippage to occur before jacking and, therefore, there will be a component of shearing ahead of any 'jacked' zone (Baria R. et al., 1985; Baria R. & Green A.S.P., 1990).

Hijiori Project History

From 1981 to 1986, the New Energy and Industrial Technology Development Organisation (NEDO) participated in joint research into the development of geothermal energy through stimulation of low permeability rock at Fenton Hill, New Mexico, with the United States and West Germany under an implementation agreement of the International Energy Agency (IEA) (Tenma and Iwakiri, in Baria et al, 2002). On the basis of this research, NEDO conducted studies at Hijiori to determine if the technology developed at Fenton Hill could be adapted to the geological conditions found in Japan.

The Hijiori site is located in Yamagata Prefecture, on the Japanese island of Honshu. The project site was on the southern edge of Hijiori caldera, a small caldera on the side of the large Pleistocene Gassan volcano, which last erupted approximately 10,000 years ago. The location was chosen to take advantage of the very high temperature gradient in this area of recent volcanic activity. The area had been extensively mapped and some temperature gradient drilling had been carried out. Although the regional tectonics are compressional along the axis of the island of Honshu, the stress regime near the edge of the caldera is very complex. Major faults along with ring fractures associated with the caldera collapse cause stress changes, both horizontally and vertically and over short distances.

The shallow reservoir was first drilled in 1989. One injector – SKG-2 and 3 producers – HDR-1, HDR-2, HDR-3 were drilled between 1989 and 1991. The depth of all but HDR-1 was ~1800 m. HDR-1 was completed at a depth of 2151 m. Natural fractures were intersected in all the wells at depths between 1550 m – 1800 m. The temperature reached over 225°C at 1500 m. The maximum temperature in the 1800 m deep fractures was close to 250°C. The distance from SKG-2 to HDR-1 is about 40 m, to HDR-2 about 50 m, to HDR-3 about 55 m at the 1800 m depth.

The deep reservoir, below 2150 m, was accessed by deepening HDR-2 (renamed HDR-2a after deepening) and HDR-3 between 1991 and 1995 to about 2200 m. HDR-1 was used as an injector for the deep reservoir. Natural fractures were intersected in all wells at about 2200 m. The distance from HDR-1 to HDR-2a was about 80 m and to HDR-3 about 130 m at 2200 m.

Hydraulic fracturing experiments began in 1988 with water injection into SKG-2. A 30-day circulation test was conducted in 1989 following stimulation, which showed a good hydraulic connection between the injector and the two producers, but over 70 per cent of the injected water was lost to the reservoir. Nevertheless, the test was short and the reservoir continued to grow during the entire circulation period suggesting that stimulation was still occurring.

After HDR-1 was deepened to 2205 m in 1991, the well was hydraulically fractured to stimulate the deep fractures in 1992. Following stimulation, a 25-day circulation test was conducted in 1995 with injection into HDR-1 while steam and hot water were produced from HDR-2 and HDR-3. A total of 51,500 m^3 of water was injected while 26,000 m^3 of water was produced with about 50 per cent recovery.

During 1996 further stimulation and short-term testing was conducted to prepare for a long-term test. In an attempt to better connect the HDR-3 to the injection well HDR-1 in the deep reservoir and reduce the amount of fluid loss, HDR-1 was used as an injector while HDR-3 was produced and back pressure was held on HDR-2a. While no marked improvement in the connectivity was seen, this experiment held out the hope that modifying pressure in the reservoir could have an effect on the results of stimulation. Following additional circulation tests in 1996, a long-term test of the deep and shallow reservoirs was initiated in 2000 with testing continuing into 2002. For Phase I, 36°C water was injected into HDR-1 at 56-73 tonnes/hr (15-20 kg/s). For the second phase of testing, injection was into SKG-2 and production of steam and water was from HDR-2a at 5 kg/s at ~163°C and from HDR-3 at 4 kg/s at 172°C. Total production was ~8 MW_{TH}. At the end of the test, the flow was used to run a 130 kW binary power plant. Test analysis showed that production was from both the deep and shallow reservoir. During the test, scale problems in boreholes necessitated clean-out of the production wells. One interesting result of the test is that while the injection flow rate remained constant at about 16 l/s of production the pressure required to inject that flow decreased during the course of the test from 8.4 MPa to 7.0 MPa. Total production from HDR-2a and HDR3 was 8.7 kg/s with a loss rate of 45 per cent.

Well HDR-2a cooled dramatically from an initial temperature of 163°C to ~100°C during the long-term flow test (Swenson and Ito, 2003). The test was finally halted due to the drop in temperature. The measured change in temperature was larger than that predicted from numerical modelling.

Lessons learned from Hijiori

The Hijiori project provided very useful data for future projects. Added to the Fenton Hill and Rosemanowes experience it is clear that it is better to drill and stimulate one well while mapping the acoustic emissions during stimulation and then drill into the acoustic emissions cloud rather than to try and drill two or more wells and attempt to connect them with stimulated fractures.

- The reservoir continued to grow during the circulation test.
- If natural fractures already connect the well bores, stimulation may result in an improved connection that causes short circuiting.
- The acoustic emissions locations from the deep circulation test suggest that the stress field changed direction away from the well.
- If the stress direction changes from one part of the reservoir to another, it may be almost impossible to predict how the stimulated fractures will be oriented and where they will grow and be most permeable.
- With current technology, it is very difficult if not impossible to predict the stress field far from the wellbore prior to drilling.
- It is much easier to drill into the zone mapped from acoustic emissions locations at the fracture zone and establish a connection than to connect two existing wells.
- While attempts to control the stress field by modifying pressure in wells not being directly stimulated did not accomplish what was hoped for at Hijiori, this type of experiment still holds promise.
- At Hijiori it was clear that while stimulation by injecting at high pressures for short periods had some effect on the permeability of the naturally fractured reservoir, injecting at low pressures for long time periods had an even more beneficial effect.
- The reservoir grew and connectivity improved more during circulation tests than during efforts to stimulate at high pressures.
- The data suggest that cool water short circuited possibly because fracture growth during injection testing connected the deep reservoir with the shallow or because the deep and shallow reservoirs connected through one of the well bores penetrating both zones.
- Well spacing needs to be as large as possible while still making a connection.

The Hijiori project shows the value of understanding not only the stress field, but also the natural fracture system. Both the Fenton Hill project and the Hijiori project were on the edges of a volcanic caldera. While very high temperature gradients can provide access to a large reservoir of heat accessed with shallower wells and can make the project economics better, the geology, stress conditions and fracture history of rocks in such areas can be extremely complex.

Ogachi project history

The Ogachi project is located in Akita Prefecture, near Kurikoma National Park on Honshu Island, Japan. The first exploration wells were drilled in the area between 1982 and 1984 on the edge of the Akinomiya geothermal area. The heat source is Mt Yamabushi volcano. The site was considered as an EGS project because while temperatures were high, over 230°C at 1000 m, the productivity of the wells was low.

The OGC-1 well, later used as an injection well, was drilled in 1990 to a depth of ~1000 m and a temperature of 230°C. Two fracture stimulations were done in the 10 m of open hole in the bottom of the well, but both appeared to stimulate the same zone. In order to create a second stimulated zone, a window was milled at a depth of 710 m and a second fracture, termed the upper reservoir, was created from approximately 710–719 m.

Production well OGC-2 was drilled in 1992 to a depth of 1100 m where a temperature of 240°C was reached. The well was less than 100 m from OGC-1. A circulation test in 1993 with injection into OGC-1 and production from OGC-2 showed only 3 per cent of injected water was produced. To improve the connection between the wells, OGC-2 was stimulated in 1994. A five-month circulation test following this stimulation showed that only 10 per cent of the injected water was produced back. The production and injection wells were again stimulated in 1995. A one-month circulation test showed an improved recovery of over 25 per cent of the total injection. The permeability found before fracturing ranged from 10^{-6} – 10^{-7} cm/s. Permeability after fracturing improved an order of magnitude from 10^{-4} – 10^{-5} cm/s. About 15 per cent of the total produced fluid could be attributed to the upper reservoir, while 85per cent came from the lower reservoir. The stimulated reservoir volume was ~10 m^3 in the upper reservoir and 250 m^3 in the lower reservoir.

Because the first two wells at Ogachi did not appear to be well connected and significant injected water was lost to the reservoir, OGC-3 was drilled in 1999 into fractures indicated from acoustic emissions mapping. Borehole televiewer imaging was used to observe fractures in the wellbore from which better fracture orientations were obtained. Testing also showed an improved response to injection into OGC-1 at OGC-3. One important result of the borehole televiewer imaging, which coincided with the results of enhanced analysis of the acoustic emissions data, was that the upper fractures had a NE fracture orientation while the deeper fractures were oriented NNE.

Lessons learned from Ogachi

The experience at Ogachi, with the attempt to fracture between two wells, reinforced the experience at Fenton Hill, Rosemanowes and Hijiori that showed that drilling, stimulating with acoustic emissions mapping and then drilling into the fracture cloud yielded the best connection between injector and producers.

- The complex geologic history at Ogachi made it difficult to predict the direction of fracture growth.
- The stress state in the original boreholes was not well understood until borehole televiewer data was collected and analysed after the wells had been stimulated.
- Drilling OGC-3 into the mapped fractures from acoustic emissions analysis resulted in a significant improvement in connectivity between the wells.
- Efforts to connect the original two wells at Ogachi by stimulating the production well were unsuccessful after the initial attempts to connect, by stimulating the injection well, failed.
- While efforts to stimulate the two wells resulted in reservoir growth, they did not result in better connectivity between the wellbores.
- Fluid losses to the reservoir were high during injection testing because the wells were not well connected. Once OGC-3 was drilled into the stimulated area, connection was improved and fluid loss was reduced.
- Stress changes in the boreholes with depth using a borehole televiewer and from improved analysis of the acoustic emissions data showed the change in stress direction with depth in the reservoir.

Soultz-sous-Forêts project history

As a result of the interest generated by the Fenton Hill project, several European countries began experiments along similar lines. Besides the UK project at Rosemanowes, Germany supported two projects – a shallow experiment at Falkenberg and a deep (4500 m) single borehole project at Bad Urach. France had an experiment in 800 m boreholes at Le Mayet in the Massif Central and, together with Germany, began a desktop study in the mid-1980s of the potential of a site at Soultz-sous-Forêts in the Upper Rhine Valley. As the latter is the site of the former Pechelbron oilfield, the geology was very well characterised down to about 1500 m, the top of the granitic basement, and temperature gradients in the upper 1000 m were known to exceed 110˚C/km.

In 1987 the first well, GPK1, was drilled to 2002 m depth. The drilling was difficult with directional control, lost circulation and a stuck pipe presenting the primary problems. Consequently, the project ran over budget. The project site was in an old oil field and the data from oil wells were used extensively to characterise the resource. In 1988 three existing old oil wells were deepened so that they penetrated the granite to provide good coupling for seismic sondes, as experience at Rosemanowes had shown this to be necessary. A seismic network based on those used at Rosemanowes and Fenton Hill was designed and installed.

In 1991 GPK-1 was stimulated with high flow rates targeting the open-hole section from 1420-2002 m. A fractured volume of 10,000 m^3 was created based on microseismic mapping. It is possible that a natural fracture was intersected that stopped fracture growth and allowed for loss of injected fluid. In 1992 GPK1 was deepened from 2002 to 3590 m, reaching a temperature of 168˚C. The following year, GPK1 was again stimulated, this time targeting the newly drilled segment from 2850 to 3590 m. GPK1 was then flow tested by producing back the injected fluid in 1994. Targeting and drilling of GPK2 to 3876 m at a temperature of 168˚C was done in 1995. The bottom-hole location was 450 m from GPK1.

During 1995, GPK2 was stimulated in the open-hole section from 3211 to 3876 m with a maximum pressure of about 10 MPa and a flow of 50 l/s. Acoustic monitoring showed the reservoir growing in a NNW-SSE with a tendency for the fracture cloud to grow upward forming a stimulated volume of about 0.24 Km^3. GPK1 showed a significant pressure response to the stimulation showing a connection between the two wells. During 1995–1996 some circulation tests were undertaken and that included the use of an electric submersible pump. With the production well pumped, a circulation rate of more than 21 l/s was achieved. The surface temperature of the produced water approached 136˚C with injection at 40˚C with an energy output of ~9 MW_{TH}. The use of a production pump helped maximise energy output in this situation with large open fractures. In 1996 GPK2 was re-stimulated using a maximum rate of 78 l/s with a total volume of 58,000 m^3 injected. Following this stimulation, in 1997, a four-month flow test was conducted, injecting into GPK2 and producing from GPK1. Injection and production stabilised at 25 l/s, with no net fluid losses. Only 250 kWe pumping power was required to produce the thermal output of 10 MW_{TH}.

In 1997–1998, with the aim of gradually transferring the project to industrial management, several new participants were added to the Soultz project, including Shell and several French and German utility companies. With new funding, the decision was made to deepen GPK2 to a TVD of 5000 m to reach at least 200˚C. This required the removal of the existing casing, cementing, reaming out from 6.25” to 8.5” and installing casing to 4200 m. New high-temperature cement and new metal packers allowed a successful completion of the new GPK2. The predicted temperature of 200°C was measured at a depth of 4950 m. An additional acoustic monitoring well, OPS4, was drilled to a depth of 1500 m and instrumented to improve the accuracy of acoustic event locations. The measurement of the initial, natural pre-stimulation injectivity of around 0.2 l/MPa/s in the new deep part of GPK2 was consistent with those seen in the depth range of 3200 to 3800 m.

During the summer of 2000, GPK2 was stimulated using heavy brines in an attempt to stimulate the deeper zones preferentially. The overpressure needed to create the large reservoir was lower than anticipated. In total, a volume of 23,400 m^3 water was injected at flow rates from 30 l/s and 40 l/s to 50 l/s and a maximum wellhead pressure of 14.5 MPa. Acoustic emission mapping showed the stimulated reservoir extending NNW/SSE, about 500 m wide, 1500 m long and 1500 m tall. No leak-off to the upper reservoir was detected.

Starting in 2001, the deep production wells for the high-temperature reservoir were drilled. All of the wells were started from the same pad. GPK3 was drilled to 5093 m to target a zone in the stimulated area created from GPK2 in 2000. The bottom-hole separation between GPK2 and GPK3 was 600 m. The bottom zone of GPK3 was stimulated to extend the existing reservoir of GPK2 by an overlapping volume of enhanced permeability. The deviated well, GPK4, was drilled starting in August of 2003 to a TVD of 5105 m from the same platform as GPK2 and GPK3 into a target zone selected from the stimulation of GPK3. The bottom of GPK4 was separated from the bottom of GPK3 by around 650 m (a total deviation of some 1250 m). Following completion, GPK4 was stimulated by injecting heavy brine to encourage development of deep fractures. While an area of enhanced reservoir developed, a linear aseismic zone was apparent separating GPK4 from the other two deep wells. Despite a second stimulation and acidising, no good connection yet exists between GPK4 and the rest of the reservoir. The injectivity index for this well is good, but the well is not well connected to the other two.

During testing and stimulation of GPK2 and GPK3, it became apparent that a small number of induced seismic events were being felt by the local population. No damage was done, but the potential for larger events was unknown, and experiments were conducted to determine what conditions generated the larger events and if they could be controlled. It was found that by using ’soft’ shut-ins after injection or production, the number of large events was reduced.

In 2008 a 1.5 MW demonstration plant was constructed and tested at the Soultz project. The plant flow is produced from GPK-2 and GPK-4 and injected into GPK-1 and GPK-3. During the more than 10 years of testing and the five years of plant operation there has been little to no temperature drop in the production flow. The injection is balanced by the production.

Lessons learned from the Soultz Project

The Soultz project, more than any other previous HDR/EGS project, used the lessons learned from the earlier work and has come the closest to create an economic artificially created reservoir. The Soultz project demonstrated that large fractured volumes can be created repeatedly in rock that contains pre-existing natural fractures that are ready to fail in shear.

- Large overpressures are not needed to extend the reservoir, and fairly high productivity and injectivity can be created.
- Natural fractures and the natural connectivity of these fractures seem to dominate the enhanced reservoir system.
- Natural fractures can be stimulated, but there seems little data to support the creation of a totally artificial reservoir when no natural fractures are present.

- Stimulating an entire wellbore section with some open fractures will preferentially stimulate the highest open fracture. Much less benefit will be seen in the smaller fractures.
- Use of high-density brine may assist with smaller fractures.
- While microseismic monitoring works well overall to map fractures the sector still does not totally understand the relationship between mapped acoustic emission events and fluid flow.
- There are several methods for reducing near-wellbore pressure drop such as acidising, emplacing proppants and stimulating with fracturing fluids. Further testing is needed to determine which of these is most beneficial.
- Acidising reduced the injection pressure for a given flow rate and the effect seems to be lasting.
- Injection testing shows a nearly linear correlation between wellhead pressure and injection rate. This is typical of flow in porous media in general, suggesting that there was an overall fracturing pattern, not separate discrete fractures. This finding suggests that permeability is not dependent on pressure, which had previously been suspected.
- While injecting at high pressures can increase flow rates during operation of the reservoir, it can also stimulate fracture growth. Another alternative to high-pressure injection is pumping the production well.
- Logging tools have temperature limits and there is little incentive for oil and gas to bring these limits to very high temperatures.
- The larger the injected volume without pressure relief through production, the larger the potential for problematic induced seismicity.

Deep Heat Mining, Basel, Switzerland project history

The Deep Heat Mining (DHM) projects in Switzerland planned to generate power at sites in Basel and Geneva. At Basel, a 2.7 km exploration well was first drilled and studied and then equipped with seismic instrumentation. The Basel site was selected to enable the development of a combined heat and power project and because the City of Basel was anxious to reduce the dependence on non-renewable resources for both power generation and heating and cooling. The location of the project in an industrial area was considered to be sufficient to reduce the impact of the construction phase of the project on the population. Various sites around the city were investigated for the primary production and injection wells, but only Basel was evaluated for the project location.

The Basel area is at the south-eastern end of the Upper Rhine Graben and at the northern front of the Jura Mountains, the outermost expression and youngest part of the alpine fold belt (Haring, 2004). The graben's related Cenozoic rift system is limited to the south by the fold-and-thrust belt of the Jura Mountains (Meghraoui, et al., 2001). The local geology consists of folded and tabular Jura units, as well as Tertiary sediments overlying down-dropped granitic rock (Kastrup, et al., 2004). The Rhine River runs through the city depositing soft sediments, which may amplify seismic shaking. (Giardini, 2004)

A microseismic monitoring array was put into operation in February 2006 to both map fractures and record seismicity that might be an issue in the project area. The well Basel 1 was drilled between May and October 2006 to a total depth of 5 km through 2.4 km of sedimentary rocks and 2.6 km of granitic basement. A fault zone was encountered during the drilling of the granitic section as evidenced by cataclastic alteration. After an extensive logging and testing phase, the granite in the open hole below 4629 m depth was hydraulically stimulated to enhance the permeability. The stimulation operation was planned to take 21 days. However, high rates of microseismic activity built up during the first six days of fluid injection with event magnitudes of up to ML 2.6. Consequently, injection stopped. The decision adhered to a pre-defined seismic response procedure approved by the local authorities, which specified the measures to be taken at increased levels of seismic activity. After shutting in the well for about five hours a seismic event of ML 3.4 occurred during preparations for bleeding off the well to hydrostatic conditions. Over the following 56 days, three aftershocks of ML > 3 were recorded. At present the project has been abandoned following an independent risk analysis and identification of acceptable ways of reservoir enhancement.

Lessons learned from Basel

- The wells were drilled in the city of Basel in an industrial part of town with a dense population to demonstrate the potential for coexistence of EGS projects with other industrial activities within the city limits.
- Given the location of the project wells under a city centre, the potential for problematic seismicity associated with the stimulation and operation of the system is high.
- A fault zone was encountered during drilling and the pattern of microseismicity suggests that a fairly long fracture length may have developed in that zone. To reduce the risk of significant problematic seismicity, it is important to avoid injecting directly into a fault.
- Community outreach could have helped the public to understand the issues. A similar project in St. Gallan, Switzerland that did excellent community outreach had a seismic event that people could feel, but the public was aware of the risks and were notified immediately and included in ongoing decision making. The town elected to continue the project.

Landau project history

The Landau project, in the Rhine Valley region of Germany, was developed as a commercial EGS project to provide both power and district space heating for the nearby town. The project was a joint venture between the local utilities Pfalzwerke Aktiengesellschaft and Energie Südwest AG and a commercial entity, the geo x GmbH. Bestec GmbH, a company formed with members of the Soultz project team, was the general contractor. The project takes advantage of the high feed in tariff in Germany to be commercially viable.

Like the Soultz project, this project is in the Rhine Graben geologic province where deep normal faults bring heat closer to the surface. The stress regime is also conducive to stimulation by injecting cold water at lower pressures. Natural fractures are also present in the area and augment production from the stimulated fractures.

The project was initiated in 2004 and became operational in 2007. The injection well was stimulated and the production well was drilled into the stimulated fractures. Flow rates were improved when the producer intersected a natural fracture. The wells at Landau are around 3000 m deep and produce 70–80 l/s of 160°C water. The project generates up to 3.8 MW_{TH} of electric power and about 3 MW_{TH} for district heating.

As with the Soultz project, some small magnitude (2.4–2.6M) seismic events have been felt and heard by the public. While this has created a short-term issue of concern by the public, good community outreach and injection management has resulted in both a reduction in magnitude of seismicity and in public concern. One lesson that has been learned from the Landau project is that increasing flow by injecting at higher pressures can lead to higher rates of seismicity of concern. Increasing flow by pumping at higher rates (with more drawdown) in the production wells has led to lower seismicity and also higher fractures of recovered fluid.

Lessons learned from Landau

- Commercial EGS geothermal production is possible with sufficiently high feed in tariffs.
- Public/private partnerships can lead to more rapid project development. The Landau project took only three years from start to power online.
- Community outreach is a critical part of any industrial activity close to residential areas.
- Induced seismicity from geothermal projects can be mitigated during operation at higher flow rates by pumping rather than injecting at higher pressures.
- A combination of natural and stimulated fractures improves project economics.
- Finding exploration methods that will identify natural fractures at depth would improve success of EGS projects.

Conclusions

One of the most significant outcomes of the various international research projects to date has been the realisation that shearing on existing joints constitutes the main mechanism of reservoir growth. This has led to a basic change in the vision of an EGS reservoir. It has led to a departure from the conventional oil-field reservoir development concepts and techniques towards a new technology related to the uniqueness of any jointed rock mass subjected to a particular anisotropic stress regime.

All rocks that have been investigated so far, even those in continental shield areas with very low stresses on them, have some sort of fractures. It is understood that these fractures can be stimulated and that these fractures can stay open using pumping pressures just over the critical pressure that will cause them to fail in shear. What this means for the development of EGS as an energy producing technology is that it is likely that an EGS reservoir can be formed anywhere at any depth that has sufficient temperature for energy conversion.

Despite the important lessons learned from the various projects in the world, much still needs to be known and risks remain for EGS. In particular, the sector still faces the risks that cause problems down hole, such as mapping existing major faults and fractures that may act as flow barriers or conduits, or that can slip substantial distances and, thus, result in seismicity of concern to people. Further, it is not possible to accurately predict the long-term effect of injecting water not in equilibrium with the rock into the reservoir over a long period. For instance, if one permeable fracture in the system is developed it can result in a short circuit. If this develops, it is not clear how to fix the short circuit other than drilling a side track into a new area of rock. Importantly, the geothermal sector will need to be able to circulate at the high flow rates necessary to be commercially viable without growing the reservoir and losing fluid to the new fractures or causing induced seismicity.

None of these risk and challenges are insurmountable. Past developments show that the sector can: (1) drill the wells; (2) stimulate the existing fractures; (3) drill into the stimulated fractures; and (4) make a connection between wells. Further, it has been demonstrated that fluid can both circulate and be heated so as to generate electricity. The major breakthrough that still remains elusive, but was overcome by the oil and gas industry in 2003, is to create multiple large zones of stimulated rock and to reliably ensure that the volume of stimulated rock is interconnected.

ARENA'S COMMERCIALISATION PATHWAY AS APPLIED TO GEOTHERMAL ENERGY

5

The IGEG has conducted Commercial Readiness Assessments for three categories of geothermal energy resources. These assessments were based on earlier work that ARENA had conducted with the Australian geothermal energy sector at a workshop in June 2013. The three categories of resources considered are:

a. *Shallow Direct Use*: Typically in the 500 m to 1500 m depth range targeting aquifers with high permeabilities at low to moderate temperatures for direct use applications. Geothermally heated swimming pools in Perth are an example.

b. *Deep Natural Reservoir*: Typically greater than 1500 m targeting aquifers with high permeabilities (no or minimal stimulation required) for direct use or electricity generation. These resources are in sedimentary aquifers (the fluid is stored within the space between sedimentary grains), fractured aquifers (the fluid is stored and flows within fractures in the rock) or some combination of the two. Examples include proposed deep HSA/direct-use applications in Perth and the resources targeted by Salamander-1 and Celsius-1.

c. *Enhanced Geothermal Systems*: Geothermal resources where the reservoir needs to have its permeability increased via the stimulation of existing structures or the creation of new ones. Heat may be used for direct use or electricity generation, although electricity generation is the main target. Examples include Geodynamics Ltd's Innamincka Deeps project in the Cooper Basin and Petratherm's Paralana project.

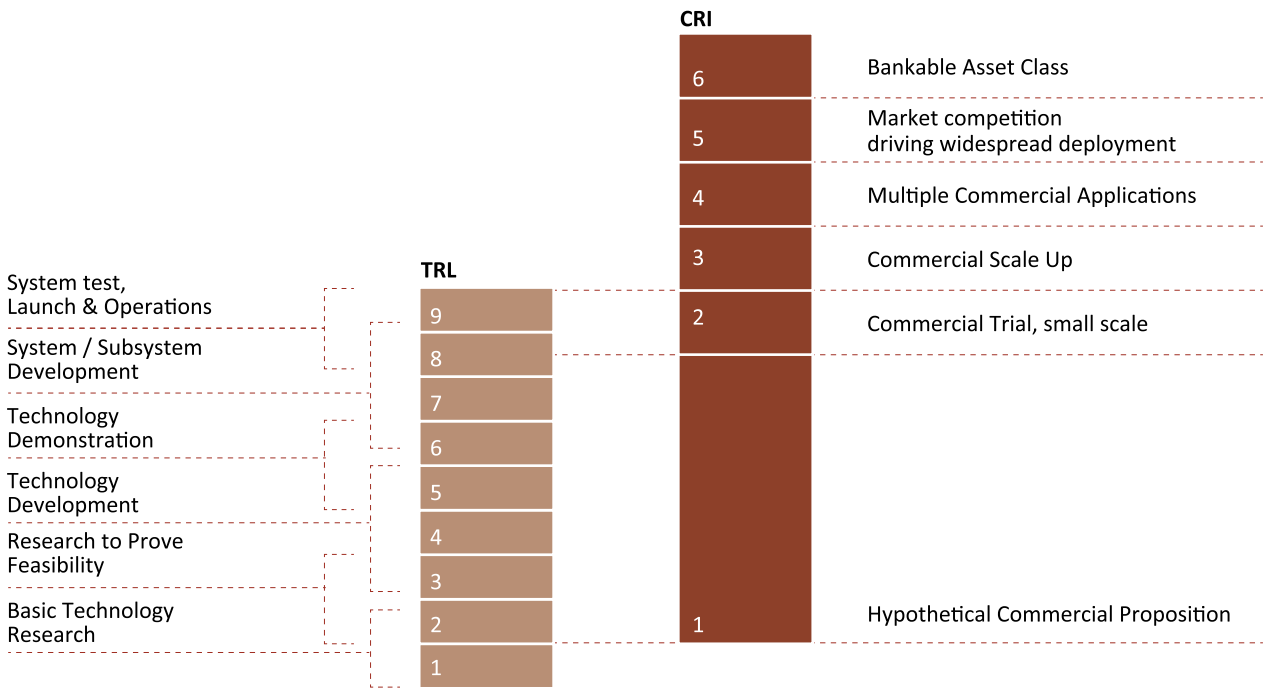
5.1 Commercial readiness of geothermal energy in Australia

ARENA has developed the Commercial Readiness Index (CRI) to identify where a technology or project is located in the commercial development cycle. The CRI considers all aspects of a technology's readiness, including the maturity of the technology, costs, market and the supporting framework. A more detailed description of the Commercial Readiness Index is provided in Annex C.

The Technology Readiness Level (TRL) index is a globally accepted benchmarking tool for tracking progress and supporting development of a specific technology through the early stages of the innovation chain from blue sky research (TRL 1) to actual system demonstration over the full range of expected conditions (TRL9). The TRL methodology was developed by Stan Sadin with NASA in 1974 (see www.nasa.gov/ topics/aeronautics/features/trl_demystified.html).

Since its inception, the TRL process has evolved and is used across a wide range of sectors, including renewable energy. ARENA uses the TRL index in the Emerging Renewables Program and R&D Program to help applicants identify the stage of development of their particular innovation. While the majority of technology risk is retired through the TRL 1-9 framework, there is often significant commercial uncertainty/risk remaining in the demonstration and deployment phase. In particular, new technology/entrants entering a market place typically supplied by proven incumbents and financed by capital markets that are often risk adverse, face a multi-faceted range of barriers during the commercialisation process. This is particularly relevant in the context of renewable energy where capital cost, and therefore access to capital, is a key barrier to accelerating deployment.

Figure 5.1: The relationship between the CRI and TRL



5.1.1 Technology Readiness Levels for Australian geothermal resources

Before discussing the CRI of geothermal resources, it is worth considering where on the TRL scale the technology is required to exploit the various geothermal resources resides.

For Shallow Direct-use (Type A) resources, there are a number of commercial operations throughout Australia where the heat is used for heating swimming pools or spas. According to the TRL scale in Annex 3, these systems are at a TRL equal to or greater than 7 as they are at or past the prototyping stage of their development. The component technologies for the development of these resources, including drilling, pumping, surface engineering works and resource identification are all mature. While overall the technology is relatively mature there are some new components/subsystems that may be at a lower TRL such as when the heat from shallow geothermal resources is used in novel applications, including thermal effect cooling (absorption and adsorption chillers), desalination via multi-effect distillation or low enthalpy power generation. In these cases, the individual components are mature, but few examples exist of their use as a system. Consequently, their TRL may be best described as TRL 4. For comparative purposes, the Birdsville Geothermal Power Station may be best described as at the upper boundary for Type A resources.

There are no examples of the exploitation of Deep Natural Reservoirs (Type B) in Australia. The component technologies are all proven for extracting the resource (drilling, pumping) with a number of examples internationally (particularly in Europe). Similarly, the technologies for utilising the thermal energy from these resources is also mature in the case of power stations and district heating. The international evidence is that the technology readiness for the use of these resources for electricity generation and district heating is at TRL 7. To date, the Australian experience with these resources has been disappointing. This poor performance is related to the quality of the resource in terms of its ability to produce the required flow rates. While the properties of a reservoir are not a technology that can be developed, the exploration methods and tools used to locate a suitable resource are part of the technology set. In particular, the ability to find and target naturally permeable geothermal reservoirs at depth before drilling, and whether the permeability is in the matrix of the rock or in fractures, has not been demonstrated in Australia. This suggests a TRL of 2 to 3 for this technological component of developing a Deep Natural Reservoir. As this component appears to be critical in the successful development of this type of resource, the overall TRL for Deep Natural Reservoirs as a system in Australia cannot be considered to be any higher than 2 to 3.

The third resource type, EGS resources (Type C), has been an area of active research and development internationally for over 40 years. During this time, several projects have demonstrated proof of concept with closed circulation loops extracting heat from reservoirs. At least two projects have produced electricity from EGS resources (Soultz in France, Innamincka Deeps Pilot Plant in Australia). This places the technology at TRL 5 in the context of Australia. Full-scale prototyping (TRL 6) would probably require the development of a demonstration plant at or close to utility scale electricity generation from several production wells.

The technology readiness of the component technologies for EGS is complex. While drilling to the depth of the reservoir has been demonstrated in a range of geological settings, the time taken to drill these wells needs to be improved. Higher rate of penetration drilling technologies are being developed and these have varying TRLs. Novel methods like thermal spallation drilling have only been demonstrated in the laboratory and would be considered to be at TRL 4. Impregnated diamond bit and turbines are established technologies that are being optimised for geothermal wells and would be considered as mature as TRL 6 or 7.

Reservoir stimulation is a key component of EGS and is another technology that has been demonstrated to work in geothermal reservoirs, but much uncertainty remains over whether the resulting flow rates are sufficiently high enough to make geothermal resource commercially viable. Resource risk is another factor in EGS. The most recent perspective is that for EGS to work successfully the resource requires pre-existing fractures, which then have their permeability enhanced (Hogarth, Holl, and McMahon, 2013). If this model is correct, this requires finding a resource that has the right pre-existing fractures for EGS. At present, exploration technologies that allow such structures to be reliably detected prior to drilling do not exist.

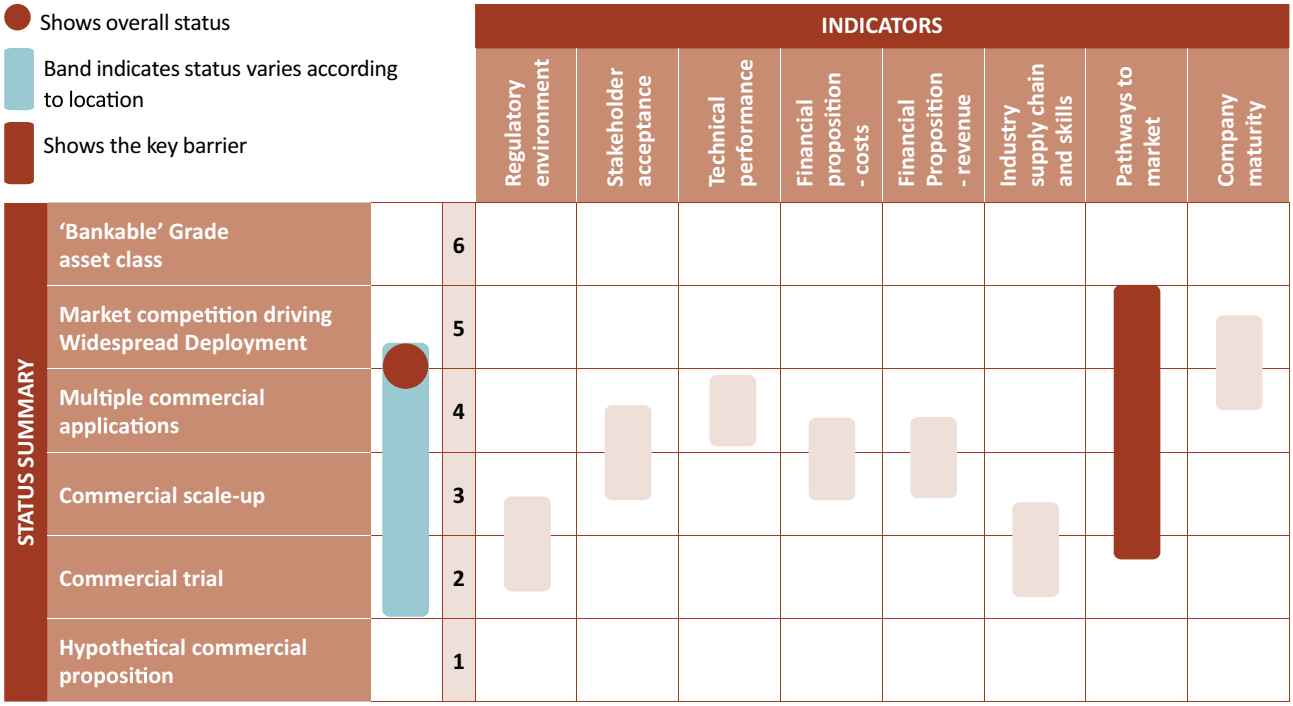
One of the key challenges in developing geothermal energy technology that sets it apart from other renewable energy is the uncertainty over the resource and the cost effective extraction of the energy. Neither the TRL nor CRI factor in this resource risk explicitly. The only way it can be captured is through the technology readiness of the workflow and methods used to reduce this risk, or through the development of reservoir development technologies that effectively decrease the importance of this risk. For example, during exploration for mineral resources, explorers will often use a generic model for the style of resource for which they are prospecting. In this sense, minerals exploration has a mature technical approach to dealing with resource risk and recent and extraordinary developments of shale gas in the US show how effective reservoir engineering technologies can be at reducing resource risk. In particular, the ability to drill multiple horizontal wells from a single pad and conduct multi-stage hydraulic fracturing treatments in a single well have allowed a previously known and extensive, but previously uneconomic, resources to be developed.

5.2 Commercial Readiness Assessments

The main distinguishing feature of the Shallow Direct-use technologies is that they can be accessed by conventional water drilling rigs, are at depths where high permeabilities in sedimentary rocks are the rule rather than the exception, and project costs are in the order of $1 million. There are many commercial examples in Australia and in similar geological settings internationally.

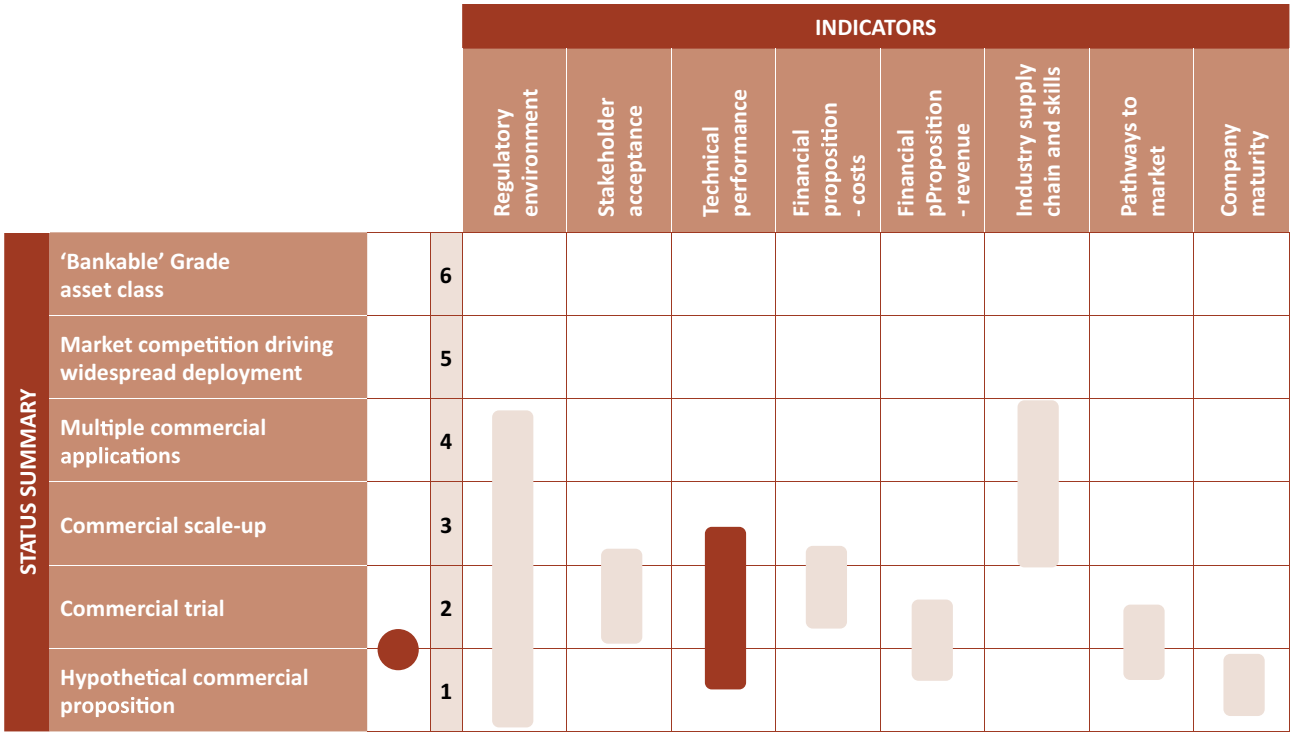
The other two resource types require significantly deeper drilling to reach the desired temperatures, resulting in project costs starting in the tens of millions. There are only a handful of projects in Australia that have drilled in to these resources with limited international experience, particular in EGS (Deep Natural Reservoirs are the main style of unconventional geothermal energy resource exploited in Europe). The difference between these two types of resource is that EGS resources require the permeability to be enhanced.

5.2.1 Commercial Readiness Index – Shallow Direct Use (Type A)



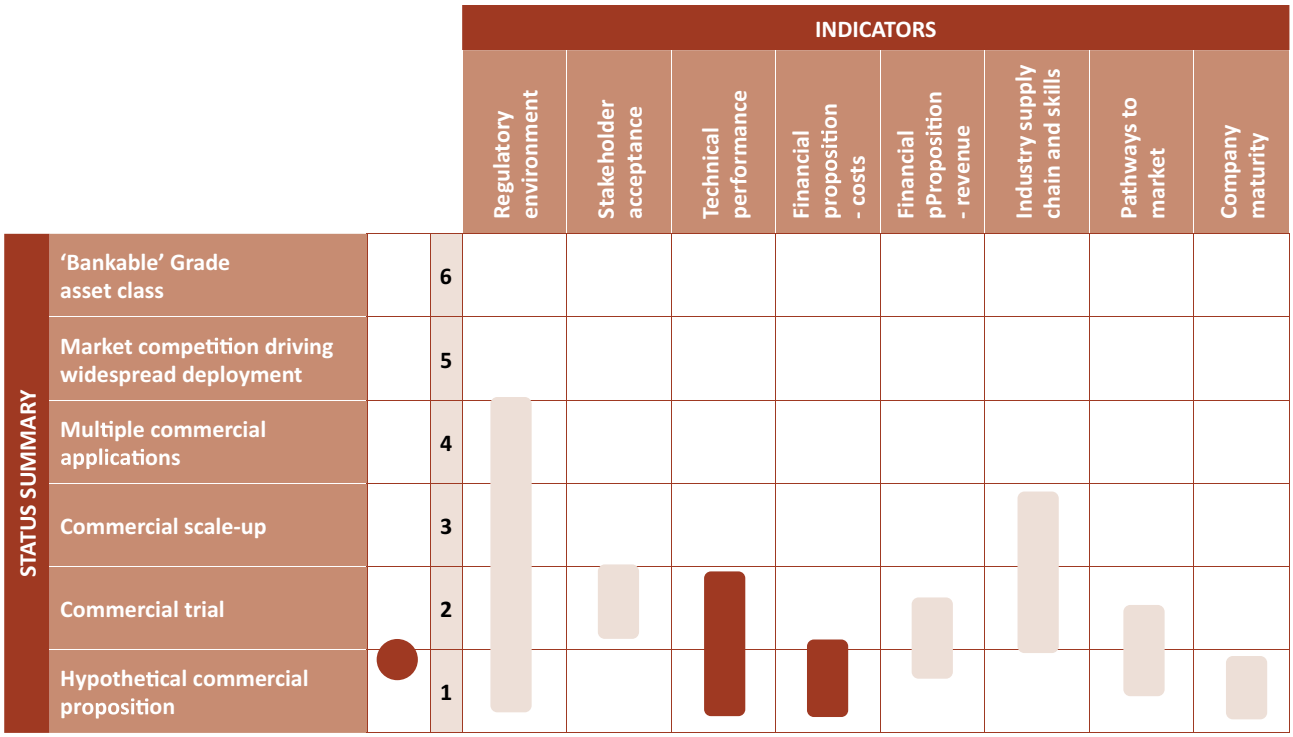
Evidence of status summary	
Status Summary:	CRI 4 (Perth Basin – brown dot), CRI 2 to 4 (other jurisdictions – green bar)
Market Position Identified (CRI 1–6)	The Perth Basin market is mature with a well-established technical and regulatory framework, demonstrated by multiple commercial applications. Projects are proceeding with little to no market intervention. Other markets are less mature.
Rationale	There are nine projects of this kind in the Perth metropolitan area. Some have received government funding as part of overall refurbishment plans for the facilities that the geothermal resources are heating, however they can all be considered to be commercial. There are two spa facilities in Victoria that are commercial operations. These examples provide evidence of a CRI 4 (Multiple commercial applications becoming evident locally although still subsidised). There are limited examples in the other states. The Great Artesian Basin (Queensland and New South Wales) water bores are not considered to be evidence of the commercial readiness of these resources as they were not developed as geothermal projects and do not provide a model for future development. The pathway to market for more widespread deployment has been identified as the key barrier for this technology.

5.2.2 Commercial Readiness Assessment – Deep Natural Reservoirs (Type B)



Evidence of status summary – Deep Natural Reservoirs	
Status Summary:	CRI 1 to 2
Market Position Identified (CRI 1-6)	Between hypothetical commercial proposition (CRI 1) and commercial trial (CRI 2). The commercial proposition for these resources is asserted by technology advocates on the basis that the technology is ready, but commercially untested and unproven (CRI 1). While there is international evidence that these resources can be successfully developed, little or no evidence of verifiable technical or financial data is available in Australia. Two commercial trials have been attempted in Australia and project proponents are actively pursuing a third (based on a fracture permeability model, CRI 2).
Rationale	Two projects have attempted to demonstrate these resources in Australia – at Penola and Innamincka Shallows. These two small-scale, first-of-a-kind projects were funded by equity and government project support in one case and completely by equity in the other. Neither project produced the anticipated flow rates raising questions over the technical viability of developing Deep Natural Reservoirs that rely on primary permeability in Australia. As yet, trials of this technology in areas with high-fracture permeability have not been completed. Such trials have been proposed by several project proponents and at least one is actively seeking government support for their project. It is possible that a project targeting fracture permeability may cross the boundary between natural reservoirs and EGS if the natural permeabilities are not high enough. Technical performance has been identified as the key barrier to progress for Deep Natural Reservoirs, with uncertainty in the resource identified as a key risk. Finding resources with the temperature and permeability required for electricity generation at acceptable costs is critical. Technologies are required that improve the accuracy of resource characterisation (temperature, permeability) prior to drilling. An assessment of Australia's geothermal resources will also be important in establishing whether there is potential for wide spread development of Deep Natural Reservoirs. A barrier to the direct use application of the thermal energy contained in lower temperature resources is the lack of a pathway to market. There has been comparatively little work done on assessing the commercial opportunities presented by large scale direct use of geothermal energy.

5.2.3 Commercial Readiness Assessment – Enhanced Geothermal Systems (Type C)



Evidence of status summary	
Status Summary:	CRI 1
Market Position Identified (CRI 1-6)	Between hypothetical commercial proposition (CRI 1) and commercial trial (CRI 2). The commercial proposition for these resources is asserted by technology advocates on the basis that the technology is ready, but commercially untested and unproven (CRI 1). While there is international evidence that these resources can be successfully developed and one successful pilot demonstration in Australia, little verifiable technical or financial data is available. Two commercial trials have been attempted in Australia (CRI 2), although proponents of both projects are struggling to raise the necessary capital to progress.
Rationale	Two projects are attempting to demonstrate these resources in Australia – at Paralana (Petratherm) and Innamincka Deeps (Geodynamics). These two-small scale, first-of-a-kind projects are funded by equity and government project support. Geodynamics' project has progressed to pilot-plant stage with a short-term trial and Petratherm has only drilled one deep well. The applicability of learnings from Geodynamics' pilot plant to other resources is unclear. Technical performance has been identified as the key barrier to progress for EGS, with uncertainty in the resource identified as a key risk. Finding resources with the temperatures and geological conditions that allow permeability to be enhanced to the level required for electricity generation at acceptable costs is critical. Technologies are required that improve the accuracy of resource characterisation (temperature, permeability) prior to drilling at a reasonable cost. The required technical performance (primarily MW/well or flow rate) must be demonstrated to be achievable and reproducible. Reducing the overall costs of the various technology components is critical to the development of the sector.

5.3 Comments on commercial readiness

The commercial readiness of projects accessing Shallow Direct-use resources is reasonably advanced, as demonstrated by the projects established in Perth and Victoria. The technology being applied is mature, the costs are well known and acceptable, and the resource is well understood. The main barrier to wider spread adoption is that a pathway to market that can sustain ongoing deployment needs to be established. Capturing data from existing projects would help to overcome this barrier.

Deep Natural Reservoir and EGS resources have low commercial readiness primarily due to poor technical performance and resource risk. This resource risk, and the lack of cost-effective means to reduce this risk, sets geothermal energy apart from most other renewable energy technologies that use resources that can be more easily characterised. Attempts at commercial demonstration of geothermal energy production from these two resource types have preceded the demonstration of the required technologies even at pilot scale. This has led to commercial propositions by proponents and a treatment of geothermal energy in Australia that may not be appropriate for the level of technology readiness, or the resource risk associated with these resources.

5.4 Uncertainty and risk

The type and level of investment in a sector is a key proxy for success in developing and operating alternative energy technologies in the energy/electricity market. This is because energy markets are, by their very nature, long term and capital intensive and involve a range of risks for all parties. Adequate investment in the geothermal sector is necessary at all phases of development, but is most critical in the exploration and initial well drilling and proof of operation period.

Geothermal energy as a potential energy source occupies a unique niche for developers and system operators. In more traditional forms, from heat exchange to hydrothermal operations, the energy available is inexpensive, long lasting and dependable. Deeper and conductive geothermal heat resources represent greater potential for substantial and widely distributed generation potential, but with a limited record of delivery and scalability. The risk perception at this stage of market development, especially in comparison to established electric generation technologies, is high.

The range of risks affecting geothermal energy projects are technology specific, yet share common characteristics with other sources such as thermal or renewable electric generation.

Resource risk

While geothermal heat is present worldwide, its heat characteristics and access to them vary widely with depth, lithology and heat gradient. Ultimately, the utility of the resource, and its cost-effective development will depend on gaining access to geologic formations at depths that can be cost effectively drilled, and stimulation methods that can consistently produce flow rates that are above minimum levels to be cost competitive. Further, and this is a practical matter, the location of the resource must be accessible at a competitive cost for dispatch within a market area.

Market risks

Electric markets are dynamic, responding to continuous changes in demand (load), weather and technology used by consumers. Forecasting load growth and shape is critical for investment decisions, yet is imprecise in both nature and scale looking into the future. Australia is a case in point as forward projections of electricity demand have, in recent years, unexpectedly needed to be adjusted downwards. Further market risk includes the pricing of carbon and policies for carbon mitigation that may impose risks for both renewable and fossil fuel technology investments.

Technology lock-in risk

The installed base of electric generation tends to change very slowly, making displacement and replacement of existing capacity difficult and expensive. Further, new and disruptive technologies, such as solar photovoltaics (PV), may have an initial cost advantage over alternatives and then may be able to 'lock in' additional cost reductions as the scale of implementation increases at a faster rate relative to alternatives, such as geothermal energy.

Operational risk

The role of any electric generation technology is to provide predictable, reliable and affordable electric power. Technologies incorporated into the grid must, therefore, be seen as fitting a clear niche for dispatch. This poses an additional risk for the deployment of alternative or experimental technologies until they have demonstrated performance over a period of time.

Sovereign risk

Policies provide guidance and regulatory authorities frame the nature of the market for electric power and the extent to which returns for investment are either competitive or regulated as a quasi-public good. Policy settings for the pricing of external costs, such as carbon, also critically influence the role of competitive technologies. A lack of consistency in policies imposes risks on investors such that investors attach higher risk premiums to those places where policies are unclear or that change erratically based on political rather than economic reasons.

Investor risk/financial risk

Every element of the energy market depends on access to capital, either in the form of equity interest, sales of shares, capital cost sharing, direct grants or subsidies to augment or supplement performance.

The appetite for risk in financial institutions is derived from experience with various technologies, knowledge and information about the technology and performance in question, and the competitive gap available to fill over time. The proxy for this estimate is the perceived risk tolerance for investors or the internal rate of return (IRR). The IRR can also be used to estimate the competitive role between technologies where markets, as opposed to policy makers, choose favourable technologies (winners) based on their expected performance against the competition.

Power markets, risk and uncertainty

Power markets represent a complex and dynamic interaction of demand, energy and fuel sources and technology to generate and distribute power to end-users. Participation in such markets is an inherently risky venture, especially at the stage before full commercialization. The effective management of energy generation systems includes the attraction of capital to maintain, replace and add capacity.

Risk and uncertainty in energy systems and investments

In ascribing risk to possible choices it is possible to assign a statistical probability to their occurrence and then assign weighted costs and expected benefits to possible outcomes. Typically, it is not possible to accurately predict the magnitude of events or outcomes due to a lack of information, experience or a lack of consensus among actors. For instance, it may be impossible to know how public attitudes to particular technologies may change depending on key events such as Three Mile Island, Chernobyl or Fukushima in terms of nuclear power.

Markets and investors manage risks in a variety of ways, such as assigning a risk premium to borrowing, typically much higher for untried or unproven technologies, or by seeking alternative sites or markets, so as to drive down costs in various segments of the industry.

The response to uncertainty for new technologies will vary by the so-called risk premium for investors or planners, or their preferences based on role and long-term confidence in the outcomes. The range of interest varies markedly as illustrated by Table 5.1 in terms of risk tolerance and expected return of value.

Table 5.1: General risk perception and discounting

Party	Term of interest	Risk premium assigned
Developer (not operator)	Short (length of construction)	High, with high expected returns
Public policy and regulator	Long term	Low – will choose safe alternatives to allow system stability and operation
Consumer	Short term	Low – price preference is dominant
Initial project investor	Short term	High, with high returns
Capital markets	Short	High – for new or unproven technologies reflects performance unknowns
Site owner/operator	Long	Low – reflects role in system operation
System operator	Long	Low – reflects base-load dependable dispatch and reliability

Response to risk and uncertainty

Risk is a statistical measure. Risk implies choice, at each point where decisions can be made. In terms of power systems, the initial risk involves assessing the market, current and projected demand vs installed and projected or committed capacity for service. Risk is also situational and will vary with preferences or the tolerance of investors, the climate or current market for capital. All of these risks will vary over time. For instance, changes in demand characteristics or the imposition of new standards and policies can dramatically alter risk perception, and consequently the availability of investment capital.

Given that risk calculations involve probabilistic outcomes, they will differ by investor. Nevertheless, in energy markets risk tends to decrease closer to consumption and with fixed delivery contracts rather than spot pricing. While there are no set rules for what risk is acceptable or not, risk is acceptable when:

- it is calculated to be below an arbitrary assigned probability
- it is calculated to fall below some level that is already tolerated
- the cost expected of reducing the risk is less than the expected stream of benefits, and
- public preferences or policies change to provide incentives or subsidies sufficient to sustain positive benefit to cost ratio.

Reducing energy market risk

Traditional electric markets reduce operational and capacity risks by market and financial tools such as future market fuels purchase, or adding capacity in robust unregulated markets via independent power producers, or in regulated markets via regulatory mandates. To manage operational risk, operators can commission and dispatch reserve capacity, change pricing – especially in terms of peak load – or operationally contract to manage load shedding designed to stabilise demand.

Other methods of sharing or diversifying risk include pairing with other technologies when the operating characteristics allow, or changing the design of the technology either permanently or in the sequence of development. For instance, because geothermal heat is available in a gradient, some markets may exist near load centres for heat exchange from low temperature resources or for electric power generation. Additionally, very specialised markets such as remote mining operations may utilise both heat *and* electric generation where no grid applications are contemplated, creating a concentrated local or regional power resource that is cost competitive.

Another way of managing risk, most recently used in Germany, is to offer insurance that allows risk to be spread for the most uncertain processes in the development of geothermal facilities. This addresses a key obstacle for the development of geothermal projects, namely the risk associated with exploration and characterisation of the resource. Additionally, once a site has been determined, the largest risk factor is the drilling process, from exploratory to injection and production wells.

The costs for '*not mature*' projects and technologies can be formidable. For instance, using the German example, risk mitigation is incorporated into an incentive program for renewable energy systems where some credit is assigned for the investment costs of a geothermal project where they exceed comparable costs for equivalent power output thermal plants. In addition to drilling risk mitigation, additional indemnification covers the risk of not obtaining forecast sustainable values for temperature and flow rate in geothermal heat or power projects.

The German government has plans to set up a revolving fund with two thirds of the fund contributed by the government and the remainder by the private insurance sector. The risk mitigation module would then consist of a loan for the drilling costs backed by a credit indemnification clause. Some of the loan can be forgiven if the project fails; typically the fund will cover 80 per cent of the drilling costs of an initial well, if it is not successful. Consequently the owners' contribution represents a deductible of 20 per cent of the drilling costs. The risk surcharge, assessed at the beginning, is represented by an increased interest rate through the high-risk credit phases until the termination of the drilling works and the hydraulic tests. The increased interest rate is high, between 10 and 20 per cent, but still represents an improvement over venture capital rates.

Another way of sharing risk is to have joint venture partners, as has occurred in Australia. The partners may have access to exclusive knowledge, such as resource potential, or may have information, skills and networks in either the upstream or downstream sectors of power generation, or be larger and with a more diversified risk exposure across various parts of the energy sector. As a result the risk, when shared, can become acceptable to all parties.

The range of risk potential in geothermal applications varies strongly by phase as shown in Table 5.2 below. This table is illustrative rather than definitive, and is intended to indicate the possible risk exposures for conductive geothermal energy development.

Table 5.2: Risk exposure by stage in conductive geothermal energy development

Stage	Risk level	Project loss	Investor loss	Investor action	Stage	Failure source	Failure mitigation
Initial finance	High	No Project	Unsecured cap Fut Market Share	Take loss	Initial	Projected return rates	Attract new investors or public subsidy
Public policy and regulatory standards	High	Increased finance costs	Loss of share value	Work to change policy	Mid Stage	Inconsistent or changing public policy standards	Sign contract with developers
Lease and land control	High	Equity	Unsecured cap Fut Market Share	Take loss do not reinvest	Initial	Private owner refusal public land restriction	Abandon project
Permits	Low	Time equity	Unsecured cap Fut Market Share	Take loss do not reinvest	Early	Regulatory denial	Abandon project
Exploration – research	Low	Time	Time	Take loss do not reinvest	Early	Inconsistent or negative results	Secure more data
Characterisation & test	High	Time equity	Unsecured cap Fut Market Share	Take loss do not reinvest	Early	Inconsistent or negative results	Additional testing
Change design from electric to heat use	Moderate	Time equity	Unsecured cap fut. market share	Do not invest in alternative design	Early	Inconsistent or negative results	Explore and adapt to alt market closer to load
Exploration – drilling	High	Time equity	Unsecured cap Fut Market Share	Take loss do not reinvest	Early	Inconsistent or negative results	Redrill Add seismic data move site
Drilling injector and production wells	High	Time equity	Unsecured cap Fut Market Share	Take loss do not reinvest	Early	Inconsistent or negative results	Change location in field area Drill deeper
Stimulation and control	High	Time equity	Unsecured cap Fut Market Share	Take loss do not reinvest	Early	Inconsistent or negative results or micro-seismic fears	Change depth Bound field
Install capacity	Low	Equity	Unsecured cap Fut Market Share		Early	Unit cost	Adopt alt. technology
Interconnect study	Low	Time	Time		Early	Utility techniques	Submit data Seek political or regulatory assistance
Production and operation	Moderate	Market Share	Capital repay		Middle	Competition bidding rules market price	Operate more efficiently
Complete well field using initial techniques	Moderate	Time equity	Capital repay		Middle	Inconsistent or negative results	Change location in field area Drill deeper
Periodic redrill and stimulation	Moderate	Time equity	Unsecured cap		Mature	Inconsistent or negative results	New site
Ongoing maintenance	Low	Time equity	Capital repay		Mature	System performance	Change operation
Creation and sale of RECs or GHG credits	High	Future revenue	Alt source of capital repay		Mid to Mature	Change in rules value of credits	Discount credit value

Investors consider risk exposures when estimating the cost of finance. In the case of geothermal energy, especially conductive resources, the relatively immature phase of development and the high resource and market risk warrant a cautious approach to investing or lending.

In the IGEG's discussion with stakeholders several themes of risk emerged dominated by the three Rs: rate, reliability and replicability. Investing in new technology such as geothermal will not be routine until the industry itself demonstrates functionally competitive technology (rate recovery) including development near to load, reliable operation over a reasonable period of time (more than two years) and also demonstrates the ability to replicate the location and operation of the technology in more than a limited number of unique regions.

Thus, the high level of risk for investors will not be diminished until, and unless, geothermal energy projects go beyond demonstration projects.

Public support and government actions

In the early phases of development of new technologies, particularly renewable power, public support may be necessary to overcome market resistance or competitive pricing for new or replacement/displacement facilities. In Table 5.3 a range of opportunities for public support are highlighted. None of these actions are costless and whether they should be undertaken requires consideration of the prospective returns, including a reduction in risk and information generation, versus the estimated marginal costs.

Table 5.3: Opportunities for public support of conductive geothermal energy

Action	Nature of action	Stage	Impact
Identify resource and characterise	Mapping & seismic exploration Publish maps and interpretive data	Initial	Reduce exploration cost Increase investor confidence Allow grid planning Set early REC values
Provide staged subsidies	Offer consumer choice subsidy Offer targeted subsidy for specific technologies	Initial to mid	Increase investor confidence Lower cost of risk capital
Provide risk insurance	Subsidise early exploration or well and field completion insurance similar to nuclear industry	All	Increase investor confidence Lower cost of risk capital
Underwrite offer price	Subsidise bid price Effectively create contract for differences between market and bid price	Mid and mature	Equalise market conditions through devices such as feed-in tariffs
Preferential dispatch	Set rule for dispatch that favours geothermal over hydrocarbon, nuclear or hydro	Mid and mature	Provide assurance to operators and investors that technology will not be displaced
Develop new R&D capacity	Long-term investment in market and technology research to identify paths and expected costs to guide developers and investors	Initial and early	Long-term public investment in alternative systems that will define dispatch and grid opportunities
Guarantee or underwrite RECs or other credits	Establish a floor price for credit created during generation	Mid and mature	Increase investor confidence and improve rate of return
Indemnify drilling activity	Assume risk of microseismic events from drilling	Early	Remove risk from drilling and stimulation while reassuring public of safety in addressing the issue of 'social licence'
Underwrite transmission costs	Create public transco and limit risk of access and distance costs for transmission of power	Early through mature	Decrease competitive delivery price of geothermal power
Change rules for ARENA awards	Revise preferences for public assistance support	Initial through early	Make industry more competitive and eliminate some long-term costs

AUSTRALIAN ELECTRICITY MARKET

6

This chapter provides an overview of the Australian electricity market along with projections for future electricity demand and wholesale electricity prices in Australia's major electricity markets out to 2020 and to 2030. These projections summarise the most relevant and recent information on Australia's electricity industry, including regional markets, projected demand, generation costs and transmission infrastructure requirements.

On the request of the IGEG, CSIRO was commissioned to provide an overview of the Australian energy market. The commissioned CSIRO report, authored by Thomas Brinsmead, Jenny Hayward and Paul Graham, and entitled *Australian Electricity Market Analysis Report to 2020 and 2030* is a supplementary document that accompanies the main report of the IGEG. Summaries of the key observations from the CSIRO report are included in this section.

6.1 Electricity demand

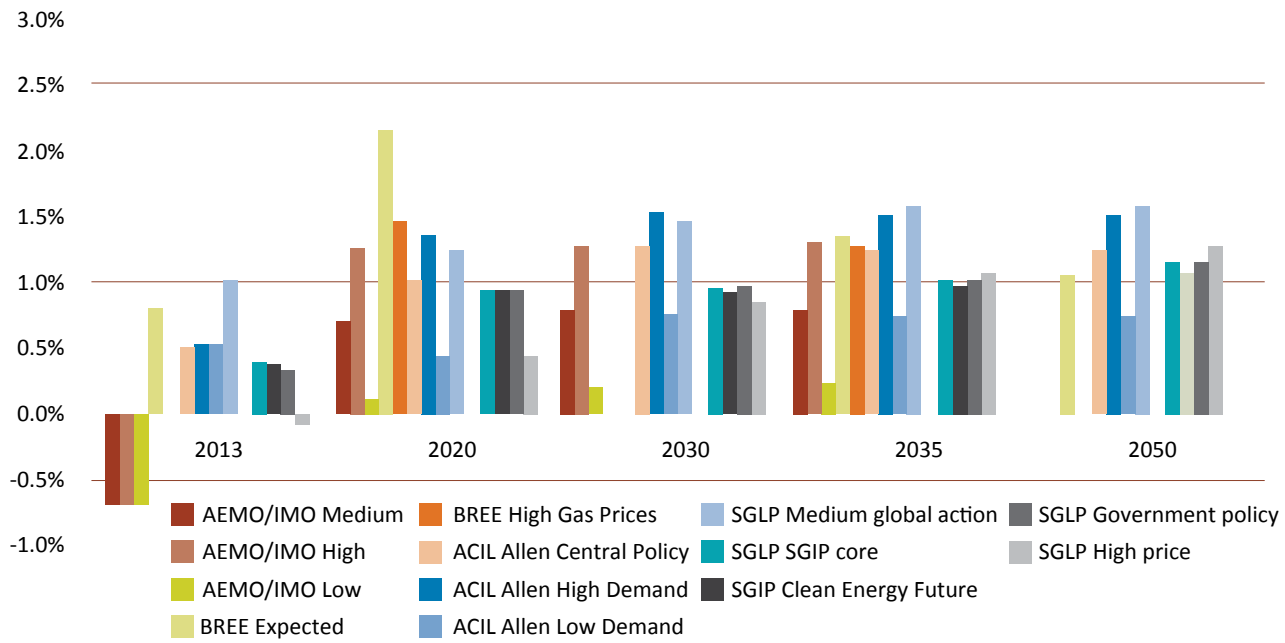
Annual demand growth projections out to 2050 are summarised in Figure 6.1. The range of the estimates indicates there is substantial uncertainty over future electricity demand growth with many of the estimates around 1 per cent per year out to 2020 and 2030.

Part of the explanation for the large range in demand growth is uncertainty over:

1. the exchange rate and its impact on the competitiveness of Australian manufacturing
2. whether households adopt more energy conservation and efficiency measures in response to higher electricity prices, and
3. the relative balance of centralised, on-site and off-site electricity generation.

A projected electricity demand increase of about 1 per cent per year is notable because it would be substantially below the long-run growth rate in GDP of 3 per cent per year. Should 1 per cent per year growth in demand occur, it would suggest that the economy may have shifted to a lower sustained growth substantially below long-term economic growth.

Figure 6.1: Rate of growth in consumption by source of demand projection (annual rate of growth expressed as from the year 2009 to target year)

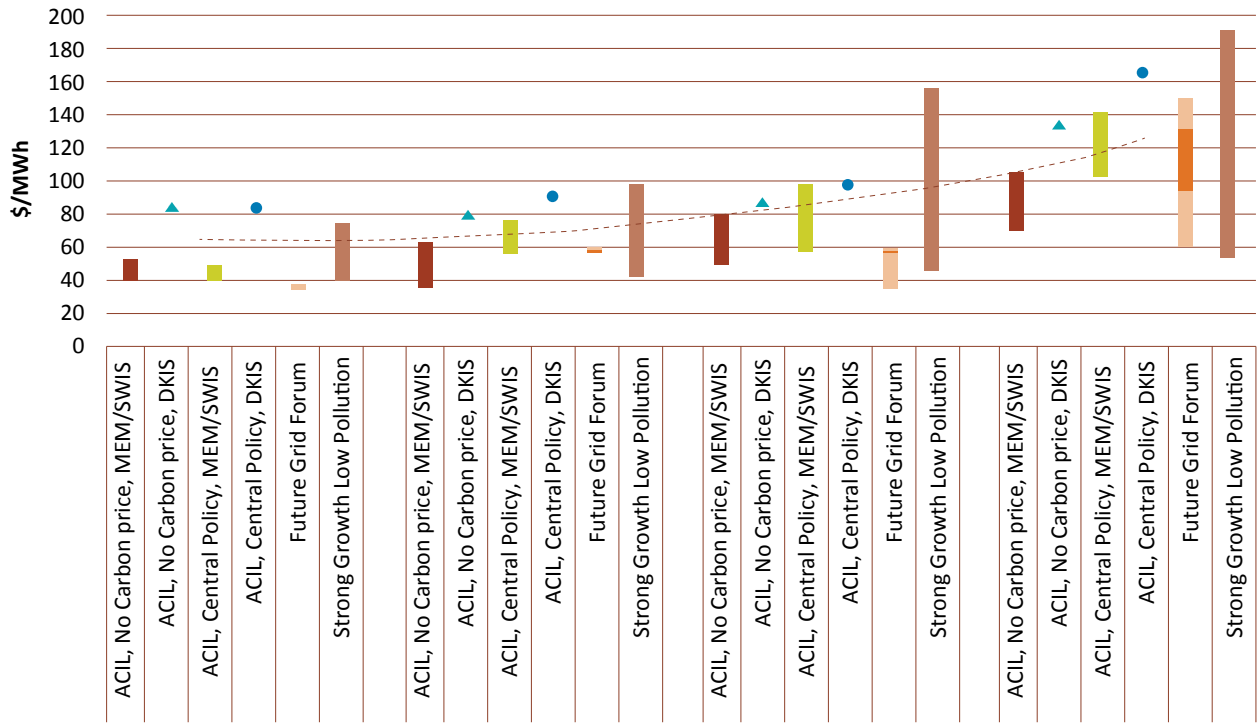


6.2 Wholesale electricity prices

A summary of the potential range of wholesale electricity market prices out to 2020 and 2035 is provided in Figure 6.2. The projections were developed from various models and under different assumptions and scenarios. As a result there are very large variations across the estimates.

Most of the projections indicate a slight trend upwards in prices over time. The ACIL 'no carbon' projection is closest to the current wholesale electricity prices in 2013 and ranges from $40-60/MWh. Using this same projection, wholesale electricity prices are expected to be, in real terms, between $50-80/MWh in 2020 and $70-105/MWh in 2030. Based on this projection, and in the absence of subsidies, geothermal energy electricity generation would need to have a levelised cost of energy of about $100/MWh to be cost competitive with alternative forms of energy if it were to supply to the national energy market.

Figure 6.2: Projected average wholesale electricity prices various sources (ACIL Allen, CSIRO, Treasury)



6.3 Renewable Energy Target

Australia's presently legislated Renewable Energy Target (RET) has a fixed target of 41 TWh for large-scale renewable energy generation inclusive of all technologies. This is additional to the expected 4 TWh small-scale, primarily rooftop solar PV, and 15 TWh of pre-existing generation. Due to lower than previously expected growth in electricity demand, renewable generation could reach a share of around 27 per cent of electricity generated under the fixed target.

The Australian government has commissioned a review of the RET with a report due later in 2014. It is unlikely that, as a result of this review, there will be an increased requirement for renewable energy production.

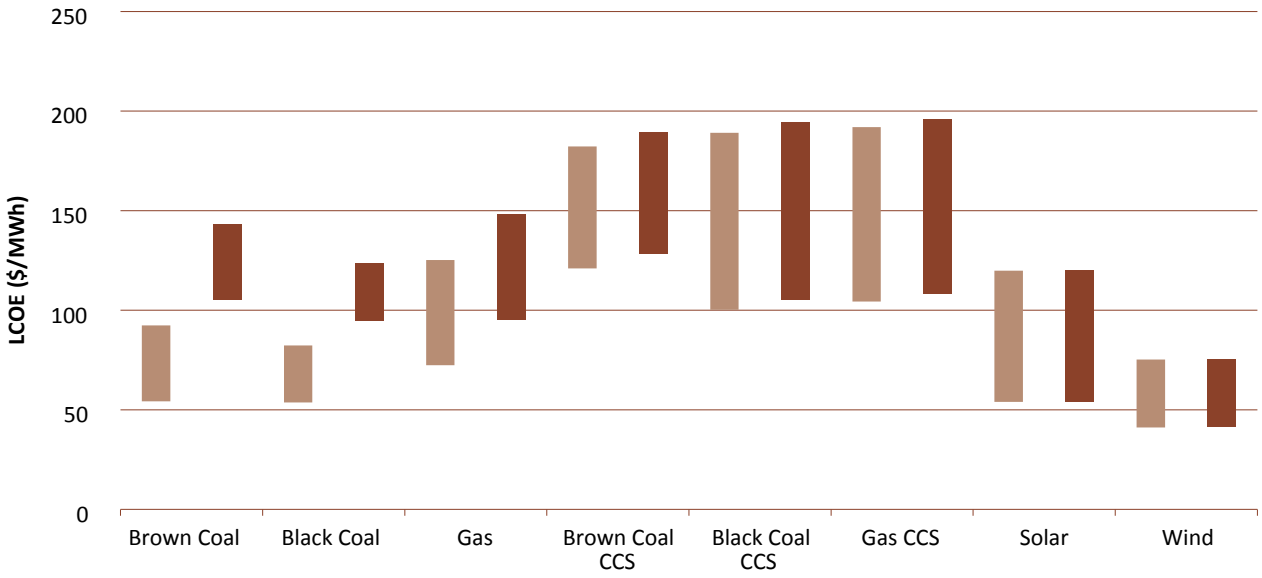
Under long-run marginal cost of electricity projections for 2020, renewable electricity generation technologies are more expensive. Consequently, it might be expected that the wholesale price of electricity would be lower with a flexible RET than a fixed RET. In fact, with a flexible RET wholesale electricity prices may be slightly higher than with a fixed RET because it shortens the time period in which the wholesale market is in disequilibrium where there is currently excess supply at existing wholesale prices. Whether the RET stays as a fixed target or is transformed to a flexible target, wholesale electricity prices are likely to rise by the 2020s as the excess supply is gradually removed over time as plants are decommissioned.

6.4 Levelised cost of energy

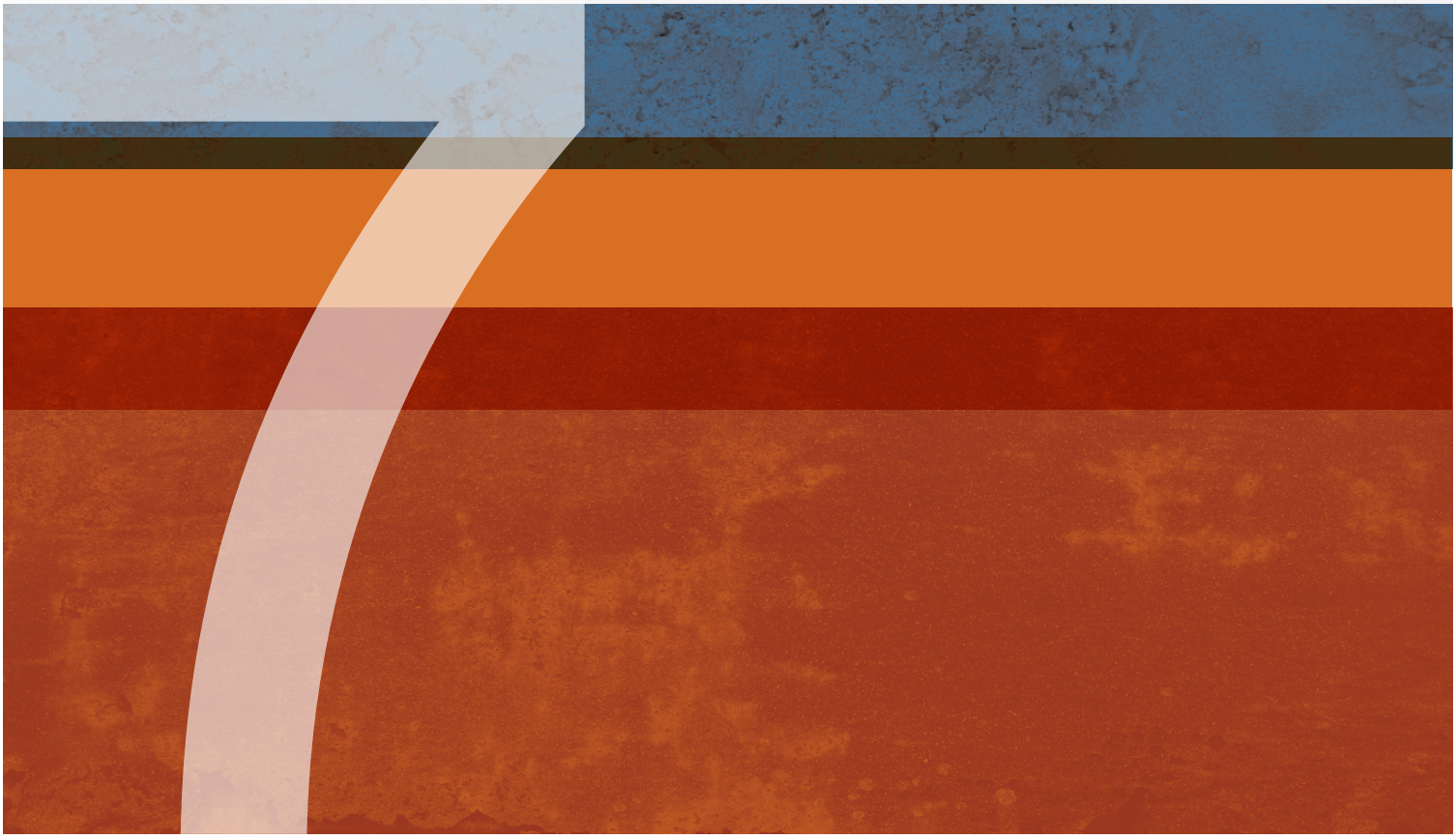
The levelised cost of energy or electricity (LCOE) generation may be interpreted as the long-run marginal cost of electricity generation. It represents the cost of producing an additional unit of electricity (MWh) with a newly constructed generation plant. It is possible for the average wholesale price of electricity to be below the LCOE of existing technologies in the short to medium term, but as plant is decommissioned and replaced the average wholesale price should converge to the lower LCOE values of competing technologies.

Figure 6.3 provides the latest range of LCOE estimates from the Bureau of Resources and Energy Economics (BREE) for both renewable and fossil fuel electricity generation technologies to 2030, with and without a projected carbon price. Assuming a carbon price, and which is the more favourable scenario for technologies with a low carbon footprint, such as geothermal energy, the LCOE for fossil fuel and dispatchable power technologies range from $100–$150/MWh without carbon capture and storage. By comparison, the LCOE for renewable energy technologies, such as solar, range from a little over $50 to more than $100/MWh. The lowest cost technology is wind that has an estimated LCOE that ranges from less than $50/MWh to about $80/MWh.

Figure 6.3: Projected 2030 levelised cost of energy with (dark brown) and without (light brown) a carbon price



THE CRITICAL BARRIERS AND CRITICAL ACTIONS



The IGEG has identified three critical barriers to the development of geothermal energy in Australia. They include:

1. Finding it: identifying and characterising a suitable resource (reducing the risk ahead of drilling)
2. Flowing it: producing hot fluid from the reservoir at a high rate
3. Financing it: financing projects in an immature technology with high resource risk.

These three barriers are separately discussed below and provide the basis for the discussion of the options presented in Chapter 9.

7.1 Finding it (flow and heat)

Exploration and assessment of geothermal resources have some similarity to exploration of oil, gas and mineral resources, in that the developers need to quantify the magnitude and quality of the resource deep below the ground surface. Nevertheless, there are also some important differences. In the case of geothermal energy, the three principal resource requirements are heat, permeability and fluid. In the case of EGS reservoirs the heat component is required, and the permeability and fluid can be introduced as part of the development, but during the exploration for an EGS site, the *potential* for permeability creation and also the *potential* for provision of working fluid should be assessed. Consequently, for EGS reservoirs, the assessment of heat, a favourable stress regime for creation of fractures and availability of fluid for recharge are all critical for successful commercial investment interest and subsequent development.

Conventional geothermal systems have been explored by a series of methodologies that have become partly standardised over time while noting that there are important regional, national and corporate variations in strategy and technique. In particular, geothermal exploration depends on geological prospecting, geophysical and geochemical measurement and interpretation, and exploratory drilling. The same methods are also used in the pursuit of conductive resources, albeit sometimes in ways that differ from the approaches used in convective systems.

Geological prospecting seeks suitable areas based on analogues of resources found to be promising elsewhere. Prospectors may be looking for appropriate geological environments, or manifestations of geothermal activity at depth. Conventional geothermal reservoirs are often found in regions of recent volcanism, or areas of rapid tectonic movement and may be identified by the presence of hot springs, fumaroles, steam-heated lakes, etc. Hot sedimentary aquifers and formations appropriate for EGS developments may not be in volcanic regions, and may not have any geological indicators at the immediate surface. Nonetheless, geology still plays an important role, as outcrop analysis and interpretation of geological cross-sections in wellbores can provide a useful understanding of the sub-surface structure and rock stresses.

Geophysical measurements may include gravity, magnetic and magnetotelluric (MT) surveys. Traditional (convective and volcanic) systems are often revealed by resistivity surveys, as the presence and movement of high temperature water may result in zones that are less resistive (electrically) and, hence, present an anomaly that can be detected from the surface. However, electrical surveys and MT can also show areas of fossil geothermal activity without present-day circulation of hot fluid and so need to be combined with other methods. Resistivity surveys may be of less utility in hot sedimentary aquifers (HSA) or EGS reservoirs, as the thermal anomaly may be more regional than localised, and hence does not necessarily represent a definitive indicator. In such systems, seismic surveys (which are rarely used in conventional volcanic systems) may be useful to show areas of uplift, and regions of advantageous geological structure such as the presence of formations with low thermal conductivity and that serve as insulators over the underlying rocks. Seismic surveys can also show areas of faulting and fracturing that reveal the regional stress regime.

Geochemical measurements are common and very useful in convective geothermal systems, as fluids may be heated by convection in the reservoir and are produced in surface manifestations or shallow boreholes. Fluids produced in this way carry a chemical signature of the formations they have passed through, and also may indicate sub-surface temperatures as functions of the concentration ratios of the ions dissolved within them. Specific chemical signatures can identify the character of the geothermal reservoir that lies below. Conventional geothermal prospecting, therefore, makes prominent use of geochemical sampling of surface springs and gas discharges, as well as soil gases and mineral deposits. Geochemical prospecting may differ in the case of HSA and EGS conductive resources, as surface discharge is no longer common. Nonetheless, geochemistry remains important, as the chemical composition of minerals assemblages in drill cuttings can reveal both current and fossil temperatures. Fluid inclusion analysis can also reveal past temperatures of the system.

A final source of data for exploration comes from drilled wells. Existing wells drilled for other purposes (e.g. oil and gas) provide temperature as a function of depth, as well as detailed information about the lithological section. It is also common in conventional geothermal exploration to drill inexpensive 'heat flow' wells to shallow or modest depth, to determine the thermal regime in the sub-surface. Such a heat flow well need only be large enough to lower a temperature gauge, and need not be able to flow fluid. Heat flow wells may be plugged with cement at the conclusion of the temperature survey. As a result they do not require the expense of a casing unless they are to be left open for monitoring.

It is acknowledged that finding a conductive geothermal resource that brings heat closer to the surface can be more difficult than finding a convective one. Convective resources often have associated surface discharge features, and the fluids that are expelled carry important information about the resource beneath. Lacking fluid delivered from depth, conductive resources are more dependent on direct measurements from

drilled wells. Nonetheless, wells from mineral exploration and oil and gas drilling provide a rich source of sub-surface data that is very useful for geothermal prospecting.

Finding a suitable geothermal formation is not simply a matter of discovering hot rock at economically attractive depth. The formation must also have suitable flow characteristics (permeability) to allow for a very significant volume of flow through the rock. Desirable commercial flow rates lie in the range from 70 to 100 kg/s, and the passage of such a mass of water through the formation requires significant permeability. Rocks that have their flow paths altered and reduced by diagenesis are likely to be unsuitable. Even if it is the intent of the developer to create new permeability by stimulation in EGS reservoirs, not all formations are amenable to such stimulation. Effective fracture creation, in particular, requires a suitable stress regime and hard, brittle rock that will sustain open fractures.

Overall, significant geothermal resources have been found in Australia. Many have been identified from data generated from wells drilled for oil and gas development, as well as wells drilled for mineral prospecting. Locating prospects with commercially useful temperatures at drillable depth has not presented much difficulty in regions where these kinds of data are available. Finding geothermal resources in areas where oil, gas and mineral exploration have been absent will be more challenging.

The discovery of suitable temperature at suitable depth has not led immediately to successful geothermal wells, as attaining a sufficiently large flow rate requires either advantageous rock properties or stress regimes and geomechanical properties that are appropriate for effective stimulation. It is not sufficient to find a thermally suitable resource – it is also necessary to find a way to flow fluid through it.

7.2 Flowing it (enhancing/ engineering)

Geothermal wells need to be able to flow very high volumes of geothermal fluids to be economically viable. These high flow rates are required as the energy density of the fluid in all but the hottest wells is very low. Compared with the average flow rates for oil wells, geothermal wells need to flow a much greater volume of fluid. To allow for the large production and injection volumes, wellbores are larger in diameter, and therefore higher in cost. The large market for drilling services – geothermal energy uses the same rigs that drill oil and gas wells – and the maturity of drilling technologies suggest that a step change reduction in drilling costs is unlikely. The flow rates required to minimise the drilling costs per megawatt of energy produced are in the order of 80 to 100 kg/s. The maximum recorded flow rate so far from an EGS well in a conductive geothermal setting in Australia is about 40 kg/s.

Conventional geothermal resources in convective regimes are in areas with high natural rates of fluid flow. Conductive geothermal resources, conversely, tend to have very low permeability. Nevertheless, there are some settings that may have high natural flow rates in conductive regimes. For example, some sediments can preserve high horizontal permeabilities, even at depth, while remaining conductive due to very low vertical permeability. Even areas with open near-horizontal fractures will also allow high flow rates, but still remain conductive due to very low vertical flow.

Given Australia's generally low geothermal gradient, geothermal resources with high enough temperatures for electricity generation are likely to be at depths where natural flow rates are poor. The experience in Australia so far suggests that finding reservoirs with naturally high flow rates will be difficult, although only two sedimentary systems have been tested. As a result, the required flow rates are unlikely to be achieved without some kind of human intervention.

Two methods have been used in the oil industry to increase fluid production rates, enhanced oil recovery (EOR) and stimulation. EOR is used generally to get more oil from a reservoir by adding water or another fluid to the reservoir to both recharge the pressure and sweep the oil from the pore spaces. Stimulation methods improve the permeability of the reservoir, both near the wellbore and out in the far field away from the well, through hydraulic fracturing, explosive fracturing or chemical treatment. In a conductive geothermal reservoir both enhanced recovery operations through injection of cool water for heat sweep and stimulation to improve permeability are used.

Enhanced recovery operations for geothermal operations involve the injection of additional fluid into the reservoir, but still depend on good natural permeability. While Australian resources are likely to require the addition of fluid to transport heat from the reservoir to the surface, enhancing permeability through stimulation is likely to be more important.

Stimulation has been used in the oil and gas industry for over half a century. Improvements in multi-zone fracturing technology in unconventional oil and gas combined with the ability to economically drill horizontal wells has allowed access to a much larger volume of very tight formations such as shales where both oil and gas can now be economically extracted. It is not uncommon for unconventional gas wells to have over 50 stimulations in the one well.

Stimulation has been applied to conventional geothermal wells since the 1970s. It has been used to increase the performance of individual wells with moderate success. The development of the concept of Enhanced Geothermal Systems (EGS) relies on the stimulation to create or enhance permeability in the reservoir, and began at Fenton Hill in the US in the 1970s. The situation in very low permeability geothermal heat reservoirs is similar to unconventional gas in that there needs to be stimulus to large rock volumes to access the heat. To date, accessing geothermal heat by stimulation has proven a challenge in the Australian EGS projects. One issue that has been largely overcome by EGS projects in other areas is the use of oil and gas methods for geothermal stimulations.

Unconventional gas wells are typically completed with a fully cemented casing string that allows multiple zones to be stimulated by allowing the use of perforation (creating holes in the casing, generally using explosive charges) and packers (which allow individual zones to be isolated for stimulation). The majority of geothermal wells are completed with either an open hole (no casing or liner) or with slotted or perforated liners. These completions make it nearly impossible to use packers to isolate zones for stimulation. As a result, it is difficult to create the pervasive fracture network in the reservoir to provide the most efficient extraction of heat over time. This is compounded by the fact that single fracture zones are unlikely to be able to flow the volumes of fluid required and increase the risk of thermal breakthrough.

Development of stimulation methods for EGS is focused on two areas, reservoir to well and well-to-well. Flow in the reservoir is at the highest in the immediate vicinity of the well, and restrictions on flow in this area can significantly affect reservoir performance. Stimulation of the near well bore environment may also improve the flow rates available from natural reservoirs by effectively increasing the surface area of the well bore. To make stimulation more effective, fracture initiation mechanics need to be understood and methods to reduce fracture tortuosity formed during initiation also need to be developed and tested.

Flow between wells requires large volumes of rock to be stimulated to allow heat to be extracted from a large volume. There is still a debate about whether a significant number of new fractures can be created or if only existing fractures can be enhanced. The fact that zonal isolation techniques are not readily available for EGS wells means that the ability to create new fractures through targeted stimulation has not been adequately tested in geothermal wells. Zonal isolation methods, such as temporary diverting agents (material that can block flow in existing fractures) that can be used in open-hole sections are starting to be commercialised. Many oil and gas stimulations involve the injection of a proppant, such as fine sand, to hold the fractures open. Proppants have not been successfully used in geothermal wells because they have not been able to carry the fracture closure stress or are chemically unstable in the geothermal environment. However, advancements are being made in the development of proppants made of materials, such as ceramics, that are stable at high pressures and temperatures.

The longevity of flow in EGS reservoirs has yet to be demonstrated. As production occurs, the reservoir will be subject to cooling over an ever-expanding volume. This effect needs to be studied so that the change in reservoir flow can be understood and included in the production operating plan. Likewise, other changes in conductivity, such as those associated with chemical leaching or precipitation of minerals in the reservoir, need be understood.

In summary, developing the flow rates for geothermal resources in conductive thermal regimes remains a significant challenge. The number of stimulations conducted in geothermal resources is dwarfed by those conducted in shale gas. The huge improvements in productivity from oil and gas wells through the application of reservoir stimulation technologies provides some optimism that similar productivity increases can be achieved for geothermal wells. For this to occur, there will need to be improved understanding of the physics of reservoir stimulation at the pressures and temperatures of geothermal resources and in the rock types in which these resources are found. The development of technologies that allow zonal isolation and controlled stimulation at these conditions is also critical. Understanding the physics of stimulation and the suite of technologies available to the geothermal sector is part of the pathway of finding suitable targets or resources (Finding it) and to provide confidence that these resources can be exploited to generate a commercial rate of return (Financing it).

7.3 Financing it (mitigating risk)

Few projects in any industry are initiated and maintained solely with current cash flow or savings from investors. Most capital projects are funded or capitalised using long-term financing instruments such as project finance, loans or grants. Project finance then is synonymous with the long-term financing of infrastructure and industrial projects based upon the projected cash flows of the project rather than the balance sheets of its sponsors. In other words, project financing is a proxy for a loan structure that relies primarily on the project's cash flow for repayment, typically with the project's assets, rights, and interests held as secondary security or collateral.

Market failure

Some stakeholders have suggested that the inability of the geothermal industry to become established and competitive is evidence of a market failure. While this is an attractive notion, it is not accurate, and distorts some of the roles and potential tools for making geothermal power more competitive.

Market failure describes a situation when the allocation of goods and services by a competitive market is not efficient. Market failure is generally associated with capture of a market niche by competitors who gain unfair advantage and can control prices or access to goods, and as such may enjoy monopoly rents (market power) and distort market operations. Given the nature of energy markets where natural monopolies are likely, regulatory institutions manage the marketplace, not to exclude single companies who may control significant shares of the market, but to ensure fair pricing (marginal cost) for the good. Other instances of market failure might include conditions where production of the good or service generates an unmitigated externality, or if the good or service is considered a pure public good.

Geothermal projects that are experimental or unproven in existing markets do not represent a case of market failure; they represent a technology that has not yet demonstrated its performance or cost of service potential. Under these circumstances, there is a risk for investment that must be measured against some public policy or regulatory standard that commits or even mandates public support. Various means of support are available to integrate or subsidise such a technology in order to assure that its desirable characteristics are utilised, whether or not the existing marketplace assigns sufficient value for it to succeed.

As an illustration of the difference, in one submission to the IGEG Geoscience Australia noted that 'feedback from potential investors, and those withdrawing from the sector, is that there is too much risk in two areas: unproven resources and the high cost of assessment; and uncertainty in the price of power or thermal energy from geothermal developments'[1]. Diminishing this risk, and assuming some of the financial burden, when it coincides with public policy objectives, is not only possible, but a well-explored market activity.

Energy projects

Energy generation projects are embedded within a complex web of support industries and infrastructure. As such, very few projects are funded and developed solely off of the balance sheets of individual companies, especially in early or start-up periods. For projects that do not have a proven track record of performance and reliability, obtaining short and long-term finance support requires risk capital that can render the best project uncompetitive in the marketplace.

When early projects and programs have proven unsuccessful, the so-called risk premium attached to lending can range from steep to usurious. When policy prescriptions call for development of an industry, such as geothermal energy, support can be provided that may include direct subsidies, tax relief or incentives to the private sector to participate even when projects are nominally uncompetitive.

[1] Geoscience Australia response to ARENA Consultation Draft, August 2012, pg 1

Rates of return

Energy infrastructure projects are, by definition, extremely capital intensive and long-lived, making them ideal candidates for low risk, predictable long-term investments for established and well-integrated technologies. By contrast, for relatively immature EGS and HDR technologies, especially those with known resources far from load centres, rates of return for investors must necessarily be higher to help cover the additional risks.

The Australian geothermal marketplace

Australia has diverse hydrocarbon and renewable energy resources including geothermal heat reserves. The geothermal resource is generally distant from load, deep underground and not associated with existing underground water systems. Further, access and technology to develop this resource is still in a phase of exploration and demonstration rather than repeatable commercial application. For finance markets, this combination represents relatively high risk investing especially as a range of proven and commercially competitive alternatives are available.

Various methods exist to offset sector or technology risk and include increased R&D investments, land lease offsets and direct investment to subsidies and feed in tariffs. In testimony to ARENA in 2012, one of the agencies noted that assistance directed to the Geothermal Drilling program 'did not deliver all of its expected outcomes because companies were unable to meet the matching funding requirements'[2].

As Geoscience Australia points out, 'those few projects being developed by small capital companies are dependent on technology advances such as lower cost drilling to be commercially competitive against other power sources in the long term, but in the short term these projects can contribute greatly to establishing the pathway to commercialisation for the sector, and to provide opportunities for R&D'[3].

The relationships of various investment objectives are shown in the Table 7.1 and adapted from CSIRO.

[2] Geoscience Australia response to ARENA Consultation Draft of the General Funding Strategy, August 2012, pg. 4

[3] Ibid.

Table 7.1: Investment objectives by development stage

	Research	Development	Demonstration	Pre-commercial deployment

Investment objective	• Develop new ideas to lower costs and/or enable deployment of renewable energy (e.g. by removing barriers), where Australia either already has a globally leading research capacity or where unique Australian issues need to be addressed	• Develop the 'proof of concept' for promising technologies and enablers
		• Identify a clear 'path to adoption and deployment' i.e. how the proposed development could realistically be taken up by the market
			• Eliminate technical risks of a new technology
			• Put enablers in place (ahead of deployment), e.g.
			  • Characterise the resource
			  • Develop forecasting systems
			  • Understand environmental impacts
			  • Inform communities
			  • Build skills and knowledge
				• Reduce commercial risks, e.g. demonstrate bankability of revenues
				• Contribute to future cost reductions and enable deployment at scale

Project selection criteria	• Scientific merit • Novelty	• Cost-reduction/ value creation potential	• Minimize $/MWh or GJ subsidy • Contribute to future cost reduction and deployment	• Increase attraction for investment capital
Measures of Success	• Publications & citations • Patents • Industry interest • Successful demonstration projects	• Cost-reduction/ value creation potential identified • Patents • Industry engagement in the project	• Successful adoption and scale up of research outcomes by industry • Availability of venture capital	• Availability of project finance • Successful demonstration of scale over multiple years
Typical govt support as share of project value	• Up to 100%	• 50–75 %	• 25–50%	• < 25%
Typical investment by activity	• < 1M$	• 1–10 M$	• 10–50M$	• >50M$
Number of investments by technology areas	• 10–100	• ~10	• ~5	• 1-3

Adapted from CSIRO submission 12/454, August 2012

Given these investment objectives, it is helpful to review the possible financing needed at various stages of project development in competitive markets, as per Table 7.2.

Table 7.2: Stages of risk and financing contribution

Stage	Risk	Owner/ investor equity	Public support
Pre-planning	High	Yes	No
Exploration & assessment	High	Yes	Yes Mapping R&D
Initial development & demonstration	High	Yes	Yes Power Purchase Agreements Land Lease Subsidized interconnect Transmission support
Initial commercial phase	Medium	Yes	No
Mature commercial phase	Low	No	No

Role of stakeholders

There are three primary stakeholders that influence the attraction of and investment in the geothermal energy market, public agencies, private industry and developers and investors. The primary role of public agencies is to set the rules for project development and energy system performance. In response, industry interprets the rules, calculates risk and seeks adequate financing to initiate projects. The finance industry responds by assessing risk using its own forecasts and acts to support developers.

There is a critical role for public agencies because renewable energy resources and geothermal energy generation, where available, are associated with public benefits. This category of good is difficult to price or otherwise value, other than through indirect measurements of externality control or reduction, or improved performance of the energy system in general. Some of these benefits include increased system diversity, firming and peak load reduction, carbon reduction and offsetting variable costs of fuel.

Given that the value of emerging technologies, such as geothermal, are difficult to determine, especially in terms of capital and operating costs, some public intervention may be justified. In the case of geothermal power, the resource supports base-load power generation that shares the characteristics of low cost, dependable electricity or direct heat with high and continuous availability for dispatch. These characteristics may also be valued by regulators in terms of power generation.

Intervention in the renewable energy electricity market represents a blend of public and private actions, all organised around two key objectives. First, that an action either provides temporary price support and, second, that the perceived risk around the technology or industry is reduced.

Public agencies have a range of means to influence the marketplace in order to achieve their goals and benefits. They can intervene directly, purchasing or guaranteeing some level of output from generation sources in the form of a power purchase agreement or mandate proportional or absolute levels of renewable generation (Renewable Portfolio Standards), or use generation or technology characteristics to support externality reduction (e.g. using geothermal facilities to store carbon dioxide waste). Less directly, public agencies can provide signals through policy pronouncements that support various enterprises, and effectively intervening in the marketplace to explicitly identify preferential roles or direct support for selected technologies such as geothermal power. The policy preference acts as a proxy to minimise risk and increase confidence that the technology will continue to enjoy support into the future. An indication of some of the possible public actions and support that can be provided to reduce risk or lower costs is provided in Table 7.3.

Table 7.3: Types of public actions that influence risk and costs

Action	Potential outcome
Create, monitor and document demonstration projects	Improve estimates of initial project location
Provide insurance, including underwriting certain project phases or segments such as early well failure	Lower cost of capital
Underwrite insurance rates or help fund projects by combining bond releases with government projects	Increase expected payout of projects, increase confidence of lending agencies
Offer grant funds and target competitively to appropriate phases of projects	Increase likelihood of project success, reduce failed project rates and reduce cost of capital
Study, identify and characterize the resource by region and proximity to load	Improve chance of finding adequate project site, reduce cost of development
Issue favourable contracts using bids and auctions	Improve early and consistent returns from projects
Create specialised workforce and the education programs that can assist industry or projects to develop	Reduce operating costs
Drill test wells and publish findings	Improve chance of finding adequate project site, reduce cost of development
Develop specialized R&D facilities to support industry	Improve industry performance, technology development and cost of operations
Train special workforce and offer credits or offsets for employers	Improve long-term performance and reduce costs of operation

RISKS, COSTS AND REWARDS OF ARENA SUPPORT TO GEOTHERMAL ENERGY

8

The cost competitiveness of geothermal energy in the electricity generation sector is determined by its own costs and also the costs of competing technologies. There are many risks that affect the cost of electricity generation and cost competitiveness. In the case of geothermal energy, not only is there a cost in developing the resource and bringing it to market, but there is also a very substantial cost and risk in finding a suitable resource. In this sense, geothermal faces an extra challenge compared to other renewable technologies, such as solar or wind power.

The rewards for delivering cost-competitive electricity are the returns from the sale of electricity, either within the grid or off grid. Typically, off-grid prices are much higher as a result of higher costs of electricity generation in remote or inaccessible locations. In these places, geothermal energy may be more cost competitive, provided that the ratio of its electricity price received over costs is relatively higher than for alternative technologies.

8.1 Risks and costs

The costs of electricity generation from geothermal energy are primarily driven by the capital costs of developing a geothermal energy power station. In this regard, geothermal energy is similar to other renewable technologies, such as wind and solar. The component that sets geothermal energy apart is the cost of accessing the resource itself. While wind and solar projects would still need the resource to be characterised before a project using these resources could proceed, characterising and then accessing (through drilling) a geothermal resource is a significantly more involved and expensive process. These complexities are offset by the constant availability of a geothermal resource once it has been developed.

Risk, whether financial or physical, is highest when information and data are least complete and least understood. For geothermal energy projects, this occurs during the phases of exploration and test drilling. Incomplete characterisation of sub-surface formations dramatically complicates the process of assessing prospective areas of hot (greater than 150°C) rock that have the right characteristics to allow high flow rates to be achieved.

Figure 8.1 shows the evolution of risk and cost in the life cycle of a geothermal project. There is a high degree of risk in the early exploration stages and, in fact, many projects do not proceed beyond this point, despite considerable expenditure. This is similar to many sub-surface resources such as oil, gas and metals.

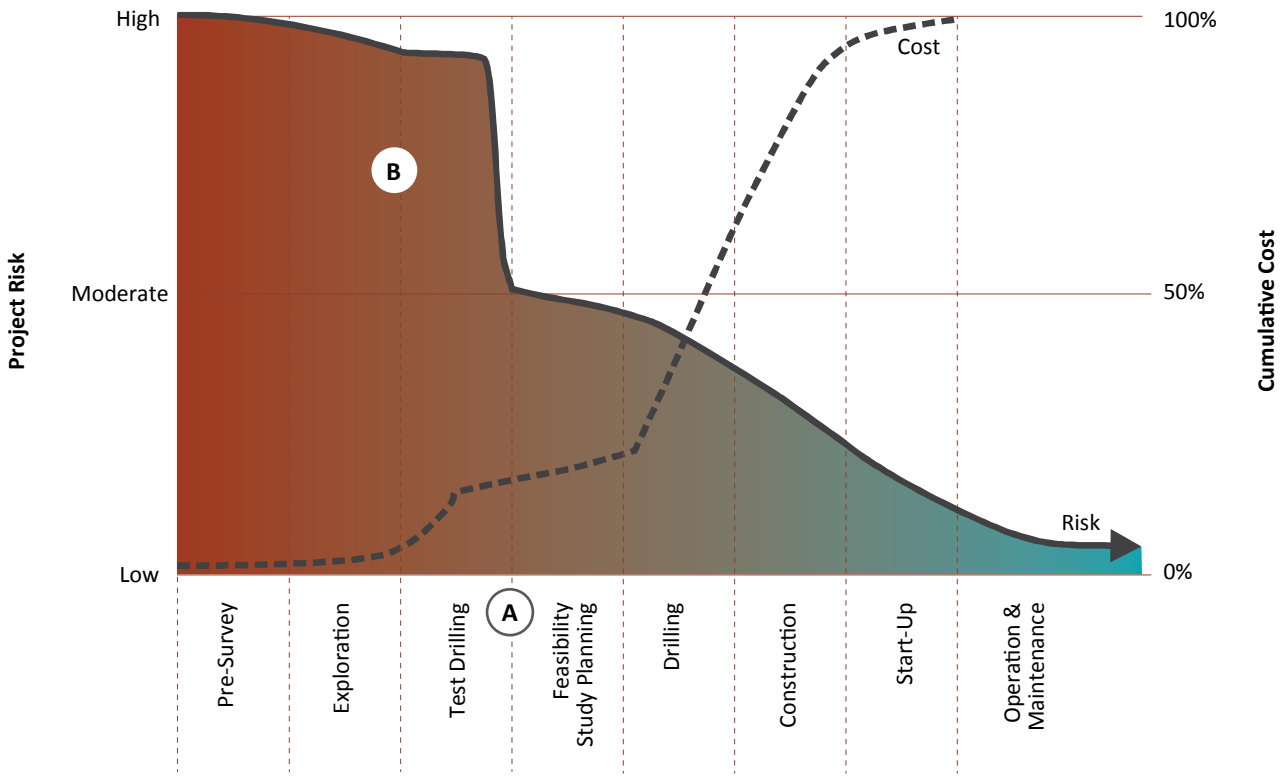
Risks can be reduced through a combination of seismic and exploration drilling, including multiple deep-test wells in areas likely to, or proven to, have hot rock resources at depth. By successfully characterising these areas, and making information available to investors and developers, a more robust exploration process can result in higher confidence and interest in the finance community. If the project risk during the early stages of a project's life, up to the point labelled A in Figure 8.1, can be halved, then the investment characteristics of geothermal in these crucial early phases will be similar to oil and gas operations in unconventional shale deposits, with affordable and competitive risk profiles.

Private enterprise is unlikely to be able to undertake such exploration and mapping over large areas. Thus, a program of government-supported pre-competitive data collection is likely to be valuable at reducing risk at the early stages of geothermal projects. A comprehensive program based on this approach can underpin targeted and sequential development of proof of concept. The process of reducing risk for early-stage investors and developers will be enhanced by sharing learning experiences, data and information and by widely distributing and demonstrating the techniques with the highest demonstrated success rates.

Actual risk reduction is associated with exploration and drilling in locations and at depths that confirm earlier research, or that are associated with oil and gas exploration and production activities. Most of these related drilling projects reflect experience and expansion of existing sites, consequently reducing initial risks to areas below the moderate level shown in Figure 8.1 below, a zone generally acceptable to investors and associated with lower cumulative costs of operation. By comparison, geothermal drilling activities currently find themselves in the higher risk profile zone (labelled B in Figure 8.1).

Figure 8.1: Project costs and risk profile through the development of a geothermal resource

There is significant risk up to the point where test drilling has confirmed the resource size and that it can be extracted economically (labelled A).



Adapted from Gehringer & Loksha (2012).

The activities and the risks in each stage are highlighted in Table 8.1 and adapted from Gehringer & Loksha (2012).

Table 8.1: Project risks of geothermal energy in Australia

Preliminary survey $500,000–$1 million 0.5–1 years	This stage involves determining the objectives of the proposed project, collecting data from publicly accessible data sources, selection of target areas, application for exploration permits, and planning exploration activities. At this stage of project development, the costs are low, but the project risks remain high as the resource is poorly constrained. The costs of this stage are well bounded as they are primarily desktop studies.
Exploration $1–$10 million 1–3 years	Once a site has been selected exploration activities can be undertaken to characterise the resource. This includes a detailed review of existing data, collection of additional geophysical data (magnetics, gravity, magnetotellurics, seismic), and heat-flow drilling (shallow wells drilled to measure heat flow). There is a very wide range of costs at this stage of project development depending on the availability of existing data for the area being explored, the depth of the target resource, and the overall approach taken to exploration. For example, a 3-D seismic survey could potentially cost several million dollars, but may significantly reduce risk ahead of drilling (the oil and gas sector would rarely drill a well without collecting seismic data beforehand). At this stage of project development, the costs are still low (compared to overall project costs), but the risks are still high as the resource is yet to be confirmed. The costs of this stage are difficult to constrain, as they will depend on the availability of existing data and the nature of the resource being targeted.
Test drilling $15–$60 million 1–3 years	If the exploration stage has identified a prospective resource, the next stage is test drilling into the resource to confirm its temperature, size, productivity and fluid chemistry. Deep wells drilled in Australia have all been production-scale wells costing $10–$25 million and there appears to be little alternative for the depths targeted in Australia. Slim holes are becoming more common in this stage of development of conventional geothermal resources. However, these resources are shallower (< 3000 m) than the conductive resources targeted in Australia and slim-hole technology is not readily available for deeper resources. Slim holes have some additional disadvantages as exploration tools. They generally can't be flow tested, are expensive if drilled to depth, and can't be used as part of the project for other than observation. Additionally, if the wells were drilled in an area where there has been little previous drilling there may be a steep learning curve as the drillers become accustomed to drilling in a new area. This stage of development would generally require the drilling of two or more wells to confirm the resource. Additional wells may be required depending on the success of earlier wells. At this stage of project development, there is a significant jump in costs although there is also a commensurate reduction in the project risks as the reservoir will have been tested. The costs of this stage are difficult to constrain as there will be a large degree of variability between projects, based on the geology of resource being targeted and risks associated with drilling deep wells.
Feasibility study/planning $5–$10 million 1–2 years	If the test drilling has successfully confirmed a viable geothermal resource, the next stage is to evaluate the feasibility of fully developing a project and planning for the development of the project. This would include project design, gaining regulatory approval, securing financing and power purchase agreements and engagement of engineering procurement and construction (EPC) contractors. This work would commence in parallel with the later stages of exploration and test drilling. At this stage of project development, the incremental costs and changes in project risk are relatively small. These activities are largely desktop based and include negotiation of agreements. Securing regulatory approval does have some risk and may cause some delays to a project. The lack of precedents in Australia for geothermal energy development means there is some uncertainty around the regulatory approval process.

Drilling (well-field development) Costs are highly dependent on the resource and the size of the project. $3–$10 million/MW 2–3 years	Production drilling is the next stage of project development. The scale of the drilling activities will be largely dependent on the characteristics of the resource and the planned generating capacity of the project. Australian geothermal resources will most likely be developed with the geothermal fluid being re-injected into the reservoir, so both production and injection wells are drilled. The total number of wells for a project would be somewhere in the order of one well for every 2 to 5 MW of electricity generation (i.e a 50 MW plant would require around 10 to 25 wells). The global geothermal energy experience also shows that not every well is successful (see discussion on well success in section 4.2.1). The risk of well failures is a contributor to the overall project risk at this stage of development. As the well field is developed, the risk of failure generally decreases and the experience also leads to a decrease in drilling costs. At this stage of project development, a large proportion of the total project costs are expended (between 50 and 70 per cent of total capital costs), but the project risks are substantially reduced by the end of this stage.
Construction Costs are highly dependent on the resource and the size of the project. $2–$3 million/MW 1–2 years	Construction of surface facilities would normally overlap with the latter stages of well-field development. In recent years, concerns about resource risk have required the field to be almost fully developed before construction begins. This stage is usually shorter than the production drilling stage and there may be some modifications to the design of surface facilities depending on the outcomes of that drilling. The surface components include the geothermal well field piping and pumping system, the power plant and transmission infrastructure. At this stage of project development, a significant proportion of the total project costs are expended (between 25 and 40 per cent of total capital costs). The risks associated with this stage of the project are low. There is a well-established global market for the provision of geothermal plant (although there is no market in Australia at present, there are no significant local issues to consider).
Start up Part of construction costs. < 1 year	Start up and commissioning stage of project development is the final phase before the project enters regular operation. The plant's performance is confirmed and EPC contractors hand the plant over to the operator. At this stage of project development, there may be some costs associated with provision of performance guarantees and bonds. The risks at this stage of the project are very low.
Operation and maintenance	Once the project is operating, it will start to incur operating and maintenance costs. These costs are clearly defined for the plant and surface facilities, but for the well field, are highly dependent on the chemistry of the geothermal fluids, the geology of the reservoir rocks, and whether the wells are pumped or self-flow. Operating and maintenance costs for the well field will include well cleaning, maintenance of pumps, and new wells to replace wells that drop-off in performance (make-up wells). The number of make-up wells will be dependent on the thermal decline in the reservoir and the tolerance of the power plant to a decrease in geothermal brines temperatures.

An additional risk not covered in Table 8.1 is the growth in electricity demand to 2020 and 2030. The lower the growth in demand the less need there is for new electricity plants. At least until 2020 it appears there is no demand to add additional dispatchable power generating capacity. Indeed, a number of plants have been taken out of operation and more may follow to 2020 depending what happens following the review of the Renewable Energy Target. Stagnant electricity demand from 2020 to 2030 would exacerbate the challenge of developing cost competitive electricity from geothermal systems.

The combined costs across stages of a geothermal power project determine its cost competitiveness. A method exists to compare costs across all types of technologies and is known as the levelised cost of energy (or electricity) or LCOE. LCOE estimates are usually calculated on an energy 'sent out' basis, which refers to the costs and amount of electricity sent to the market at the power plant's connection to the grid. They generally do not take into account factors such as transmission costs, the costs of storage or back-up generation for variable energy sources and the impacts of the generating capacity on the network (i.e. grid stability). These additional factors may affect the commercial viability of electricity generating technologies.

Chapter 6 details the LCOE for competing electricity generation technologies. To understand the risks, and whether geothermal power is cost competitive to these technologies, requires a similar exercise. The full details of the assumptions and calculations used are detailed in Annex A of this report. The principal assumption for each is detailed in Table 8.2. The major costs include: (1) drilling costs, which depend on the depth of the production wells; (2) the costs of stimulating the resource to generate flow in enhanced geothermal system; (3) temperature of the reservoir or resource; and (4) the flow rate. Of all of these variables, only the cost of drilling and stimulation and the flow rate are amenable to improvement by learning and innovation because the depth and temperature are determined by the sub-surface resource.

By far the most important technical variable in terms of LCOE is the flow rate. The higher the flow rate, all else equal, the lower the costs of geothermal electricity generation. The EGS E scenario is the closest approximation to the best parameters, including a flow rate of 40 kg/s, to be obtained from an EGS resource in Australia to date. Much higher flow rates have been obtained from EGS overseas and, thus, with learning could reasonably be assumed to be feasible in Australia.

Table 8.2: Parameter assumptions for various Australian geothermal electricity generation systems

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Temperature °C	150	180	150	180	220	250	220
Flow rate (kg/s)	100	100	80	80	80	80	40
Stimulation	No	No	Yes	Yes	Yes	Yes	Yes

A summary of the possible LCOE as dispatched from a plant for seven different sets of assumptions for geothermal electricity generation ($/MWh) is given in Table 8.3 in 2014 dollars for geothermal systems constructed in 2020. The table shows that the greater the depth, the lower the temperature, the smaller the flow rate and the higher the capital costs then the greater is the LCOE from a geothermal source. Hot Sedimentary Aquifers (HSA) that require no stimulation and have both a higher temperature resource that flows at a higher rate (natural reservoirs A and B) have the lowest LCOE that varies from about $170/MWh.

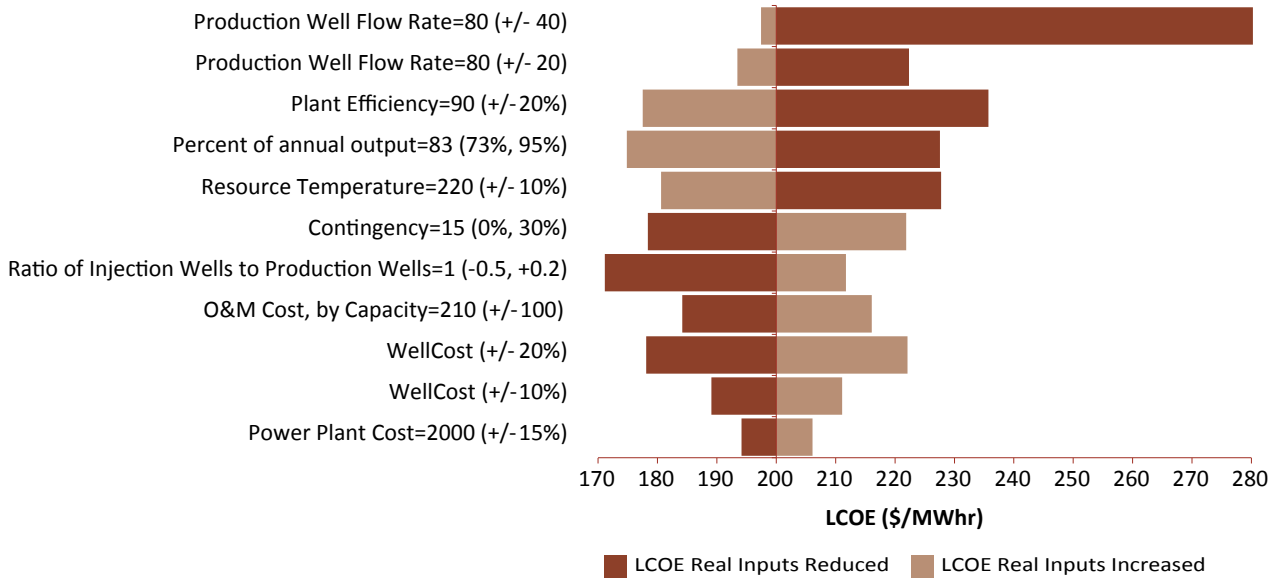
Enhanced Geothermal Systems (EGS) have higher costs relative to natural reservoirs, but costs vary depending on depth, temperature and flow. The five EGS scenarios in Table 8.3 have different LCOE that vary from a low of about $200/MWh for EGS C to some $350/MWh for EGS B. The EGS C alternative in Table 8.3 is highlighted as it is the base case system used by the IGEG in its sensitivity analysis of the LCOE for 2020 and when considering costs changes from 2020 to 2030.

Table 8.3: LCOE for various Australian geothermal electricity generation systems

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Temperature °C	150	180	150	180	220	250	220
Flow rate (kg/s)	100	100	80	80	80	80	40
Overnight capital costs ($2014/kW)	10,077	9,273	14,124	19,532	10,754	11,941	13,931
2020 LCOE (2014 $/MWh)	**187**	**172**	**252**	**345**	**202**	**221**	**248**

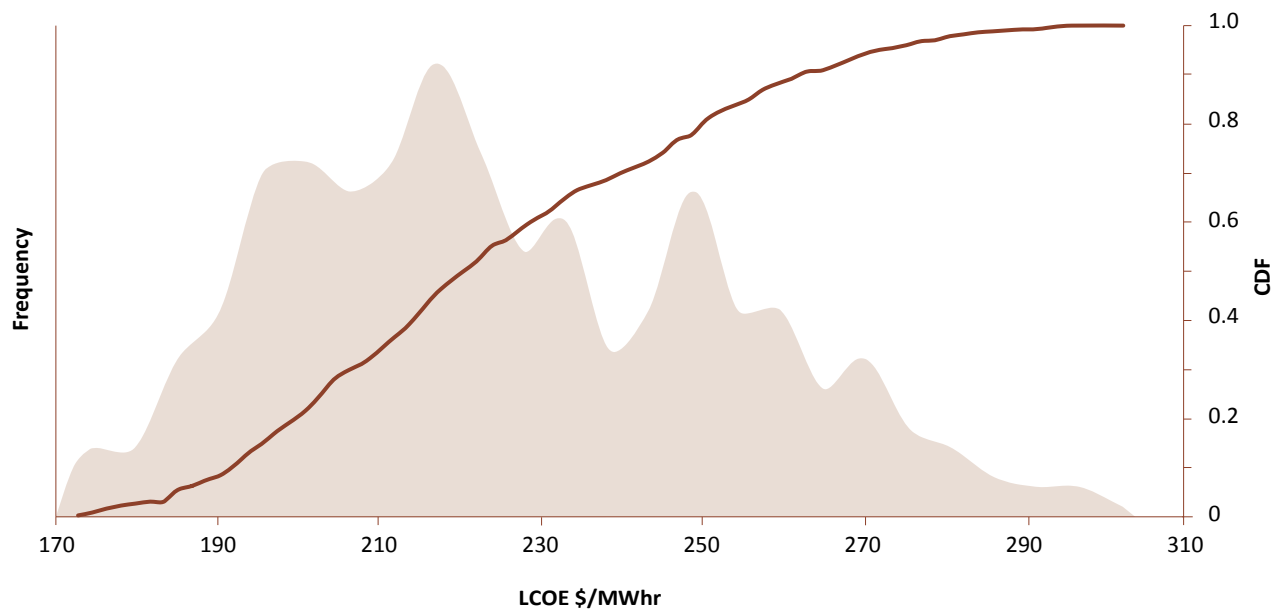
The LCOEs are sensitive to changes in the parameters, all of which are uncertain. Figure 8.2 shows the sensitivity of LCOE to changes in the key parameters of the base case system, EGS C.

Figure 8.2: Sensitivity of EGS C LCOE to parameter changes



All parameter changes will affect the LCOE, but key parameters include the rate of injection to production wells, plant efficiency and flow rate. Figure 8.3 gives an assessment of the possible ranges in LCOE for EGS C when drilling costs vary between $18 and $23 million per well, flow rates range from 60 – 100 kg/s and the resource temperature is between 180 – 240˚C. This figure graphs the cumulative density function of EGS C from multiple realisations of different values of the three variables (drilling cost, flow rate and temperature). It shows that all values lie between $174/MWh and $300/MWh with a mean value (CDF = 0.50) at around $220/MWh.

Figure 8.3: Cumulative density function of the LCOE for EGS C



The IGEG expects that with ongoing learning and research and development the LCOE for EGS would decline between 2020 and 2030 as some risks and some costs diminish. Using the EGS C LCOE in 2020 it is clear that the costs of drilling in Australia would need to fall substantially (in real terms) for geothermal energy to be cost competitive by 2030. Not only would the LCOE need to be equal to or less than the wholesale price of electricity (projected to be between $100 – $140/MWh by 2030. See Chapter 6), it must also be cost competitive with alternative technologies such as solar and wind. To assess whether this is possible, the IGEG has constructed two scenarios: (1) lower cost and (2) least cost or most favourable scenario for EGS C between 2020 and 2030. Neither represents a cost projection of what the IGEG considers likely, indeed, the least-cost scenario is a highly unlikely scenario, but is within the realms of possibility.

As part of its least-cost assessment there would have to be a substantial lowering on key costs of exploration and production. By comparison, costs for conventional (natural) geothermal developments in the US range from $45–$85/MWh, while estimated EGS costs range from $110–$220/MWh. One of the key costs is drilling of wells. As of April 2014 there were only 13 land-based drilling rigs operating in Australia compared to well over 1000 in the United States. It is possible, however, that the growth in unconventional gas development in Australia over the next decade, especially in shale gas, may result in the Australian drilling market growing substantially in size. This would increase the number of drill rigs, which may reduce the costs of drilling over time. The increased size of the industry would improve supply chains and increase experience in drilling in Australian basins, possibly reducing not only the costs of drilling, but also the risk. Another contribution to a reduction of drilling costs would be the relaxation of the requirement for a 'double barrier' in geothermal wells. Double barriers are where two concentric steel casing strings are used to protect shallow aquifers from the fluids produced from wells. Given the lower risks relative to gas production, regulators may allow wells that are only producing geothermal water to have only a single barrier, thereby reducing the costs of geothermal wells.

Other well-field services, such as reservoir stimulation, would also be expected to have reductions in cost for similar reasons if shale gas exploration and production grows between 2020 and 2030. Increased activity in the unconventional gas sector in Australia would also assist the geothermal sector through the collection of data (3-D-seismic data, drilling data). This additional data would reduce risk and cost during the exploration stage of geothermal project development.

Global efforts to develop geothermal resources over time in conductive settings could also lead to improved workflows for exploration and project development. Global developments in the geothermal sector (with both convective and conductive resources) should, over time, also improve the performance and reduce the costs of geothermal power plants. Another possibility is that with carbon mitigation the overall demand for drilling rigs in the 2020s may diminish globally. If this happens it could lower the demand for drilling rigs elsewhere, thereby reducing the costs of drilling in Australia. If none of these technology advances or market-driven changes in price of component technologies for geothermal energy systems occur, then it would be unlikely there would be significant movement in the real LCOE between 2020 and 2030.

The lower costs and least-cost scenarios in 2030 are given in Table 8.4. The two scenarios would likely allow electricity generated from geothermal energy to be delivered at below the wholesale price of electricity in 2030, which is projected to be between $100 and $140/MWh. Whether geothermal power systems would be commercially viable, however, also depends on alternative technologies. While the least-cost scenario may make geothermal power competitive with fossil fuel technologies with a carbon price, in the case of renewables the lowest cost technologies will almost certainly have a lower LCOE than geothermal. This is because wind power already has an LCOE of about $100/MWh in 2014 and because the costs of LCOE for PV solar are expected to fall substantially over the coming decade. One advantage of geothermal energy, compared to current solar and wind technologies, is that it can provide base-load and dispatchable power. To what extent this will remain a cost advantage in 2030 depends on whether cheap storage technologies can be developed for variable power sources, such solar and wind.

Table 8.4: Base case 2020 EGS C and lower cost and least-cost LCOE scenarios in 2030

Parameter	2020 base case (EGS C)	2030	
		Lower cost	Least cost
Temperature (° C)	220	220	220
Depth (m)	4,000	4,000	4,000
Flow rate (kg/s)	80	90	100
Number of fractures	3	4	5
Plant capacity factor	83%	95%	95%
Plant efficiency	90% of SAM model	95% of SAM model	100% of SAM model
% of confirmation wells used	50%	100%	100%
Well costs	$19.2 million	$16 million	$12 million
Ratio of injection to production wells	1	0.75	0.5
Surface equipment, installation	$2 million	$1.5 million	$1 million
Stimulation costs	$1 million	$0.7 million	$0.5 million
Plant capital cost $/kW	$2000	$2000	$2000
LCOE ($2014/MWh)	**$200**	**$130**	**$99**

An additional cost for geothermal systems that are not located near to the grid, such as in the Cooper Basin, is the capital costs of building transmission lines to the grid. CSIRO has made estimates of these costs, which are summarised in Table 8.5. The cost ranges are substantial and decline with the scale of the plant. For a 50 MW plant, the minimum extra cost would start from about $77/MWh and would start from about $23/MWh for a 300/MWh plant or a series of geothermal plants.

Table 8.5: Transmission costs from the Cooper Basin to East New South Wales (800–200 km)

Scale	Transmission capital charge $/ MWH		Transmission capital costs $ / MWH/year		Transmission capital costs $M	
MW	Lower bound	Upper bound	Lower bound	Upper bound	Lower bound	Upper bound
50	77.3	148.4	913	1752	320	614
100	38.7	74.2	457	876	320	614
150	25.8	49.5	304	584	320	614
200	33.8	37.1	400	438	560	614
250	27.1	29.7	320	350	560	614
300	22.6	34.0	266	401	560	843
350	19.3	29.1	228	344	560	843
400	16.9	25.5	200	301	560	843
500	13.5		160		560	
1000	7.2		86		600	

Source: Brinsmead et al (2014, p. 50)

8.2 Rewards

The rewards for the development of cost-competitive, utility-scale power generation from geothermal energy are determined by the cost of competing and alternative technologies. If there were no other carbon-neutral energy sources then the reward from cost-competitive geothermal power would be very substantial, given that Australia is likely to face a much higher carbon cost by 2030 than it does in 2020. Similarly, if alternative technologies were not available or available only at very high cost for dispatchable power, then the benefits of developing geothermal technologies that generate electricity at a much lower cost would also be considerable. Neither scenarios are valid in the case of Australia, where there are already alternative and renewable technologies that can generate electricity at a much lower LCOE than geothermal energy and would be expected to maintain this cost advantage. Further, there are much cheaper dispatchable power technologies, such as power plants that use coal, as a fuel source.

In 2013 ARENA commissioned Parsons Brinckerhoff to conduct a study on the potential for deployment of hybrid power stations in Australia. Parsons Brinckerhoff concluded that, from a technical perspective, geothermal may also present an opportunity for hybrid applications, although there is not sufficient data available to assess its potential at present (Hybridisation of Fossil Fuel Energy Generation in Australia, 20 November 2013). By comparison, it is the view of the IGEG that the success of geothermal energy developments in Germany has arisen from the combined use of direct heat with power production. This is because direct use wells in Germany can be shallower because they can use lower temperature fluids. In turn, operating direct-use projects has provided valuable data about the possible flow rates per well, injection strategy and operating parameters that has supported hybrid direct use/power projects. Studies by the US Electric Power Research Institute (EPRI) have also evaluated the use of wastewater streams from coal-fired power plants as the circulating fluid in EGS power projects. Other studies have examined the use of geothermal fluids to preheat boiler feed water in Germany. This type of 'double use' of the geothermal resource can significantly improve the value of the project.

The 'sweet spot' for geothermal energy in terms of generating substantial rewards is if Australia faces a high cost of carbon in 2030 and renewable storage technologies and smart network technologies have not developed sufficiently such that dispatchable power remains a key part of an electricity grid. In such a scenario, the formerly cheaper fossil fuel technologies would be much more expensive than in 2014 and renewables would still be unable, even with storage, to deliver highly reliable dispatchable power 24 hours per day, 365 days per year. For geothermal energy systems to realise these possible benefits, its costs of electricity generation must fall substantially to be equal with or lower than fossil-fuel dispatchable power technologies, including a carbon price.

OPTIONS FOR ARENA BOARD

9

Over the past decade ARENA and its predecessor, the Australian Centre for Renewable Energy (ACRE), as well as state governments, have provided direct financial support to the industry in excess of $100 million, including federal research and development tax rebates. This government direct funding represents about 18 per cent of the total direct funding to the industry, which, since the late 1990s, has received over $700 million in private sector/investor support. Direct government support for the sector has included funds for two demonstration projects (Renewable Energy Development Program), support for three projects to overcome roadblocks and generate knowledge (Emerging Renewables Program), and two projects that received funding for drilling (Geothermal Drilling Program). In addition to these industry programs, governments have collectively spent $25 million on research and about $30 million to develop pre-competitive data to assist the sector to target prospective geothermal resources.

The issue facing the ARENA Board is what further funding, and in what form, should (or should not) be provided to the Australian geothermal sector. This is a decision that only the ARENA Board can make because it must consider not only the risks and returns in the geothermal sector, but also the risks and returns for other (non-geothermal) renewable energy sources.

In responding to its terms of reference, the IGEG has decided to provide three options for the ARENA Board that it may wish to consider based on the evidence presented in the previous chapters, the supplementary reports, the submissions of stakeholders, and the judgement of the members of the IGEG. Before presenting these options, it is helpful to summarise the key findings of the IGEG and its views about the cost competiveness of the sector out to 2020 and 2030.

The considered view of the IGEG is that, in the absence of large subsidies, the supply of cost-competitive geothermal energy provided at a utility scale level is extremely unlikely by 2020. This is because the levelised cost of energy from geothermal energy at a utility scale in 2020, as estimated by the IGEG and depending on assumptions about parameter values, varies between about $170/MWh and $300/MWh with a mean value of around $220/MWh. By contrast, the wholesale price of electricity in Australia, which is currently around $50/MWh, is unlikely to exceed $100/MWh by 2020 in almost any possible scenario.

Looking forward to 2030, the IGEG has constructed a least-cost scenario to assess whether it may be possible that utility-scale geothermal energy, as a source of electricity to the grid, is cost competitive without subsidies. This least-cost or highly favourable scenario for the sector, relative to the 2020 base case, includes: a 38 per cent reduction in drilling costs; 25 per cent improvement (or a 2.5 times improvement relative to demonstrated flow rates in Australia in 2013) to the best possible or frontier flow rates from enhanced geothermal systems; halving of the ratio of injection to production wells (from 1.0 to 0.5); doubling in the confirmation of wells used; and halving of the stimulation costs per well. Achieving these improvements in key parameters will require continued progress not only in technical performance, but also in site selection, exploration drilling and sub-surface analysis over the period to 2030.

Under the IGEG's least-cost scenario, geothermal electricity generation in 2030 could be delivered at a levelised cost comparable ($99/MWh) to wind-powered electricity generation in 2014. On this basis, the IGEG considers it highly unlikely that geothermal energy for electricity generation at the utility scale to the grid will be cost competitive, without subsidies, with the lowest cost renewable energy sources by 2030. Nevertheless, there could be a role for geothermal energy as a replacement for higher cost fossil fuel energy sources (with a carbon price) that currently provide dispatchable power to the grid. Such a possibility is greatly enhanced if storage and network technologies have not progressed by 2030 to the point that a mix of renewable energy sources (such as solar and wind) are able to reliably supply electricity to the grid over a 24 hour cycle, 365 days per year.

Should the favourable least-cost scenario not arise for geothermal electricity generation by 2030, it still may be a possibility for the geothermal sector to be cost competitive off the grid for specialised applications, especially in remote areas. These possible applications would most likely involve the substitution of, or the complement to, alternative high-cost alternatives, such as diesel, by geothermal energy. The IGEG notes however, that cost competiveness off grid may not be sufficient to ensure adoption of geothermal energy for electricity generation. This is because 'proof of technology' beyond a single demonstration plant would also likely be needed by energy purchasers (such as the mining and processing sector) who require quantifiable and demonstrable levels of reliability. This 'proof of technology' would still require significant technology advances, primarily around obtaining predictable, and repeatable flow rates, over the next decade.

In terms of direct heat, the IGEG considers it is possible that large-scale geothermal energy could be cost competitive by 2030 without long-term subsidies. One of the most likely direct heat uses for geothermal energy is in processing applications within oil and gas fields and, in particular, in unconventional gas fields with high levels of carbon dioxide. In such locations, geothermal could be an alternative heat source to gas itself in terms of gas processing and removal of impurities. In a scenario where there are large-scale shale gas developments, which would be unlikely before 2020, a proven geothermal resource close by to a processing facility could be cost competitive without long-term subsidies. As in the case of geothermal electricity generation for specialised purposes and remote locations, proven demonstration of the technology in the field in the form of a demonstration plant would likely be required before adoption.

In summary, the IGEG does not see a credible path to cost competitive, utility or large-scale geothermal energy (direct heat or electricity) by 2020 without substantial subsidies. By 2030, and only under a least-cost or highly favourable scenario, geothermal might be cost competitive on the electricity grid compared to fossil fuel dispatchable power plants, but would be unlikely to be cost competitive with lower cost renewables. In the view of the IGEG, a more likely future scenario is that geothermal energy by 2030 provides cost-competitive energy

off the grid either as direct heat or as electricity in specialised locations and in remote areas. To achieve cost competiveness off the grid, without long-term subsidies, by 2030 would likely require government funding for the sector to speed up technological developments and to allow the sector to move along its 'learning curve'.

It is the view of the IGEG that to achieve the required cost reductions for cost competitiveness by 2030 ARENA should consider:

1. the duration of support with commitments over several years likely to be needed to encourage the necessary innovations in the sector
2. funding to develop technologies that allow prospective resources to be found that is transferable beyond a drill hole and that materially increases the likelihood of finding a resource prior to drilling
3. funding to support the development of methods to improve flow rates from enhanced geothermal systems.

Based on these pathways for cost competitiveness within the sector, the IGEG has selected three options for the ARENA Board to consider and include in its future funding choices:

1. A *Resume* option that represents a continuation of the existing ARENA programs. In the view of the IGEG this approach has, to date, not yet put the geothermal sector on a path to delivering cost competitive utility energy generation.
2. A *Reconsider* option that readjusts the current funding allocated to the sector in ways that will improve reporting standards, allow for a rebalancing in terms of how funds are spent and ensure more stringent standards, but with lower funding levels. This option also includes the possibility of providing no further funding to the sector.
3. A *Reboot* option that restarts the funding by ARENA in ways that move the geothermal sector towards a more cost competitive path with a strong emphasis on research and development in both finding (other than via drilling) and flowing the resource.

These three options are not mutually exclusive in the sense that the ARENA Board may choose to maintain some existing funding, revamp and readjust some of the current funds allocated and also redesign its approach to funding geothermal energy.

9.1 Resume option

The current funding model, should it restart, is the Resume option. Present funding is in hiatus, pending review and analysis and the advice of the IGEG and, under this option, would resume under previous guidelines. All other options can be compared to the existing funding and support and, thus, the Resume option forms the basis for evaluating any change based on the findings in this report.

9.1.1 Description

In the Resume option, the focus remains on developing utility-scale and high-grade geothermal resources focused on dispatchable and base-load power generation. In this Resume option, geothermal energy would be eligible for grants, subsidies and consideration for support in accessing transmission grid capacity. Existing projects that have been granted awards will continue to be eligible for fulfilment of these contracts and awards.

9.1.2 Actions and/or strategies

The continuation of the existing program and associated awards is a departure from the current hiatus, and as such needs an affirmation from the Board that its objectives are still valid, and that progress rates are acceptable and are expected to bear results in a reasonable period of time. The Board has no specific actions or changed strategies that must be adopted for this option and consequently, existing geothermal energy projects would be assessed using the current *merit* criteria adopted by ARENA. These criteria suggest that:

1. The current funded geothermal projects will remain unchanged without re-scoping unless this is done according to the current practice of negotiation of a variation initiated by the project proponents. These projects include:
   a. Geodynamics' Renewable Energy Development Program (REDP) Project ($58 million in grant funding remaining)
   b. Petratherm's Emerging Renewables Project (ERP, $13 million in grant funding) and REDP Project ($24.5 million grant funding)
   c. NICTA ERP Measure (ends in June 2014) on data fusion
   d. University of Adelaide/CSIRO ERP Measure on reservoir quality in sedimentary geothermal resources (ends in September 2014)

   The total value of ongoing commitments as at 1 June 2014 is just over $95.5 million
2. New projects may continue to be proposed through existing programs, including the Emerging Renewables Program (Projects and Measures), Supporting High-value Australian Renewable Energy Knowledge (SHARE), and the Accelerated Step Change Initiative (ASCI). The value of these additional projects would be dependent on the projects, if any, that were funded.
3. No new programs for geothermal energy would be undertaken, including no geothermal Research and Development Program.

9.1.3 Implications for barriers

Based on evidence included in this report and the supporting documentation it is highly unlikely that the Resume option will move the geothermal energy sector along the path to commercialisation or provide cost-competitive energy by 2030. The implications for the sector are that:

1. Proponents of demonstration projects will continue to struggle to find equity.
2. Critical barriers for cost competitive power delivery and regional resource characterisation and mapping are unlikely to be addressed.
3. Existing research and engineering capacity (personnel) are likely to seek employment in other industries.

9.2 Reconsider option

In recognition that ARENA must evaluate the benefits of funding geothermal energy versus alternative renewable technologies, the Reconsider option changes the overall allocation of existing funds and distribution already planned under the Resume option by redirecting them to alternatives. While existing projects and initiatives, including some strategic new enterprises, may be continued at much reduced levels, ultimately they would be funded and evaluated under new and more stringent standards and with lower funding levels. Depending on the returns on investment in competing renewable technologies, the Reconsider option also includes the possibility that no further funding is provided to the sector.

The primary advantage of the Reconsider option lies in the opportunity it provides to shift resources to other technologies or programs consistent with ARENA's broad mandate. A potential, and temporal, variant of this option would be to maintain existing projects where their continuation may reasonably support a path to a cost-competitive industry by 2030, albeit at lower funding levels. This would avoid shutting down potentially productive research and demonstration projects. Under this option at least some fraction of the personnel who have gained expertise in the field could be retained in the sector.

9.2.1 Description

The Reconsider option would:

1. formally wind down funding for geothermal energy projects, but with limited continuation of existing demonstration projects with changes of scope, project design and capital investment
2. allow continued program eligibility for geothermal energy in ARENA funding
3. allow for the continuation of existing projects in overcoming critical barriers in strategic geographic regions.

9.2.2 Actions and/or strategies

Under the Reconsider option, geothermal energy projects would be assessed using the current merit criteria used by ARENA, but would be subject to fundamental reductions in funding and design approvals or other project specific redesign. These changes could include:

1. Current demonstration projects would be *re-scoped,* but with no new funding, that would allow project proponents to focus primarily on addressing critical barriers in the short term. The focus would be on the most likely cost competitive pathway for off grid electricity or direct heat applications at the two existing demonstration projects.
2. In terms of knowledge generation, projects that are near completion and that will end in 2014 could be considered exempt from the changes in program design. These include the NICTA ERP Measure data fusion project and the University of Adelaide/CSIRO ERP Measure on reservoir quality in sedimentary geothermal resources (ends in September 2014) .
3. New geothermal projects submitted under the Emerging Renewables Program (Projects and Measures), the High-value Australian Renewable Energy Knowledge (SHARE), the Accelerated Step Change Initiative (ASCI) and Research and Development Program could be considered relative to alternatives. Key criteria for funding would be whether the projects could credibly support finding geothermal resources (other than by drilling) and flowing the resource.

9.2.3 Implications for barriers

Under the Reconsider option, some current budget allocations may become available for other more cost competitive technologies. The Reconsider option may reduce the chance of critical data losses and allow some further understanding of the critical barriers to geothermal energy, and how to address them. Under the Reconsider option the proponents of demonstration projects will continue to struggle to find equity without a re-negotiation of a lower contribution from the companies, and consequent increase in public subsidy of existing projects.

9.3 Reboot option

A Reboot option explicitly recognises that funding for geothermal energy is about innovation in an uncertain investment and that the return or rewards depend on a series of corollary investments in sub-surface mapping, improved drilling techniques, stimulation technology and grid delivery. From the perspective of the IGEG, a future cost-competitive geothermal sector will likely start with direct-heat applications and off-grid power generation from engineered geothermal systems.

A reinvention of the funding for geothermal would represent an evidence-based approach to maximising the reward-to-risk ratio in the geothermal energy sector and should not be constrained by the existing funding/support strategy of ARENA towards the sector.

The timeline for performance and delivery in the Reboot option should be long term and recognise that a decade-long or more 'finding and flowing it' funding strategy is required if the sector is to become cost competitive by 2030. Overall, the Reboot option provides Australia with an additional opportunity to 'keep in play' the possibility that geothermal could deliver energy in remote areas and for specialised applications. It also keeps alive the possibility that geothermal energy in the very long term, beyond 2030, might become a cost competitive energy technology for grid power.

9.3.1 Description

The Reboot option reflects the need to support technological innovation in geothermal energy, while creating options for the future integration of electrical and direct-heat systems in strategic locations across Australia. This option would support the development of future cost-competitive energy capacity, taking advantage of previous investments in geothermal programs, working with existing established thermal generation industries, and expanding the collective knowledge base of sub-surface resources in the country.

This option would halt current funding of geothermal projects in 2014. Instead, the funding process would be redesigned under changed funding and policy objectives. Geothermal energy would continue to be classed as a possibly important supplement for large-scale future energy systems, but several decades into the future. In the period to 2030, geothermal energy should primarily be viewed as a possible energy source off the grid, especially in remote areas and for specialised applications.

The two approaches for funding within the Reboot option would include:

1. support for finding prospective geothermal resources, without drilling, so as to maximise the national benefits and possibilities and options for geothermal energy nationally, and
2. support for developing the technologies to increase the flow rate from geothermal wells, noting that this is a key parameter, after a resource has been located, in determining the cost competiveness of geothermal energy.

Under the Reboot option research and development projects focused on 'finding and flowing' geothermal energy would have the highest priority.

9.3.2 Actions and/or strategies

The Reboot option is a paradigm shift for ARENA and its support for the geothermal sector. The funding focus in this option is on innovation and resolving the critical barriers for geothermal energy, identified by the IGEG, that are amenable to improvements from research and development. These include resource characterisation/finding flow and effectively creating/enhancing flow.

It is the view of the IGEG that, in the absence of very large subsidies, the funding of drilling programs will not materially reduce the costs of drilling in Australia and, thus, should not be part of a Reboot option focused on pathways to support cost competiveness of the geothermal sector by 2030. The costs of drilling in a research and development program may be included for support, but only as part of the testing of pre-competitive data collection methods and technologies to increase flow.

Actions within the Reboot option that should be considered for support include:

- Resource characterisation, technology development and component technology demonstration.
- Direct heat applications and off the grid uses that have the greatest likelihood of achieving cost competiveness by 2030.
- Co-operation and co-ordinated funding and research and development programs with the oil and gas sector, especially in locations such as the Cooper Basin where both proven geothermal resources and gas fields are co-located.
- International learning and knowledge transfer that would allow the Australian geothermal sector to 'jump' in learning pathways to cost competitiveness.
- A single national research centre or centre of excellence or collaborative research centre that has at its core:
    a. geothermal industry involvement
    b. strong links to the oil and gas sector
    c. a consortium of national universities and research organisations, and
    d. strong links to international geothermal research centres.
- Pre-competitive resource data collection program – data collection and collation that may include deep drilling, but only to confirm the above-surface characterisation and modelling.

9.3.3 Implications for barriers

The barriers to the future cost competiveness of the Australian geothermal industry are formidable. An approach that focuses on 'finding it and flowing it' and that leverages off the existing knowledge base, links key players across the sector and overseas, and focuses on the most likely commercial possibilities (direct heat and off grid) offers the greatest chance of success.

The justification for government support for geothermal energy is not that it will become the principal and cost-competitive, non-fossil-fuel-based energy source for Australia by 2030. Indeed, it is the view of the IGEG that such an outcome is highly unlikely. Instead, innovation and targeted research and development funding for the geothermal sector (especially in pre-competitive resource characterisation and flowing the resource) keeps alive the option that it can deliver an alternative energy source that is amenable for use in remote areas and for specialised, but economically important, energy uses such as the resource and energy sector. Costing of the Reboot option was not part of the terms of reference of the IGEG, but looking forward to 2020, it could amount to about $10 million per year to 2020.

9.4 Innovation Roadmap

Before implementing either the Reconsider option or the Reboot option, the IGEG proposes that the ARENA Board establish a geothermal sector 'Innovation Roadmap' to delineate funding pathways for the industry.

The Innovation Roadmap would be a policy and strategic tool that would set out goals and objectives, including milestones and standards for programs, awards, subsidies or planning that can improve or enhance the long-term competitive role of geothermal technologies in Australia. It would build on the findings of the IGEG and previous R&D proposals for the sector (Huddlestone-Holmes et al. 2012).

9.4.1 Purpose

Building an Innovation Roadmap sets out and defines expectations both from the public as well as the private sector, ultimately resulting in a 'map of intention' and development pathways for the sector. The Innovation Roadmap would also re-evaluate the current and future market for renewable-supplied electric energy in Australia including geothermal and other competing technologies.

The proposed Innovation Roadmap could focus on three key elements:

1. A re-evaluation of the remaining fund balance for ARENA that can be directed towards geothermal energy over the next 5 years, and then up to 10 years from the present.
2. The establishment of a core program of geologic resource characterisation and knowledge sharing, including compilation and evaluation of results and data from projects previously undertaken by ARENA under the geothermal program in the first 5 years of the Roadmap.
3. The development of a set of milestones and competitive objectives for participants in the post-characterisation or market phase of the Road Map five to ten years from the present.

Given these broad guidelines, the Innovation Roadmap could be used to differentiate between the technologies that at full maturity will produce robust, continuous power at full capacity, and the technologies and techniques that represent incremental improvement and contributions prior to full capacity.

9.4.2 Timing

The Innovation Roadmap will be best developed immediately after the announcement of the ARENA Board's decision on funding options and the publication of the IGEG Report. Undertaking the Innovation Roadmap early as possible would also assist ARENA in keeping key options alive, such as avoiding the capping of geothermal wells until a full assessment of the costs and benefits of such actions are fully considered. A possible example of an Innovation Roadmap is the one on Enhanced Geothermal Systems prepared for the US Department of Energy and presented in Ziagos et al (2013).

9.4.3 Proposed components

The Innovation Roadmap should cover all of the key R&D drivers of lower geothermal energy costs. In the view of the IGEG, three key components of the roadmap would include: data collection, international collaboration and collaboration with the oil and gas sector.

Data collection

In order to better assess the geothermal resource in Australia, data from well drilling for oil and gas, mineral exploration and deep-water well drilling can be collected and mapped. In the US, some states require a temperature survey of any well deeper than 100 m. If the company or individual drilling the well cannot afford to run the temperature survey, some state geological surveys will do it for them. To make these surveys more useful, information about when and for how long the well was last circulated can allow calculation of an equilibrated temperature. Some US states also require cuttings or core to be filed with the geological survey or Division of Mineral Resources from wells and core holes drilled for oil and gas, mineral exploration or geothermal. Other US states require copies of mud logs and required geophysical logs. These data can be held proprietary for a period of time and then made public as part of a database. A uniform policy to collect all of these data across all Australian jurisdictions would enhance the value of this type of data and allow it to be used in a publically accessible database that could be used for preliminary geothermal resource assessment.

Ideally, all geothermal relevant data would be collected into a publically accessible GIS database. Oil and gas database could be the model for how to store and access this data, but tailored for geothermal use.

An example worth exploring would be the National Geothermal Data System (NGDS) where US data from all federally funded geothermal projects, plus state collected data, are centralised. The US provides ongoing federal support for developing the database, reporting data from individual state databases, scanning documents not available in digital format, and moving data from the Office of Scientific and Technical Information to the NGDS and also maintaining the database. A similar scheme in Australia for data collection and integration into an accessible database for geothermal resource evaluation/exploration would be highly desirable from an innovation and learning and development perspective. For instance, a geothermal database could be maintained by a national agency, such as Geoscience Australia.

In Australia, a possibility exists to collect data (primarily temperature) for use in geothermal resource assessment whenever wells are drilled for oil and gas, mineral exploration and water well drilling. The recently announced $100 million Exploration Development Incentive, which aims to encourage more mineral discoveries will involve drilling mineral exploration wells. It would be desirable if this program required that all wells drilled be temperature logged and that data on timing of circulation be collected so heat flow calculations could be made.

International collaboration

While the Australian geothermal resource will have its own unique challenges, the opportunity to learn from international projects will be invaluable to the development of geothermal energy in Australia. International collaboration could be in the following forms:

- Contribute funding to obtain data and experience in projects where experimental efforts are going on in the area of reservoir creation and enhancement that would be valuable for Australia. Existing international engagement through the International Partnership for Geothermal Technology (IPGT) and the International Energy Agency Geothermal Implementing Agreement (IEA-GIA) could be used to facilitate these activities.
- Secondments of technical personnel to country institutions where projects researching reservoir enhancement and creation are underway. An example of such a program is that initiated by AltaRock, which is hosting two Chinese scientists to visit for three months in 2014 to work on the US Department of Energy-funded Newberry project. These scientists will participate in the stimulation and work on planning for and drilling of the production well. Their institution pays their salaries while Altarock covers their housing and board.
- Support for internationally recognised technical experts to visit Australia to mentor and to exchange ideas on specific projects. Such a program could build on existing collaborations. For instance, Robert Podgorney from the Idaho National Laboratory recently visited CSRIO and worked with CSRIO scientists on geothermal projects.

Collaboration with the oil and gas sector

The development of unconventional gas in Australia and elsewhere faces similar technical challenges to geothermal energy, particularly in regard to the need to 'find it and flow it'. Consequently, there are important overlaps in understanding the resource (i.e. Australia's sedimentary basins) and opportunities to translate learnings and technologies used to find and flow the resource between the oil and gas sector and the geothermal sector. Some examples of where scope for crossover may exist includes:

- wells of opportunity for experimental fracturing
- evaluation of fracturing methods in the two sectors to better understand how to successfully undertake multistage fracturing for conductive geothermal resources
- modelling/evaluation of how results from the oil and gas sector might transfer to geothermal developments
- combined research efforts across the two sectors in terms of stimulation methods, well completions, microseismic monitoring, and resource characterisation.

ANNEXES

Annex A Geothermal LCOE

Prepared for the ARENA International Geothermal Expert Group by Dr Cameron Huddlestone-Holmes, Geothermal Energy Stream Leader, CSIRO

Cost comparisons

Table 1 shows a summary of current projected estimates of capital costs and LCOE for EGS plants. The variation in costs reflects the uncertainty surrounding this emerging technology and the assumptions that need to be made on the cost of drilling, the temperature and depth of the resource and the cost of the balance of power. The cost submitted by 'Company X' is substantially lower than the other forecasts. Details provided by this company indicate that they are assuming a much lower cost of drilling than used in the other models (approximately $12 million per 5000 m well), which they base on the costs over a 60-well program. Their operating and maintenance costs are also significantly lower than used in other models (approximately $90 per kilowatt of installed capacity). Their assumptions for flow rate are also high (over 110 kg/s).

Table 1: Capital cost estimates for a hot dry rocks plant in AUD 2014/kW sent out

CSIRO (2011) is from Hayward et al. (2011), EPRI (2010) is from the Australian Electricity Generation Technology Costs – Reference Case 2010 (EPRI and Commonwealth of Australia, 2009), Gurgenci (2013) is from (Gurgenci, 2013), Mines 2013 is Scenario C from (Mines & Nathwani, 2013), Company X is from a detailed commercial-in-confidence submission made by an Australian geothermal company to the IGEG, and the two AETA costs are from the Australian Energy Technology Assessment (Bureau of Resources and Energy Economics, 2012).

	CSIRO (2011)	EPRI (2010)	Gurgenci (2013)	Mines (2013)	Company X (2014)	HSA AETA (2012)	EGS AETA (2012)
Capital Cost	$7,363	$9,199	NA	$11,850	NA	$7347	$11,125
LCOE	$156	$188	$195	~$260	$60	$161	$222

Note: The LCOEs are in AUD 2014/MWh

The Australian Energy Technology Assessment (Bureau of Resources and Energy Economics, 2012) is the most recent authoritative assessment of geothermal energy costs in Australia. Table 2 shows the technology specific assumptions that were used in these calculations.

Table 3 shows the results of some recent modelling conducted by the US Department of Energy (Mines & Nathwani, 2013). These models use significantly higher costs for the power plant installation and operating and maintenance than used in the AETA model. The resource types in these projections are based on significantly higher geothermal gradients than are found in Australia. It is also unlikely that Australian geothermal resources would ever use flash power plants. The costs of binary power plants at high-resource temperatures (over 200°C) are poorly constrained as they are rarely used at these resource temperatures.

Table 2: Input parameters for the AETA models

Parameter	EGS	HSA
Capacity	50 MW	50 MW
Production wells	12	13
Injection wells	6	7
Resource depth	5000 m	4000 m
Resource temperature	250° C	150° C
Rejection temperature	70° C	70° C
Flow rate	60 kg/s	100 kg/s
Production well costs	$281 million ($23.4 million per well, including stimulation)	$120 million ($9.3 million per well)
Injection well costs	$128 million ($20.3 million per well)	$65 million ($7.3 million per well)
Power plant costs	$100 million ($2,000 per kW)	$125 million ($2,500 per kW)
Power plant efficiency (net of all parasitic loads)	9%	12%
Brine reticulation costs	$15 million	$20
Geology and permitting costs	$15 million	$20
Fixed O&M costs	2% of total capital cost	3% of total capital cost
Thermal draw down	None	None
Project life	30 years	30 years

Data provided by the Bureau of Resources and Energy Economics.

Table 3: EGS cost modelling results for various scenarios in the US

Costs are in US Dollars (Mines & Nathwani, 2013).

EGS results	Scenario A	Scenario B	Scenario C	Scenario D	Scenario E
Temperature	100°C	150°C	175°C	250°C	325°C
Resource depth	2 km	2.5 km	3 km	3.5 km	4 km
Plant type	Air-cooled binary	Air-cooled binary	Air-cooled binary	Flash steam	Flash steam
# of production wells	21.5	7.6	7.9	6.4	4.3
Ratio of production to injection wells	2:1	2:1	2:1	2:1	2:1
Production well cost – each	$5,187K	$6,965K	$8,973K	$8,237K	$10,280K
Injection well cost – each	$5,187K	$6,965K	$8,973K	$11,210K	$13,678K
Total geothermal flow	860 kg/s	303 kg/s	316 kg/s	256 kg/s	171 kg/s
Power sales	10 MW	15 MW	20 MW	25 MW	30 MW
Geothermal pumping power	3,499 kW	738 kW	383 kW	997 kW	679 kW
Plant output	13.50 MW	15.74 MW	20.38 MW	26 MW	30.68 MW
Generator output	17.07 MW	20.34 MW	24.4 MW	27.42 MW	31.72 MW
Power plant cost	$8,128/kW	$4,668/kW	$3,597/kW	$2,091/kW	$1,571/kW
Overnight project capital cost (with contingency)	$343,960K	$187,291K	$217,994K	$176,620K	$152,299K
Present value of project capital cost	$396,252K	$235,706K	$276,042K	$229,634K	$211,177K

EGS results	Scenario A	Scenario B	Scenario C	Scenario D	Scenario E
Exploration & confirmation (¢ /kW-hr)	9.44	7.27	6.56	4.83	4.88
Well-field completion – including stimulation (¢ / kW-hr)	32.46	7.47	7.24	4.56	2.53
Permitting (¢ /kW-hr)	0.37	0.23	0.17	0.13	0.11
Power Plant (¢ /kW-hr)	16.98	7.13	5.30	3.09	2.33
O&M (¢ /kW-hr)	17.22	5.65	4.74	4.78	3.53
Levelised cost of energy – LCOE (¢ /kW-hr)	76.47	27.75	24.01	17.4	13.39

Cost modelling

The costs of geothermal energy projects are dependent on a wide range of variables, many of which are interdependent. For this reason a range of scenarios have been modelled to identify the range of costs for geothermal energy in Australia. The scenarios are shown in Table 4. The scenarios have been chosen as they represent the range of resources that have been targeted in Australia.

These scenarios are based on a range of assumption on the technical performance of geothermal energy systems that have yet to be demonstrated for conductive geothermal resources in Australia (primarily flow rate). It is also important to note that there have been no utility-scale power stations built anywhere in the world that utilise the types of resources that are found in Australia. The global experience is limited to plants that are a few MW in scale.

Table 4: Scenarios used for cost modelling with base case parameters

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Temperature °C	150	180	150	180	220	250	220
Flow rate (kg/s)	100	100	80	80	80	80	40
Stimulation	No	No	Yes	Yes	Yes	Yes	Yes

Comparison with AETA Costs

The AETA input parameters were used to validate the System Advisor Model (SAM). SAM has a much more detailed model of geothermal systems than was used in the AETA, and parameters were chosen to ensure that the key parameters were consistent between the two models (total power, installed capital costs, operating and maintenance costs). Using these parameters, SAM calculated an LCOE of approximately $210/MWh for EGS, which is in good agreement with AETA's predictions. The AETA model includes the cost of interest during construction. These costs were not included in the scenarios modelled with SAM.

System Advisor Model

SAM is a performance and financial model for renewable energy technologies that has been developed by the National Renewable Energy Laboratory (NREL) (Blair et al., 2014). Further details on SAM are available at https://sam.nrel.gov/.

SAM uses system design parameters, installation costs and operating costs to determine the performance and costs of the renewable energy. Modelling of a range of technologies including solar, wind, biomass and geothermal can be performed in SAM. AUSTELA commissioned a guide for modelling concentrating solar power using SAM in Australia (Lovegrove, Franklin, & Elliston, 2013).

SAM allows a comprehensive range of system design parameters to be used for modelling geothermal energy systems, including resource type, depth and temperature; drilling costs; pumping requirements; reservoir performance; plant costs and efficiencies; and ambient conditions (SAM can predict hourly, monthly and annual output of a system). A range of financial inputs can be used with SAM, including installation costs; operating costs; required return on investment; financial incentives; tax and inflation rates; and sources of funding (i.e. equity versus debt). A more detailed discussion of how SAM calculates LCOE is available in AUSTELA's Companion Guide to SAM for Concentrating Solar Power (Lovegrove et al., 2013) from the SAM website (https://sam.nrel.gov/).

SAM was used to model the seven scenarios set out in Table 4. All of the parameters used in the model-scenario base cases are presented and some commentary on the selection of these parameters is provided. The SAM models are for geothermal costs in 2020. Accordingly, there are some assumptions made about technology development and costs between 2014 and 2020.

Input parameters that are considered important are summarised in the breakout boxes in each section below. The parameters that have the biggest influence on costs are highlighted in red.

SAM was chosen by the IGEG as an analysis tool because it allows a range of system design parameters and costs to be modelled rapidly as well as allowing parametric analysis of some of the inputs. The standard version of SAM uses default cost curves for drilling.

Exploration costs

The costs of exploration will vary markedly between projects depending on the availability of precompetitive data and the nature of the resource. For these models, the exploration phase is considered to include:

- acquisition of exploration permits
- compilation and interpretation of existing data
- acquisition of new geophysical data (gravity, magnetics, magnetotellurics)
- drilling of shallow (less than 1000 m deep) heat flow wells
- interpretation of results of data collection and planning for deep confirmation wells
- the drilling of deep confirmation or test wells (that intersect the target reservoir), and
- interpretation of the results of confirmation drilling.

In the scenarios modelled here, total exploration costs are defined at $2 million plus the cost of drilling of two confirmation or test wells. The cost of these wells is assumed to be 20 per cent higher than that of the production wells to reflect the higher costs of these wells early in the life of a project. Lower-cost slim exploration wells to reservoir depths have not been demonstrated for the resource depths being considered here. One of the two confirmation wells is converted into a production well.

The exploration costs should be considered a minimum cost and assume that there is some precompetitive data available that allows initial site selection. Similarly, it is assumed that reservoir engineering methods are available that reduce the need for finding specific geological settings. The absence of precompetitive data or more specific resource requirements would likely lead to higher exploration costs.

An example of additional costs during exploration is the collection of 3-D seismic data. 3-D seismic surveys have become a routine part of exploration in the oil and gas sector. While they have not been routinely used in the exploration for conventional geothermal resources, 3-D seismic surveys may become more important in reducing risks during exploration for geothermal resources in conductive environments. The data collected may help to target areas that have more favourable geology for reservoir development, such as permeable structures or lithologies.

For most resource exploration, a company would normally evaluate several prospects simultaneously in order to spread the risk, with exploration shifting its focus to the more promising of these prospects as they are evaluated. The costs of exploration across all of the sites would be attributed to the final successful project. For the scenarios modelled here, these additional costs have not been considered.

Base case scenarios – exploration costs key assumptions:

- Exploration costs of $2 million per project.
- Two confirmation wells per project, costing 20 per cent more than the production wells.

Reservoir characteristics

The characteristics of geothermal reservoirs in Australia are largely unknown. Only Geodynamics Ltd with their Innamincka Deeps project has demonstrated proof of concept with the closed-loop system. This reservoir appears to consist of a single sub-horizontal fracture or fault zone (Hogarth, Holl, & McMahon, 2013). How representative this reservoir is of future development at Innamincka, let alone other reservoirs, is unclear. There is also very little published data on the characteristics of geothermal reservoirs in conductive settings similar to those found in Australia or elsewhere in the world. As a result, the parameters used in the SAM modelling can only be considered estimates.

The key reservoir characteristics are:

- resource temperature
- resource depth
- reservoir quality (in the case of a closed loop geothermal system, reservoir quality is a measure of how easily fluid can move from injection wells to production wells)
- the distance between injection and production wells.

The resource temperatures used in the SAM models are based on those found in the four projects that drilled to reservoir depths in Australia. They represent thermal gradients in the order of 40°C to 50°C per kilometre, with the exception of the Natural Reservoir A, which has a much higher thermal gradient (similar to that observed at Celsius 1). The resource depth and resource temperature are closely related.

The SAM model uses reservoir quality parameters as inputs for the calculation of the required pumping power to circulate fluid through the reservoir. The model can consider Darcy flow, fracture flow or a straight change in pressure across the reservoir as a function of flow rate. In the scenarios modelled here, Darcy flow has been used for natural reservoirs and fracture flow has been used for EGS reservoirs. It should be noted that SAM uses a simple model for the reservoir to calculate the pressure drop between injection and production wells for the calculation of pumping power. The thermal performance of the reservoir has not been modelled.

The distance between injection and production wells has been set at 1000 m.

Base case scenarios – reservoir characteristics:

- Resource temperatures between 150°C and 250°C with thermal gradients in the order of 40°C to 50°C/km.
- Resource depths between 2,500 m and 5,000 m.
- Distance between injection and production wells of 1,000 m.
- Permeability thickness for natural reservoirs of 50 Dm.
- Equivalent permeability thickness for EGS reservoirs of 1.5 to 2.5 Dm.

Flow rate

The flow rate per well of the geothermal brine is one of the most critical parameters in determining the costs of geothermal energy. The flow rates used in the base scenarios of 100 kg/s for natural reservoirs and 80 kg/s for EGS Reservoirs represent the flow rates that the industry has been aiming for over the last 10 to 15 years. These flow rates have yet to be demonstrated in Australia and the assumption that they can be achieved routinely by 2020 is the most uncertain in these scenarios. EGS E is included with a 40 kg/s flow to provide a scenario with a flow rate that matches the best achieved from EGS wells so far in Australia.

There is only one resource in Australia that has been properly flow tested. That is Geodynamics Ltd's Innamincka Deeps project in the Cooper Basin. The maximum flow rate achieved in a closed loop was 18 kg/s (Hogarth et al., 2013). This flow rate was restricted by damage to the reservoir around the injection well, Habanero 1. The maximum production flow rate achieved at this project was around 40 kg/s from the Habanero 4, and this demonstrated flow rate forms the basis for scenario EGS E. This is arguably the highest flow rate recorded for a single well in to an EGS reservoir in a conductive setting worldwide. A possible exception is Landau in Germany, which produces flow rates of 70 kg/s. Landau is located in a rift basin, and is considered by many to be a natural reservoir, where limited stimulation was used to improve connectivity of the reservoir to the well.

High flow rates have been demonstrated from natural reservoirs internationally, particularly from sedimentary resources in Germany, particularly in the Molasse Basin (e.g. Unterhaching produces 123° C brine at 150 kg/s from its production well). However, the two wells drilled into Australian Hot Sedimentary Aquifer (HSA) style resources so far, Salamander-1 and Celsius-1, achieved poor flow rates.

Base case scenarios – reservoir characteristics:

- Flow rates for natural reservoirs of 100 kg/s.
- Flow rates are EGS reservoirs of 80 kg/s.
- Flow rate for Scenario EGS E of 40 kg/s.

Drilling costs

Drilling costs are the most significant contributor to the overall capital costs of a geothermal energy project. Unfortunately, drilling costs are difficult to estimate with any certainty. The Australian drilling services sector is relatively small, with only 13 land-based rigs capable of drilling to the depth required for geothermal energy development, compared to over 1000 drilling rigs in the United States as of the end of March 2013 (data from the Baker Hughes Rig Count accessed from http://phx.corporate-ir.net/phoenix.zhtml?c=79687&p=irol-rigcountsoverview on 30/04/2014). As a result of the relatively small industry in Australia, drilling costs are volatile and can vary markedly depending on contractual arrangements for individual wells or drilling campaigns. Compounding this uncertainty has been the high volatility in drilling costs globally over the last decade. This volatility is illustrated in Figure 1 and while these data are for the United States, similar cost increases have been observed globally.

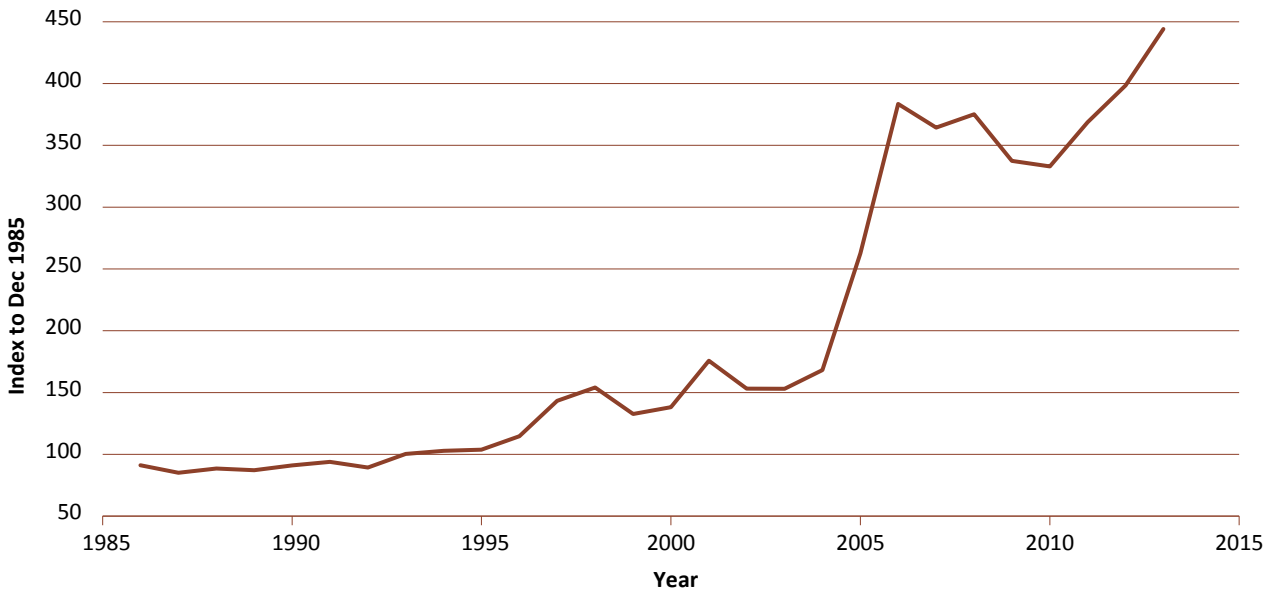
The close link between the costs of geothermal wells and petroleum wells has been demonstrated many times (e.g. Augustine, Tester, Anderson, Petty, & Livesay, 2006; Mansure & Blankenship, 2011; Tester et al., 2006). It follows therefore that there is a link between the costs of drilling and the price of oil and gas (Mansure & Blankenship, 2011). There are many factors that go into determining the cost of a well. These factors fall into two main categories: the design of the well and its completion; and, the geology being drilled through including the rock types, formation fluids and stress state. The primary considerations in the design of the well are the depth, the diameter, and the casing requirements. These three aspects combine to determine the size of the drill rig required to drill the well. Combined with the geology, they also directly influence the amount of time taken to drill the well. The size of the drill generally determines the daily cost of drilling activities and this, combined with the amount of time to drill the well, determines the overall cost. The daily cost of drilling activities is comprised of the drilling rig day rate (the cost of the rig itself plus its crew) plus consumables (casing, cement, drill bits, drilling fluids) plus services (wireline logging, mud logging, mud engineer, cementing, site preparation).

A study of drilling costs for petroleum wells in Australia (Leamon, 2006) suggested a correlation between drilling day rates and overall costs per day for drilling activities. This correlation allows for some estimates of current well costs to be made based on current drilling rig day rates. The relationship is as follows:

Well cost = (Rig day rate/rig ratio) x well time

The well time is the number of days that the drill rig spends drilling a well (between spudding and rig release). The well time is dependent on the depth of the well, the nature of the formations being drilled through, the size (diameter) of the well, and the design of the well (including the number of casing strings). The rig ratio is a factor that relates the rig day rate to the daily cost of drilling. Leamon (2006) found that the rig ratio varied between 0.25 and 0.40. For this study, a rig ratio of 0.25 has been assumed as this seems to produce drilling costs similar to those obtained through consultation with individuals in the drilling sector.

Figure 1: Producer price index of drilling oil and gas wells services in the United States from 1985 to the end of 2013



Data sourced from the United States Bureau of Labour Statistics (http://www.bls.gov/).

Table 5 shows how this formula has been applied to wells for the scenarios modelled here with SAM. These costs do not include mobilisation or demobilisation costs. The costs also assume that there are no unusual geological conditions that may increase the cost of drilling. For example, drilling at Geodynamics Ltd's Innamincka Deeps project has encountered significant overpressures in the reservoir. Overpressures are where the fluid pressure in the reservoir is higher than the hydrostatic gradient. The fluids will flow from the well under their own pressure unless they are controlled. Controlling such overpressures can add significantly to the costs of drilling.

The well time in Table 5 assumes that drilling in sedimentary basins is quicker than drilling in crystalline basement (i.e. granite or metamorphic rocks). It has also been assumed that the wells are drilled as part of a campaign and that the drilling is being conducted in an area that has been drilled previously allowing for local learning. The costs also assume that the drilling is 'trouble free'. Drilling 'trouble' can be caused by adverse geological conditions or equipment/operator failures and can increase the well time, and therefore costs, significantly. These problems are more common at the start of a drilling program than at the end. This improved performance from learning in a local area can result in a reduction of drilling costs by as much as 20 per cent over the life of a large drilling program. The rig size increases with well depth because of the extra weight of casing that the rig needs to be able to lift in deep wells.

Scenario EGS E uses 6-inch wells as this size is large enough to accommodate the lower flow rate of 40 kg/s used in that case.

Table 5: Drilling costs used for the seven base case scenarios modelled with SAM

Well description	Rig size	Rig day rate	Well time	Well cost
Natural reservoir A, completely within sedimentary basin, 8" diameter, 2,500 m total depth.	1,000 HP	$60,000	30	$7.2 million
Natural reservoir B, completely within sedimentary basin, 8" diameter, 4,000 m total depth.	1,500 HP	$70,000	40	$11.2 million
EGS A, sedimentary basin with crystalline basement, 8" diameter, 3,000 m total depth.	1,500 HP	$70,000	40	$11.2 million
EGS B and C, sedimentary basin with crystalline basement, 8" diameter, 4,000 m total depth.	2,000 HP	$80,000	60	$19.2 million
EGS D, sedimentary basin with crystalline basement, 8" diameter, 5,000 m total depth.	2,000 HP	$80,000	90	$28.8 million
EGS E, sedimentary basin with crystalline basement, 6" diameter, 4,000 m total depth.	1,500 HP	$70,000	60	$16.8 million

No allowance has been made for unsuccessful wells. This means that all wells drilled are assumed to perform as expected. A study of success rates for geothermal drilling in conventional resources shows that the global average success rate is around 78 per cent (International Finance Cooperation, 2013). Conventional geothermal systems rely on the wells intersecting naturally occurring fracture zones to supply geothermal fluid to the well. As a result, there will always be a risk of drilling a 'dry' well. There is an assumption that for EGS there is no such thing as a dry well as the reservoir will be engineered or created. Similarly, natural reservoirs in sedimentary basins are likely to be laterally extensive if they do exist, specifically reducing the chances of a dry well. However, if an EGS resource or natural reservoir relies on the existence of naturally occurring structures, or a natural reservoir relies on sedimentary layers that are not laterally extensive, then the chance of encountering dry wells is a real possibility. The scenarios modelled here assume that dry wells will not occur as either reservoir stimulation will always be able to create a reservoir, or exploration methods will allow the appropriate geology to be targeted ahead of drilling.

The assumptions made about drilling costs mean they should be considered to be 'minimum' costs. The SAM model allows for contingency to be applied to the drilling component of the project costs. A 15 per cent contingency to the overall capital costs of the project has been included in the models to factor in the likelihood of additional costs in the drilling program as well as for other components of a geothermal energy project.

The ratio of injection wells to production wells has been assumed to be one for the base case in each scenario.

In addition to the drilling costs, a fixed rate of $2 million per well has been included for surface equipment including the well head and brine reticulation systems. For the EGS scenarios it is assumed that a reservoir stimulation costs $1 million per well.

Base case scenarios – drilling costs:

- Drilling costs as outlined in Table 5.
- Additional costs associated with drilling 'trouble' are included in the 15 per cent contingency applied to the overall capital costs for the project.
- All wells are successful (achieve desired flow rates).
- Ratio of injection wells to production wells of 1.
- One of the two confirmation wells is converted into a production well.
- Well head and brine reticulation costs of $2 million per well.
- Reservoir stimulation costs of $1 million per well for EGS resources.

Thermal draw down

The rate of heat extraction from a geothermal reservoir in a conductive regime is likely to exceed the rate at which heat is replenished into the reservoir. As a result, the temperature of the geothermal brine produced from the reservoir will decrease over time. The decrease in temperature will lead to a decrease in power output and may require additional wells to be drilled into new parts of the reservoir to augment or replace wells drilled at the start of the project. The rate of thermal draw down depends on the volume of rock that the circulating fluid sweeps as it passes through the reservoir. There is still considerable uncertainty about the rate of thermal draw down in conductive geothermal resources.

For the scenarios modelled here, an annual rate of decline of 0.2 per cent has been assumed for natural reservoirs and 0.3 per cent for EGS reservoirs. The maximum temperature decline allowed before the reservoir is replaced is 20°C for resource temperatures of 150°C and 30°C for higher resource temperatures (SAM does not allow the reservoir to be supplemented, only for full replacement). The rates of decline

chosen mean that the reservoir temperatures do not decline by these amounts over the life of the plant modelled in these scenarios.

Base case scenarios – thermal drawdown:

- Annual rate of decline of 0.2 per cent for natural reservoirs and 0.3 per cent for EGS reservoirs.
- Maximum temperature to decline before replacement of well field of 20°C for initial resource temperatures equal to or under 150°C and 30°C for initial resource temperatures over 150° C.

Power plant

Air-cooled binary power plants have been used for all scenarios. The use of flash-steam power plants is considered to be unlikely in Australia because of the scarcity of water needed for injection into the reservoir. SAM calculates the power plant performance based on an empirical formula derived from data from the United States. These data assume a lower ambient temperature than the average ambient temperature in Australia (10°C for the United States versus 22°C for Australia). The effect of this difference in ambient conditions is most noticeable at lower resource temperatures. The brine effectiveness has been calculated based on the ideal efficiency of binary power plants in DiPippo (2007), using the following equation:

$$b_e = 0.65\, C_p \frac{(T_r - T_0)}{(T_r + T_0)} (T_r - T_c)$$

where T_r is the temperature of the resource, T_0 is the ambient temperature, T_c is the temperature of the geothermal brine leaving the exchanger and C_p is the specific heat of the brine. For all scenarios, T_0 is 22° C, T_c is 80° C and C_p is 4.25 kJ/kg. The efficiency factor used here of 0.65 is at the upper ends of the range that DiPippo used, and assumes that power plants built in or after 2020 will incorporate modern technology at the upper end of the efficiency range. The brine effectiveness cannot be entered directly into SAM, but the plant performance can be adjusted to a user-defined percentage of the calculated performance so that the brine effectiveness that SAM uses matches the user's requirements.

The capacity factor of the power plant is another important parameter in energy generation costs. Published data for geothermal energy production worldwide shows an average capacity factor for geothermal plants worldwide of around 72 per cent (Bertani, 2010). These data are dominated by flash-steam plants and conventional geothermal resources and plants of all ages. Capacity factors in countries with more recent development of geothermal energy are higher: Germany, 86 per cent; and Indonesia, 92 per cent. With the exception of those in Germany, these are flash-steam plants. Energy production data for California and Nevada in 2010 show capacity factors similar to the global average at 72 per cent and 74 per cent respectively (data from http://www.eia.gov/renewable/annual/trends/). The SAM models do not take in to account the effects of changes in ambient temperature. The output of air-cooled binary plants that are expected to be used in Australia is expected to be affected by seasonal variations in ambient temperature. For these reasons, a value of 83 per cent has been used for the capacity factor here, which is also consistent with the AETA forecasts (Bureau of Resources and Energy Economics, 2012).

The costs of the geothermal power plant have been assumed to be $2500/kW for resource temperatures of 180°C or less and $2000/kW for resources above this temperature. Again, these costs are based on those presented in the AETA. Recent cost estimates suggest that the costs of binary power plants may be significantly higher than this, with Mines and Nathwani (2013) suggesting costs of around $US 3600/kW for geothermal power plant a resource temperature of 175° C.

Base case scenarios – power plant performance:

- Brine effectiveness of 4.692 w-hr/lb for a 150°C resource, 7.210w-hr/lb for a 180°C resource, 12.034 w-hr/lb for a 220°C resource, and 15.528 w-hr/lb for a 250°C resource.
- Capacity factor of 83 per cent.
- Capital costs of power plant of $2500/kW for resource temperatures ≤ 180°C, and $2000/kW for higher resource temperatures.

Operating and maintenance costs

The SAM model can calculate fixed and/or variable operating and maintenance costs. For the scenarios modelled here, these costs have been calculated based on a fixed rate per installed capacity of $210/kW-yr. Again, this is based on AETA where the operating and maintenance costs are calculated as a percentage of total capital costs (see Table 2), which are equivalent to approximately $210/kW-yr installed capacity. Mines and Nathwani (2013) calculated operating and maintenance costs for binary power plants of approximately $400/kW-yr.

Base case scenarios – operating and maintenance costs:

Operating and maintenance costs of $210/kW-yr of installed capacity.

Indirect capital costs

No indirect capital costs have been included except for a 15 per cent contingency on all capital costs. This contingency covers additional costs associated with engineering, procurement and contracting, land access, licensing and permitting. It also allows for some costs associated with drilling, such as trouble during drilling operations or replacement of wells that are unsuccessful.

Base case scenarios – indirect capital costs:

- 15 per cent contingency on all capital costs.

Financial

The financial parameters used in the SAM models are provided at the end of Annex A. These parameters are based on those used in the AETA (Bureau of Resources and Energy Economics, 2012). The costs of finance during construction are not considered.

Base case scenarios – financial:

- Life of plant of 30 years

SAM Results – 2020

Table 6 shows the results of the base case models, the LCOE's ranging from $170/MWh to over $300/MWh. The wide range of LCOE's across the seven scenarios show how dependent the cost of energy production is on the resource characteristics and the assumption regarding the construction costs. Figure 2 shows the results on the sensitivity analysis based on the scenario EGS C. This analysis shows that the LCOE of geothermal energy is strongly dependent on maximising the amount of energy produced per well and minimising the costs of drilling. Energy production per well is maximised by increasing the resource temperature, increasing the efficiency of the power plant, increasing the flow rate per well, and increasing the capacity factor of the plant. The costs of drilling are minimised by reducing the number of wells, which can be achieved by increasing the flow rate or reducing the ratio of injection wells to production wells. These parameters are not independent. For example, the sensitivity analysis shown in Figure 2 suggests that there is little improvement in performance with an increased flow rate. This is because as the flow rate increases, so do pumping requirements requiring an increased capacity to cover the extra parasitic load. Alternatively, larger diameter wells could be drilled to accommodate larger flows with lower pumping requirements, but this would come at the penalty of increased drilling costs. Increasing resource temperature can only be done by drilling deeper, which will increase drilling costs, once a site has been selected. The importance of resource temperature is clearly shown by comparing scenarios EGS A, B and C.

Many of the assumptions made in the SAM models could be considered to be favourable towards lower cost forecasts of geothermal energy, including the flow rate. The EGS E scenario is included to show the LCOE based on further development of Geodynamics Ltd's Innamincka Deeps resource. The scenario assumes that the no further exploration is required and a 6-inch wells would be drilled to handle the 40 kg/s flow rate that has been demonstrated from this resource.

Table 6: Results of the SAM modelling of base cases

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Temperature °C	150	180	150	180	220	250	220
Flow rate (kg/s)	100	100	80	80	80	80	40
Overnight capital costs ($2014/kW)	10,077	9,273	14,124	19,532	10,754	11,941	13,931
2020 LCOE (2014 $/MWh)	**187**	**172**	**252**	**345**	**202**	**221**	**248**

Figure 2: Sensitivity of LCOE to various parameters

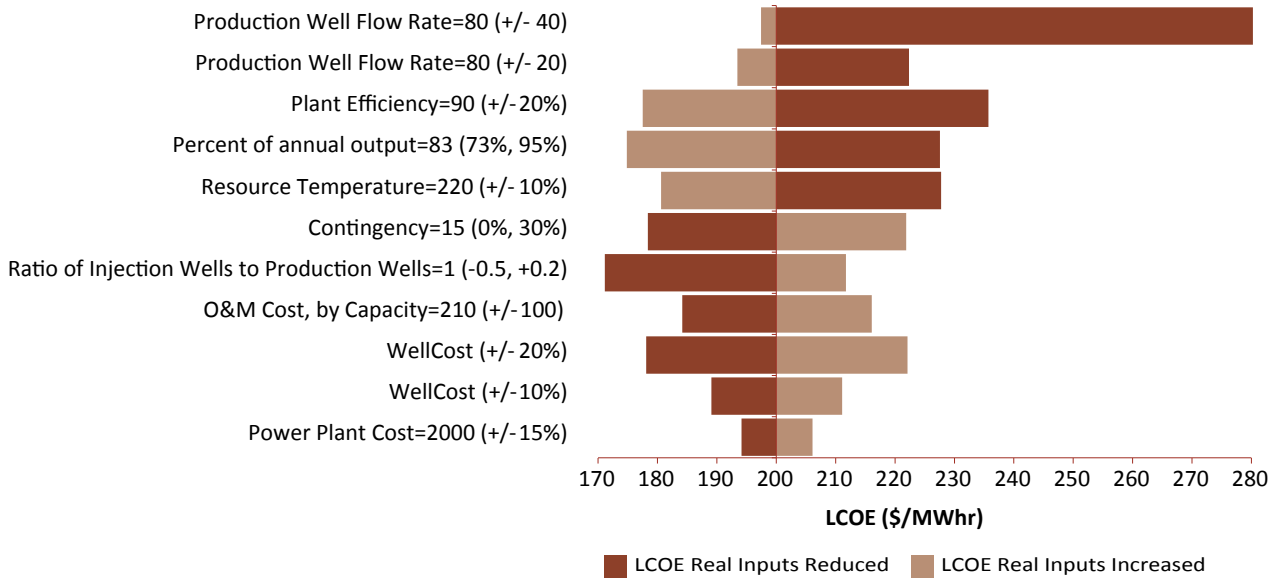
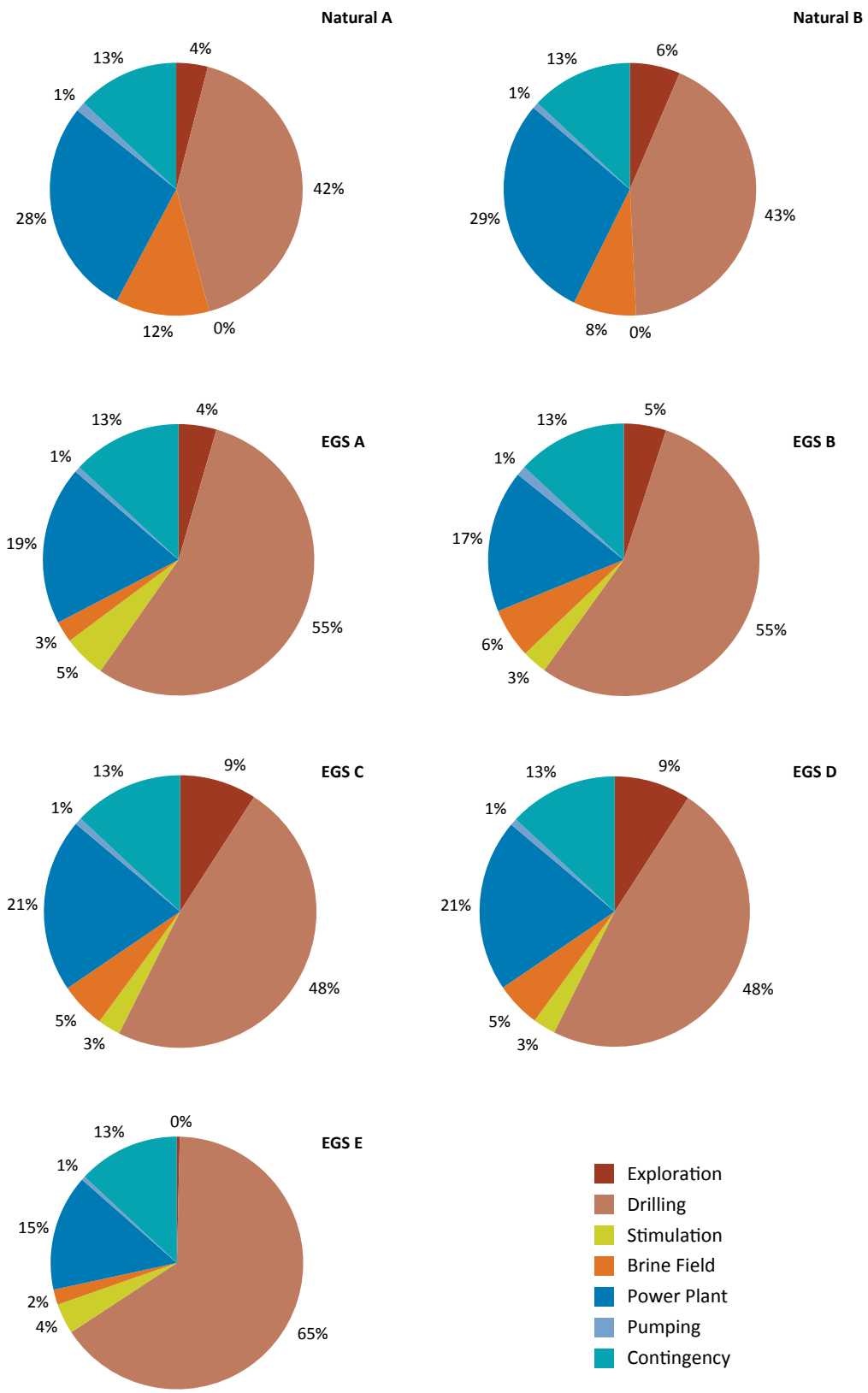


Figure 3: Breakdown of capital cost of the seven scenarios modelled using SAM

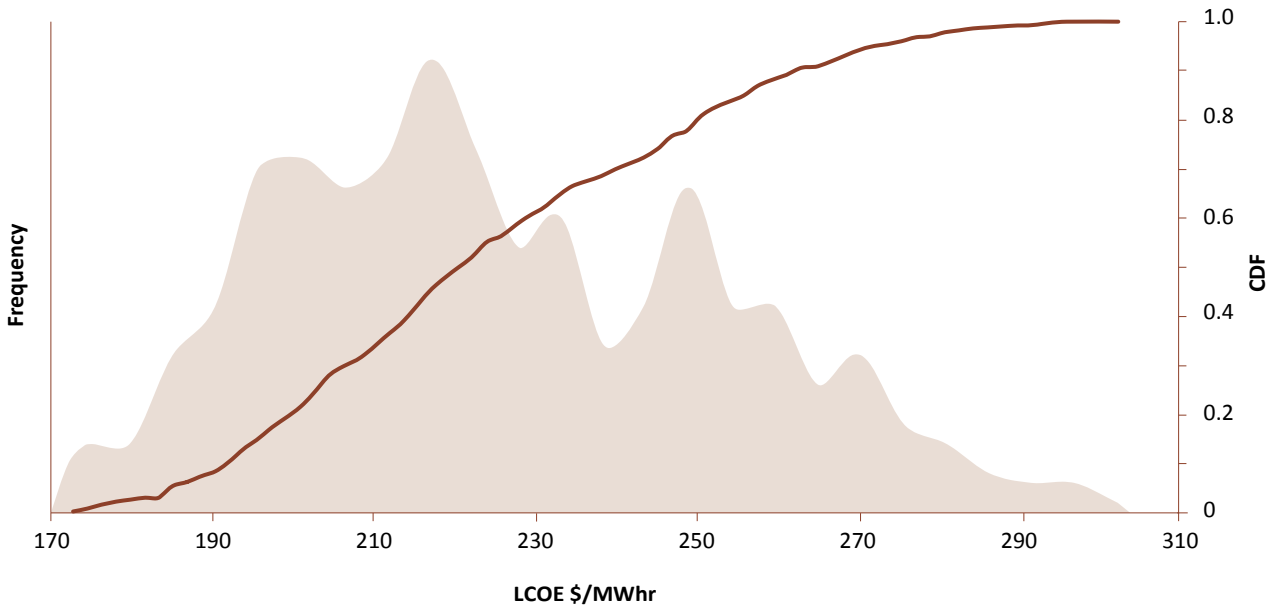


Operating and maintenance costs are also a significant contributor to the LCOE of geothermal energy (Figure 2). The plants are designed to run at low staffing levels and with minimum intervention. However, the chemistry of the geothermal fluids is a significant factor in determining the level of maintenance required in a geothermal power plant. This model did not consider the costs of drilling replacement (or make up) wells, maintenance of downhole pumps or well work-overs. Well work-overs or replacement may be required due to thermal draw down in the reservoir or degradation of hardware in the well due to the corrosive nature of geothermal fluids. Replacement wells are usually added to the overall capital costs of the project while work-overs and maintenance of pumps are included in the operating and maintenance costs.

Figure 3 shows the breakdown of capital costs for the seven scenarios modelled using SAM. The cost of drilling is the largest component in each of the scenarios. The contingency costs include the indirect cost of capital as well as contingencies for drilling costs and plant construction. In the case of natural reservoir scenarios, the cost of drilling is a smaller proportion of costs because of the assumption that drilling in sedimentary rocks will have lower cost than drilling in to crystalline basement. However, the power plant costs are higher because of the lower resource temperature.

It is important to note that there are very few precedents globally for the geothermal power plants modelled using these seven scenarios, and data for Australia is even more limited. The least supported assumptions in these models are the flow rates as the flow rates for EGS have not yet been demonstrated (except for scenario EGS E) and the flow rates for natural reservoirs have also not been demonstrated in Australia. The assumption that every well is successful is also optimistic. Further, there is a high level of uncertainty around the cost of drilling in Australia because of the small size of the drilling market and the lack of published data. Drilling costs also appear to be highly variable depending on market conditions. Figure 4 is an analysis of the range of LCOEs given uncertainty in flow rate, drilling costs, and resource temperature. A uniform distribution was used for each parameter and 500 simulations were run. The wide range of results shows the effects of uncertainty on forecasting the LCOE of geothermal energy.

Figure 4: Range of LCOEs assuming the cost of drilling varies between $18 and $23 million per well, flow rate varies between 60 and 100 kg per second, and resource temperature varies between 180 and 240°C



Towards 2030

A reduction from the levelised cost of energy in 2020 to commercially competitive levels by 2030 would require improvements in a number of areas. The following outlines a future scenario in which the right technical and market improvements have occurred to allow geothermal energy generation to substantially reduce its costs by 2030. An underlying assumption is that the imperative for reducing global reliance on fossil fuels increases creating a stronger demand for low emissions energy generating technologies.

Reliable production of geothermal brine at high flow rates is a key component of commercially competitive geothermal energy projects. The effectiveness of reservoir stimulation could increase significantly over the next decade as technology is driven by developments in the international geothermal and unconventional gas sectors. High-pressure, high-temperature unconventional gas resources have reservoir conditions that are similar to those found in conductive geothermal resources. Exploration techniques are also likely to improve that will allow the targeting of resources with favourable conditions for reservoir stimulation. In addition to improving the performance of individual wells, improved stimulation methods may also allow the ratio of production wells to injection wells to be increased.

Drilling costs are the largest contributor to the overall capital costs of geothermal energy projects. The costs of drilling in Australia would need to fall substantially (in real terms) for geothermal energy to be commercially viable in Australia. The Australian drilling sector is small, with only 13 land-based rigs operating as at the end of April 2014. The expected growth in unconventional gas development in Australia over the next decade may result in the Australian drilling market growing markedly in size. An increased size of the unconventional oil and gas sector would improve supply chains and increase experience in drilling in Australian basins, possibly reducing the costs of drilling. Another contribution to a reduction of drilling costs would be the relaxation of the requirement for a double barrier in geothermal wells. Double barriers (effectively two concentric steel casing strings) are used to protect shallow aquifers from the fluids produced from wells. Regulators may allow wells that are only producing geothermal brines to have only a single barrier, reducing the costs of geothermal wells. Other well field services, such as reservoir stimulation, would also be expected to have reductions in cost for similar reasons.

Increased activity in the unconventional gas sector in Australia would also assist the geothermal sector through the collection of data (3-D-seismic data, drilling data). This additional data would reduce risk and cost during the exploration stage of geothermal project development.

Global efforts to develop geothermal resources in conductive settings could lead to improved workflows for exploration and project development. Global developments in the geothermal sector (with both convective and conductive resources) are expected to improve the performance and reduce the costs of geothermal power plants.

If these technology advances or market-driven changes in price of component technologies for geothermal energy systems do not occur, then there will be no significant movement in the real levelised cost of energy generated from geothermal energy projects between 2020 and 2030.

Table 7 shows the results of SAM modelling on the EGS C scenario with improvements in flow rate, drilling costs, stimulation costs, plant capacity factor and reductions in the costs of the brine reticulation system through the use of pad drilling. Two cases are shown, a moderately favourable case (lower cost) and a highly favourable case (least cost). The LCOE drops by 35 per cent to 50 per cent with the reduction in the cost of drilling, the reduction in the number of wells due to a lower injection-well to production-well ratio and higher flow rates.

Table 7: SAM input parameters and model results for 2030 levelised costs assuming moderately favourable and highly favourable scenarios for geothermal energy production

These models are based on the EGS C case used in the 2020 forecast with all parameters kept the same except for those listed below.

Parameter	2020 base case (EGS C)	2030	
		Lower cost	Least cost
Temperature (° C)	220	220	220
Depth (m)	4,000	4,000	4,000
Flow rate (kg/s)	80	90	100
Number of fractures	3	4	5
Plant capacity factor	83%	95%	95%
Plant efficiency	90% of SAM model	95% of SAM model	100% of SAM model
% of confirmation wells used	50%	100%	100%
Well costs	$19.2 million	$16 million	$12 million
Ration of injection to production wells	1	0.75	0.5
Surface equipment, installation	$2 million	$1.5 million	$1 million
Stimulation costs	$1 million	$0.7 million	$0.5 million
Plant capital cost $/kW	$2000	$2000	$2000
LCOE ($2014/MWh)	**$200**	**$130**	**$99**

Summary

Exploration costs (reducing the risk)

At the early stages of the development of a geothermal energy project the risk is around characterising the resource. To be properly characterised, details of the temperature of the resource and the ability to flow fluid through the reservoir are required. The limited success in developing flow rates over 40 kg/s from EGS resources means the risk associated with flow is very high. Geodynamics's success in achieving 40 kg/s from a well is largely because this well intersects a structure (interpreted to be a thrust fault) that could be stimulated. If such structures are a prerequisite of high flow rates, then the risks and costs of the exploration stage of project development will be high.

The cost of getting to feasibility study and planning requires the collation of pre-existing data and the drilling of two confirmation wells as a minimum. Depending on the depth of the target, these costs would be in the range of $20 million to $60 million. If more than one site has been tested to have a successful discovery, the costs could be considerably higher. If advanced data interpretation methods can be proven to characterise the resource ahead of drilling, the costs will be limited to those of gathering the data required for interpretation (if 3-D seismic data is collected, these costs would be between $5 million to $10 million). Such data interpretation methods are a long way from being proven.

Costs of geothermal energy in Australia

This study of forecast geothermal energy costs in Australia suggests LCOEs in a range of $170/MWh to $300/MWh by 2020. This forecast is based on the following key assumptions:

- that the required flow rates can be achieved (80 kg/s to 100 kg/s)
- drilling costs do not increase in real terms, and
- drilling can be conducted at a very high success rate.

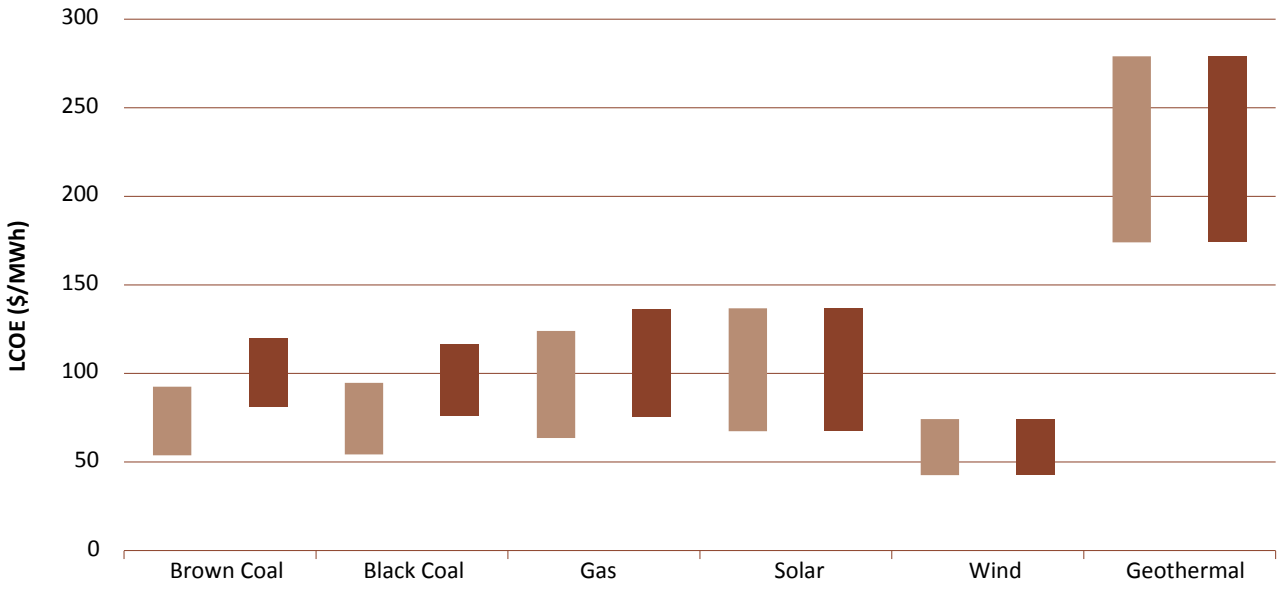
These assumptions are highly favourable. These flow rates have yet to be demonstrated in Australia or internationally in resources that are directly comparable to those found in Australia. Drilling costs are highly variable and are strongly influenced by market factors. The first deep geothermal well drilled in Australia, Habanero 1, is reported to have been drilled with a trouble-free cost of around $7 million (Tester et al., 2006) in 2003. The most recently completed well, Habanero 4, had a trouble-free cost more than three times higher than this in 2012. This difference can be partly explained by well design, but is largely due to market-driven increases in the cost of drilling in Australia.

The 2020 LCOE for geothermal energy is significantly higher than the other energy generating technologies (Figure 5), even if the flow rates required can be obtained routinely and drilling costs do not increase in real terms between now and 2020. Geothermal energy does not appear to be competitive with these other technologies in 2020 without significant subsidies, even if some of geothermal energy's other

favourable characteristics such as its dispatchable nature are considered. It should also be noted that with the long lead times for developing utility scale geothermal energy projects, it is unlikely that any significant capacity could be developed between now and 2020 even if the costs were competitive.

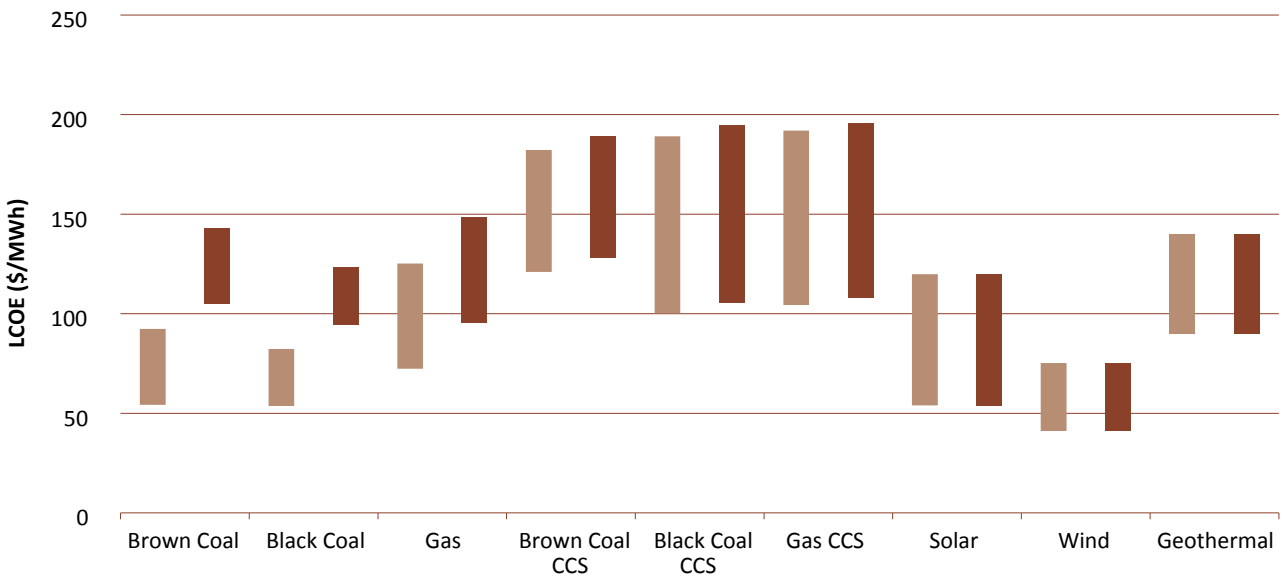
A scenario where market forces and technology improvements reduce the cost of drilling significantly by 2030 and technology for engineering geothermal reservoirs to the high flow rates required can be achieved has been considered. In this least-cost scenario, the LCOE of geothermal energy is much lower than in 2020, but still higher than some alternative renewable technologies such as wind (Figure 6). In this scenario, geothermal energy may be competitive in niche off-grid applications where its dispatchable nature and small physical footprint compared to other renewable energy technologies has added value.

Figure 5: 2020 costs (light brown, no carbon price, dark brown, carbon price)



Data for geothermal energy from this study. Other data from Australian Energy Market Analysis for IGEG, CSIRO.

Figure 6: 2030 Costs (light brown, no carbon price, dark brown, carbon price)



Data for geothermal energy from this study. Other data from Australian Energy Market Analysis for IGEG, CSIRO.

A.1 SAM inputs technical and engineering – base cases

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Ambient conditions input page							
Not used in these models (GETEM power block used)							
Geothermal resource input page							
Resource characterisation							
Resource type[1]	EGS	EGS	EGS	EGS	EGS	EGS	EGS
Total resource potential (MW)[2]	5,000	5,000	5,000	5,000	5,000	5,000	5,000
Resource temperature (°c)	150	180	150	180	220	250	220
Resource Depth (m)	2,500	4,000	3,000	4,000	4,000	5,000	4,000
Reservoir parameters							
	Calculate the reservoir pressure change using permeability x area selected						
Width (m)	1,000	1,000					
Height (m)	200	200					
Permeability (Darcy)	0.25	0.25					
Distance from injection to production wells (m)	1,000	1,000					
			Calculate the reservoir pressure change using simple fracture flow (EGS only) selected				
Fracture aperture (m)			0.0003	0.0003	0.0003	0.00025	0.0003
Number of fractures			3	3	3	3	3
Fracture width (m)			500	500	500	500	500
Fracture angle (deg from horizontal)			1	1	1	1	1
Sub-surface water loss (% of water injected)			1	1	1	1	1
Distance from injection to production wells (m)			1,000	1,000	1,000	1,000	1,000
Plant and equipment input page							
Plant configuration							
Specify plant output (kW)	50,000	50,000	50,000	50,000	50,000	50,000	20,000
Conversion type	Binary	Binary	Binary	Binary	Binary	Binary	Binary
Plant efficiency (%)	65	70	65	70	90	100	90
SAM actual plant efficiency (W-hr/lb)	4.692	7.210	4.692	7.210	12.034	15.528	12.034
SAM default plant efficiency (W-hr/lb)[3]	7.219	10.300	7.219	10.300	13.371	15.528	13.371
GETEM brine effectiveness (W-hr/lb)[3]	4.630	8.268	4.630	8.268	13.221	15.618	13.221
Dipippo brine effectiveness 2280 (W-hr/lb)[3]	4.275	7.236	4.275	7.236	12.051	16.233	12.051

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Getem thermal efficiency 2280[3]	6.2	9.1	6.2	9.1	11.8	12.2	11.8
Dipippo thermal Efficiency 2280[3]	9.8	11.6	9.8	11.6	13.8	15.3	13.8
Plant design temperature	Automatically set to resource temperature for all cases						
Temperature decline							
Specify temperature decline rate (%/yr)	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Maximum temp to decline before reservoir replacement (° C)	20	20	30	30	30	30	30
Pumping parameters							
Production well flow rate kg/s per well	100	100	80	80	80	80	40
Pump efficiency	60%	60%	60%	60%	60%	60%	60%
Pressure difference across surface equipment (psi)	25	25	25	25	25	25	25
Excess pressure at pump suction (psi)	50	50	50	50	50	50	50
Production well diameter (inches)	8	8	8	8	8	8	6
Production pump casing size (inches)	8	8	8	8	8	8	6
Injection well diameter (inches)	8	8	8	8	8	8	6
Power block page							
Power block model							
Model	GETEM	GETEM	GETEM	GETEM	GETEM	GETEM	GETEM
Power block design point **NOT USED**							
Cooling system **NOT USED**							
Performance adjustment page							
System output adjustments							
Percent of annual output (%)	83	83	83	83	83	83	83
Geothermal system costs page							
Number of wells to drill							
% of confirmation wells used for production	50	50	50	50	50	50	100
Ratio of injection wells to production wells	1	1	1	1	1	1	1
Drilling and associated costs							
Exploration well cost multiplier	1	1	1	1	1	1	1
Exploration number of wells	0	0	0	0	0	0	0

Parameter	Natural reservoir A	Natural reservoir B	EGS A	EGS B	EGS C	EGS D	EGS E 6" Wells
Exploration non-drilling cost	$2 million	$2 million	$2 million	$2 million	$2 million	$2 million	$1 million
Confirmation well cost multiplier	1.2	1.2	1.2	1.2	1.2	1.2	1.2
Confirmation number of wells	2	2	2	2	2	2	0
Confirmation non-drilling cost (per well)	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000	$0
Cost curve multiplier	7,200,000	11,200,000	11,200,000	19,200,000	19,200,000	28,800,000	16,800,000
Cost curve exponent	0	0	0	0	0	0	0
Production and injection Wells – non-drilling costs	0	0	0	0	0	0	0
Surface equipment, installation[4]	$2 million	$2 million	$2 million	$2 million	$2 million	$2 million	$2 million
Stimulation cost (per well)	0	0	$1 million	$1 million	$1 million	$1 million	$1 million
Plant capital cost Set to 'Calculate'.							
Cost ($/kW)	2,500	2,500	2,500	2,000	2,000	2,000	2,000
Pump cost inputs Set to 'calculate'.							
Installation and casing cost ($/ft)	75	75	75	75	75	75	75
Pump cost ($/hp)	15,000	15,000	15,000	15,000	15,000	15,000	15,000
Recapitalisation cost Set to 'Calculate'. Only required if the reservoir needs to be redrilled due to thermal draw down.							
Total installed costs							
Contingency	15%	15%	15%	15%	15%	15%	15%
Indirect capital costs							
Engineer, procure, construct (% of direct cost)	0	0	0	0	0	0	0
Project, land, miscellaneous (% of direct cost)	0	0	0	0	0	0	0
Sales tax	0	0	0	0	0	0	0
Operation and maintenance costs Escalation rate set to 0%							
Fixed annual cost	0	0	0	0	0	0	0
Fixed cost by capacity ($/kw-yr)	210	210	210	210	210	210	210
Variable cost by generation	0	0	0	0	0	0	0

[1] The EGS resource type is more suitable for modelling conductive resources whether they are EGS or natural reservoirs.

[2] The resource potential the first the total size of the resource that could be developed. The size is set arbitrarily high and has no bearing on the cost estimates in this model.

[3] Not SAM input, included for information only.

[4] Surface equipment includes wellheads, the brine reticulation system, steam separators etc.

A.2 SAM inputs – financial

The following inputs were used uniformly across all scenarios modelled using SAM.

Parameter	Value	Description
SAM case		
Financial model	Utility Independent Power Producer	SAM has a range of financial models that can be used. The Utility Independent Power Producer model is for a project developed and owned by single entity that sells electricity at a price negotiated through power purchase agreement. The model calculates project LCOE, NPV and PPA price based on a target IRR.
Sam financing tab		
Solution mode	Specify IRR target	SAM has two solution modes for this financial model. In this case, an IRR target is specified and SAM calculates a PPA price.
Minimum required IRR	12.75.%	The target IRR. To calculate the correct real LCOE in SAM, the target IRR and the nominal discount rate must be the same (Lovegrove et al., 2013).
Require a minimum DSCR	No	No minimum debt-service coverage ratio.
Require a positive cash flow	No	Positive cash flow not required.
Financial optimisation	No	SAM can pick the debt fraction to minimise LCOE or pick a PPA escalation rate to minimise LCOE. These options aren't used in this model.
Debt fraction	0%	AETA does not consider the source of finance and so it is not considered here.
Loan term	0	AETA does not consider the source of finance and so it is not considered here.
Loan rate	0	AETA does not consider the source of finance and so it is not considered here.
Analysis period	27 years	27 years as the default period used in AETA. This period is from the commencement of construction. AETA assumes a three-year construction period.
Inflation rate	2.50%	This is the midpoint of the Reserve Bank of Australia's target range for inflation.
Real discount rate	10.00%	This is the default value used in AETA.
Federal income tax rate	0%	AETA does not consider federal taxes and so they are not considered here.
State income tax rate	0%	State taxes are not relevant in the Australian context, although the relevant state governments are likely to impose some kind of royalty on geothermal projects. AETA does not consider royalties and so they are not considered here.
Sales tax	0%	Sales tax is not applicable in the Australian context. The GST has not been included.
Last property tax	0%	Property tax is not applicable in the Australian context.
Salvage value	0%	Salvage costs are assumed to cover the commissioning costs.
Construction financing	See Note	AETA assumes a three-year construction period with capital costs of 40%, 40%, and 20% across those three years although the cost of construction financing is ignored. SAM calculates an overnight capital cost, and the cost of construction finance will also be ignored these models.

Annex B Stakeholder engagement

More than 40 stakeholders from the geothermal industry, the research sector, the resources and energy sectors, services companies, the financial services sector and government were invited to take part in the first round of stakeholder engagement in October 2013. The two peak geothermal organisations, the Australian Geothermal Energy Association (AGEA) and the Australian Geothermal Energy Group (AGEG) as well the Geothermal Research Initiative (GRI) were invited to participate. The Australian Geothermal Energy Association (AGEA) and Geoscience Australia (GA) were briefed on the IGEG project in September 2013.

Three members of the IGEG, Quentin Grafton, Susan Petty and Roland Horne, held meetings in Sydney, Brisbane and Adelaide from 14 to 18 October 2013 with 18 different stakeholders representing peak bodies (AGEA, AGEG and Clean Energy Council), geothermal companies (Geodynamics, Petratherm, Hot Rock Ltd, Green Rock), resource companies (Rio Tinto and Beach Energy), energy companies (AGL, Energy Australia, Ergon), researchers, AEMO and the finance sector. Michal Moore and Bill Livesay participated in some of these meetings by teleconference. Bill Livesay was unable to travel to Australia at the last minute due to health concerns. The IGEG members also met with the CEO and Chair of the ARENA Board.

The IGEG received five written submissions one of which is commercial-in-confidence with the remaining four – from National ICT Australia, Geoscience Australia, SA Centre for Geothermal Energy Research and AGEA – being made public along with this Report.

The Chair of the IGEG, Professor Quentin Grafton, attended the Australian Geothermal Energy Conference (Brisbane, November 2013) and the South Australian Unconventional Gas Workshop (Adelaide, December 2013) and used both opportunities to engage with stakeholders.

All of the participants in the October round of stakeholder meetings were invited to participate in the Expert Group's presentation of preliminary findings and an open invitation was extended via the ARENA website.

Three members of the Expert Group, Quentin Grafton, Michal Moore and Roland Horne, presented the IGEG's preliminary findings to stakeholders at meetings in Brisbane and Adelaide on 12 and 13 February 2014. The PowerPoint deck of the Expert Group was also distributed to stakeholders who were not able to attend the meetings. These meetings were designed to provide stakeholders with the opportunity to critique and question the Expert Group's understanding of the key issues and its main assumptions regarding the status of geothermal energy in Australia. Susan Petty participated in the sessions by teleconference. Participants were also invited to submit written feedback on the presentation and two additional written submissions, both commercial-in-confidence, were received in response to the presentation of preliminary findings.

The International Geothermal Expert Group members met with the ARENA CEO on 14 February 2014.

Key themes from stakeholder submissions

Barriers

- Common Themes - Technical
  - Technology Readiness Level is lower than previously thought – more R&D is needed
  - Some R&D may have been misdirected
  - Drilling costs are high and uncertain
  - Finding/creating permeability is a key technical issue
  - Insufficient understanding of what constitutes a suitable resource and their location
  - Challenge of find permeability/flow (or rocks in which permeability can be enhanced)
- Common Themes - Economic
  - Low cost incumbents (competitors) in electricity market, no growth in electricity demand, and price too low
  - Investor sentiment is negative – need to see a number of demonstration plants, with a low failure rate (there is actually a higher burden to overcome following failure than starting from scratch)
  - Geothermal electric will not be commercial (cost competitive) within 10 years
  - Off-grid users' key drivers are: (1) reliability and (2) costs competitiveness with other energy options
  - Claim is that LCOE's from geothermal energy projects range between $60/MWhr and $250/MWhr

Funding and Policy Options

- Common Themes
  - Sector needs intensive capital support, with government investment required now for geothermal to be a possible energy option in the future
  - Co-ordinated program of investment that is consistent and sustained with funding of demonstration projects is required between now and 2020
  - Co-ordinated research and pre-competitive data programs is required
  - A consistent and stable policy environment with regulatory support (FITs, RETs, etc.) is required to ensure growth in the geothermal sector
  - Focus funding where it generates the best value and outcomes rather than spread the money too thinly across many projects
  - Consider direct-use applications as part of the pathway to cost-competitive energy source
  - Government grant conditions need to be pragmatic and flexible to changing circumstance

Annex C Briefing note: Commercial Readiness Index

Prepared for the ARENA International Geothermal Expert Group by Dr Cameron Huddlestone-Holmes, Geothermal Energy Stream Leader, CSIRO.

ARENA's Commercial Readiness Index

ARENA has developed the Commercial Readiness Index (CRI) to assist in identifying where a technology or project is located in the commercial development cycle. CRI's consider all aspects of a technology's readiness, including the maturity of the technology, costs, market and the supporting framework. The CRI was developed by ARENA as there was no other metric suitable for this task.

The Technology Readiness Level (TRL) index is a globally accepted benchmarking tool for tracking progress and supporting development of a specific technology through the early stages of the innovation chain from blue-sky research (TRL 1) to actual system demonstration over the full range of expected conditions (TRL 9). The TRL methodology was developed by Stan Sadin with NASA in 1974 (see http://www.nasa.gov/ topics/aeronautics/features/trl_demystified.html). Since its inception, the process has evolved and is used across a wide range of sectors including renewable energy. ARENA uses the TRL index in the Emerging Renewables Program and R&D Program to help applicants in the early stages of technology development identify the stage of development of their particular innovation. While the majority of technology risk is retired through the TRL1–9 framework there is often significant commercial uncertainty/risk remaining in the demonstration and deployment phase. New technology/entrants entering a market place typically supplied by proven incumbents and financed by capital markets that are often risk adverse, face a multi-faceted range of barriers during the commercialisation process. This is particularly relevant in the context of renewable energy where capital cost and therefore access to capital is a key barrier to accelerating deployment.

Historically, the majority of support for the development of new renewable energy technologies has been through the provision of upfront capital grants. Upfront grants can be useful in assisting companies with acquiring funding for their projects, especially where they are small scale and the Government funding covers most of the costs. Yet through this historic funding process, it is acknowledged that rapid change has enhanced risks to projects. Projects that have attempted to go straight from bench/desktop to demonstration at a commercial-scale face the greatest challenges, such as raising private sector co-investment commitments, costs exceeding early expectations and the external market context changing over time such that the original goals no longer will deliver a sustainable commercial proposition. ARENA has been given a broad mandate for assisting renewable energy technologies and projects through to commercialisation, accordingly, ARENA will structure its funding support to best reduce risks and barriers at the various stages of the innovation chain.

ARENA may use the CRI to provide a set of measureable criteria that can be used to assist applicants for funding to identify where the proposed project will advance the 'commercial readiness' of the underlying technology / commercial proposition. The CRI can assist ARENA to identify where the critical barriers are to the development of a technology and then to develop strategies and programs that address these programs. To date, the CRI has only been applied to the Accelerated Step Change Initiative (ASCI).

Commercial Readiness Index in practice

There are two components to the CRI, the summary status rating (CRI 1–6) and the detailed indicators. The status summary is the single, overall rating numbered 1 to 6 (Table 1). The status summary rating correlates to the current status in the market, such as commercial trial (CRI 2) or multiple commercial applications (CRI 4), and so on. The summary status is determined by evidence in the market (i.e. has there been a commercial trial conducted or not?) and does not require that each of the individual indicators are at the same level. In most cases, an individual project will not raise the overall summary status but rather will increase an indicator/s.

The individual status *indicators* are used to reflect the commercialisation process of renewable energy. The CRI addresses a range of interlinked barriers in making progress towards widespread deployment. In drawing on past experience, consulting with stakeholders and reviewing available literature, ARENA identified eight indicators that can be quantified (Table 2). To improve a technology or application's overall commercial readiness, it is believed that it needs to progress along each of these dimensions. Detailed descriptions of these indicators are included in Appendix C.1.

The summary status and individual indicators are displayed together in the final CRI assessment (Figure 3). This provides a quick overview of the commercial readiness of a technology or project. In grant applications, a project proponent can show how the individual indicators will change as a result of their project.

Figure 1: The relationship between the CRIs and TRLs

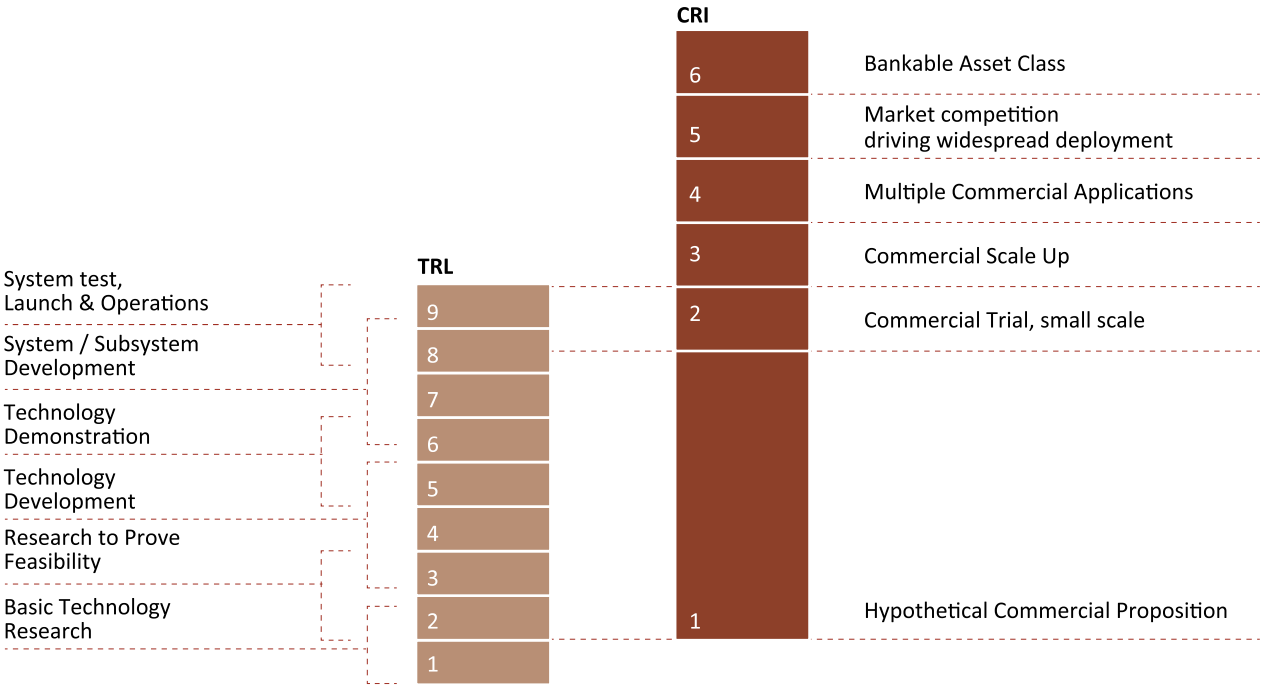


Figure 2: TRLs and CRIs mapped on innovation chain

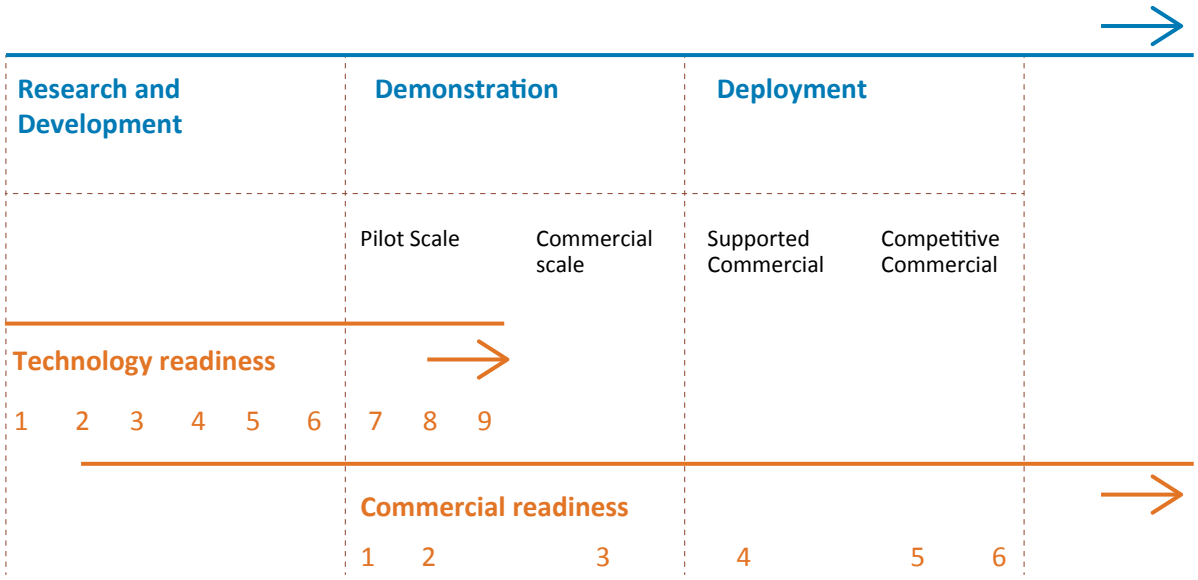


Table 1: Description of the Commercial Readiness Index status summary level

Status Summary	Descriptions
6	**'Bankable' grade asset class** driven by same criteria as other mature energy technologies. Considered as a 'bankable' grade asset class with known standards and performance expectations. Market and technology risks not driving investment decisions. Proponent capability, pricing and other typical market forces driving uptake.
5	**Market competition driving widespread deployment** in context of long-term policy settings. Competition emerging across all areas of supply chain with commoditisation of key components and financial products occurring.
4	**Multiple commercial applications** becoming evident locally although still subsidized. Verifiable data on technical and financial performance in public domain driving interest from variety of debt and equity sources however still requiring government support. Regulatory challenges being addressed in multiple jurisdictions.
3	**Commercial scale up** occurring driven by specific policy and emerging debt finance. Commercial proposition being driven by technology proponents and market segment participants - publically discoverable data driving emerging interest from finance and regulatory sectors.
2	**Commercial trial:** Small-scale, first-of-a-kind project funded by equity and government project support. Commercial proposition backed by evidence of verifiable data typically not in public domain.
1	**Hypothetical commercial proposition:** Technically ready – commercially untested and unproven. Commercial proposition driven by technology advocates with little or no evidence of verifiable technical or financial data to substantiate claims.

Table 2: Description of the Commercial Readiness Index indicators

Indicators	Summary of indicators
Regulatory environment	The maturity of the planning, permitting and standards relating to the technology.
Stakeholder acceptance	The maturity of the process for evidence based stakeholder consultation linked to renewable energy integration into the energy markets.
Technical performance	The availability of discoverable technical performance information.
Financial proposition – costs	The availability of robust, competitive financial information linked to capital and operating costs and forecast revenues allowing investors to take increasing levels of future market and project risk.
Financial proposition – revenue	
Industry supply chain and skills	The development of a competitive and efficient industry product and skills supply chain required to support a commercially viable sector.
Pathway to market	The development from a hypothetical commercial plan to the emergence of competitive channels to market and sustainable business models that underpin deployment.
Company maturity	The development of the sector to include established companies with strong credit ratings and established performance records.

Figure 3: Commercial Readiness Index – summary status and indicators template

			INDICATORS							
			Regulatory environment	Stakeholder acceptance	Technical performance	Financial proposition - costs	Financial pProposition - revenue	Industry supply chain and skills	Pathways to market	Company maturity
STATUS SUMMARY	'Bankable' Grade asset class	6								
	Market competition driving widespread deployment	5								
	Multiple commercial applications	4								
	Commercial scale-up	3								
	Commercial trial	2								
	Hypothetical commercial proposition	1								

Commercial Readiness Level assessments for geothermal energy

ARENA convened a workshop with representatives of the geothermal energy community to discuss the CRI and to assess the Commercial Readiness Levels (CRI) for geothermal energy in June in 2013. The assessment below is based largely on the outcomes of those workshops. The workshops were attended by four ARENA staff (including the CEO, Ivor Frischknecht) and one board member (Mark Twidell), along with representatives from several companies, universities, CSIRO, Geoscience Australia and DMITRE.

Ivor Frischknecht explained that ARENA was looking for more measurement and rigour for proposed projects. Project proposals need to show how individual projects will progress the technology they represent to higher CRIs.

At the workshop, the attendees agreed that 'geothermal energy' covered too broad a range of resources and technologies for a single assessment. The group agreed on the three categories of resources described in section 1.2 of the Geothermal Energy in Australia report. These three categories are:

- *Shallow Direct Use*: Typically in the 500 m to 1500 m depth range targeting aquifers with high permeabilities at low to moderate temperatures for direct use applications. Geothermally heated swimming pools in Perth are an example.
- *Deep Natural Reservoir*: Typically greater than 1,500 m deep targeting aquifers with high permeabilities (no or minimal stimulation required) for direct use or electricity generation. These resources are in sedimentary aquifers (the fluid is stored within the space between sedimentary grains), fractured aquifers (the fluid is stored and flows within fractures in the rock) or some combination of the two. Examples include proposed deep HSA/direct use applications in Perth and the resources targeted by Salamander-1 and Celsius-1.
- *Enhanced geothermal systems (EGS)*: Geothermal resources where the reservoir needs to have its permeability increased via the stimulation of existing structures or the creation of new ones. Heat may be used for direct use or electricity generation, although electricity generation is the main target. Examples include Geodynamics Ltd's Innamincka Deeps project in the Cooper Basin and Petratherm's Paralana project.

The main distinguishing feature of the Shallow Direct-use technologies is that they can be accessed by conventional water drilling rigs, are at depths where high permeabilities in sedimentary rocks are the rule rather than the exception, project costs are in the order of $1 million, and there are many commercial examples in Australia and in similar geological settings internationally.

The other two resource types require significantly deeper drilling to reach the desired temperatures, resulting in project costs in the tens of millions of dollars. There are only a few projects in Australia that have drilled in to these resources with limited international experience, particular in EGS (Deep

Natural Reservoirs are the main style of unconventional geothermal energy resource exploited in Europe). The difference between these two types of resource is that EGS resources require the permeability to be enhanced.

At the June 2013 workshop, only Shallow Direct-use and EGS resources were discussed; the CRI assessment of Deep Natural Reservoirs was added after the workshop with input from the workshop participants, using the EGS assessment as a starting point. Only the summary CRI status charts were produced at the workshop.

There was some discussion at the workshop about whether geothermal energy was at the right technology readiness level to allow its commercial readiness to be considered. The group considered that the TRL 7 lower bound for CRIs may be too high, as it is possible to have a 'hypothetical commercial proposition' (CRI Status Summary Level 1) without having proven or demonstrated technology. The group agreed to proceed with the CRI Assessments on that basis.

A comment on Technology Readiness Levels for Australian geothermal resources/technology

Before discussing the CRI of geothermal resources, it is worth considering where on the TRL scale the technology required to exploit the various geothermal resources sit.

For Shallow Direct-use (Type A) resources, there are a number of commercial operations throughout Australia where the heat is used for heating swimming pools or tourist facilities. According to the TRL scale in Appendix C.2, these systems are at a TRL equal to or greater than 7 as they are at or past the prototyping stage of their development. The component technologies for the development of these resources, including drilling, pumping, surface engineering works and resource identification are all mature. Further, such developments exist internationally. While the overall technology is relatively mature, there are some new components/subsystems that may be at a lower TRL such as when the heat from shallow geothermal resources is used in novel applications including thermal effect cooling (absorption and adsorption chillers), desalination via multi-effect distillation or low enthalpy power generation. In these cases, the individual components are mature, but few examples exist of their use as a system. Consequently, their TRL may be best described as TRL 4. For comparative purposes, the Birdsville Geothermal Power Station may be best described as at the upper boundary for Type A resources.

There are no examples of the exploitation of Deep Natural Reservoirs (Type B) in Australia. The component technologies are all proven for extracting the resource (drilling, pumping) with a number of examples internationally (particularly in Europe). Similarly, the technologies for utilising the thermal energy from these resources is also mature in the case of power stations and district heating. The international evidence is that the technology readiness for the use of these resources for electricity generation and district heating is at TRL 7.

To date, the Australian experience with these resources has been disappointing with low flow rates encountered in the Celsius 1 and Salamander 1 wells. This poor performance is related to the quality of the resource in terms of its ability to produce the required flow rates. While the properties of a reservoir are not a technology that can be developed, the exploration methods and tools used to locate a suitable resource are part of the technology set. In particular, the ability to find and target naturally permeable geothermal reservoirs at depth before drilling, and whether the permeability is in the matrix of the rock or in fractures, has not been demonstrated in Australia. This suggests a TRL of 2 to 3 for this technological component of developing a Deep Natural Reservoir. As this component appears to be critical in the successful development of this type of resource, the overall TRL for Deep Natural Reservoirs as a system in Australia cannot be considered to be any higher than 2 to 3.

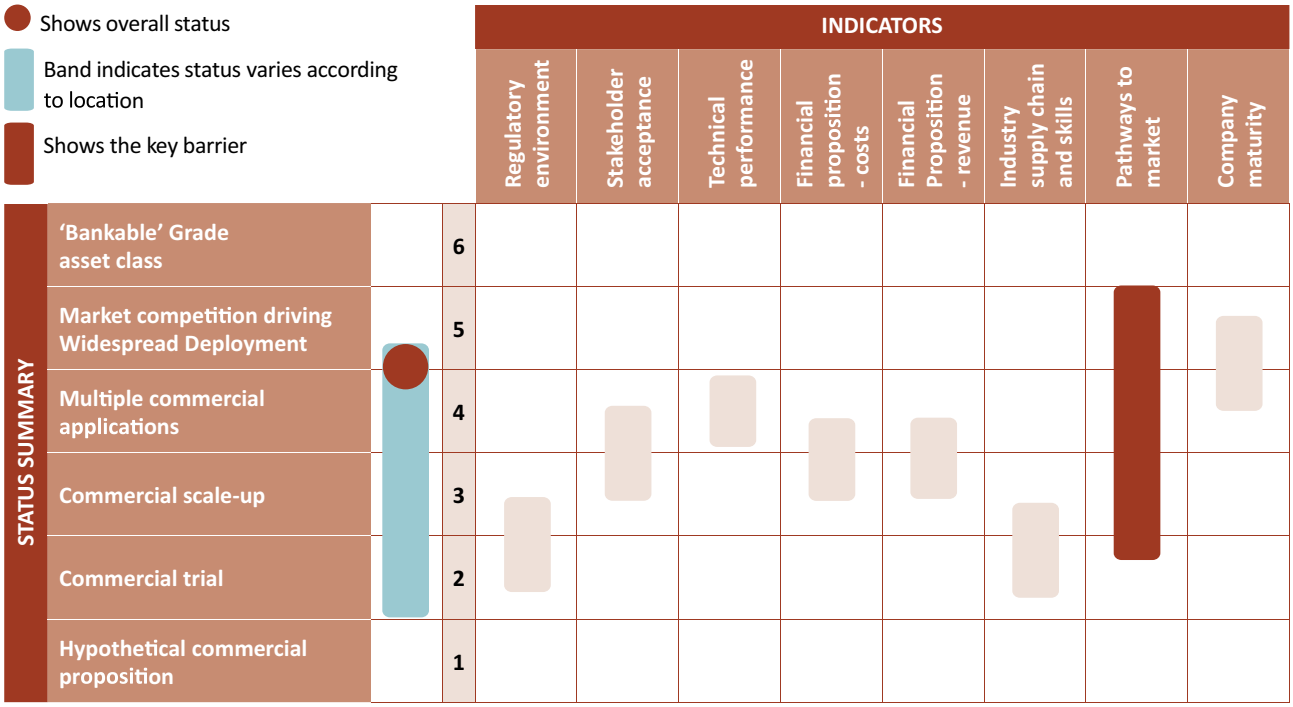
The third resource type, EGS resources (Type C), has been an area of active research and development internationally for over 40 years. During this time, several projects have demonstrated proof of concept with closed circulation loops extracting heat from reservoirs. At least two projects have produced electricity from EGS resources (Soultz in France, Innamincka Deeps Pilot Plant in Australia). This places the technology at TRL 5 in the context of Australia. Full-scale prototyping (TRL 6) would probably require the development of a demonstration plant at or close to utility scale electricity generation from several production wells.

The technology readiness of the component technologies for EGS is complex. While drilling to the depth of the reservoir has been demonstrated in a range of geological settings, the time taken to drill these wells needs improving i.e. costs need to drop substantially. Higher rate of penetration drilling technologies are being developed and these have varying TRLs. Novel methods like thermal spallation drilling have only been demonstrated in the laboratory and would be considered to be at TRL 4. Impregnated diamond bit and turbines are established technologies that are being optimised for geothermal wells and would be considered as mature as TRL 6 or 7.

Reservoir stimulation is a key component of EGS and is another technology that has been demonstrated to work in geothermal reservoirs, but much uncertainty remains over whether the resulting flow rates are sufficiently high enough to make geothermal resource commercially viable. Resource risk is another a factor in EGS with the most recent view that the resource requires pre-existing fractures, which then have their permeability enhanced (Hogarth, Holl, & McMahon, 2013). If this model is correct, this requires finding a resource that has the right pre-existing fractures for EGS. At present, exploration technologies that allow such structures to be reliably detected prior to drilling do not exist. If stimulation technologies are developed that allow new fractures to be created then these exploration technologies will not be required.

One of the key challenges in developing geothermal energy technology that sets it apart from other renewable energy is the uncertainty over the resource and the cost effective extraction of the energy. Neither the TRL nor CRI factor in this resource risk explicitly. The only way it can be captured is through the technology readiness of the workflow and methods used to reduce this risk, or through the development of reservoir development technologies that effectively decrease the importance of this risk. For example, during exploration for mineral resources explorers will often use a generic model for the style of resource for which they are prospecting. In this sense, minerals exploration has a mature technical approach to dealing with resource risk and recent and extraordinary developments of shale gas in the US show how effective reservoir engineering technologies can be at reducing resource risk. In particular, the ability to drill multiple horizontal wells from a single pad and conduct multi-stage hydraulic fracturing treatments in a single well have allowed a previously known and extensive, but previously uneconomic, resource to be developed.

Commercial Readiness Index – Shallow Direct Use (Type A)



Evidence of status summary	
Status summary:	Level 4 (Perth Basin), Level 2 to 4 (other jurisdictions – green bar)
Market position identified (CRI level 1–6)	The Perth Basin market is mature with a well-established technical and regulatory framework, demonstrated by multiple commercial applications. Projects are proceeding with little to no market intervention. Other markets are less mature.
Rationale	There are 9 projects of this kind in the Perth metropolitan area. Some have received government funding as part of overall refurbishment plans for the facilities that the geothermal resources are heating, however they can all be considered to be commercial. There are two spa facilities in Victoria that are commercial operations. These examples provide evidence of a CRI level of 4 (Multiple commercial applications becoming evident locally although still subsidised). There are limited examples in the other states. The Great Artesian Basin (Queensland and New South Wales) using water bores are not considered to be evidence of the commercial readiness of these resources as they were not developed as geothermal project and do not provide a model for future development. The pathway to market for more widespread deployment has been identified as the key barrier for this technology.

Evidence of indicators	
Indicator:	Regulatory environment
Indicator level (CRI 1–6)	Level 2 to 3
Rationale	The different state jurisdictions treat these shallow resources differently. Some differentiate them from deep geothermal resources and they are managed under water regulations (WA, NT, Qld, Vic.) while others do not. Apart from WA and Victoria, the regulatory framework has not been tested and is still developing. Regulatory approval has been on a case-by-case basis (Level 2) with some jurisdictions at the early stages of implementing specific regulations, or applying regulations used for managing groundwater resources (Level 3).

Evidence of indicators	
Indicator:	Stakeholder acceptance
Indicator level (CRI 1–6)	Level 3 to 4
Rationale	The projects in Perth have been developed without any major community concerns. These projects provide good evidence and experience that can be used to inform stakeholders (level 4). There are some concerns that more widespread uptake, and the increased public awareness that would entail, may increase the level of stakeholder concern with these projects, which will need to be managed (Level 3).

Evidence of indicators	
Indicator:	Technical performance
Indicator level (CRI 1–6)	Level 4
Rationale	Performance and key drivers understood based on the projects in Perth and Victoria. Shallow resources well characterised in many regions of Australia through water well drilling, resulting in high confidence in expected renewable resource.

Evidence of indicators	
Indicator:	Financial proposition – costs
Indicator level (CRI 1–6)	Level 3 to 4
Rationale	While the costs of these projects are not well publicised, the major components (drilling, surface engineering) are based on standard activities for which the costs are well established. Some case studies of existing projects would improve the level of knowledge within the public domain.

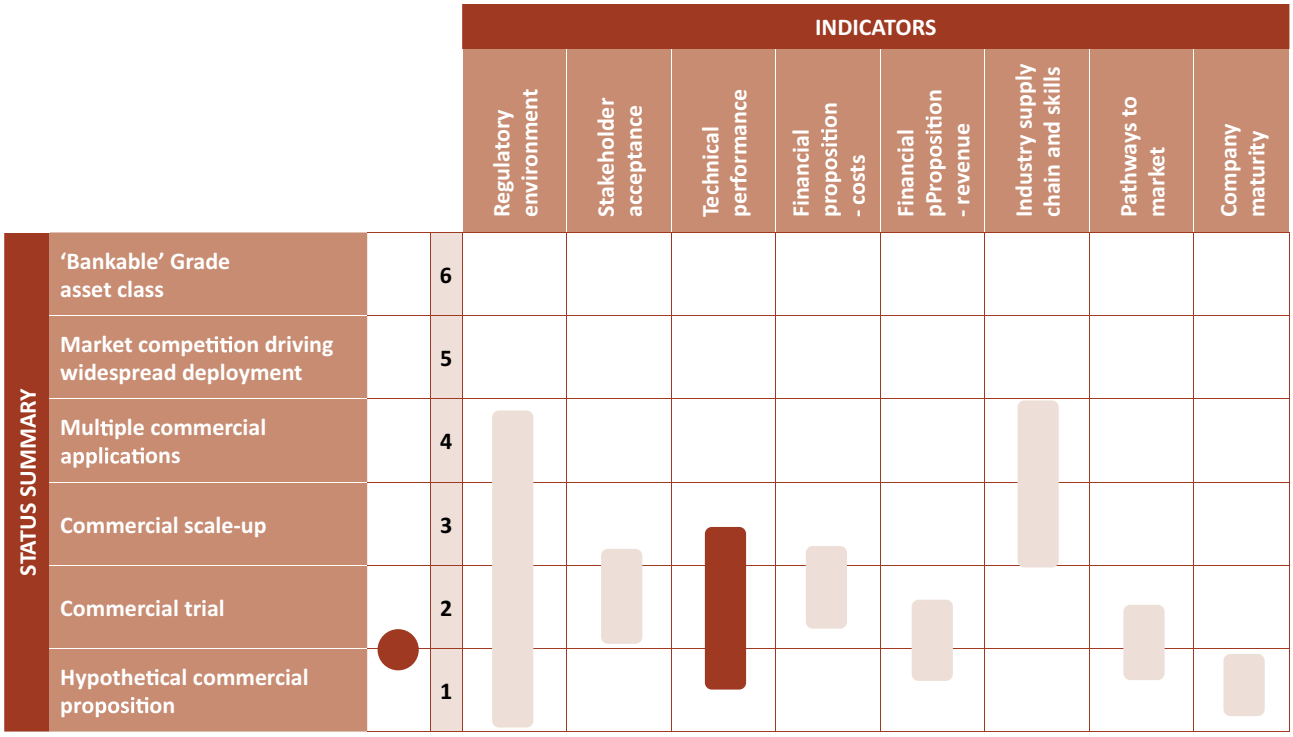
Evidence of indicators	
Indicator:	Financial proposition – revenue
Indicator level (CRI 1–6)	Level 3 to 4
Rationale	Few of these projects are directly generating revenue; rather, they are offsetting costs (reducing electricity demand for heating pools for example). The projected savings are now backed by commercial data (although case studies are required to put this knowledge in the public domain).

Evidence of indicators	
Indicator:	Industry Supply Chain and Skills
Indicator level (CRI 1–6)	Level 2 to 3
Rationale	The relatively small number of projects (averaging about one per year) means that the supply chain and skills specifically for geothermal projects using shallow resources is not well developed (Level 2). Key components (water well drilling, surface engineering) supply chains are well established, but not as a system, leading to a project by project approach from EPC providers (Level 3).

Evidence of indicators (key barrier)	
Indicator:	Pathways to market
Indicator level (CRI 1–6)	Level 2 to 5
Rationale	The market has been self-driven, with individual organisations seeking solutions to reduce their electricity demand (Perth pools) or to create business opportunities, requiring little market incentive to adopt this technology (Level 5). The pathway to market for more widespread deployment is less mature, particularly in other states without a history of these developments (Level 2), and has been identified as the key barrier for this technology. Improving the visibility of this technology and market support for early adopters is seen as critical in increasing the uptake of this technology.

Evidence of indicators	
Indicator:	Company maturity
Indicator level (CRI 1–6)	Level 4 to 5
Rationale	Typical developments using Shallow Direct-use resources are for municipalities, schools and other public entities. The engineering, procurement and construction companies involved in these projects are typically large engineering firms. The project owners and EPC providers are mature and have the resources to complete these projects once commenced (Level 5). There are some projects proposed by smaller enterprises and start-up companies, but the project costs ($100s of thousands to $1 million) are generally not within their reach.

Commercial Readiness Assessment – Deep Natural Reservoirs (Type B)



Evidence of status summary – Deep Natural Reservoirs	
Status summary:	Level 1 to 2
Market position identified (CRI 1–6)	Between hypothetical commercial proposition (CRI 1) and commercial trial (CRI 2). The commercial proposition for these resources is asserted by technology advocates on the basis that the technology is ready, but commercially untested and unproven (CRI 1). While there is international evidence that these resources can be successfully developed, little or no evidence of verifiable technical or financial data is available in Australia. Two commercial trials have been attempted in Australia and project proponents are actively pursuing a third (based on a fracture permeability model, CRI 2).
Rationale	Two projects have attempted to demonstrate these resources in Australia – at Penola and Innamincka Shallows. These two small-scale, first-of-a kind projects were funded by equity and government project support in one case and completely by equity in the other. Neither project produced the anticipated flow rates raising questions over the technical viability of developing Deep Natural Reservoirs that rely on primary permeability in Australia. As yet, trials of this technology in areas with high fracture permeability have not been completed. Such trials have been proposed by several project proponents and at least one is actively seeking government support for their project. It is possible that a project targeting fracture permeability may cross the boundary between natural reservoirs and EGS if the natural permeabilities are not high enough. Technical Performance has been identified as the key barrier to progress for Deep Natural Reservoirs, with uncertainty in the resource identified as a key risk. Finding resources with the temperature and permeability required for electricity generation at acceptable costs is critical. Technologies are required that improve the accuracy of resource characterisation (temperature, permeability) prior to drilling. An assessment of Australia's geothermal resources will also be important in establishing whether there is potential for wide spread development of Deep Natural Reservoirs. A barrier to the direct use application of the thermal energy contained in lower temperature resources is the lack of a pathway to market. There has been comparatively little work done on assessing the commercial opportunities presented by large-scale direct use of geothermal energy.

Evidence of indicators	
Indicator:	Regulatory environment
Indicator level (CRI 1–6)	Level 1 to 4
Rationale	The regulatory environment for exploring for and developing geothermal resources is well developed in most states, based on experience with other earth resources (Level 4). The regulatory framework for geothermal energy as a grid connected power provider has not been specifically defined or tested (Level 1).

Evidence of indicators	
Indicator:	Stakeholder acceptance
Indicator level (CRI 1–6)	Level 2 (workshop – Level 3)
Rationale	The workshop agreed that the level of stakeholder acceptance was at CRI 3 for EGS. The evidence makes this difficult to justify as the geothermal developments to date are very remote. A proposed project in Geelong resulted in significant community concern. Level 2 is supported by the evidence (Stakeholder support/opposition is on a case-by-case basis) for Deep Natural Reservoirs and EGS.

Evidence of indicators (key barrier)	
Indicator:	Technical performance
Indicator level (CRI 1–6)	Level 1 to 3
Rationale	Technical performance has been identified as the key barrier to the development of Deep Natural Reservoirs. Development of these resources uses proven technologies in the petroleum sector. The technical performance of the two projects in these resources in Australia has been poor due to low flow rates. Both of these projects were targeting primary permeability in sediments; resources with fracture or fault related permeability are yet to be tested in Australia. However, Deep Natural Reservoirs have been successfully developed internationally (primarily in Europe). At this stage, technical performance *in Australia* can be described as 'forecasts based on proponent modelling' (Level 1) with 'International evidence often used to support investment case' (Levels 2 and 3). There has been limited use of site-specific data capture to define renewable resource forecasts (required for Levels 2 and 3), and confidence in expected renewable resources is low. The technical performance was rated at somewhere between Levels 1 and 3, with the upper rating largely based on extrapolation from petroleum resources and international experience. Achieving reasonable technical performance (flow rates or MW/well) was considered to be the key barrier for this type of resource. The ability to reduce resource risk ahead of drilling was identified as a critical technology gap.

Evidence of indicators	
Indicator:	Financial proposition – costs
Indicator level (CRI 1–6)	Level 2
Rationale	As there are no completed pilot or demonstration projects for this type of resource, the key costs are based on 'projections with little actual data available to verify' (Level 2). The availability of costs from the petroleum sector provides the prior data that allows a rating of Level 2.

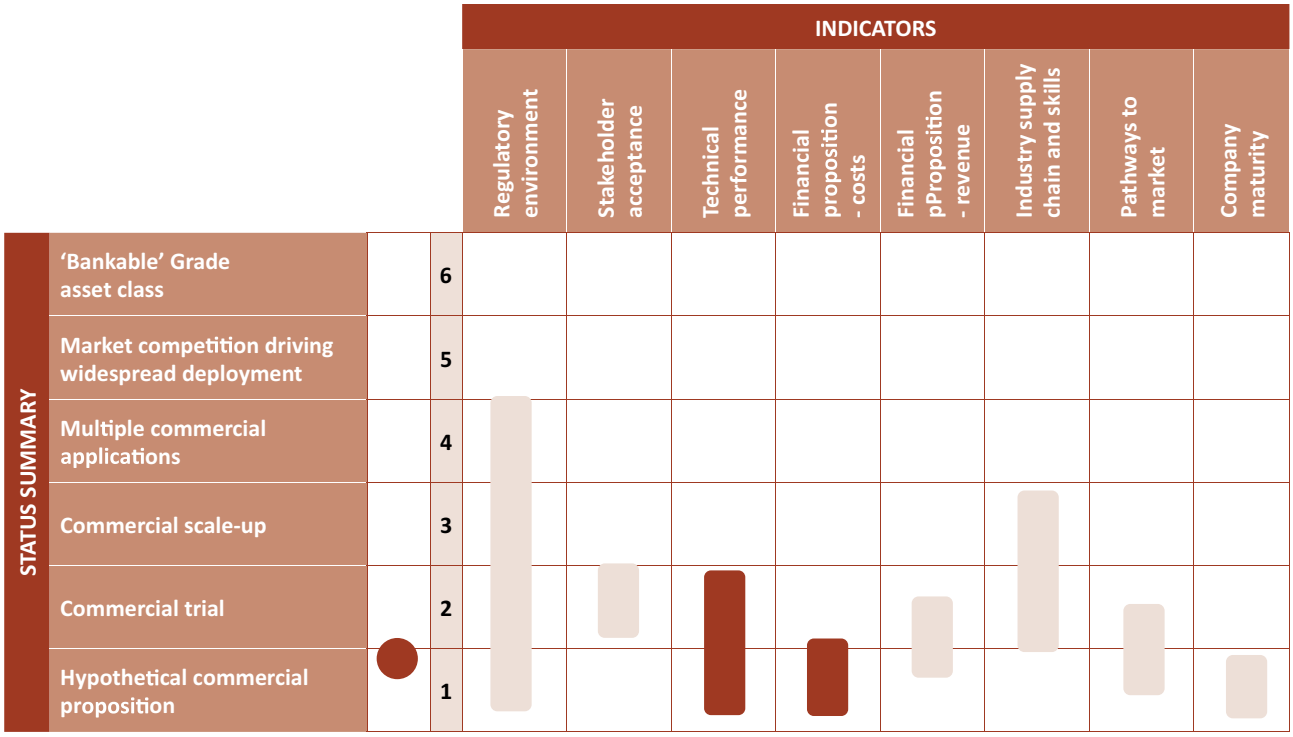
Evidence of indicators	
Indicator:	Financial proposition – revenue
Indicator level (CRI 1–6)	Level 1 to 2
Rationale	As there are no completed pilot or demonstration projects for this type of resource, there is no evidence for potential revenues for these projects (Level 1). The poor technical performance to date (in terms of the potential energy produced – MW/well) has led to a lack of market confidence (Revenue projections highly discounted by investors – Level 2).

Evidence of indicators	
Indicator:	Industry Supply Chain and Skills
Indicator level (CRI 1–6)	Level 3 to 4
Rationale	The use of standard oil-field technologies for development of these resources demonstrates that 'key skills demonstrated with replicable results' (Level 4). However, only two wells have been drilled for Deep Natural Reservoirs, with EPC providers adopting a project-by-project approach with limited prior experience in geothermal resources, leading to a project by project approach by EPC providers (Level 3).

Evidence of indicators (key barrier)	
Indicator:	Pathways to market
Indicator level (CRI 1–6)	Level 1 to 2
Rationale	The technology is at a 'Critical stage for a technology to move from a promising technical solution to a prospective commercial opportunity.' (Level 1), and there is some evidence provided by project proponents that 'there is an investment case supported by peer-reviewed business plans with verifiable cost and revenue projected'. Key risks have been identified. Individual projects have been proposed that meet the Level 2 criteria (Commercial trial has identified target market segment for a trial...even if uneconomic...to demonstrate basic commercial performance,), although funding mechanisms to bridge the gap between costs and revenue have not been established.

Evidence of indicators	
Indicator:	Company maturity
Indicator level (CRI 1–6)	Level 1 (Level 2 at workshop)
Rationale	The geothermal sector had established the Australian Geothermal Energy Association (AGEA). This industry body was 'weaker than contract counterparts' (Level 2). In November 2013, AGEA changed from an industry body to a professional association. Individual project proponents are now left to their own capabilities, with no engagement from established energy players (Level 1).

Commercial Readiness Assessment – Enhanced Geothermal Systems (Type C)



Evidence of status summary	
Status summary:	CRI 1
Market position identified (CRI 1–6)	Between hypothetical commercial proposition (CRI 1) and commercial trial (CRI 2). The commercial proposition for these resources is asserted by technology advocates on the basis that the technology is ready, but commercially untested and unproven (CRI 1). While there is international evidence that these resources can be successfully developed and one successful pilot demonstration in Australia, little verifiable technical or financial data is available. Two commercial trials have been attempted in Australia (CRI 2), although proponents of both projects are struggling to raise the necessary capital to progress.
Rationale	Two projects are attempting to demonstrate these resources in Australia – at Paralana (Petratherm) and Innamincka Deeps (Geodynamics). These two small-scale, first-of-a kind projects are funded by equity and government project support. Geodynamics' project has progressed to pilot-plant stage with a short-term trial and Petratherm has only drilled one deep well. The applicability of learnings from Geodynamics' pilot plant to other resources is unclear. Technical Performance has been identified as the key barrier to progress for EGS, with uncertainty in the resource identified as a key risk. Finding resources with the temperatures and geological conditions that allow permeability to be enhanced to the level required for electricity generation at acceptable costs is critical. Technologies are required that improve the accuracy of resource characterisation (temperature, permeability) prior to drilling at a reasonable cost. The required technical performance (primarily MW/well or flow rate) must be demonstrated to be achievable and reproducible. Reducing the overall costs of the various technology components is also seen as critical.

Evidence of indicators	
Indicator:	Regulatory environment
Indicator level (CRI 1–6)	Level 1 to 4
Rationale	The regulatory environment for exploring for and developing geothermal resources is well developed in most states, based on experience with other earth resources (Level 4 - Multiple jurisdictions with experience leading to emergence of national standards). Hydraulic fracturing operations may be contentious in states with public concerns over coal-seam gas developments (Qld, NSW and Vic.) and the response of these jurisdictions is yet to be demonstrated. Regulation of geothermal energy as a grid-connected power provider has not been demonstrated (Level 1).

Evidence of indicators	
Indicator:	Stakeholder acceptance
Indicator Level (CRI 1–6)	Level 2 (Workshop – Level 3)
Rationale	The workshop agreed that the level of stakeholder acceptance was at CRI 3 for EGS. The evidence makes this difficult to justify as the geothermal developments to date are very remote. A proposed project in Geelong resulted in significant community concern. Level 2 is supported by the evidence (Stakeholder support/opposition is on a case-by-case basis).

Evidence of indicators (key barrier)	
Indicator:	Technical performance
Indicator level (CRI 1–6)	Level 1 to 2
Rationale	Development of EGS resources largely relies on adapting technologies used in the petroleum sector. The application of these technologies in EGS is pushing them to their limits and some component technologies cannot be used or perform poorly because of the high temperatures found in geothermal resources (e.g. drilling mud systems, down hole packers, logging equipment). There is also a high degree of uncertainty in the resource. Recent results from Geodynamics' 1 MW pilot plant have been encouraging; however, this is a single data point and the validity of extrapolating these results to other locations has not been proven. There is limited international experience with only a handful of EGS projects in similar geological settings to those found in Australia. Performance forecasts are based on proponent modeling (Level 1) with some evidence from pilot scale demonstration (Level 2). Achieving reasonable technical performance (flow rates or MW/well) is considered to be the key barrier for this type of resource. This requires proving of technical performance and understanding how leanings can be transferred from site to site. The ability to reduce resource risk ahead of drilling was identified as a critical technology gap.

Evidence of indicators (key barrier)	
Indicator:	Financial proposition – costs
Indicator level (CRI 1–6)	Level 1
Rationale	The costs of developing/demonstrating EGS resources to date have been very high given the technical performance achieved. These costs need to be reduced as the technical performance is increased. Cost data (beyond pilot-plant scale) have not been established, or are prohibitively high. These high and uncertain costs have been identified as key barriers. Reduced costs for validating the resource and establishing development options prior to drilling will be critical. Reducing overall costs to acceptable levels (linked to technical performance – MW/well and $/well) is also considered critical.

Evidence of indicators	
Indicator:	Financial proposition – revenue
Indicator level (CRI 1–6)	Level 1 to 2
Rationale	As there has been only one completed pilot or demonstration project for this type of resource, there is very limited information on potential revenues for these resources (Level 1). The poor technical performance to date (in terms of the potential energy produced – MW/well) has led to a lack of market confidence (Revenue projections highly discounted by investors – Level 2).

Evidence of indicators	
Indicator:	Industry supply chain and skills
Indicator level (CRI 1–6)	Level 2 to 3
Rationale	The use of adapted oil-field technologies for reservoir development requires a project-by-project approach by EPC providers, with limited experience working in this environment (Level 3), and project developers to procure some elements to their own specifications (Level 2). Supply chains and skills are also dependent on the development of appropriate technologies that will improve the technical performance of these projects.

Evidence of indicators	
Indicator:	Pathways to market
Indicator level (CRI 1–6)	Level 1 to 2
Rationale	The technology is at a 'Critical stage for a technology to move from a promising technical solution to a prospective commercial opportunity.' (Level 1), and there is some evidence provided by project proponents that 'there is an investment case supported by peer reviewed business plans with verifiable cost and revenue projected'. Key risks have been identified. Individual projects have been proposed that meet the Level 2 criteria (Commercial trial has identified target market segment for a trial…even if uneconomic...to demonstrate basic commercial performance), although funding mechanisms to bridge the gap between costs and revenue have not been established, or have failed to achieve their goal with companies struggling to raise required equity contributions (e.g. REDP grants to Petratherm and Geodynamics).

Evidence of indicators	
Indicator:	Company maturity
Indicator level (CRI 1–6)	Level 1 (Level 2 at workshop)
Rationale	The geothermal sector had established the Australian Geothermal Energy Association (AGEA). This industry body was 'weaker than contract counterparts' (Level 2). In November 2013, AGEA changed from an industry body to a professional association. Individual project proponents are now left to their own capabilities, with no engagement from established energy players (Level 1).

C.1 Commercial Readiness Indicator Descriptions

From http://arena.gov.au/initiatives-and-programs/ the-accelerated-step-change-initiative-asci/)

Regulatory environment

CRI	Summary of indicator
6	Regulatory, planning and permitting process documented and defined with ongoing process of review and refinement. Investment markets see policy settings long term, robust and proven.
5	Regulatory, planning and permitting challenges understood and under review yet some unresolved and becoming critical as penetration grows.
4	Key findings published on planning, permitting and regulatory challenges based on actual evidence. Multiple jurisdictions with experience leading to emergence of national standards. Policy settings moving to 'Market pull'.
3	Draft recommendations emerging to address key barriers. Early developers investing in process development in order to gain certification. Policy settings focused on project/technology push.
2	Key regulatory barriers emerging that often require project specific consideration.
1	Regulatory processes including planning, permitting, OH&S, and specific Australian standards, such as electrical connection, are undefined. Timing and cost of network connection assumed in modelling but not known.

Stakeholder acceptance

CRI	Summary of indicator
6	Established process understood and expected by all parties, used to gain stakeholder acceptance.
5	Transparent process using discoverable evidence used to engage stakeholders.
4	Evidence and experience is available to inform stakeholders increasing their acceptance.
3	Broader stakeholder support issues emerging. Stakeholder concerns & addressing these become key considerations in project development timelines and future commercial uptake scenarios.
2	Stakeholder support/opposition is on a case-by-case basis, with project developer skills a critical success factor.
1	Stakeholder support/opposition is hypothetical.

Technical performance

CRI	Summary of indicator
6	Secondary markets exist to access externally verified performance information for routine due diligence. Performance review and warranty credit rating transparent.
5	Multiple data sets discoverable on commercial projects operating in range of operating environments. Performance evaluation methodology and warranties defined and driven by project financing requirements. Renewable resource forecasts highly sophisticated, based on experience from wide range of sources.
4	Performance yield, efficiency vs forecasts published and key drivers understood. Performance evaluation methodology and warranties becoming standard with key risk allocation process driving equity and debt return expectations. High confidence in expected renewable resource.
3	Performance and yield forecasts based on extrapolation from reduced scale sites / similar applications. Credit rating of project performance warranties become a key factor in bankability of project. Renewable resource forecasts driven by site-specific data capture. International evidence key in investment.
2	Performance forecasts based on simulation models referenced to evidence from R&D or pilot scale demonstration. Renewable resource forecasts driven by site-specific data capture. International evidence often used to support investment case.
1	Performance forecasts based on proponent modelling.

Financial proposition – costs

CRI	Summary of indicator
6	System cost detail widely published and accepted for multiple similar applications. Global / local price indices established and reported.
5	Price and value proposition clear with open access to cost trends and projections based on actual project data from wide range of applications.
4	Key cost elements of projects in public domain. Commoditisation of major components occurring. Cost drivers are understood with roadmaps in place to address.
3	Costs data based on projections from single site / comparable site type application. Key cost drivers are understood enabling broader market to judge long-term prospects of technology.
2	Key costs based on projections with little actual data available to verify.
1	Cost data (if available) based on projections and forecasts with little or no prior data to substantiate.

Financial proposition – revenue

CRI	Summary of indicator
6	Revenue forecasting proven and accepted by finance industry with transparent benchmarking evident. Examples of different forms of market participation strategies with debt finance willing to back merchant risk.
5	Revenue projections based on proven forecasts and accepted commercial data. Greater PPA/contract optionality for utility scale developers with investors comfortable with underlying value of proposed asset.
4	Revenue projections backed by commercial data. Price gaps understood and roadmaps in place to address. Long-term PPAs/contracts required to secure debt.
3	Revenue projections being tested in commercial context, highly discounted by investors with requirements for long-term PPAs/contracts for utility scale applications.
2	Revenue projections highly discounted by investors.
1	Revenue data based on projections and forecasts with little or no prior data to substantiate.

Industry supply chain and skills

CRI	Summary of indicator
6	Multiple alternatives with proven capability. Project and service differentiation key selection factor.
5	Specialisation occurring along supply chain with standards defined and supplier performance externally benchmarked.
4	Key skills demonstrated with replicable results. Limited supply options proven. Time to build a key driver of future efficiencies.
3	Project by project approach from EPC providers with limited prior experience. Limited availability of key components and EPC / O&M skills.
2	Supply chain not available for many key components. Project developer typically designing and procuring multiple elements to own specification. EPC costs often based on time and materials with high degree of risk loading.
1	Supply chain not fully considered with key elements typically from specialist source, often under technology proponent specification.

Pathways to market

CRI	Summary of indicator
6 5	Market driving the investment process with little or no concessional policy support. External factors may slow down or accelerate ongoing deployment. Pathways to market clear and understood.
4	Market demand primary driver of the investment case with clarity on market segments and industry supply chain / market channels to deliver. Funding gaps between net present value of revenue and cost understood with target segment customers a key stakeholder in the investment decision process. Some concessional policy support required to drive uptake.
3	Focus moving from proving commercial performance to optimising project cost and revenue structures and lowering $/unit of energy support required in the target market segment. Post subsidy revenues generating sufficient cash flow to service debt and equity expectations.
2	Commercial trial has identified target market segment for a trial with goal of proving to future investors that the technology can operate reliably and generate predictable revenue from a cost base that is understood even if still uneconomic. The commercial trial does not seek to optimise $/unit but seeks to balance the absolute cost of the trial with the scale required to demonstrate basic commercial performance.
1	Critical stage for a technology to move from a promising technical solution to a prospective commercial opportunity. Investment case for commercial trials supported by evidence of peer reviewed business plans with verifiable cost and revenue projected estimates and early channel to market identified. Key risks identified both within and external to the proponents sphere of control.

Company maturity

CRI	Summary of indicator
6	Leading proponents are major, public companies with large balance sheets. Management capability no longer a consideration for most projects as proponents have track record.
5	Leading players in sector have significant balance sheets and wide management experience in energy and delivery of technology / project class.
4	Established energy players now also considered part of the sector (although at the edge). Balance sheets and the influence of technology proponents increasing. Capability of management still a significant factor in project selection.
3	Industry bodies in place and strongly representing sector to external stakeholders. Industry still driven by technology proponents.
2	Industry bodies have formed but are weaker than contract counterparts.
1	Established energy players not yet part of sector. Management capability is dependent on individual proponent.

C.2 Technology Readiness Level Descriptions used by ARENA

These are the Technology Readiness Level (TRL) descriptors used by ARENA, from ARENA's R&D Program Information manual (arena.gov.au/initiatives-and-programs/research-and-development-program/). ARENA has not defined TRLs 8 and 9. The definitions presented here are based on definitions used by the U.S. Department of Energy (U.S. Department of Energy, 2011).

TRL 1	**Basic principles observed and reported:** Transition from scientific research to applied research. Essential characteristics and behaviours of systems and architectures. Descriptive tools are mathematical formulations or algorithms.
TRL 2	**Technology concept and/or application formulated:** Applied research. Theory and scientific principles are focused on a specific application area to define the concept. Characteristics of the application are described. Analytical tools are developed for simulation or analysis of the application.
TRL 3	**Analytical and experimental critical function and/or characteristic proof of concept:** Proof of concept validation. Active research and development is initiated with analytical and laboratory studies. Demonstration of technical feasibility using breadboard or brassboard implementations that are exercised with representative data.
TRL 4	**Component/subsystem validation in laboratory environment:** Standalone prototyping implementation and test. Integration of technology elements. Experiments with full-scale problems or data sets.
TRL 5	**System/subsystem/component validation in relevant environment:** Thorough testing of prototyping in representative environment. Basic technology elements integrated with reasonably realistic supporting elements. Prototyping implementations conform to target environment and interfaces.
TRL 6	**System/subsystem model or prototyping demonstration in a relevant end-to-end environment:** Prototyping implementations on full-scale realistic problems. Partially integrated with existing systems. Limited documentation available. Engineering feasibility fully demonstrated in actual system application.
TRL 7	**System prototyping demonstration in an operational environment:** System prototyping demonstration in operational environment. System is at or near scale of the operational system with most functions available for demonstration and test. Well integrated with collateral and ancillary systems. Limited documentation available.
TRL 8	**Actual system completed and qualified through test and demonstration.** The technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development.
TRL 9	**Actual system operated over the full range of expected conditions.** The technology is in its final form and operated under the full range of operating mission conditions.

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