Australian Renewable Energy Agency

Competitive Role of Geothermal Energy near Hydrocarbon Fields

Revised Final Report

20 June 2014

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Executive Summary

Terms of Reference

Evans & Peck has been engaged by the Australian Renewable Energy Agency (ARENA) to provide a "desk-top" assessment of the following questions:

- The possible commercial uses of geothermal direct heat applications in the Cooper Basin, Australia; now, in 2020 and in 2030, including a review of the likelihood of these commercial uses developing by 2020 and 2030 and the underlying economic and regulatory assumptions (Refer section 2 of the report);
- The economic implications of a significant increase in gas development in the Cooper Basin on geothermal energy (Refer section 3 of the report); and
- Other areas in Australia that may have similar opportunities for combined geothermal energy and unconventional gas development as for the Cooper Basin (Refer section 4 of the report).

Key findings

The key findings from Evans & Peck's assessment are presented below:

1) The Cooper Basin has a very low resident population. Any large application of direct heat would be to serve industrial users.
2) Geothermal heat is not portable. Users of direct heat will have to be located very close to the heat production area.
3) Other than oil and gas pipelines there is no high capacity/low cost infrastructure servicing the Cooper Basin. The remoteness of the Cooper Basin from existing major infrastructure makes constructing new infrastructure expensive. There are high logistics costs for supply of feedstocks not locally available at a competitive price.
4) Depending on the product format of potential goods (e.g. fertiliser, product gases etc.) product distribution cost to domestic markets and export facilities can also be high.
5) There are applications of geothermal heat in the hydrocarbon industry that have locally available competitively priced feedstock and access to cost effective product distribution infrastructure. These applications will be the first to become commercially viable and are described below:

Application	2014	2020	2030
Enhanced oil/gas recovery	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable
Gas Processing Facilities	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable
Utilities and Offsite	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable
Urea Production	Not Commercially Viable	Possibly Commercially Viable	Possibly Commercially Viable
Carbon Capture and Storage	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable

Table 1 Potential for Commercial Application of Geothermal Heat

6) The applications in item 5) are shown to have an increased likelihood of commercial viability over time. This is because of improving competitiveness of geothermal resources.

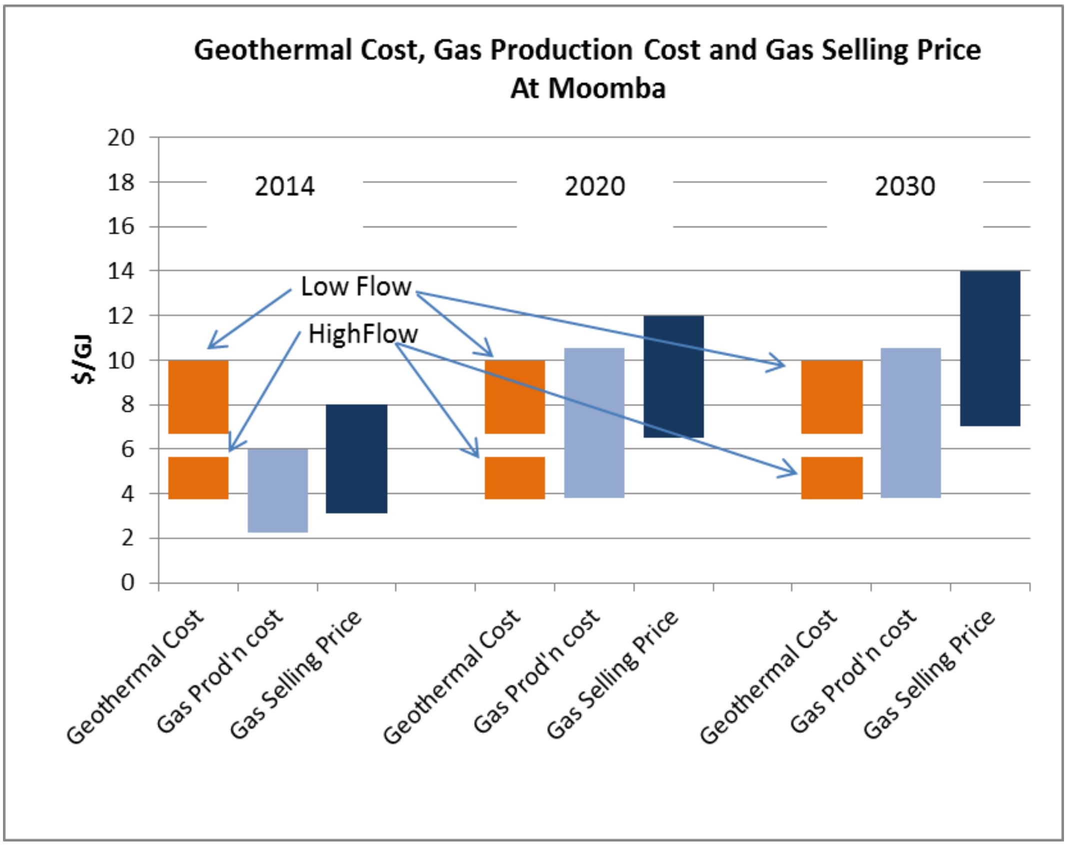

Figure 1 Geothermal Commercial Competitiveness

The figure above shows that gas production cost and selling prices are increasing over time as geothermal energy cost remains stable. Geothermal energy costs are shown as high flow case and low flow case. These two cases reflect the uncertainty range of the productivity of the wells. For each flow case shown, the cost range reflects uncertainty of the well construction cost. In actuality there is a cost continuum ranging from high flow and low well cost to low flow and high well cost.

The following observations can be made for each time frame:

- 2014: The cost of geothermal energy is not less than the selling price of gas in 2014. There is no commercial driver to pursue geothermal energy.
- 2020: The cost of geothermal energy starts to become competitive with gas fired heat. Assuming the long range forecast is still accurate by 2020, there is an opportunity to consider designing in fuel flexibility to include geothermal energy as a hedge against changing regulations with respect to potential CO_2 emissions costs and to take advantage of forecast favourable price competitiveness of geothermal energy.
- 2030: Geothermal energy will become increasingly competitive towards 2030. Under some scenarios the cost of geothermal energy is below the production price of gas. If this eventuates, there is added incentive for monetising low cost geothermal heat in more highly transformed hydrocarbon products.
- In general: Gas production costs at the Cooper Basin are expected to increase over time as a larger proportion of the gas produced is from more expensive unconventional resources. Increasing production cost creates headroom for geothermal energy which is expected to have relatively stable cost over time.

7) There are several indicators that suggest 2020 will be a turning point in the Cooper Basin. A large portion of the existing facilities are coming to end of life. If production is to be sustained reinvestment will be required around 2020. Unconventional gas resources are currently being actively explored and have attracted significant international interest. If deemed economically viable these resources may come on stream around 2020 or soon thereafter.

8) Hydrocarbons that have high impurities content (carbon dioxide, nitrogen and water) have greater demand for gas purification and thus greater potential to use geothermal heat in the purification processes. Details on processing requirements for the Canning and Amadeus fields which are also near geothermal energy sources will not be available until investigation of raw gas composition is further advanced. The Bowen and Surat Basin gas processing facilities have low CO_2 content but significant dehydration and water treatment facilities which could make use of geothermal heat.

Abbreviations and Definitions

Term/ Abbreviation	Definition
2C reserves	Defined by the internationally recognised Petroleum Resources Management System as the best estimate of contingent resources.
2P reserves	Defined by the internationally recognised Petroleum Resources Management System as 1P (proven reserves) plus probable reserves.
3P reserves	Defined by the internationally-recognised Petroleum Resources Management System as 2P plus possible reserves.
3P/2C reserves and resources	Refers to possible reserves (i.e. total 3P reserves less 2P reserves) plus 2C resources.
ARENA	Australian Renewable Energy Agency
Conventional Gas	Conventional gas is obtained from reservoirs that largely consist of porous sandstone formations capped by impermeable rock, with the gas trapped by buoyancy. The gas can move to the surface through the gas wells without the need to pump.
EGS	Enhanced Geothermal System
Endothermic	Reaction or process accompanied by or requiring the absorption of heat
Exothermic	Reaction or process accompanied by the release of heat.
Gas	Unless explicitly stated otherwise gas is intended to mean natural gas of acceptable quality to be distributed to consumers.
GJ	Gigajoule (10^9 Joules)
HSA	Hot Sedimentary Aquifer
IGEG	International Geothermal Expert Group
LNG	Liquefied Natural Gas
Parasitic load	The amount of energy required to run the energy production facility. For a gas treatment plant it is the amount of gas consumed by the gas processing facility.
PJ	Petajoule (10^{15} Joules)
Raw gas	Hydrocarbon gas as produced at the well head.
Shale Gas	Natural gas trapped within shale formations.

Term/ Abbreviation	Definition
Tight gas	Natural gas held in sandstone or limestone with very low permeability.
TJ	Terajoule (10^{12} Joules)
Unconventional Gas	Unconventional gas is generally produced from complex geological systems that prevent or significantly limit the migration of gas and require innovative technological solutions for extraction. The difference between conventional and unconventional gas is the geology of the reservoirs from which they are produced.

1 Introduction

The Australian Government has contributed and continues to contribute funds towards developing geothermal energy projects.

There has been significant progress in developing knowledge of Australian geothermal potential and government co-funded projects are in varying stages of completion. Experience to date has revealed that baseline level of resource knowledge, technology to access the resources and commercial issues getting to market has resulted in slower implementation than what might have been previously anticipated.

Outside of Australia, there is significant geothermal energy being developed on a commercial scale although these plants are predominantly located close to active volcanic systems, which are not present in Australia.

Proponents of geothermal energy have been seeking ongoing financial support for Australian projects. In September 2013 the Australian Renewable Energy Agency (ARENA) established the International Geothermal Expert Group (IGEG) to determine whether, over the periods to 2020 and 2030, there are plausible commercialisation pathways for either Enhanced Geothermal Systems (EGS) or Hot Sedimentary Aquifer (HSA) geothermal energy to deliver cost competitive utility scale energy to Australia without long-term subsidy.

The IGEG's work will inform the ARENA 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.

Preliminary findings were made available to the public in February 2014. These preliminary findings revealed a number of barriers and options for advancements geothermal energy. Amongst those barriers are the pathways to market for geothermal energy.

This report, prepared by Evans & Peck, focusses on how geothermal energy in the form of direct heat might be deployed in regions where there is also hydrocarbon production. The specific terms of reference for this study are provided below.

1.1 Terms of Reference for Report on the Competitive Role of Geothermal Energy

The Board of the ARENA is seeking advice on the barriers to, and opportunities for, the development and deployment of geothermal energy in Australia.

To this end, ARENA has established an (IGEG) 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.

To assist the IGEG in consideration of the full range of applications of geothermal energy, advice is sought on the possible uses of direct heat from geothermal energy in the Cooper Basin, Australia.

The advice would be in the form of a desktop study that identifies and synthesises existing data and information about:

1) The possible commercial uses of geothermal direct heat applications in the Cooper Basin, Australia at present, in 2020 and in 2030, including a review of the likelihood of these commercial uses developing by 2020 and 2030 and the underlying economic and regulatory assumptions;

2) The economic implications of a significant increase in gas development in the Cooper Basin on geothermal energy; and

3) Other areas in Australia that may have similar opportunities for combined geothermal energy and unconventional gas development as for the Cooper Basin.

1.2 Cooper Basin Background

The Cooper Basin is a sedimentary geological basin located in the South-West corner of Queensland and the North-West corner of South Australia, approximately 1,300km West of Brisbane and 1,000km North of Adelaide (see Figure 2). It is 130,000 km² in area and has a population of less than 2,000 people. Its surface is mostly covered by desert.

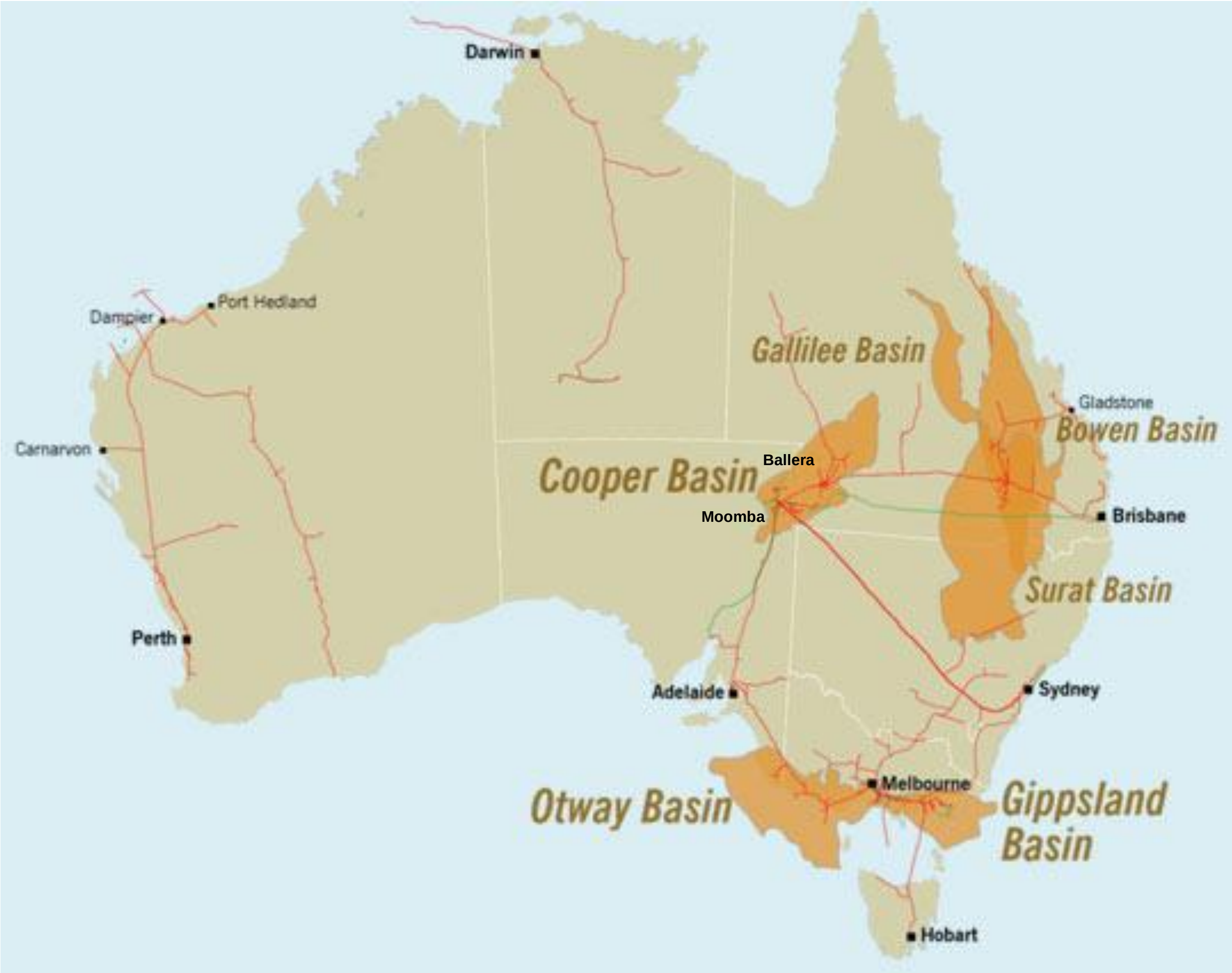

Figure 2 Map of Australian showing location of Cooper Basin (Source: Geoscience Australia)

[Gas pipelines are shown in red]

Oil and gas production started in the Cooper Basin in the late 1960's, peaked in the late 1990's and is looking to start expanding again through production of new conventional fields and unconventional fields. Current production is primarily sales quality natural gas, but also includes LPG, condensate, crude oil and ethane.

A key driver of increased gas production in the Cooper Basin is to utilise liquefaction facilities in Gladstone that serve export markets.

Santos is the largest operator in the basin. However several of the world's largest energy companies have recently formed joint ventures (JV) with local firms in search of exploration and development opportunities. Current JV parties in and around the Cooper Basin include:

- Santos/Beach/Origin Energy (This JV includes Santos' activities at Moomba and Ballera);
- Beach/Chevron (This JV covers Beach's activities around Innamincka);

- Drill Search/ BG; and
- Senex/ Origin Energy.

The nature of the gas resources tapped in the Cooper Basin is changing. The natural gas found in the Cooper Basin originates from the Shale Gas deposits in the basin. Most of the production to date is from gas that has migrated into conventional sandstone structures. These reservoirs have associated liquids including butanes and propanes which are exported through a dedicated pipeline to Port Bonython for processing. The high value liquids add some processing complexity but also offset gas production costs.

With the advent of commercially proven techniques for extracting tight gas and shale gas, and depletion of the conventional sandstone reservoirs, the future of the Cooper Basin is likely to include increasing extraction of unconventional gas resources which do not have the same liquids content and are classified as dry gas.

Impurities, most notably CO_2 content, varies across the basin, tending to be higher around Innamincka (Beach/Chevron). CO_2 content varies from 40% down to around 5%. Santos' average CO_2 content over the years of production has averaged around 15%. The CO_2 dilutes the hydrocarbons stream, reducing well productivity. Removal of CO_2 adds processing cost. Production of CO_2 can become a significant risk consideration for firms concerned about changes to imposts on CO_2 emissions.

Figure 3 presents a schematic representation of hydrocarbon deposits in the Cooper Basin[1].

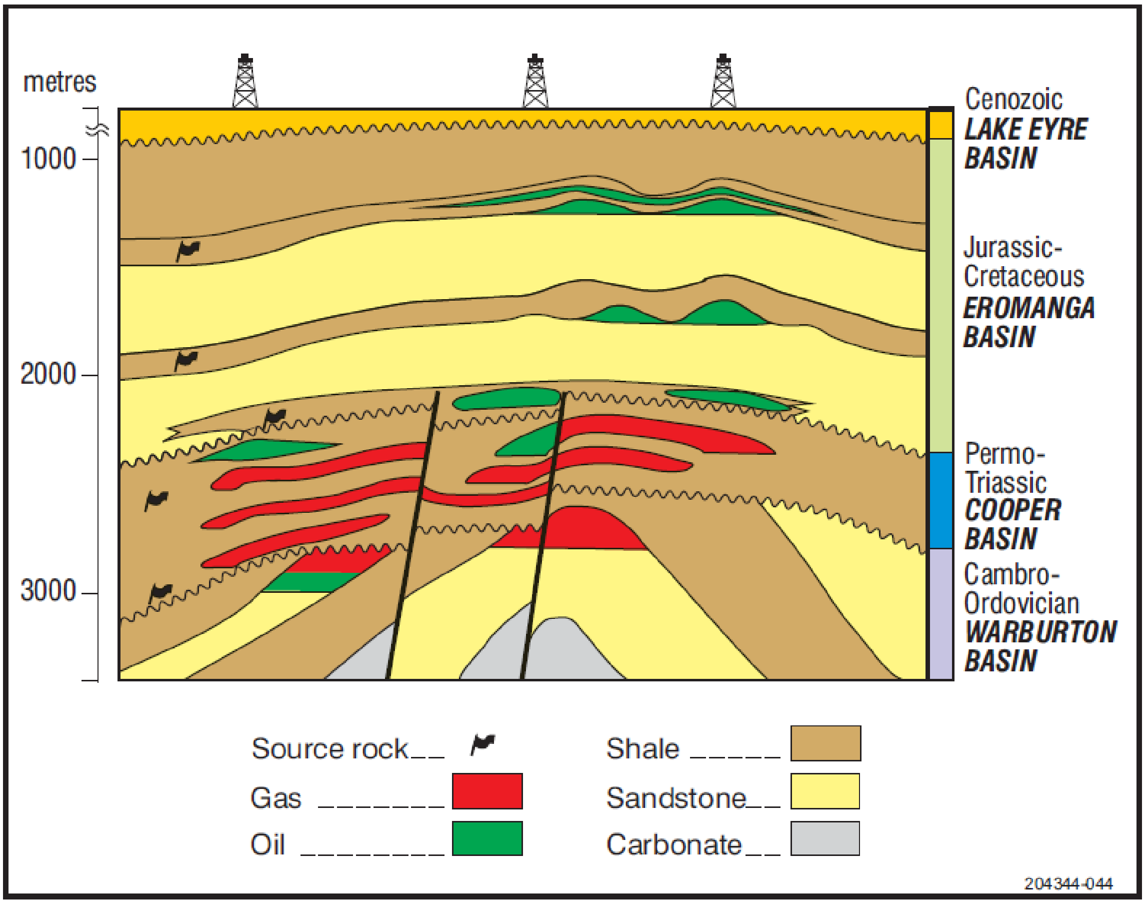

Figure 3 Schematic representation of hydrocarbon deposits in the Cooper Basin.

[1] Petroleum and Geothermal Resources in South Australia, Government of South Australia, Department of Manufacturing, Innovation, Trade Resources and Energy http://www.pir.sa.gov.au/__data/assets/pdf_file/0003/33663/prospectivity_cooper.pdf, accessed May 2014.

Table 2 presents an overview of the gas reserves by reservoir type. The data indicates current proven resources are largely conventional but that the long term outlook is increasingly likely to include a high proportion of unconventional gas production.

Cooper and Eromanga Basins reservoir type	2P reserves[2] (PJ)	3P/2C Reserves and Resources (PJ)
Conventional Gas	1,943	2,006
Unconventional gas including shale gas and tight gas	5	4,945
Coal seam gas	-	-
Total	1,948	6,951

Table 2 Gas reserved at the Cooper and Eromanga Basins (Source: Current and Projected Gas Reserves and Resources for Eastern and South Eastern Australia, Core Energy Group, August 2013)

Total gas production from 1970 to June 2012 is 5,363 PJ[3].

The Cooper Basin has significant geothermal resources. It has unusually hot granite within 5km of the earth surface. In its November 2010 presentation to the Australian Geothermal Energy Association, Geodynamics claimed within its tenements alone, there was the potential to establish 6,500 MW of base power generation to run for over 50 years[4]. Although this has not been further substantiated it gives a flavour for the order of magnitude of the potential resource.

[2] Refer to definitions and abbreviation section for explanation of these terms.

[3] Cooper Basin Fact Sheet, South Australia Government Department for Manufacturing, Innovation, Trade, Resources and Energy (DMITRE), http://www.pir.sa.gov.au/__data/assets/pdf_file/0018/26901/cooper_fs.pdf

[4] http://www.geodynamics.com.au/getattachment/33b1ecda-211e-46d9-b977-eb8b16997395/Presentation-to-Australian-Geothermal-Energy-Confe.aspx accessed 9 May 2014

2 Commercial Uses of Geothermal Direct Heat Applications in the Cooper Basin – Present, in 2020 and in 2030

This section of the report reviews the potential commercial uses of geothermal direct heat in the Cooper Basin in the near term, in 2020 and in 2030. An overview of the applications considered is presented in Figure 4.

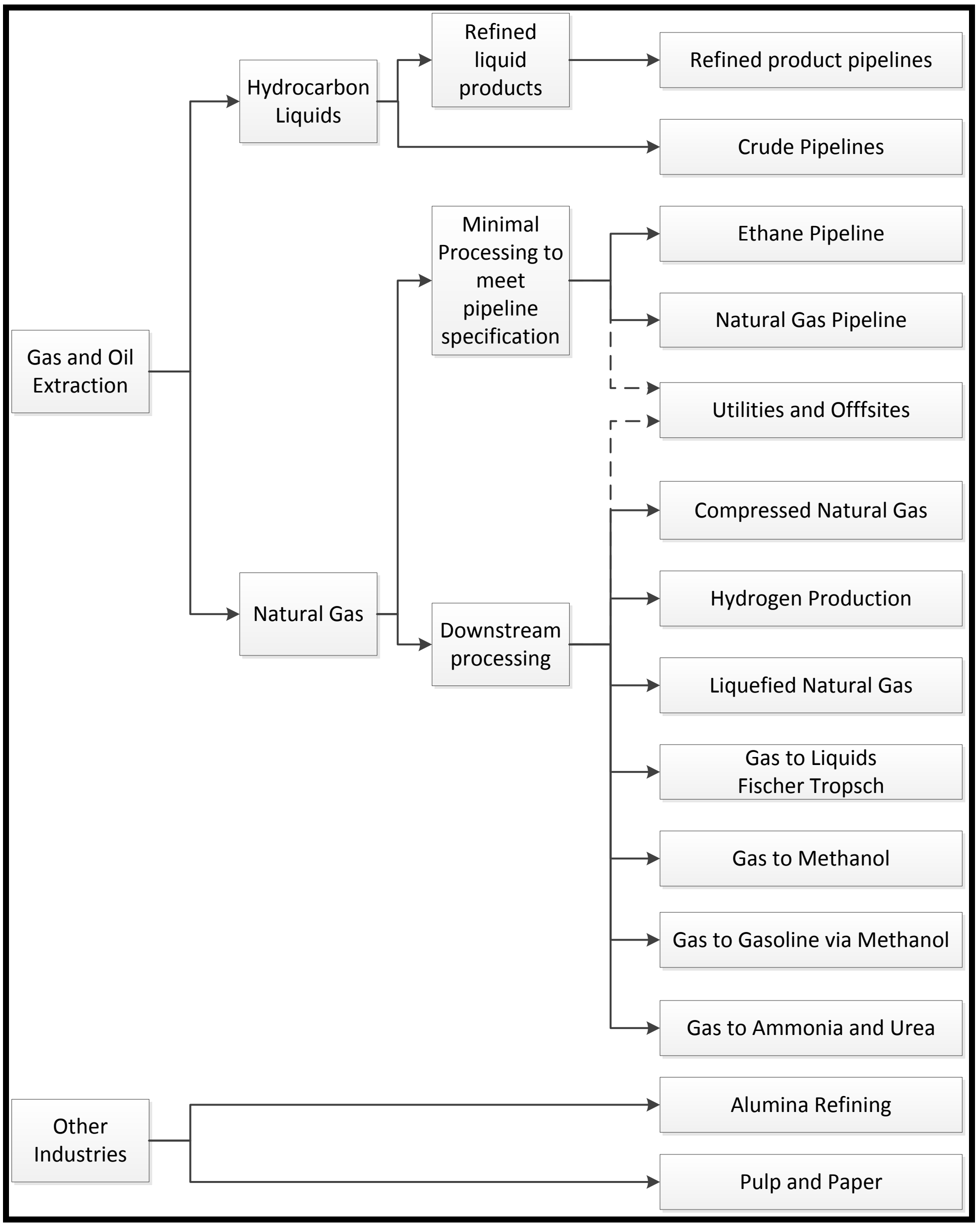

Figure 4 Overview of applications of direct heat considered

2.1 Test for Commercial Application of Geothermal Direct Heat

Each potential application of geothermal heat was tested using the framework in Figure 5. The results of the tests are documented in Appendix B and are presented in summary form in section 2.2.

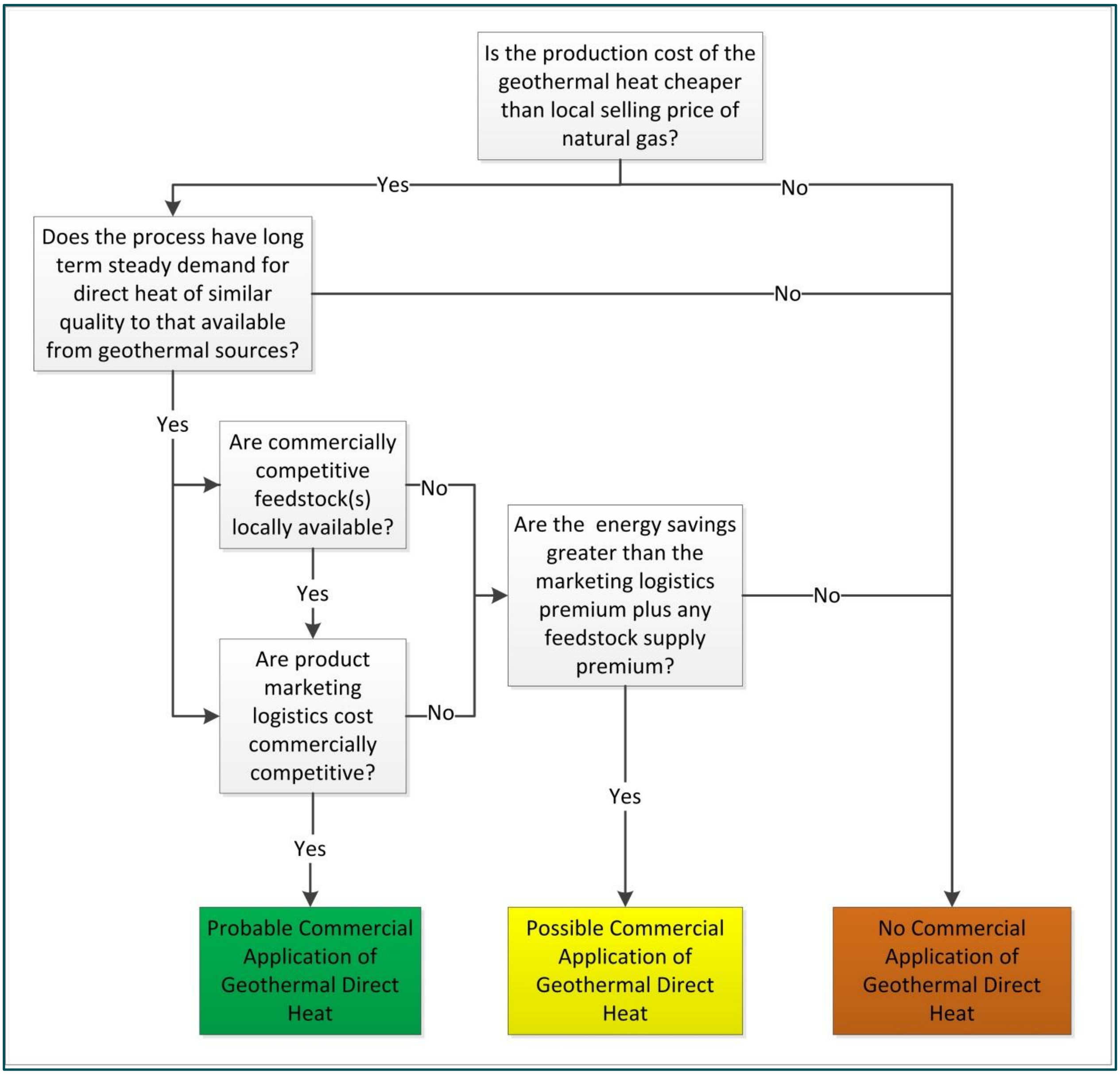

Figure 5 Framework for testing commercial viability of application of geothermal heat

2.2 Viability of Geothermal Direct Heat Applications in 2020 and 2030

The first test of the framework in Figure 5 is that the production cost of geothermal energy is cheaper than the local selling price of natural gas. Section 3.5 finds that this test is not likely to be satisfied in 2014. Therefore the potential uses covered in this section do not include individual comment on the at present (2014) commercial case. However, as direct heat from geothermal sources is expected to change over time, each potential commercial use is tested on the 2020 and 2030 cases.

The summary findings are grouped by application type and can be found in locations below:

- Table 3 Hydrocarbon Production and Minimal Processing
- Table 4 Support Manufacture of Downstream Hydrocarbon Products
- Table 5 Support Mining and Other Energy Intensive industries

The commercial viability of each application is shown using the legend below:

✓✓	Probable commercial application of direct heat
✓	Possible commercial application of direct heat
×	No commercial application of direct heat

	2020		2030	
Enhanced Oil/Gas Recovery	✓	Possibly commercially viable pending reservoir response to CO_2 injection and gas prices that justify additional resource recovery. Increases in the cost to emit CO_2 will make this technology more attractive.	✓✓	Rising gas prices, more stringent environmental policy and technology advances appear to be aligned with use of CO_2 as enhanced recovery medium. Geothermal heat could be used to address additional gas treatment load from recirculating CO_2.
Processing Facilities	✓	Strong opportunity to apply geothermal direct heat however, this is unlikely to happen before 2020. A significant portion of existing facilities expected to reach end of life by 2020. Pending the timing of reinvestment and construction of new facilities this application may not be in place by 2020.	✓✓	Significant potential to apply geothermal direct heat on new capital investment.
Pipeline Export Power	×	No application of direct heat.	×	No application of direct heat.
Utilities and Offsites	✓	Switching existing utilities and offsites from their existing technology to geothermal heat will involve capital investment that is only worthwhile once the long term production life of the region is confirmed. A significant portion of existing facilities are expected to reach end of life by approximately 2020. Pending the timing of the new investment, this application may not be viable by 2020.	✓✓	The opportunity to utilise geothermal heat will become commercially viable if it is designed in to replacement and/or additional facilities. This is expected to have occurred by 2030.

Table 3 Potential commercial applications of geothermal direct heat to support hydrocarbon production and minimal processing

Table 3 indicates there is strong potential for geothermal energy to supply the hydrocarbon industry. The availability of local feedstocks and cost effective product distribution infrastructure makes this result unsurprising. Geothermal energy could help stem any cost increases associated with using CO_2 in enhanced hydrocarbon recovery techniques. Direct heat geothermal energy could also be deployed to address the parasitic loads of gas treatment, utilities and offsites. Provided the cost of geothermal energy is less than the gas selling price, the use of geothermal energy enables the operator to collect additional revenue by marketing gas that would otherwise have been consumed by the plant.

	2020		2030	
Refined Products	×	Insufficient quantum of competitive cost feedstock available to sustain economies of scale. Increased product export logistics cost with proliferation of products to distant consumers. Energy cost saving insufficient to overcome lack of competiveness from small scale.	×	As per 2020 case
Compressed Natural Gas	×	No application of direct heat	×	No application of direct heat
Liquefied Natural Gas	×	No application of direct heat	×	No application of direct heat
Gas to Liquids Fischer Tropsch	×	Exothermic process chemistry not suited to use geothermal energy.	×	Exothermic process chemistry not suited to use geothermal energy.
Gas to Liquids Methanol	×	Unlikely to be commercially viable based on current gas price forecast and logistics costs.	✓	Potentially commercially viable pending the results of the heat integration study confirm that low cost geothermal energy can mitigate additional product logistics cost.
Gas to Liquids Gas to Gasoline	×	Process chemistry not suited to use geothermal energy.	×	Process chemistry not suited to use geothermal energy.
Urea	✓	Application of geothermal heat possibly commercially viable, dependant on the results of the heat integration study. A commercial scale plant would consume around 15 percent of current gas production. Because of competing demand from LNG export facilities plants, these quantities may not be cheaply available from the Cooper Basin by the 2020 time frame.	✓	For the 2030 case the urea application remains potentially commercially viable, dependant on the results of the heat integration study.
Hydrogen production	×	High distribution costs mean the domestic hydrogen market is not economically served from the Cooper Basin. The international hydrogen market is unlikely to be fully developed by this timeframe.	✓	Possible commercial application pending market conditions and establishment of infrastructure for long distance overland and overseas transport. This application has high exposure to local and international government policy decisions on emissions.
Oil Shale	×	Non-viable oil shale resources in the Cooper Basin.	×	Non-viable oil shale resources in the Cooper Basin.
Carbon Capture and Storage	✓	Potential application of geothermal pending clarification of government policy.	✓✓	Likely to be considered as a hedge against uncertain carbon pricing policy. Will be a key consideration for producing gas with high CO_2 components.

Table 4 Potential commercial applications of geothermal direct heat to support manufacture of downstream hydrocarbon products

Table 4 shows mixed results for the application of geothermal heat to downstream hydrocarbon processes. In some instances the chemical processes do not require (additional) heat. In other cases, the process chemistry and heat recovery operations are complex and a detailed heat integration study is required to see how much geothermal direct heat can be usefully applied.

All but two of these applications are challenged by product distribution logistics. Urea production has potentially quite favourable product distribution costs. Urea is a solid that can be cost effectively distributed by truck to rural consumers in South Australia, New South Wales and Queensland. The second application that has good product logistics is carbon capture and storage. Geothermal heat can be used to help capture the carbon and nearby reservoirs can be used to sequester it.

	2020		2030	
Mining				
Minerals and Metals	×	Logistics to existing mines in operation not viable. Pending development of new deposit near geothermal resources, this application is not commercially viable in 2020.	×	Logistics to existing mines in operation not viable. Pending development of new deposit near geothermal resources, this application is not commercially viable in 2030.
Coal Gasification	×	Low cost heat for gasification will be supplied by in situ coal.	×	Low cost heat for gasification will be supplied by in situ coal.
Other energy intensive industries (including geothermal regions outside the Cooper Basin)				
Alumina Refining	×	No application at Cooper Basin because of challenging logistics cost.	×	As per 2020 case.
	✓	Outside Cooper Basin - Ongoing investigation of geothermal energy near Gove alumina refinery.	✓	As per 2020 case.
Pulp and Paper	×	No application at Cooper Basin because of challenging logistics cost.	×	No application at Cooper Basin because of challenging logistics cost.
	✓✓	Potential application in geothermal regions with paper feed stocks.	✓✓	Potential application in geothermal regions with paper feed stocks.

Table 5 Potential commercial applications of geothermal direct heat to support mining and other heat intensive industries

Table 5 shows there are limited mining opportunities in the Cooper Basin that might be able to use geothermal energy. Other industries that are considered suitable for heat supplied by geothermal sources are alumina refining and pulp and paper. Although Australia has a large alumina refining industry, there are no bauxite deposits (feedstock to alumina refinery) near the Cooper Basin. There is a large deposit and an existing refinery in Gove in the Northern Territory. There is also some potential for geothermal energy nearby. This opportunity has already been identified and is currently under commercial review by geothermal energy proponents.

One of the largest known industrial applications of geothermal direct heat to a single industrial facility is at a pulp and paper mill in New Zealand (Refer Appendix A for more details). For the Cooper Basin, as was the case with bauxite, neither feedstock nor paper consumers are located nearby. There are other areas in Australia that have an established pulp and paper industry coincident with prospective regions for geothermal energy. These locations have not been reviewed as part of this study.

3 Economic Implications of a Significant Increase in Gas Development in the Cooper Basin on Geothermal Energy

This section of the report considers the implications of significant changes to gas development in the Cooper Basin by reviewing forecast gas selling price and gas production cost trends in comparison with the production cost of geothermal energy.

3.1 Selling Price of Gas

The selling price of gas in Australia is different for domestic consumers than export markets. Domestic consumers currently enjoy a lower gas price than export markets. The long term consensus among economists is that, barring major government intervention into the gas markets, the domestic price will converge with the prices offered by export markets. Figure 6 shows the increasing role of gas exports on the eastern Australian gas markets.

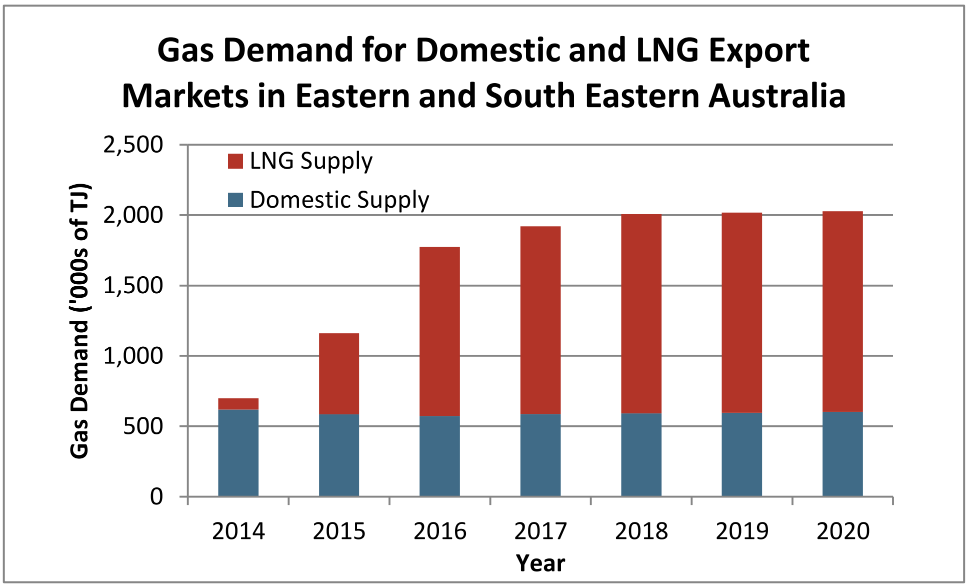

Figure 6 Gas Demand for Domestic and LNG Export markets in Eastern and South Eastern Australia (Source Gas Statement of Opportunities Update May 2014, Australian Energy Market Operator.)

3.1.1 Gas Selling Price to Domestic Markets

The selling price of gas at Moomba can be determined by using the wholesale gas market prices and then discounted by the transportation cost to reach those markets (netback price). In this analysis we have taken the major markets for Cooper Basin gas to be Brisbane, Sydney and Adelaide. Figure 7 gives a context for the recent history of domestic wholesale gas price volatility over time and by season. The netback price for domestic gas supplies is calculated in Table 6.

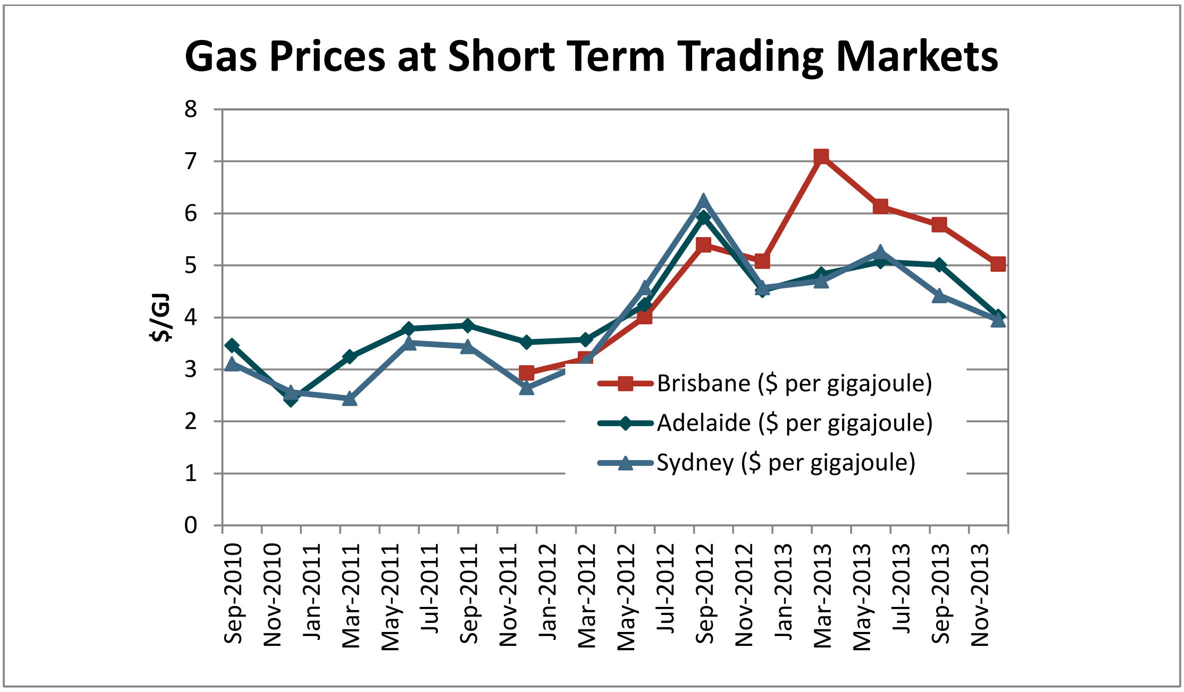

Figure 7 Gas prices at selected cities (Source: Australian Energy Regulator)

Market	Wholesale Short Term Market Price[5] ($/GJ)	Estimated Transport Cost from Moomba($/GJ)	Netback price at Moomba ($/GJ)
Adelaide	4.40	0.57	3.83
Sydney	4.08	0.94	3.14
Brisbane	4.89	1.73	3.16

Table 6 Netback domestic gas price at Moomba

3.1.2 Gas Selling Price to International Markets

Australian exports of gas in the form of liquefied natural gas (LNG) will rapidly increase as the facilities in Queensland, Northern Territory and West Australia come on stream over the next few years. Because the Cooper Basin is connected by pipeline to LNG facilities in Queensland, demand for gas for export is a significant factor for gas prices at the Cooper Basin.

Gas supplies to LNG exporters are typically committed by contracts outside the market place or are sourced from the exporter's own supplies. A November 2013[6] study on the Australian domestic gas market evaluated recent long term gas supply contracts to domestic and LNG export facilities and found gas pricing ex Moomba to be in the order of $6-$8. Long range gas price forecasts ex Moomba can be found in a 2012 report for the Australian Energy Market Operator and are shown in Table 7.

[5] Australian Energy Regulator Wholesale Short Term gas market average price year to date 2013-14 as shown in report 20, 26 April 2014 http://www.aer.gov.au/sites/default/files/20140420-20140426%20gas%20weekly%20report.pdf

[6] *Study on the Australian Domestic Gas Market*, by Intelligent Energy Systems Advisory commissioned Department of Industry, and Bureau of Resources and Energy Economics, section 8.4

Export Gas Price	2014 ($/GJ)	2020 ($/GJ)	2030 ($/GJ)
At Moomba	6 - 8[7]	6.50 - 12[8]	7 - 14[9]

Table 7 Forecast price of gas to serve export markets

With the increasing interconnectedness of gas markets and the variety of drivers that influence these markets, the forecasts do not have high precision. Key uncertainties that cloud the inputs to gas price forecasts include: foreign exchange rates, technology advancement enabling exploitation of previously uncommercial resources, regulatory changes on how fuel is priced, taxation changes on different types of fuels, local and international governments' policy on fuel exports etc.

The quadrupling of natural gas production in Australia over the current decade is indicative of changes in the marketplace. Another good example of the recent rapid changes in the gas market is the shale gas industry in the United States. Until recently the United States was an importer of natural gas. Due to the new shale gas extraction technologies, the United States meets virtually all domestic needs and has started construction of LNG export facilities. Uncertainty in gas price forecasts could contribute to reduced willingness to commit to geothermal energy which has high upfront fixed cost.

3.2 Cost of Gas Production

Gas production costs are driven by the host formation (well construction costs) and the chemical composition of the produced gas (processing cost). If the gas is associated with hydrocarbon liquids, the high value liquid production can effectively subsidise the cost of gas.

Operators preferentially deplete the easiest (cheapest) formations first. Until 2012, all of the commercially sustained gas production from the Cooper Basin had been from conventional resources. The Cooper Basin still has further opportunities to produce gas by exploiting new conventional reservoirs and improving gas recovery from existing fields using infill drilling[10].

Discussion with the existing producers in the Cooper Basin, as well as press releases from prospective producers, suggests future production beyond 2020 will be increasingly from unconventional methods and from shale and tight gas formations[11]. In 2012, Santos placed the first unconventional gas well in the Cooper Basin into commercial production. The ramp up rate for production from unconventional resources is not yet known and will be subject to review as gas prices develop over time.

Gas produced in the Cooper Basin has CO_2 content ranging from 5% to 40%. Current production has typically around 15% CO_2 content. Impurities such as CO_2 dilute the process stream and drive higher gas treatment costs. There is limited public information on the impurities content of gas from the various reservoirs however there is no suggestion that this is likely to decrease. A 2012 presentation[12] by Santos indicated that existing CO_2 processing capacity limitations will become a pinch point for future production.

Existing production in the Cooper Basin includes gas with some hydrocarbon liquids content. These liquids are highly prized for their high energy density. Inclusion of liquids in the process stream does add to gas

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[7] ibid

[8] *Fuel Cost Projections – Updated natural Gas and Coal Cost for AEMO Modelling*, ACIL Tasman, June 2012.

[9] ibid

[10] Infill drilling involves adding new, closely spaced wells within an existing field to access resources that were previously inaccessible or have become better defined over time by production data gathered from the field.

[11] Unconventional gas typically involves more elaborate wells and flow stimulation techniques which increase production costs.

[12] *Cooper Gas Growth Program,* Santos Colin Cruickshank, February 2012 www.southaustralia.biz/files/589_santos.pdf?v=439

processing costs but also creates much greater revenues. Shale and tight gas has almost no hydrocarbon liquids content.

The actual gas production cost at the Cooper Basin is confidential to the operators. The data presented in Table 8 is extracted from *Gas Production Cost*, 2012, report by Core Energy Group to the Australian Energy Market Operator unless otherwise marked.

	2014 ($/GJ)	2020 ($/GJ)	2030 ($/GJ)
Conventional gas production Including liquids processing cost Excluding liquids processing cost Infill drilling	3.79 - 6.00[13] 3.79 2.23 1.33 - 2.41	3.79 - 6.00 3.79 2.23 See 2014	3.79 3.79 2.23 Expect increase cost as easy targets become less frequent
Unconventional gas production	Not currently in large scale production	7.74 - 10.51	Refer 2020

Table 8 Cooper Basin gas production cost (Source: *Gas Production Cost*, 2012, report by Core Energy Group to the Australian Energy Market Operator)

3.3 Cost of CO_2 Emissions

Cooper Basin CO_2 emissions come from disposal of CO_2 in the raw gas as well as emissions from fuels combusted to operate the gas processing and ancillary facilities.

The current applicability and price of carbon emissions in Australia is uncertain as is the long term policy position of carbon pricing. A white paper[14] published by research group Carbon Disclosure Project suggests that some firms are not waiting for clarity on carbon pricing but are already factoring the risk of carbon pricing into long term investments. Four of the world's largest international energy companies have an internal price of Co_2 emissions in excess $30/t.

This report does not consider carbon price because of the uncertainties on whether it will be applied and what this price might be if it were applied. If CO_2 emissions costs were included, the production cost of gas would increase. Although this has the effect of making geothermal energy more competitive relative to gas production cost, if the emissions price goes up too high, the field could become non-viable because of high CO_2 content in the raw gas.

3.4 Cost of Geothermal Energy Production

The variables that influence the unit cost of geothermal energy include:

- The flow rates achieved through the geothermal resource;
- The cost of well construction;
- The temperature of the resource; and

[13] *Study on the Australian Domestic Gas Market* Report has been prepared by Intelligent Energy Systems Advisory for the Australian Government Department of Industry and Bureau of Resources and Energy Economics Gas Market Study Task Force, see section 5.4

[14] *Use of internal carbon price by companies as incentive and strategic planning tool - A review of findings from CDP 2013 disclosure*, December 2013 https://www.cdp.net/CDPResults/companies-carbon-pricing-2013.pdf, accessed April 2014

- Capacity factor.

This section reviews the inputs and assumptions used to determine the overall cost per GJ of thermal energy from geothermal sources.

Flow Rates

Fluid flows through the heat source rock determine the productivity of the well and are closely related to final cost of production of heat. The flows can be influenced by the extent and distribution of the fracture network and the pressure differential between injector and producer wells. Pending further trials and advancement of fracturing techniques, as well as pressurising the closed loop system to increase flow, flows up to 80 kg/s are believed to be achievable.

Geodynamics reports sustained flows of 37 kg/s were achieved by the Habanero 4 well under open flow circumstances.

Geothermal energy costs were modelled under two flow scenarios to show the effect of flow on project economics:

- High flow – 80 kg/s; and
- Low flow – 40 kg/s.

Well Construction Cost

The cost of geothermal energy is heavily influenced by the cost to access that energy i.e. well construction costs. The well construction costs are a function of depth, well complexity (directional drilling, side tracks etc.), well design (diameter and casing strings) and geology.

Drilling cost was analysed by Dr Cameron Huddlestone-Holmes who is a consultant supporting the IGEG. This analysis is presented below.

Drilling costs are quite difficult to estimate with 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 well over 1,000 drilling rigs in the United States as of the end of March 2013[15].

As a result of the relatively small size of the industry in Australia, drilling costs are quite volatile and can vary markedly depending on contractual arrangements for individual wells or drilling campaigns. Further compounding this uncertainty has been the high volatility in drilling costs globally over the last decade. This volatility is illustrated in Figure 8 and while this data is 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[16].

[15] (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

[16] Refer Augustine, Tester, Anderson, Petty, & Livesay, 2006; Mansure & Blankenship, 2011; Tester et al., 2006

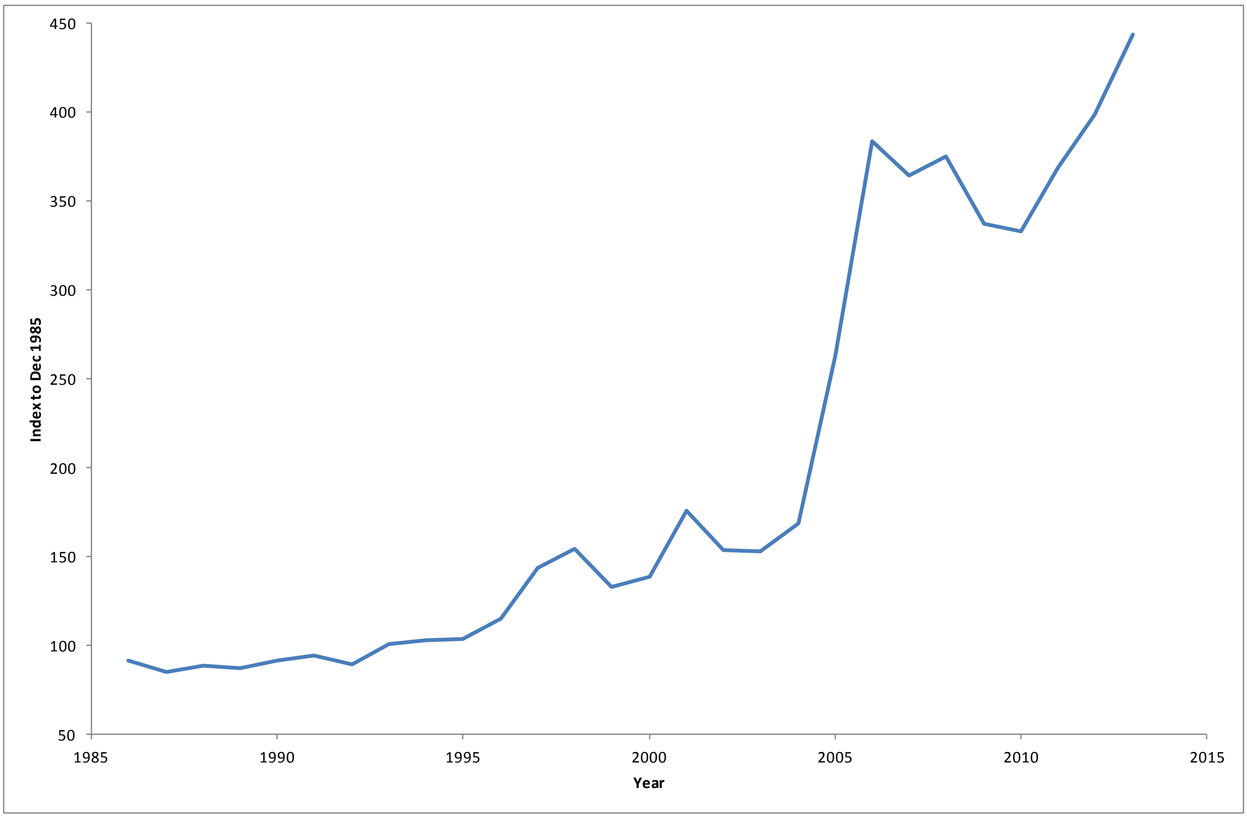

Figure 8 Producer price index of drilling oil and gas wells services in the United States from 1985 to the end of 2013. Data sourced from the United States Bureau of Labour Statistics (http://www.bls.gov/).

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 = 4 x Rig Day Rate 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 the well, the nature of the formations being drilled, the size (diameter) of the well, and the design of the well including the number of casing strings.

Table 9 shows indicative costs for geothermal wells based on the above formula. These costs are based on drilling as part of a campaign rather than for one off or "Wildcat" wells and are for trouble-free wells. These costs do not include rig moves or mobilisation.

Well Description	Rig Size	Rig Day Rate	Well Time	Well Cost
EGS, sedimentary basin with crystalline basement, 8" diameter, 4,000 m total depth.	2,000 HP	$80,000	60	$19.2 million
EGS, sedimentary basin with crystalline basement, 6" diameter, 4,000 m total depth.	1,500 HP	$70,000	60	$16.8 million

Table 9 Drilling costs (Source: Dr Cameron Huddlestone-Holmes, CSIRO and consultant to the IGEG)

The two [drilling] well costs shown in the table above represent the most likely type of well required to reach the granitic geothermal basement consistent with a high quality EGS system.

Empirical data from Geodynamics has shown that the well construction cost can be much higher than data in Table 9 would suggest. The Habanero 4 well (4,204 m) cost over $50 million[17] and took around 170 days to drill. As a one-off well, a significant engineering design cost (on the order of $8 million), additional costs associated with drilling a single well (mobilisation costs for the rig, contingency supplies cannot be shared amongst wells and so on), "trouble costs" (delays caused by unplanned and non-productive time) have all contributed to this high cost.

It has been assumed that geothermal wells will be drilled in the context of a much larger campaign of oil and gas drilling. The effect of a large drilling campaign can be very significant. Aside from defraying mobilisation and engineering costs, there is empirical data to substantiate benefits of learning on a large scale campaign. A study[18] on time to drill and complete multiple wells in the same large field indicated drilling time for the 60th well was half the initial well and drilling time for the 80th well was approaching one third of the initial well.

A 1:1 ratio of injector and producer wells has been assumed. The number of wells shown in Table 10 is the approximate order of magnitude needed to address parasitic heat load of gas processing at current throughput of 350 TJ natural gas per day.

Cost Item	Low Flow "Scenario 1"	High Flow "Scenario 2"
Diameter of Well	6"	8"
Number of wells	8	4
Mobilisation cost	$ 1,000,000	$ 1,000,000
Cost of individual wells	$ 16,800,000	$ 19,200,000
Cost of well stimulation/well	$ 1,000,000	$ 1,000,000
Well head equipment/well	$ 2,000,000	$ 2,000,000
Cost of wells ($)	$ 159,400,000	$ 89,800,000
Cost per Well (Optimistic)	**$ 19,925,000**	**$ 22,450,000**
Cost per Well (Optimistic + 50%)	**$ 29,887,500**	**$ 33,675,000**

Table 10 Well Costs to sustain process heat requirements for 350 TJ/day gas production

On consideration of the effect of a large campaign, we do not consider the cost outcomes experienced by Geodynamics to be likely to be applicable here. However, the costs derived from the formula are a best case scenario and considered optimistic. To balance the optimism, an alternate case was run at 50 percent higher cost (Optimistic + 50%).

Resource Temperature

This calculation assumes the temperature of the produced brine to be 220°C. This is less than peak temperatures recorded in the Cooper Basin and is generally consistent with what has been achieved during the trial plant flows. In this calculation brine is reinjected at 80°C. Long term temperature degradation has not been considered in this analysis. The flow duration is 15 years.

[17] ASX Announcement 10 August 2012 Habanero 4 drilling progress

[18] Application Of Learning Curve Models To Oil And Gas Well Drilling, Chi U. Ikoku, Society of Petroleum Engineers California Regional Meeting, 12-14 April 1978, San Francisco, California

Capacity Factor

Geothermal energy is not well suited to variable loads because the costs of geothermal energy production are largely upfront and fixed. This analysis assumes the geothermal heat required is base load that is supplemented by co-firing from natural gas for peak demands.

The overall capacity factor[19] assumed in this calculation is 95%. An allowance of 5% is made for downtime for descaling and well/flowline servicing activities.

Cost Summary

The cost per GJ of thermal energy from geothermal sources is presented Table 11.

	Low Flow (40 kg/s/well pair) $/GJ heat	High Flow (80 kg/s/well pair) $/GJ heat
Optimistic Wells Cost	6.66	3.75
Optimistic Well Cost + 50%	9.99	5.62

Table 11 Geothermal heat production costs $/GJ

The table shows a low flow scenario and a high flow scenario. For each scenario there is an error range reflecting uncertainties associated with the well construction cost. Showing cost ranges in these groups helps identify the effect of drilling versus flow rate on overall economics. In actuality both flow rates and well construction cost represent a continuum such that the overall estimated range of outcomes is from $3.75 to $9.99 / GJ.

There are some notable exclusions to the cost shown above.

Costs shown in Table 11 do not include the heat exchanger required to make the heat available to the end application. Similarly we have not added the furnace cost that would be required to convert natural gas into heat. Relative to the “fuel” costs, the differential in equipment cost (furnace - heat exchanger) is taken to be sufficiently small as to not substantially drive the overall economics in either direction.

Costs to bring the heat to the process plant are not included. In practical terms the source of geothermal heat needs to be close to the heat load to minimise transmission losses and pipeline cost.

Injection costs to sustain circulation of the geothermal system are not included. It is anticipated this energy will be provided by electrical resources, not direct heat. Estimates of power demand for circulation at 40 kg/s and 80kg/s are approximately 0.15 MW and 0.75MW respectively[20].

[19] Ratio of its forecast output over a period of time, to its potential output if it were possible for it to operate at full nameplate capacity

[20] Estimates prepared by Dr Cameron Huddlestone-Holmes, consultant to the IGEG.

3.5 Comparison of Energy Costs

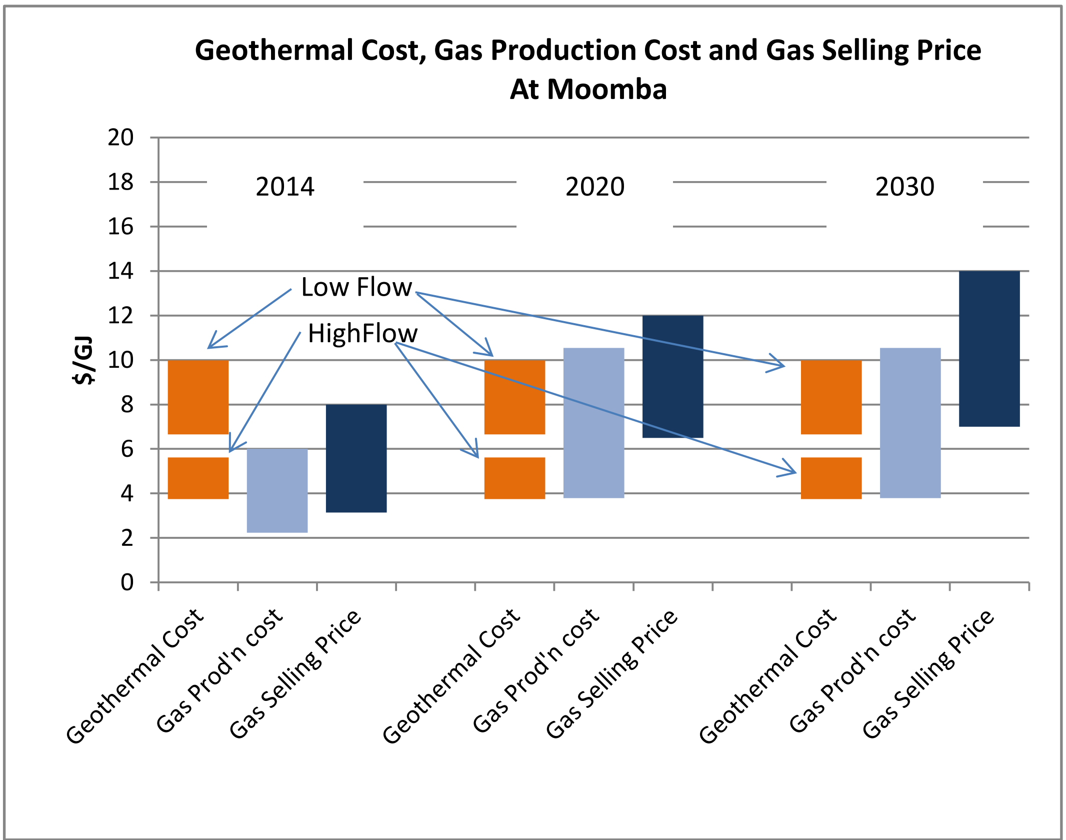

Figure 9 Comparison of Geothermal Energy Cost, Gas Production Cost and Gas Selling Price at Moomba

Figure 9 shows that gas production cost and selling prices are increasing over time as geothermal energy cost remains stable. Geothermal energy costs are shown as high flow case and low flow case to differentiate sensitivity to flow results. For each case the range of cost shown reflects uncertainty of the well construction cost. In actuality there is a cost continuum ranging from high flow and low well cost to low flow and high well cost.

The three time frames and the relative prices under the flow regimes are reviewed in Table 12 below.

Time frame	Geothermal viability
2014	Under the low flow scenario, geothermal viability of geothermal energy is not commercially attractive. Under the high flow scenario geothermal energy is marginal. If gas prices are in the low end of the range geothermal is not viable. In the event the producer is able to obtain gas prices at the top end of the range, it is possible to gain additional revenue by substituting geothermal energy for the applicable parasitic loads presently covered by gas. On balance, geothermal energy is a risky investment in light of the current gas prices and production costs.
2020	Under the low flow scenario, geothermal energy is unlikely to be commercially viable unless gas selling prices move to the top end of the forecast range. Under the high flow scenario, the operator can gain additional revenue by substituting geothermal energy for the suitable parasitic loads presently covered by gas.
2030	Under the low flow scenario, geothermal energy becomes viable around the midpoint of the forecast gas price range. The operator can gain additional revenue by substituting geothermal energy for the suitable parasitic loads presently covered by gas. Under the high flow scenario, the operator can gain additional revenue by substituting geothermal energy for the suitable parasitic loads presently covered by gas. If the production cost of gas moves towards the top end, there may be an opportunity to further increase revenue by expanding the extent of downstream processing to take advantage of cheaply available geothermal heat. This could prolong the commercial operating life of the field.

Table 12 Geothermal viability under varying flow regimes in the specified timeframes

It should be noted that because of current uncertainty on CO_2 emissions cost, this cost is not included in the results above. If CO_2 emissions costs were included, the production cost of gas would increase. Although this has the effect of making geothermal energy more competitive, if the emissions price becomes too high, the field could become non-viable because of high $CO2$ content in the raw gas.

4 Regions with High Quality Geothermal Energy outside the Cooper Basin

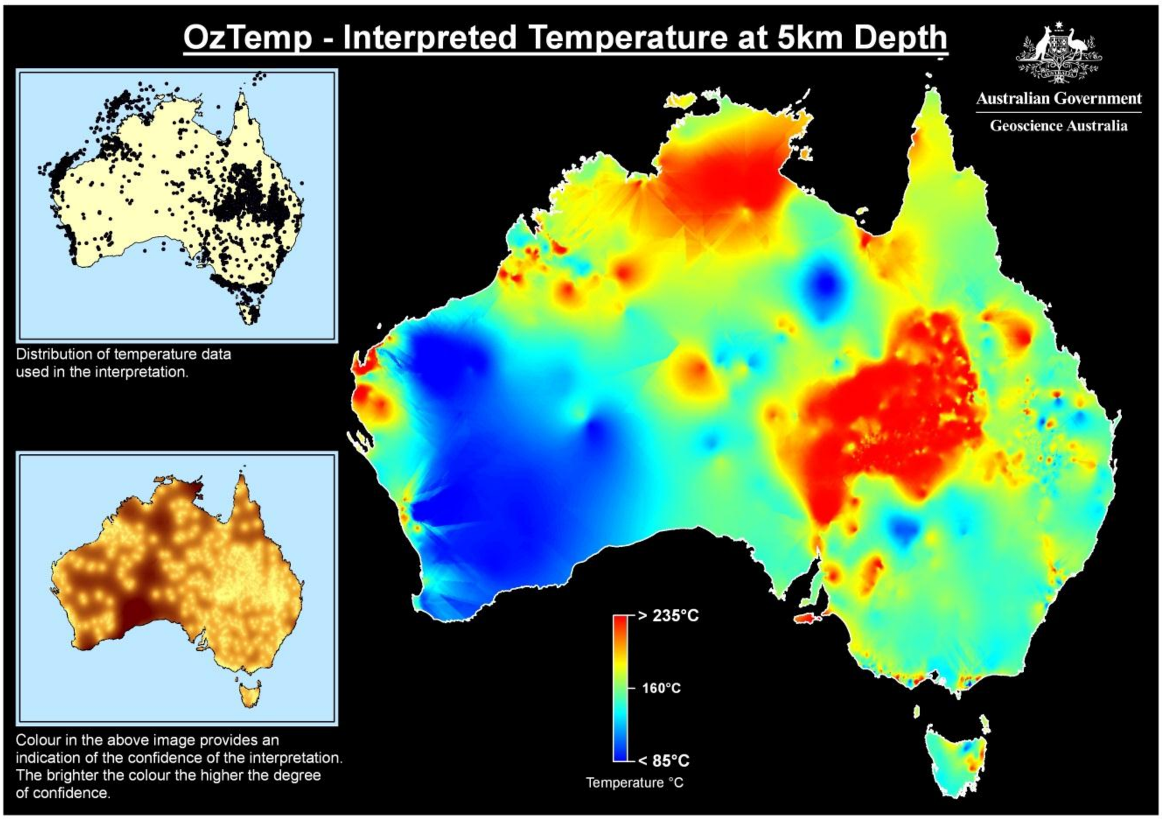

Figure 10 Interpreted temperature at 5km depth. [Source: Geoscience Australia]

Figure 10 above shows the available data and regions of attractive of geothermal prospectively.

Figure 11 identifies the major gas basins that have some potential to exploit geothermal energy. Key considerations include processing requirements (hydrocarbons composition), proximity to major population centres, bulk transport infrastructure and pipeline infrastructure. Using those merit criteria the basins near the coast with geothermal resources will be of primary interest.

Hydrocarbons that have high impurities content (carbon dioxide, nitrogen and water) have greater demand for heat and thus greater potential to use geothermal heat. Details on processing requirements for the Canning and Amadeus fields will not be available until exploration is further advanced. The Bowen and Surat Basin gas processing facilities have low CO_2 content but significant dehydration and water treatment facilities which could make use of geothermal heat.

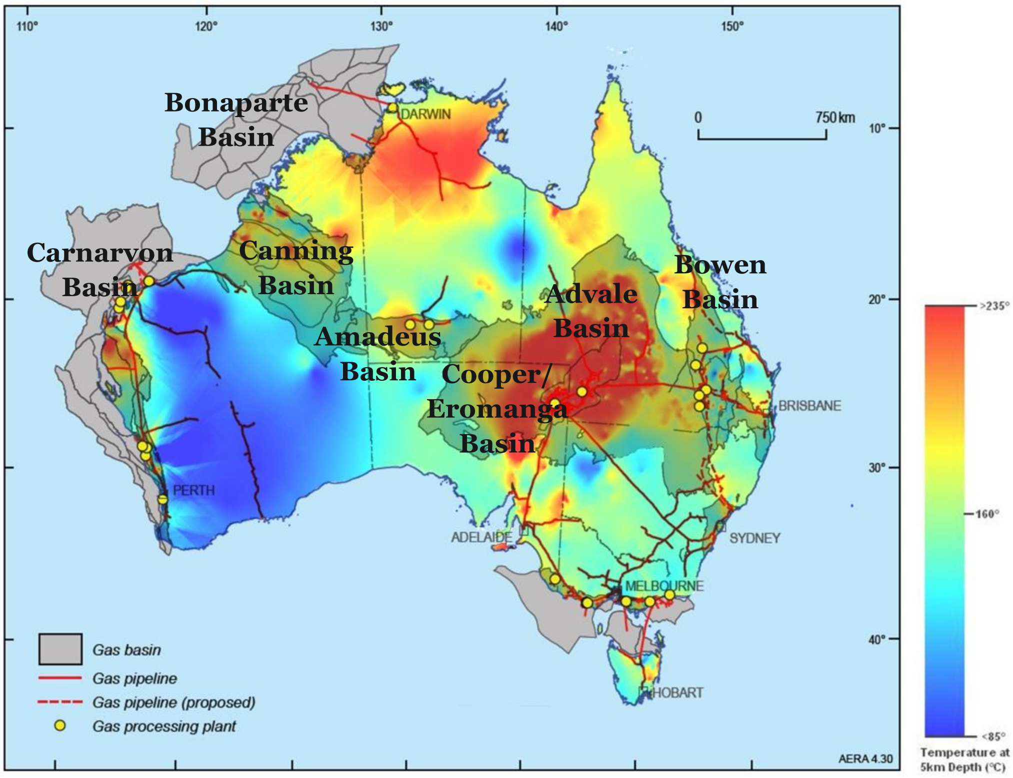

Figure 11 Overlay of gas basin on geothermal resources

5 Conclusions

The key conclusions from Evans & Peck's assessment are presented below:

1) The Cooper Basin has a very low resident population. Any large application of direct heat would be to serve industrial users.

2) Geothermal heat is not portable. Users of direct heat will have to be located very close to the heat production area.

3) Other than oil and gas pipelines there is no high capacity/low cost infrastructure servicing the Cooper Basin. The remoteness of the Cooper Basin from existing major infrastructure makes constructing new infrastructure expensive. There are high logistics costs for supply of feedstocks not locally available at a competitive price.

4) Depending on the product format of potential goods (e.g. fertiliser, product gases etc.) product distribution cost to domestic markets and export facilities can also be high.

5) There are applications of geothermal heat in the hydrocarbon industry that have locally available competitively priced feedstock and access to cost effective product distribution infrastructure. These applications will be the first to become commercially viable and are described below:

Application	2014	2020	2030
Enhanced oil/gas recovery	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable
Gas Processing Facilities	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable
Utilities and Offsite	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable
Urea Production	Not Commercially Viable	Possibly Commercially Viable	Possibly Commercially Viable
Carbon Capture and Storage	Not Commercially Viable	Possibly Commercially Viable	Probably Commercially Viable

Table 13 Potential for Commercial Application of Geothermal Heat

6) The applications in item 5) are shown to have an increased likelihood of commercial viability over time. This is because of improving competitiveness of geothermal resources.

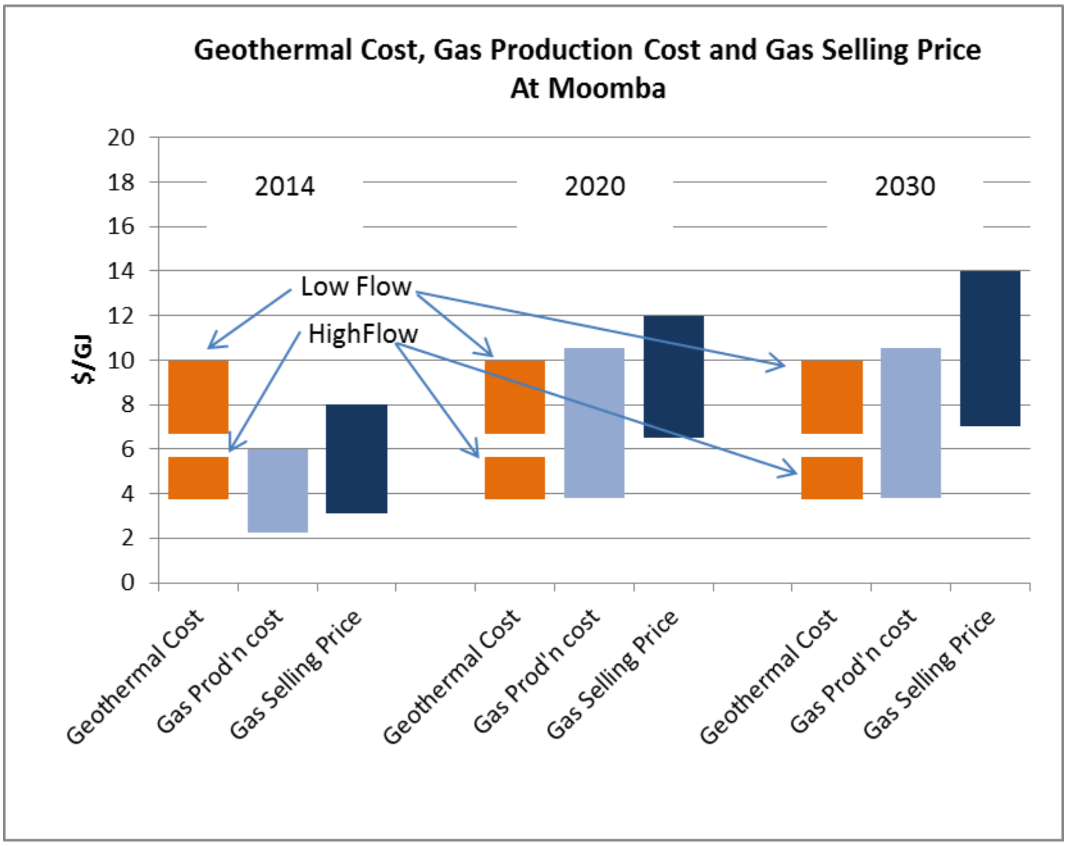

Figure 12 Geothermal Commercial Competitiveness

The figure above shows that gas production cost and selling prices are increasing over time as geothermal energy cost remains stable. Geothermal energy costs are shown as high flow case and low flow case. These two cases reflect the uncertainty range of the productivity of the wells. For each flow case shown, the cost range reflects uncertainty of the well construction cost. In actuality there is a cost continuum ranging from high flow and low well cost to low flow and high well cost.

The following observations can be made for each time frame:

- 2014: The cost of geothermal energy is not less than the selling price of gas in 2014. There is no commercial driver to pursue geothermal energy.
- 2020: The cost of geothermal energy starts to become competitive with gas fired heat. Assuming the long range forecast is still accurate by 2020, there is an opportunity to consider designing in fuel flexibility to include geothermal energy as a hedge against changing regulations with respect to potential CO_2 emissions costs and to take advantage of forecast favourable price competitiveness of geothermal energy.
- 2030: Geothermal energy will become increasingly competitive towards 2030. Under some scenarios the cost of geothermal energy is below the production price of gas. If this eventuates, there is added incentive for monetising low cost geothermal heat in more highly transformed hydrocarbon products.

- In general: Gas production costs at the Cooper Basin are expected to increase over time as a larger proportion of the gas produced is from more expensive unconventional resources. Increasing production cost creates headroom for geothermal energy which is expected to have relatively stable cost over time.

7) There are several indicators that suggest 2020 will be a turning point in the Cooper Basin. A large portion of the existing facilities are coming to end of life. If production is to be sustained reinvestment will be required around 2020. Unconventional gas resources are currently being actively explored and have attracted significant international interest. If deemed economically viable these resources may come on stream around 2020 or soon thereafter.

8) Hydrocarbons that have high impurities content (carbon dioxide, nitrogen and water) have greater demand for gas purification and thus greater potential to use geothermal heat in the purification processes. Details on processing requirements for the Canning and Amadeus fields which are also near geothermal energy sources will not be available until investigation of raw gas composition is further advanced. The Bowen and Surat Basin gas processing facilities have low CO_2 content but significant dehydration and water treatment facilities which could make use of geothermal heat.

Appendix A

Existing Examples of Application of Geothermal Direct Heat

A1 Geothermal Energy Use – International and Australia

This portion of study investigates common characteristics of the pathways to market for economically sustainable international geothermal assets with a view to finding where Australian geothermal assets might enjoy similar pathways to market.

This study focuses on high quality geothermal resources. The quality of geothermal energy includes factors such as resource temperature, flow rate, mineralisation and contaminants picked up or deposited by the heat transmission media. Direct heat applications typically need high temperature resources and the application must be selected based on maximum available temperature. Large scale industrial processes also need consistent and large heat flows. High quality geothermal energy also means that resources do not impart mineralisation, which can rapidly cause scaling on heat exchangers that cause loss of reliability, efficiency or increased maintenance cost.

The proximity of the geothermal energy to the end consumers is a key determinant of who the end consumers are likely to be. Energy sources in remote locations are burdened with high connection infrastructure costs and transmission losses rendering their exploitation economically challenged.

The report finds that Australia has no large scale geothermal facilities. The handful of geothermal resources that are in service are small scale and in some instances demonstration plants.

The large scale geothermal facilities overseas tend to be located in volcanic areas. These plants have access to high temperature resources (>200 ° C) and are able to get high steam flow rates through fairly large numbers of wells in naturally permeable rocks. The depth of the geothermal resources is typically in the range 1,000-2,500m. Productivity is between 2-7 MW_e/well. None of the plants identified in the survey use high temperature geothermal heat (>150 ° C) for any application other than electricity generation, although lower grades of heat may be distributed for space heating and agricultural/aquaculture applications, especially in cooler climate regions.

A1.1 Geothermal and Hydrocarbon Coproduction

In wells with ongoing oil and gas exploitation, co-produced hot water can be used as a resource that can produce electricity for field operations or sold to the grid. Similarly, abandoned oil and gas wells can be refitted to circulate water and generate electricity, overcoming the high capital costs of drilling for geothermal energy. Co-production distributed power from waste heat has seen significant attention in the U.S. with estimates that there are 823,000 old wells producing hot water concurrent with oil and gas production in the States alone [21].

These technologies currently use a binary Organic Rankine Cycle (ORC), which transfers the heat from geothermal fluid (mostly water) to a second fluid that vaporizes at a lower temperature and higher pressure than water. This vapour is then used to drive a turbine to produce electricity. This type of system is closed-loop with minimal emissions.

Generally, the power produced is small-scale ranging from 100-300 gross kW. One example is ElectraTherm who has recently commissioned its 410 ° C Green Machine in Nevada which utilizes low grade waste heat (77-116°C), with outputs up to 110kWe for distributed power generation.

[21] 2013 Geothermal Power: International Market Overview, Geothermal Energy Association, 2013, http://geo-energy.org/events/2013%20International%20Report%20Final.pdf

A1.2 Direct Heat Applications

A1.2.1 Timber processing and Paper Manufacture

The timber processing and paper manufacture operation at Kawerau New Zealand is reputed to be one of the largest industrial process applications of direct heat in the world.[22] The heat is used in timber drying kilns and pulp and paper mills. Geothermal heat is also combined with process heat to supply steam at optimal conditions for electricity generation.

A1.2.2 Heat pumps

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 interesting 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 means to process heat in a nearby dairy for cheese production.

A1.2.3 Geothermal Food Processors

Drying and dehydration is another example of an industrial use of geothermal energy. A variety of vegetable and fruit products can be considered for dehydration at geothermal temperatures. Dehydration processes involve either continuous belt conveyors or batch dryers, using low temperature air from 40 ° to 100 ° C. Blowers and exhaust fans move the air over coils through which the geothermal fluid flows. The heated air then flows through the beds of vegetables or fruit on conveyors, to evaporate the moisture. Geothermal Food Processors near Fernly, Nevada, dehydrate onions, garlic, celery, and carrots using 130 ° C geothermal fluid. This plant has been operating since 1978[23].

In New Zealand, the Ohaaki Geothermal Power Station has pioneered various industrial uses nearby. Ohaaki Heat uses wastewater from the power plant at 140 ° C to heat kilns that oven dry firewood. Taupo Lucerne Limited has also utilised high pressure steam from Ohaaki Geothermal Station. By operating adjacent to Ohaaki Geothermal Station and close to alfalfa growers in the area, Taupo not only saves in transport costs but also produces a commercially higher grade alfalfa by ensuring that it is cut, windrowed and dried all in the same vicinity.

A1.2.4 Heap Leaching for Gold recovery

Two mines have used geothermal fluids in their heap leaching operations to extract gold and silver from crushed ore: Round Mountain Gold and the Florida Canyon Mine, located in the north-central part of the Nevada, USA.

The leaching process for gold consists of placing crushed ore on an impervious pad and sprinkling the ore with dilute sodium cyanide. The gold dissolves in the liquid which is processed such that gold is recovered. The process is made more effective by heating the leaching fluid, particularly in cooler months when the

[22] http://www.nzgeothermal.org.nz/publications/Reports/NZGADirectHeatAssessmentReport_2006.pdf
[23] http://geoheat.oit.edu/pdf/tp23.pdf

ambient temperature is low. These plants have been able to increase the extraction of ore by 17% and extend their operating season into the colder months, compared to conventional means.[24]

A1.2.5 Enhanced Oil Recovery

When oil is produced, only about a third of the oil in the ground can be recovered by simply pumping production wells. Secondary recovery, the injection of water to move oil toward production wells, is often used to recover up to an additional third of the original oil. In the oil fields of North and South Dakota, Wyoming and Montana, geothermal fluid is produced with the oil from several deep zones. This fluid is often between 60 and 100 ° C as it is produced at the surface, and is mixed with surface water to be re-injected into the same formation for secondary oil recovery.

The injected water used in the four states mentioned above comes primarily from the Dakota Sandstone and the deeper Madison Limestone. Dakota aquifer water ranges between 60 and 80°C and Madison aquifer water ranges between 75 and 100°C[25].

Alberta, Canada uses an in situ mining technique of tar sands called steam assisted gravity drainage (SAGD). This technique grants access to resources that are too deep to mine economically using traditional shovel and truck. This is a batch process where steam is injected to gradually heat the buried tar sands which, once warmed, will gradually flow by gravity toward a collector well. While there was some initial enthusiasm to reduce the cost of steam by using geothermal energy, ultimately the low cost of gas removed the commercial driver to use geothermal energy. There were also concerns that the geothermal wells might occupy tenement space that could no longer be used for surface mining. There has been some rekindling of interest for the companies to revisit geothermal energy in pursuit of renewable energy credits.

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[24] Examples of industrial uses of geothermal energy in the United States, John W Lund, International Geothermal Conference, Reykjavík, Sept. 2003

[25] Direct Heat, P. J. Lienau, 1990, <http://geoheat.oit.edu/pdf/tp23.pdf>

Appendix B

Supporting analysis of possible commercial uses of Geothermal direct heat in the Cooper Basin

B1.1 Support Hydrocarbon Production – Enhanced Oil/Gas Recovery

Enhanced oil and gas recovery techniques seek to ease the path of hydrocarbons to the production well by enhancing rock permeability, reducing viscosity of the produced fluids or displacing hydrocarbons by pumping inert gas into the reservoir. Use of these techniques increases flow rate and also increases total reserves recovered from the reservoir.

B1.1.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Enhanced oil/gas recovery techniques applicable to the Cooper Basin do not use direct heat as a means of increased oil / gas recovery. However the techniques below would potentially increase the heat demand of downstream facilities.

Enhanced oil recovery (EOR):

- Miscible flooding: Involves the injection of CO_2 which mixes with hydrocarbons to reduce fluid viscosity. The less viscous material flows better and can be displaced by the CO2 gas. It is estimated that there is currently around 20 – 30% Oil in Place in the "depleted" oilfields in the Cooper Basin. CO_2 could be utilized to "float" the Oil in Place to support the recovery of around half of the 20-30% available. Current economics have not allowed for this work to proceed however this situation may change pending on regulations on CO_2 emissions.

Enhanced gas recovery (EGR):

- CO_2 injection for conventional gas resources: Proven technology and likely to be applicable to Cooper Basin reservoirs although the total amount of gas recovery and the recirculation of CO_2 are not known and would need to be tested before firm statements of economic viability can be made. If CO_2 injection media were used for enhanced gas recovery it is likely that the CO_2 content of the production stream will increase due to recirculating injection media. Additional heat would be used by the CO_2 removal processes applied to the production stream.
- CO_2 injection for shale gas recovery: Still in the early stages of development. Ongoing research in the USA suggests CO_2 is preferentially adsorbed by shale with respect to methane[26]. If the same properties are observed in Australian shale gas formations, this technique would achieve the dual objectives of increasing natural gas production and sequestering CO_2. Any recirculating CO_2 would increase the heat load on gas processing facilities.

Are commercially competitive feedstocks locally available?

Main feedstocks for this process are injection media (CO_2) and in-situ oil and gas. CO_2 is commercially competitive and locally available.

Are product logistics cost commercially competitive?

Main products are produced oil and gas and recirculating CO_2.

Hydrocarbon product logistics costs are currently commercially competitive, use of enhanced gas recovery will not change this.

[26] Nuttall, B.C., Drahovzal, J.A., Eble, C.F., and Bustin, R.M., 2006, Analysis of the Devonian Black Shale in Kentucky for Potential Carbon Dioxide Sequestration and Enhanced Natural Gas Production, Final Report: Kentucky Geological Survey,

The costs associated with disposal of CO2 are expected to change over time. The current governmental policy appears to be shifting away from carbon pricing, reducing the incentive to reinject CO_2 beyond what can be gained from additional hydrocarbon production.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

The energy cost savings are achieved through cheaply available geothermal heat for incremental CO_2 removal in the product stream that could result from recirculating injection media. Without detailed analysis of the reservoir response to CO_2 injection it is not possible to definitively say whether the reduced CO_2 processing cost would sufficiently offset the increased costs associated with CO_2 injection. As discussed above, current practice in the Cooper Basin suggest EOR and EGR are not commercially viable, and as the reservoir types and production processes are unlikely to materially change before 2020, we expect low adoption of enhanced recovery techniques.

Commercial Viability

Possibly commercially viable pending reservoir response to CO_2 injection and gas prices. Increases in the cost to emit CO2 will make this technology more attractive.

B1.1.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Situation is anticipated to be the same as in 2020.

Are commercially competitive feedstocks locally available?

The nature of the reservoirs being tapped is expected to shift from conventional reservoirs in 2020 to tight gas and shale gas reservoirs by 2030. The economics of enhanced gas recovery from these formations are still under development. There are current studies on CO_2 injection on shale gas formations in the USA that indicate that enhanced gas recovery may become commercially achievable by 2030.

Are product logistics cost commercially competitive?

Product logistics costs are currently commercially competitive, use of enhanced gas recovery will not change this.

Many hydrocarbon firms anticipate government to financially encourage sequestration of CO_2 in the long term. If this happens in Australia by 2030, there will be additional incentive to reinject CO_2 as means of sequestration.

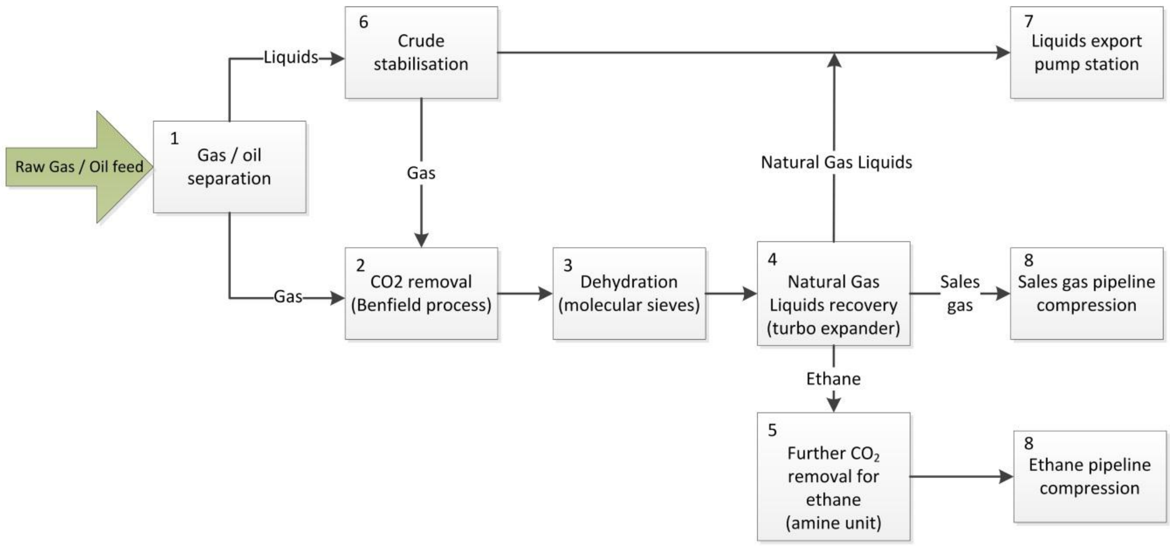
Commercial Viability

Pending detailed assessment of the reservoir response to CO_2 injection, geothermal energy provides additional benefit to enhanced gas recovery by reducing costs from gas treatment processes associated with recirculation of injected CO_2 media.

Higher gas prices enable higher production costs associated with CO_2 injection and product treatment processes. Increased cost for disposal of CO_2 also favour EOR/EGR as means of sequestering unwanted CO_2 bi-product. Advances in research on uses of CO_2 as a method for enhanced oil and gas recovery, particularly for tight gas and shale gas will contribute to improvement in the amount of hydrocarbons recovered/produced. The three factors: a) higher gas selling prices, b) greater incentive to sequester CO_2 and c) increased EOR/EGR productivity, lead to this industrial application of geothermal heat becoming increasingly commercially viable.

B1.2 Support Hydrocarbon Production – Processing Facilities

Figure 13 presents a simplified diagram of Cooper Basin processing facilities. For each of the process steps shown, the figure includes an assessment on direct heat applications.



Process Step	1	2	3	3 alt	4	5	6	7	8
Potential Geothermal Application	Gas / Oil separation	CO2 removal process (Benfield process)	Dehydration (mol. sieves)	Alternative dehydration - Glycol	NGL's recovery	Amine Unit for ethane	Crude Stabilisation	Pumping station	Pipeline compression
Direct heat	limited	low heat ~90 deg C	regeneration of sieve materials ~315 deg C	glycol regeneration ~200 deg C	none	< 300 deg C	Pending plant design detail	none	none

Figure 13 – Simplified diagram of Cooper Basin processing facilities

B1.2.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Moomba and Ballera, both currently use heat (as steam) and electricity at the site which is all self-generated. The combined parasitic load at Moomba and Ballera is 8% of gas production to provide the energy plant operations.

Assuming current daily production level of 350,000 GJ, we can estimate the total parasitic load on natural gas as shown in Table 14.

Load Type	GJ/day	Proportion economically supplied by geothermal energy
Gas consumed for power generation	15,000	0%
Heat energy consumed by CO_2 removal	1,200	100%
Other gas powered loads	12,000	50%
Total parasitic load	28,000	26% (7,200 GJ)

Table 14 Parasitic loads at natural gas production of 350TJ/day

We have not calculated the sources of "other gas powered load", but estimate them to include crude stabilisation, mole sieve dehydration regeneration, amine treatment of ethane, minor utilities and off sites. It is estimated that more than half of the other gas powered load could be substituted by geothermal heat.

A significant portion of existing facilities are expected to reach end of life by approximately 2020. It would be costly to retrofit the existing facilities with capacity to use geothermal heat. The exact timing for replacement/renewal of existing facilities and additional of new facilities to support unconventional is not precisely known.

Are commercially competitive feedstocks locally available?

Main feedstocks for this process are hydrocarbon liquids and gas. These are commercially competitive and locally available.

Are product logistics cost commercially competitive?

Product logistics costs are currently commercially competitive and use of geothermal energy will not change this.

Commercial Viability

There is a significant opportunity to apply geothermal direct heat by 2020.

Because of the uncertainties of investment timing, viability in 2020 is considered to be possible but not probable.

B1.2.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The process is anticipated to be similar to the 2020 case.

Are commercially competitive feedstocks locally available?

As per 2020 situation with the exception of the CO_2 content in the produced gas potentially increasing over time as high purity sources of gas increasingly depleted. This would increase the heat load.

Are product logistics cost commercially competitive?

Does not change from the 2020 case.

Commercial Viability

Commercial viability will continue to increase as the CO_2 removal load increases. New plant will also be designed to optimise the use of low cost geothermal energy. This is considered to be a probable commercial application of geothermal energy in 2030.

B1.3 Support Hydrocarbon Production – Pipeline Export Power

B1.3.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Pipeline transmission does not use direct heat. Steam generated from geothermal heat could be used to drive compressors or pump stations. However, this is not a direct heat application and hence is outside the terms of reference for this report.

B1.3.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Pipeline transmissions will not use heat, as per the 2020 case.

B1.4 Support Hydrocarbon Production – Utilities and Offsites

B1.4.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

This category includes a variety of potential direct heat uses including:

- Indoor climate control – space heating, adsorption cooling;
- Hot water;
- Food preparation facilities;
- Water treatment plants – potable water; and
- Water treatment plants – industrial uses.

The direct heat applications above are well proven technologies for mid and low grade geothermal heat. These applications could be readily applied to waste heat left over from the process plant.

Switching water treatment plant and heating plant from their existing technology to geothermal heat will involve capital investment that is only worthwhile once the long term production life of the region is confirmed. We have assumed that this is will not have been confirmed by 2020, hence there will not be a long term steady demand for direct heat for use by utilities and offsites.

Are commercially competitive feedstocks locally available?

Main feedstock for this process is water. This is currently sourced via boreholes in the region. Geothermal energy will not change feedstock availability or cost.

Are product logistics cost commercially competitive?

Minor capital investment in hot water distribution within the site may be required.

Commercial Viability

Switching water treatment plant and heating plant from their existing technology to geothermal heat will involve capital investment that is only worthwhile once the long term production life of the region is confirmed. A significant portion of existing facilities are expected to reach end of life by approximately 2020. The opportunity to utilise the use of geothermal heat will become more commercially viable as it is integrated into the development of replacement and/or additional facilities.

B1.4.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

As per 2020 situation, except we have assumed the long term demand to have been resolved.

Are commercially competitive feedstocks locally available?

Main feedstock for this process is water. This is currently sourced via boreholes in the region. Geothermal energy will not change feedstock availability or cost.

Are product logistics cost commercially competitive?

Minor capital investment in hot water distribution within the site may be required.

Commercial Viability

The opportunity to utilise the use of geothermal heat will become commercially viable as it is integrated into the development of replacement and/or additional facilities. This is expected to have occurred by 2030. This is a probable application of geothermal direct heat in 2030.

B1.5 Support Manufacture of Downstream Hydrocarbon Products – Oil Refinery Products

B1.5.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

This process has a long term steady demand for direct heat.

Are commercially competitive feedstocks locally available?

Main feedstock for this process is crude oil. There are insufficient quantities of locally available crude oil to sustain a refinery of scale that would be commercially competitive.

Are product logistics cost commercially competitive?

Typical oil refinery products include:

- Liquified petroleum gas (LPG);
- Gasoline;
- Naphtha;
- Kerosene and related jet aircraft fuels;
- Diesel fuel;
- Fuel oils; and

- Asphalt.

The proliferation of product streams, distances to end users and pump ability of heavier products such as asphalt make the product logistics cost not competitive.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

Energy savings do not overcome additional costs associated with crude oil supply and product distribution for a Cooper Basin refinery of scale that would be commercially competitive.

Commercial Viability

Not commercially viable for the reasons described above.

B1.5.2 Viability in 2030

Commercial Viability

No change is anticipated from 2020 case.

B1.6 Support Manufacture of Downstream Hydrocarbon Products – Compressed Natural Gas

B1.6.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No direct use of heat. Steam generated from geothermal heat could be used to drive compressors or pump stations. However, this is not a direct heat application and hence is outside the terms of reference for this report.

B1.6.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No changes are anticipated from the 2020 case that would bring it back within the terms of reference for this report.

B1.7 Support Manufacture of Downstream Hydrocarbon Products – Liquefied Natural Gas

B1.7.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The primary energy demand from LNG facilities is not direct heat but rather mechanical power to drive compressors. This is again outside the terms of reference of this report.

B1.7.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No changes are anticipated from the 2020 case that would bring it back within the terms of reference for this report.

B1.8 Support Manufacture of Downstream Hydrocarbon Products – Gas to Liquids via Fischer Tropsch

B1.8.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The Fischer Tropsch reaction is exothermic, thus there is no steady demand for direct heat. This application is outside the terms of reference of this report.

B1.8.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No changes are anticipated from the 2020 case. This application is outside the terms of reference of this report.

B1.9 Support Manufacture of Downstream Hydrocarbon Products – Gas to Methanol

B1.9.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The process does have long term steady demand for direct heat, however, geothermal heat will be in competition with heat recovery cycles already in the process design. Determining the total heat demand suited to geothermal energy requires a detailed heat integration study which has not formed part of this study. This study should include how waste heat and combustible by-products of the methanol production process could be integrated with the overall site heat load.

Are commercially competitive feedstocks locally available?

Main feedstocks for this process are gas, water and CO_2.

These feedstocks are locally available and commercially competitive.

Methanol plants are very capital intensive. For the plant to be justified long term feedstock supply must be secured. Long term availability of gas cannot be confirmed before the reform/renewal process begins in the Cooper Basin.

Are product logistics cost commercially competitive?

There are no existing nearby consumers of methanol. The Australian methanol market consumes less than 10 GJ/day of natural gas. The majority of the market is served by existing production in Laverton, Victoria[27]. If constructed the Cooper Basin facility would be competing in the export market.

Methanol is a volatile liquid at ambient conditions. Long distance transportation of methanol is typically done via rail, road, barge and ocean going vessel. Long distance transportation by pipeline has been demonstrated as technically viable however there are no current commercial operational examples of long distance overland transport by pipeline to benchmark.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

Total energy cost savings depend on the outcome of the detailed heat integration study and methanol pipeline economics analysis. In the 2020 case where the difference between gas prices and geothermal energy cost is quite thin, there is unlikely to be a sufficient energy saving to overcome logistics costs premiums.

Commercial Viability

Noting the marginal economics described above, and uncertainty of investment in future gas development, the 2020 case is not commercially viable.

B1.9.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The process is anticipated to be similar to the 2020 case.

Are commercially competitive feedstocks locally available?

Long term gas supply is predicted to be more secure following new facilities potentially coming on-stream post 2020.

Are product logistics cost commercially competitive?

Product logistics cost is anticipated to be similar to 2020 case.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

Total energy cost savings depend on the outcome of the detailed heat integration study and methanol pipeline economics analysis. In the 2030 case, pending the price differential between geothermal energy and gas fired heat, sufficient energy cost savings may be achievable but are likely to be marginal.

Commercial Viability

It is potentially commercially viable pending the results of the heat integration study confirm that low cost geothermal energy can mitigate additional product logistics cost.

[27] http://gastoday.com.au/news/industrial_gas_use_-_fuelling_australias_growth/004355/

B1.10 Support Manufacture of Downstream Hydrocarbon Products – Gas to Gasoline via Methanol

B1.10.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The methanol to gasoline process includes some highly exothermic processes and thus has limited use for geothermal energy. It is interesting to note that one of the few methanol to gasoline plants in the world, located in New Plymouth, New Zealand, close to the Taranaki geothermal region, does not use geothermal energy.

B1.10.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No changes are anticipated from the 2020 case that would increase the use of geothermal energy.

B1.11 Support Manufacture of Downstream Hydrocarbon Products – Urea

Natural gas is the main feedstock to ammonia production. Ammonia has applications in its raw form, however the majority of the global production of ammonia goes into fertilisers. The most commonly produced ammonia based fertiliser is urea. There are other potential processes that use ammonia however these have not been considered in this report as urea is reasonably representative of other ammonia based products. Urea is also commonly used by farmers as fertiliser in nearby regions.

B1.11.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The ammonia / urea production process is quite complex, with high temperature and low temperature processes and opportunity for heat recovery and thermal efficiency. However the same heat recovery techniques are likely to meet energy needs at temperatures supplied by geothermal heat. Thus although the overall heat balance is still endothermic, the potential for using geothermal energy for process heat would need to be analysed in detail, and could end up being quite small.

A detailed heat integration study would be required to establish the scale of demand for direct heat of similar quality to that available from geothermal sources. Depending on the results of this study there remains a potentially viable application of geothermal heat.

Are commercially competitive feedstocks locally available?

Main feedstocks for this process are gas, air, water and CO_2. They are all locally available at low cost.

The total feed-gas consumption to the ammonia/urea complex will be approximately 10 PJ. Typical annual production of 500,000 t urea (a typical modern plant size). This equates to around 15 percent of Cooper Basin gas production. Locally produced gas may need to be supplemented with gas from other regions to meet this demand. This could result in increased gas supply prices.

Ammonia/ urea plants are very capital intensive. For the plant to be justified long term feedstock supply must be secured. Long term availability of gas cannot be confirmed before the reform/renewal process begins in the Cooper Basin.

Are product logistics cost commercially competitive?

Domestic consumers are located relatively close to the Cooper Basin. The product can be competitively transported by truck to these end users.

Commercial Viability

For the 2020 case urea production is possibly commercially viable, dependant on the results of the heat integration study and gas prices.

B1.11.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

It is unlikely to change significantly from the 2020 case.

Are commercially competitive feedstocks locally available?

Availability of long term low cost gas supplies required to support commercial scale production are likely to be better in 2030 than was the case in 2020.

Are product logistics cost commercially competitive?

It is unlikely to change significantly from the 2020 case.

Commercial Viability

For the 2030 case it is possibly commercially viable, dependant on the results of the heat integration study.

B1.12 Support Manufacture of Downstream Hydrocarbon Products – Hydrogen Production

B1.12.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Hydrogen can be produced from gas using the steam methane reforming (SMR) process. The SMR process has two key reactions: reformation and shift. The reaction temperature for the first reaction, reformation, is around 850 ° C and is endothermic. The shift reaction occurs at lower temperatures (250 – 400 ° C) and is mildly exothermic.

The heat recovery between the reformation and shift reactions as well as the energy produced during the shift reaction liberates heat energy that both complements and potentially competes with geothermal energy. A detailed heat integration study is required to validate the extent to which geothermal energy can be usefully applied.

Are commercially competitive feedstocks locally available?

Main feedstocks for this process are gas, water, and CO_2. These are all locally available and commercially competitive.

Are product logistics cost commercially competitive?

Products of steam methane reforming are hydrogen and CO_2.

There are two stages to the hydrogen logistics: its domestic distribution and overseas distribution. The current domestic market for hydrogen is somewhat limited to largely industrial chemical applications, which are geographically dispersed around Australia and facing increasing competition from large scale, low cost producers overseas. There are no domestic users located near the Cooper Basin. Therefore a long distance pipeline would be required. At the present time, most industrial users of hydrogen have local hydrogen manufacture facilities, because transmission of gas over long distance is cheaper than the transmission of hydrogen and the gas distribution network offers broad geographic coverage.

Recent investment activity in Victoria in relation to hydrogen production from coal suggests there is potentially a growing hydrogen export market to supply Japan. Large scale ocean freight ports and vessels to transport hydrogen are in the formative stages of development prior to 2020.

Because the domestic market is distant and dispersed and the international market is not expected to be well formed by 2020 the product logistics costs will not be commercially competitive.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

The domestic market costs are significantly higher than can be currently achieved through using localised hydrogen production from gas delivered by the existing grid to the end user.

Commercial Viability

Not commercially viable.

B1.12.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No change to the 2020 case.

Are commercially competitive feedstocks locally available?

No change to the 2020 case.

Are product logistics cost commercially competitive?

Challenges associated with the distribution to domestic hydrogen consumers will remain similar to 2020 case.

For international hydrogen consumers it is possible to build a dedicated hydrogen pipeline to a hydrogen export facility. Pipeline costs per unit of energy transmitted are expected to be higher for hydrogen than natural gas. Global norms for hydrogen pipeline specification are still under development, however it is known that hydrogen pipelines have low tolerance for minor imperfections. Small hydrogen molecules are highly mobile and find their way through seals that would not be breached by natural gas molecules.[28] Building and maintaining a very long pipeline that does not leak could be a significant challenge. If constructed, this pipeline would be several times longer than the longest hydrogen transmission pipeline currently in service.

[28] Overview of Interstate Hydrogen Pipeline Systems, J Gilette and R Kolpa, November 2007 Argonne National Laboratory. http://corridoreis.anl.gov/documents/docs/technical/APT_61012_EVS_TM_08_2.pdf

The by-product of steam methane reforming is CO_2. Consequently the viability of hydrogen production from steam methane reforming is influenced by the relative cost of CO_2 emissions/disposal in Australia compared to overseas. It is not possible to reliably predict Australian or international CO_2 prices at this time.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

Further analysis is required to finalise heat integration at hydrogen manufacture and long range hydrogen transport cost.

Commercial Viability

Hydrogen production in 2030 is a possible commercial application of geothermal energy pending market conditions and establishment for long distance overland and overseas transport infrastructure.

B1.13 Support Manufacture of Downstream Hydrocarbon Products – Oil Shale

B1.13.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The process does have a long term steady demand for heat. The heat would need to be upgraded from 200°C to approximately 450°C through some co-firing with natural gas.

Are commercially competitive feedstocks locally available?

Main feedstocks are oil shale and heat. Oil shale is not currently identified in commercial quantities in the Cooper Basin.

Commercial Viability

Not commercially viable.

B1.13.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

As per the 2020 case.

Are commercially competitive feedstocks locally available?

As per the 2020 case.

Commercial Viability

No change from the 2020 case. It is not commercially viable.

B1.14 Support Manufacture of Downstream Hydrocarbon Products – Carbon Capture and Storage

B1.14.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Carbon capture does have long term steady demand for direct heat. Carbon capture processes are currently applied to raw gas process stream. Similar technologies could also be applied to effluent streams from gas combustion processes at the site, such as power generation.

Carbon storage is anticipated to involve injection of CO_2 to depleted conventional reservoirs. This mechanical process is not a direct application of heat

Are commercially competitive feedstocks locally available?

Main feedstocks are gaseous streams with CO_2 content. These are commercially competitive and locally available.

Are product logistics cost commercially competitive?

There are nearby depleted and production gas reservoirs that could be used as CO_2 storage sites.

Commercial Viability

This is commercially viable pending the government policy on CO_2 emissions.

B1.14.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

The process is expected to be unchanged from 2020 case.

Are commercially competitive feedstocks locally available?

We anticipate CO_2 content of raw gas stream is unlikely to decrease and could increase over time which increases the importance of reducing carbon capture costs. In the event that total production increases there is expected to be a commensurate increase in utilities and offsites which will also present opportunities for carbon capture.

Are product logistics cost commercially competitive?

No significant change expected from the 2020 case.

Commercial Viability

Likely to be considered as a hedge against uncertain carbon pricing policy. Will be a key consideration for producing gas with a high CO_2 composition.

Carbon capture is a probable commercial application of geothermal direct heat.

B1.15 Mining – Minerals and Metals

B1.15.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Most minerals and metals processing technologies do not have a long term steady demand for heat.

Are commercially competitive feedstocks locally available?

At the present time there are no commercial minerals or metals deposits near or in the Cooper Basin geothermal region.

Commercial Viability

Pending development of new deposit(s) near geothermal resources, this application is not commercially viable in 2020.

B1.15.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No change expected from the 2020 case.

Are commercially competitive feedstock's locally available?

No change expected from the 2020 case.

Commercial Viability

Pending development of new deposit near geothermal resources, this application is not commercially viable in 2030.

B1.16 Mining – Underground Coal Gasification

B1.16.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Underground coal gasification does have a long term steady demand for direct heat. Under normal circumstances the heat required for reaction is entirely supplied by the coal. The temperature required for coal gasification exceeds that available from geothermal energy. If geothermal energy were deployed, some co-firing would be required.

Underground coal gasification produces CO_2, which can be removed from the process stream using technologies that require direct heat of similar quality to that available from geothermal sources.

Are commercially competitive feedstocks locally available?

Main feedstocks are coal, steam, air or O_2.

There are significant coal seams in the Cooper Basin although they are quite deep. The Weena Trough in the southern Cooper Basin contains the shallowest occurrence of thick Patchawarra Formation sub-bituminous coal seams at around 1,500 m depth. There are very thick coal seams in the same formation at around 2,900m.

The depth of coals seams in the Cooper Basin is on the cusp of what has been proven for Underground Coal Gasification. The deepest coal gasification project to date is 1,400m at Swan Hills in Alberta, Canada.

Are product logistics cost commercially competitive?

Main products are syngas (mainly methane), hydrogen, CO_2 and CO.

Methane produced by coal gasification could be exported using existing gas export infrastructure which is commercially competitive. This may require some additional treatment of the gas at the surface to meet pipeline specifications.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

It is theoretically possible to use geothermal heat to reduce the amount of underground coal to be combusted for the gasification process. This could result in greater gas yield for a given amount of coal as the geothermal energy reduces the need for combustion to achieve gasification temperatures. However the total reduction in energy is relatively minor and the cost of the incumbent fuel (coal) is very low as it is already in position. The incremental syngas production volume is not expected to cover the cost of bringing geothermal heat to the coal seam.

Commercial Viability

Not commercially viable.

B1.16.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No change expected from the 2020 case.

Are commercially competitive feedstocks locally available?

No change expected from the 2020 case.

Are product logistics cost commercially competitive?

No change expected from the 2020 case.

Commercial Viability

Not commercially viable.

B1.17 Other Heat Intensive Industries – Alumina Refining

B1.17.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Most alumina production is through refining of bauxite via the Bayer process. The digestion stage of the Bayer process has long term steady heat demand for direct heat of similar quality to that available from geothermal sources. The calcination stage of the Bayer process requires temperatures above what is available from geothermal sources.

Are commercially competitive feedstocks locally available?

The main feedstocks are bauxite, caustic soda and fuel for calcination.

There are no commercially competitive sources of bauxite in close proximity to the Cooper Basin. There are commercially competitive source of bauxite in other regions that also have geothermal resources, most notably in Gove, Northern Territory.

Are product logistics cost commercially competitive?

There is no existing product export infrastructure of sufficient size to accommodate commercial scale alumina production in the Cooper Basin.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

For the Alumina refinery at Gove, energy savings are likely to yield a positive return relative to natural gas.

At the Cooper Basin the energy savings are not sufficient to cover the additional logistics costs.

Commercial Viability

There is ongoing investigation of commercial viability of geothermal energy near Gove alumina refinery.

This application is not commercially viable for the Cooper Basin.

B1.17.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No change expected from the 2020 case.

Are commercially competitive feedstocks locally available?

No change expected from the 2020 case.

Are product logistics cost commercially competitive?

No change expected from the 2020 case.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

No change expected from the 2020 case.

Commercial Viability

No change expected from the 2020 case.

B1.18 Other Heat Intensive Industries – Pulp and Paper

B1.18.1 Viability in 2020

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

Pulp and paper mills have long term steady demand for direct heat of similar quality to that available from geothermal sources. It is noted that a significant amount of the heat demand is met from fuels produced as by-products, however these plants are still net consumers of heat, particularly in the drying phase of the paper machines. Geothermal heat has been successfully applied to Norske Skog Tasman pulp and paper mill at Kawerau, New Zealand and this mill is considered to be one of the largest applications of geothermal direct heat in the world

Are commercially competitive feedstocks locally available?

Main feedstocks include wood, recycled paper and water.

These feedstocks are not locally available in the Cooper Basin. There are other regions in Australia where the required feedstocks are coincident with geothermal energy.

Are product logistics cost commercially competitive?

There are no local consumers for the product and no low cost transportation infrastructure nearby the Cooper Basin.

Commercial Viability

Not viable in the Cooper Basin. There are other regions outside the Cooper Basin that have both feedstocks nearby as well as good transport connections to consumer markets. Pending further investigation of the quality and production cost of geothermal heat in those regions, this is considered to be a probable application of geothermal direct heat.

B1.18.2 Viability in 2030

Does the process have long term steady demand for direct heat of similar quality to that available from geothermal sources?

No change expected from the 2020 case.

Are commercially competitive feedstocks locally available?

No change expected from the 2020 case.

Are product logistics cost commercially competitive?

No change expected from the 2020 case.

Are the energy savings greater than the marketing logistics premium plus any feedstock supply premium?

No change expected from the 2020 case.

Commercial Viability

Not viable in the Cooper Basin. There are other regions outside the Cooper Basin that have both feedstocks nearby as well as good transport connections to consumer markets. Pending further investigation of the quality and production cost of geothermal heat in those regions, this is considered to be a probable application of geothermal direct heat.

Australia

Brisbane
Level 2, 555 Coronation Drive
Toowong QLD 4066
Telephone +617 3377 7000
Fax +617 3377 7070

Melbourne
Level 15, 607 Bourke Street
Melbourne VIC 3000
Telephone: +613 9810 5700
Fax: +613 9614 1318

Perth
Level 6, 600 Murray Street
West Perth WA 6005
Telephone +618 9485 3811
Fax +618 9481 3118

Sydney
Level 17, 141 Walker Street
North Sydney 2060
Telephone: +612 9495 0500
Fax: +612 9495 0520

Asia

Hong Kong
Level 32, 248 Queen's Road East
Wanchai, Hong Kong
Telephone: +852 2722 0986
Fax: +852 2492 2127

Evans & Peck Group Pty Ltd
ABN50 098 008 818
E: info@evanspeck.com
W: www.evanspeck.com