Project: RDE493-35

An In-depth Assessment of Geothermal Assisted Power Generation for NSW Coal-Fired Power Plants

FINAL REPORT

Project Recipient	The University of Newcastle, Australia	
Project Sponsors	NSW Department of Planning and Environment	

Report Type	Reporting Period		Report Number	Notes
	From	To		
Final Report;	1 Jan 2019	31 Dec 2019	3112-2019	

Prepared by:
A/Prof. Elham Doroodchi
Dr. Cheng Zhou

31/12/2019

Project Information

Project Leader	Prof Behdad Moghtaderi
Chief Investigators	A/Prof Elham Doroodchi Dr. Cheng (Wallace) Zhou
Project Sponsors	NSW Department of Planning and Environment (100%)
Number of Project Phases	1
Current Lifecycle Phase	N/A
Total Project Budget	\$ 109,082 (incl. GST)
Project Duration	12 months
Official Project Start Date (Date of the execution of the agreement)	16 Jan 2019
Actual Project Start Date	01 Jan 2019
Project End Date	31 Dec 2019

Acknowledgement and Disclaimer

The authors would like to express their gratitude to the kind financial support received from the Department of Planning and Environment through the Coal Innovation NSW Fund, which is administered by the Minister for Resources, and the unique opportunity provided to us to explore this clean energy technology in great details. Any views expressed herein do not necessarily reflect the views of Coal Innovation NSW, the Department of Planning and Environment, the Minister for Resources, or the NSW Government.

EXECUTIVE SUMMARY

Australia has abundant geothermal hot dry rock resources, buried untouched deep underground up to 3 – 5 km. These are clean energy resources and used to be exploited by a stand-alone Enhanced Geothermal System (EGS). However, the EGS technology fails to be fully demonstrated in Australia due to the complexity and difficulties associated with financial and engineering risks. Most of the easily attainable geothermal resources are of low-grade nature which largely determines a low thermal utilisation efficiency. In this study, the geothermal assisted power generation (GAPG) implemented at the coal-fired power station was examined in depths to understand its effectiveness in improving the technical and financial performances of EGS technology and thus help accelerate the utilising of Australia geothermal resources. In addition, the GAPG technology can help reduce emissions and thus convert the existing coal plants into cleaner hybrid renewable energy plants. In particular, the study looked at all major New South Wales (NSW) coal-fired power stations and investigated their potentials for a successful GAPG integration via a merit index evaluation. The technoeconomic and environmental benefits of GAPG technology for NSW, Australia was also identified and quantified. Benchmarking studies were conducted to compare those results against solar assisted power generation (SAPG), a stand-alone EGS plant and the business-as-usual case (i.e. the coal plant itself). The study was made possible by using the property simulation packages, Aspen HYSYS v10, and by establishing an advanced economic tool taking into account 25-years varied cash flows.

Through the merit index evaluation, it was found that Bayswater and Eraring power stations held the best potentials for GAPG technology primarily due to their high quality geothermal resources within 20 km, abundant coal reserves, high plant availability, large achievable GAPG capacity and reasonable plant lifetime. In contrast, the MT Piper, Liddell and Vales Point B power stations were found to be less favorable owing to either an aging plant, an unstable coal reserve, or a poor geothermal resource quality. Geothermal energy resources in NSW especially surrounding the coal-fired power plants were characterised for three specific drilling depths, 2km, 3km, and 5km. The geothermal gradient across the area was found to be unevenly distributed and not always linear with drilling depth. The maximum acheiveable well head temperature was estimated to be about 184°C for a drilling depth of 5 km and at 15 km west of the Bayswater power station.

Thermodynamic study shows that the optimum pipeline configration is the use of a single return pipeline with a 101.6 mm-thick mineral wool insulation. The geothermal heat exchanger was found to be better located near the geothermal field, rather than the coal plant, to minimize heat losses, pressure drop, and brine corrosion. In addtion, considering the limitation posed by the maximum achievable well head temperature, the scope of the hybridisation options has to be narrowed down to mainly replace the bled steam from the last couple of stages of the intermediate turbine and all stages of the low pressure turbine. The maximum benefits that GAPG technology can bring to NSW coal-fired power plants were calculated to be up to 826 thousand tonnes/year of coal saving or 2,224 GWh/year of additional clean power generation. After GAPG integration, the thermal efficiency of the coal plant is increased by 1.1% - 6.5%, which is compared to 2.2% - 8.7% for SAPG system at the design point. The emission intensity of the coal plant is reduced by 1.2% - 6%.

The technical analysis showed that after the GAPG integration, the Bayswater hybrid plant can produce up to 6.3% more electricity or 5.6% fuel saving when compared with the reference case. These are obtained after considering the heat losses and power consumption in the geothermal pipeline system.

Similarly, for the Eraring hybrid plant, the maximum net boosted power is 5.8% of the reference level and the fuel saving obtainable is 4.9%.

The economic analysis consists of a capital cost analysis, a levelized cost of electricity (LCoE) calculation, and a cash flow analysis. The capital cost analysis showed that the total installed cost of GAPG system was between $350 million – $650 million for the Bayswater plant and $210 million – $500 million for the Eraring plant depending on which operating mode was employed. Of the total installed cost, the well development cost is the single largest investment reaching 57% for the low hybridisation level (BT-2km or FS-2km), and up to 84% for the high hybridisation level (BT-5km or FS-5km). The second largest investment is the pipeline system, accounting for 10-22% for a resource distance of 10 km and 15-30% for a resource distance of 20 km. The heat exchanger takes the next biggest investment proportion ranging from 4-12% depending on the required heat duty of the heat exchanger. It also turns out that the costs of plant modification, feedwater pump, and production and injection system are insignificant compared to other major cost items and takes less than 4% altogether.

With an assumed plant lifetime of 25 years, the LCoE of the hybrid plant and the LCoE of geothermal conversion were obtained. The LCoE of the hybrid plant were found to be approximately 0.04 - 0.32 cents/kWh greater than that of the coal plant regardless of carbon price. This is mainly due to the low marginal cost of coal resources compared with the costly HDR resources in the GAPG system. On the other hand, the minimum LCoE of geothermal conversion for the Bayswater power station was found to be 17.5 cents/kWh, 8.6 cents/kWh, and 7.1 cents/kWh for the drilling depths of 2 km, 3 km, and 5 km, respectively. These numbers increase to 39.5 cents/kWh, 15.0 cents/kWh, and 7.4 cents/kWh, respectively for the Eraring power station. The locations of the geothermal resources for achieving those minimum LCoE were also identified.

The cash flow analysis showed that with revenues from electricity sales and proper economic incentives, the Bayswater hybrid plant under the booster (BT) modes, BT-3km and BT-5km, was found to generate an extra NPV of $170 million and $499 million, respectively at the end of the project lifetime when compared to that of the business-as-usual case (i.e. the coal plant). That is about $7 million - $20 million of profit gain each year. The Eraring hybrid plant under the booster mode BT-5km was also found to generate an excess NPV of $397 million, or a profit gain of $16 million/year. Nevertheless, the booster mode BT-2km, due to a low hybridisation extent and thus a weak thermodynamic boost, was found to be uneconomical. The same was found for the fuel saving (FS) modes, being unviable largely due to the low cost of fuel and low emission penalty, thus making little economic sense to reduce coal consumption. The areas where the GAPG technology yields excess net profit gain were visualised in several reference maps for both the Baywater and Eraring power stations within the 40 km range. These areas are then the recommended places to deploy GAPG system in order to gain the best chance of success during commercialisation.

Under the typical operating and economic conditions, the minimum payback period for GAPG technology was found to be 10.2 years for the location at 15 km west of Bayswater plant with a drilling depth of 5 km, and 11.5 years for the Eraring plant at the location of 10 km south with a drilling depth of 5 km. A sensitivity analysis was also performed to evaluate the impact of key variables on the performance of GAPG technology under non-typical conditions. It was found that the three most critical factors affecting the LCoE of geothermal conversion are the single well productivity, discount factor and plant availability. Thus, a low discount factor, a high plant availability and a high single well productivity can be the most favourable conditions for GAPG technology to success. The profitability or payback period of GAPG technology was found to be greatly affected by, from high impact to low impact, plant availability, discount factor, electricity wholesale price and renewable energy certificates (RECs). Other parameters like carbon tax, retrofit period, and pipeline insulation thickness were found to have limited influence on the project. On average, an increase of carbon tax at 20 $/tonne and RECs at 25 $/MWh was found to improve the profitability of GAPG technology by $8.4 million/year and $14.7 million/year for the booster mode operation, BT-3km and BT-5km, respectively. This finding clearly indicates the importance of government policies in leading the industry on the road of emission reduction and the adoption of clean energy technologies such as GAPG concept.

The benchmarking study based on the best possible hybridisation in Bayswater power station revealed the superiority of GAPG techonology over SAPG counterpart. Although with a high-quality energy source, the SAPG system was found to produce only 21% -31 % of the additional electricity achievable for GAPG system on an annual basis. The intermittent nature of solar energy and the high cost of solar field were identified as the key drawbacks of the SAPG technology, and with a capacity factor of only 14.5% the SAPG system was found to be unable to payback itself within even 30 years. The base load characteristic of GAPG technology clearly exhibits a key advantage against its counterpart and the payback period was found to be 11 – 16 years for GAPG system under the typical conditions. The LCoE of clean power production, i.e. converting solar thermal energy to electricity, was calculated to be 23 – 39 cents/kWh. This is about twice to triple of the LCoE of geothermal-to-electricity in GAPG system. In conclusion, the SAPG technology was found to be a less favourable business option.

Lastly, a life cycle assessment was performed for the GAPG system to evaluate its energy, materials consumptions and environmental impact. The GAPG system was found to reduce the material usages by 3,155 tonnes/TWh or 26.6% compared to that of the equivalent stand-alone EGS plant. This is owing to the 17.4% reduction of steel usage and 100% reduction of aluminium, concrete and iron usages that would otherwise be required for constructing the power block. On the other hand, the GAPG system was found to consume about 24.3 – 51.2 GJ/MWh of geothermal energy, 3,814 litres/MWh of water resources, and produce zero emission. This is about 2.3 times of the water consumption in the coal plant but 1.4% less than that of the stand-alone EGS plant. This is mainly because of the extensive water requirement in the hydraulic fraction process, while the Bayswater coal plant uses much less water since it can source water from the Hunter river. In addition, the total GHGs emissions of the GAPG system were found to be up to 29% less than the emissions of the stand-alone EGS plant and 98.3% less than the emissions of the coal plant. This thus implies that GAPG is the technology with the least impact on the environment. Specifically, when compared to a EGS plant, the GAPG technology can help to achieve a series of environmental benefits, including a reduction of about 6.3 kg/MWh of CO_2 emission; a reduction of about 7.8 g/MWh of CO emission; a reduction of about 5.8 g/MWh of NO_x emission; a reduction of about 9.0 g/MWh of SO_x emission; a reduction of about 2.0 g/MWh of PM_{10} particulate matter; a reduction of about 1.0 g/MWh of $PM_{2.5}$ particulate matter; and a reduction of about 8.1g/MWh of CH_4 emission. When compared to the power sourced from a coal-fired power plant, using GAPG technology can help to achieve even greater environmental benefits, e.g. for the Bayswater power plant alone and over a 10-year period: (i) avoided fossil fuel consumptions including up to 4.7 million tonnes of coal and 1,140 TJ equivalent petroleum; (ii) cost savings of about $147.5 million due to reduced coal usage, (iii) an estimated reduction in GHGs emissions of up to 9.5 million tonnes, and a revenue of the associated carbon tax/credit at $238 million assuming a carbon price of $25/tonne, (iv) reduction in sulphur dioxide emissions of up to 49,020 tonnes, nitrogen oxide emissions of up to 23,010 tonnes, methane emissions of up to 14,760 tonnes, nitrous oxide emissions of up to 160 tonnes, combined PM_{10} and $PM_{2.5}$ particulate matter of about 1,560 tonnes as well as reductions in heavy metals, volatile organic compounds, black carbon, and organic carbon of up to 800 tonnes in total.

LAY SUMMARY

Australia has an enormous amount of low-medium-quality geothermal resources buried deep underground at a depth of 3-5 km. These clean energy resources have not been successfully commercialised using the latest enhanced geothermal system (EGS) due to engineering difficulties and financial risks. The nature of the resources demands a deep drilling and hydraulic fracturing process, which results in a high cost and low efficiency of the EGS plant. This project is concerned with an alternative approach to the EGS technology, namely hybridising Australian geothermal resources into the NSW coal-fired power stations (also called geothermal assisted power generation, GAPG), in order to achieve potential synergies such as better resource utilisation efficiency, a reduction of greenhouse gas (GHG) emissions, and a reduction of the cost of clean energy technology.

Both the coal-fired power plants and their nearby geothermal resources within the 40-km range and up to 5 km deep were characterised. The study found that Baywater and Eraring power stations were the best condidates for delopying such new technology. Other NSW coal plants were found to be less favorable because of either an aging plant, an unstable coal reserve, or a poor geothermal resource quality. The maximum acheiveable well head temperature was estimated to be about 184°C for a drilling depth of 5 km and at 15 km west of the Bayswater power station. The maximum benefits that GAPG technology can bring to NSW coal-fired power plants were calculated to be up to 826 thousand tonnes/year of coal saving or 2,224 GWh/year of additional clean power generation. After GAPG integration, the thermal efficiency of the coal plant could be increased by up to 6.5% and the emission intensity of the coal plant could be reduced by up to 6%.

The well development cost was found to be the largest cost component reaching 57%-84% of the total cost of the GAPG system. This is followed by the pipeline cost at about 10-30% depending on resource distance. Its electricity cost can be as low as 17.5 cents/kWh, 8.6 cents/kWh, and 7.1 cents/kWh for the drilling depths of 2 km, 3 km, and 5 km, respectively. On the other hand, geothermal heat was found to be better used for producing more clean power rather than replacing coal usages at the coal plant. Under the typical conditions, e.g. a carbon price of 20$/tonne and a Renewable Energy Certificates (RECs) of 50$/MWh, the Bayswater hybrid plant was found to yield about $7 million - $20 million of net profit every year when compared with the business-as-usual case. On average, an increase of carbon price at 20 $/tonne and RECs at 25 $/MWh was found to improve the profitability of GAPG technology by $8.4 million to $14.7 million per year. The minimum payback period for GAPG technology was found to be 10.2 years.

The benchmarking study also obtained the cost of electricity in a solar assisted power generation (SAPG) system, which turned out to be about twice to triple of those of the GAPG system. The intermittent nature of solar energy and the high cost of solar field were identified as the key drawbacks for the SAPG technology. The GAPG technology was also found to have the least impact on the environment compared to both the EGS and coal plants. It consumes 1.4% less water and produce 29% less GHGs emission than the EGS plant, and a massive 98.3% less GHGs emission than the coal plant. Provided that residential electricity is sourced from the integrated GAPG system instead of the Bayswater power station, the new technology can help to achieve the following environmental benefits over a 10-year period: (i) avoided fossil fuel consumptions including up to 4.7 million tonnes of coal and 1,140 TJ equivalent petroleum; (ii) cost savings of about $147.5 million due to reduced coal usage, (iii) an estimated reduction in GHGs emissions of up to 9.5 million tonnes, and a revenue of the associated carbon credit at $238 million assuming a carbon price of $25/tonne, (iv) reduction in sulphur dioxide emissions of up to 49,020 tonnes, nitrogen oxide emissions of up to 23,010 tonnes, methane emissions of up to 14,760 tonnes, nitrous oxide emissions of up to 160 tonnes, combined PM_{10} and $PM_{2.5}$ particulate matter of about 1,560 tonnes as well as reductions in heavy metals, volatile organic compounds, black carbon, and organic carbon of up to 800 tonnes in total.

Table of Contents

List of Figures & Tables

Figures:

Tables:

List of Abbreviations

BC: black carbon

BT: booster mode

CEPCI: chemical engineering plant cost index

CFBC: circulating fluidised bed combustor

CV: capital value

EGS: enhanced geothermal system

FOB: free-on-board

FOM: fixed operating and maintenance

FS: fuel saving mode

GAPG: geothermal assisted power generation

gCO_2e: grams CO_2 equivalent

GETEM: geothermal electricity technology evaluation model

GHGs: greenhouse gases

GREET: greenhouse gases, regulated emissions, and energy use in transportation

HDR: hot dry rock

LCA: life cycle analysis

LCoE: levelised cost of electricity

LMTD: log mean temperature difference

MW: mega watt

NPV: net present value

NSW: new south wales

OC: organic carbon

PF: pulverised fuel

ppm: part per million

RECs: renewable energy certificates

SAPG: solar assisted power generation

UA: overall heat transfer coefficient multiplied by surface area

USA: United States of America

VOC: volatile organic compound

VOM: varied operating and maintenance

1 Introduction

1.1 Project Description

This seed project is concerned with geothermal assisted power generation (GAPG) and its primary goal is to determine the feasibility of rolling out this concept across the NSW coal-fired power generation assets. The GAPG concept is designed to either produce additional clean power or directly reduce emission intensity in coal-fired power plants by partly replacing coal with geothermal heat. The proposed feasibility study consists of four overlapping milestone tasks, namely: (i) characterisation of NSW geothermal resources and coal-fired power plants, (ii) thermodynamic study and optimisation of retrofit options and operation modes, (iii) techno-economic assessment of two selected coal-fired power stations upgraded with a GAPG system, and (iv) consolidation and dissemination of project findings. If proved feasible, the research team envisages to undertake a larger program of study in the future to demonstrate the benefits of the GAPG concept.

This feasibility study is primarily a desktop mathematical modelling study in which a variety of numerical tools will be employed including process simulation software packages such as Aspen+ and/or HYSYS, mathematical solvers such as MATLAB and other tools (some to be developed in-house) for economic assessment and life cycle analysis (LCA).

1.2 Background

In Australia, abundant geothermal energy exists between 3 - 5 km underground predominately in the form of Hot Dry Rock (HDR) resources located in central Australia—a region called the Great Artesian Basin. Utilising one percent of these energy would be sufficient to provide about 26,000 times Australian annual power usage [1]. However, most of the easily accessible HDR resources are low-grade non-hydrothermal forms of energy [2]. Hence, the enhanced geothermal system (EGS) [3]—normally used to exploit the HDR resources—would have inherently low thermal efficiency. In addition, exploring and exploiting these energy resources require significant capital investments and risk, mainly associated with the drilling and hydraulic fracturing of the HDR reservoirs. To improve the economics of EGS technology and accelerate the utilisation of geothermal energy in Australia, one of the cost-effective approaches is to hybridise HDR resources with other energy resources such as solar, biomass, and fossil fuels [4]. Hybridising HDR resources with high-quality solar energy has been extensively examined by Zhou et. al. [3], while this study explores the approach of hybridising HDR resources in an existing coal-fired power plant, or the GAPG concept.

The GAPG concept, as shown in Figure 1, refers to the use of low-grade geothermal heat (between 70°–170°C) to provide a thermal boost to the existing coal-fired power plants via feedwater preheating. The geothermal heat (stream 12 in Figure 1) replaces the need of bleeding high temperature steam (stream 5) from the intermediate stages of the steam turbine for feedwater pre-heating, which allows the high temperature steam to return to the turbine and generate extra electricity. This rather simple yet effective concept enables coal-fired power stations to increase either their generating capacity (up to 30%[1]) with the same consumption of coal during periods of peak demand or alternatively to provide the same generating capacity with reduced coal consumption. In both cases the GHG emissions per unit of generating capacity are significantly reduced.

[1] *If all feedwater is pre-heated by geothermal energy.*

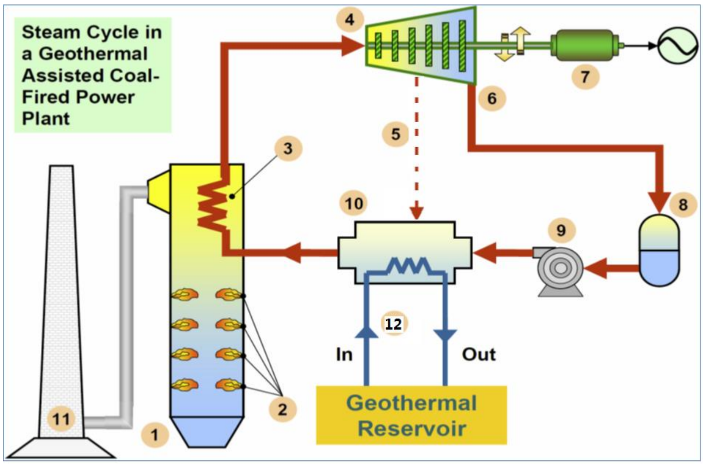


Figure 1: Schematic representation of the proposed geothermal assisted coal-fired power generation concept. Major unit operations are: (1) furnace; (3) burners; (3) boiler; (4) steam turbine; (5) turbine bled steam (partially expanded) to the feedwater heater; (6) fully expanded saturated steam; (7) generator; (8) condenser; (9) cycle pump; (10) feed-water heater; (11) stack; and (12) geothermal energy inlet and outlets to the feedwater heater.

GAPG also creates significant benefits for the utilisation of geothermal energy. Thermodynamically, the low-grade geothermal energy which has a limited heat-to-electricity conversion efficiency can now be converted to electricity more efficiently, attributed to the efficient regenerative steam Rankine cycle of the coal plant. Economically, co-locating a geothermal power plant with an existing coal-fired power plant enables the share of existing power generating facilities, land uses, and transmission lines, which helps to save significant cost and time required for developing geothermal resource.

Although other renewable energy sources such as biomass, solar and wind can be potentially hybridised with coal power generation, their effectiveness is limited at best because solar and wind energy suffer from intermittency. More importantly, many parts of the world lack adequate supplies of economically and logistically accessible biomass, solar and wind sources. The full potential of the GAPG concept for a given coal-fired power plant can be best realised if: (i) the power plant is located close to logistically accessible geothermal sources, and (ii) the geothermal source is under a coal seam since coal tends to act as a heat blanket and hence traps the geothermal energy. The above conditions are not restrictive and indeed many coal-fired power generation assets around the world would meet them. As such the GAPG concept would also have a global appeal.

Favourable conditions for implementation of the GAPG concept exists in NSW where over 97% of electricity needs are met by coal-fired power plants located in the close proximity of high-quality geothermal reservoirs. The coal for these power plants is mined from the Sydney Basin, with major Permian coal measures which also provides a blanket of low thermal conductivity rocks that raises temperatures at depth and enhances the region’s geothermal energy potential.

The distance between the coal plant and geothermal resources mostly likely still require the construction of a long pipeline system to connect the two sites. The addition of a pipeline system in a GAPG system not only increases the investment cost, but also introduces two technical penalties, including the auxiliary power consumption for fluid transportation and energy losses during the transportation processes. As a result, the net power output of the hybrid plant[2] using long-distance geothermal resources can be lower than expected. The extent of these technical and economic penalties thus determines the boundaries where the GAPG concept changes from unfeasible to profitable.

The main advantages of GAPG technology are summarised as follows:

- Transform the existing coal-fired power assets into cleaner hybrid renewable energy plants.
- Creating a shortcut to develop geothermal energy in NSW.
- No transmission line is needed.
- The fuel saving operation can help reduce coal consumption, and thus emissions and fuel costs are less per MWh of generated capacity.
- The booster mode operation can help boost additional power using clean energy sources.
- The deployment of GAPG technology can help boost local economies.
- Hybrid technologies could help lower capital cost for the same capacity compared to the stand-alone renewable energy plants. The construction period can be shortened due to the shared facility with coal-fired power plant.
- Reducing emission using GAPG technology can potentially prolong the operation of existing coal plants if the environmental policy becomes so stringent that unqualified plant may face closure.
- Potentially less limitations and restrictions for the hybrid plant compared to a new greenfield plant.

1.3 Previous Work/ State of the Art

The GAPG concept has been investigated by the research team as part of Dr Zhou's PhD thesis. In his thesis and one journal publication, the authors investigated the GAPG concept using thermodynamics and preliminary techno-economic analysis without detailed cash flow calculations. The study was also limited to a randomly chosen coal-fired power plant in NSW. White and his co-authors [5] investigated the techno-economic feasibility of building a new hybrid geothermal fossil-fuel plant implicated through the GAPG concept in Arizona, USA. The hybrid plant used low-cost shallow hydrothermal resources and was found to have an electricity cost of about 18.3 US$/MWh, which was about 5% less than that of the fossil fuel-only power plant. Anno et. al. [6] economically assessed the GAPG concept in the Western United States. The preliminary economic analysis confirmed the feasibility of GAPG concept based on the local economic conditions, provided that the supplies of both fossil fuel and geothermal resources to the power station were sufficient. Unfortunately, Anno's work was limited to hydrothermal resources with reservoir temperatures of 55 - 85°C with all cost information obtained in 1970s, and therefore the applicability of their results in Australia are limited. Dipippo et al. [7], via the thermodynamic analysis, discussed the conditions when GAPG system outperforms the stand-alone geothermal and fossil fuel power plants mainly for using onsite hydrothermal resources.

The vast experience of geothermal district heating also provides some useful insights to the GAPG system using long distance geothermal resources. For example, the longest commercialised geothermal pipeline so far, for the utilisation of a hydrothermal geothermal resource with a reservoir temperature of 90°C, is about 60 km using pipes insulated by 50 - 100 mm thick rock wool [8]. Whilst for uninsulated pipes, due to the significant heat losses the maximum pipeline length for an effective and economical transportation of geothermal fluid was found to be approximately 10 km [9].

Parsons Brinckerhoff and ARENA [10] completed a study with an even wider scope on the hybridisation of fossil fuel energy generation in Australia. They explored and screened the potential integration options of renewable energy (biomass, geothermal, solar) into the existing fossil fuel power stations including

[2] The term "GAPG system" and "hybrid plant" are used interchangeable in this work.

both gas-fired and coal-fired plants. The work is an Australia-wide desktop survey at a prefeasibility level for identifying appropriate fossil fuel generation plants and determining their hybridisation potential. Criteria was formulated with a scoring methodology to evaluate various hybridisation potential and ultimately the ranking of different hybrid options was obtained. Owing to the extensive scope of the study, it failed to explore GAPG technology in great details and some aspects were not accurate/correct. A pre-set bias may also be present against GAPG technology. For example, the study did not include a booster mode operation and assumed no reserve generating capacity for coal-fired power plant. This assumption is not true because large steam turbines used in the coal plants can operate across a broad speed range and are liberally designed to provide about 10% additional load capability beyond the nominal rated capacity. Conventionally, the nominal capacity is achieved when the control valves are close to fully open and the additional capability can be obtained by fully opening the control valves [11]. Also, adding more power generation would make the hybridisation more appealing to generators, as opposed to supplementing existing generation using renewable energy. In addition, a simplified 'typical' coal-fired plant configuration, rather than a comprehensive modelling based on the actual plant thermal cycle, was used when evaluating the technical benefits of GAPG system. This is not ideal and may lead to large error in the obtained results.

Apparently, most of the past analyses are site-specific and mainly focused on the GAPG system using onsite hydrothermal geothermal resources in the northern hemisphere, which includes the United States [7, 12, 13], Germany [14, 15], and Poland [16, 17]. A detailed study of GAPG concept for Australia, especially for the full scope of NSW coal-fired power plants where favourable offsite HDR resources are present, has never been done before. The greater drilling and fracturing costs in exploring the HDR resources compared to those of the hydrothermal resources would also make the study to be unique and valuable.

1.4 Rationale of the Project

Compared to EGS technology, GAPG technology is a potentially cleaner and low-hanging "fruit" for utilising Australia geothermal resources. Through the project, the economic and environmental benefits of GAPG technology for NSW coal-fired power stations can be identified and quantified. The economic analysis results also provide insight to the level of government policy required for deploying such technology.

1.5 Aims and Objectives

The primary aim of this project is to determine the feasibility and techno-economic performances of the GAPG integration across the NSW coal-fired power plants. The research, in particular, focuses on:

- Identification of the most attractive coal-fired power station(s) for GAPG implementation and any possible technical/economic barriers
- Create an advanced economic tool for evaluating the GAPG concept for any given coal-fired power station
- Benchmarking study of solar assisted power generation (SAPG) against GAPG technology.
- Educate the power generation industry, coal producers, government agencies (at both State and Federal levels), decision/policy makers and the public about the technoeconomic and environmental benefits of the GAPG concept
- Disseminate key findings in prestigious journals/conferences and attract public citations and interest
- Gather enough data and results to support the next-stage site demonstration of the GAPG concept
- Timely completion of the tasks listed in the milestones

2 Project Status, Milestones and Performances

The aims and objectives of the project were completely achieved in this study. Specifically, by merit index analysis, the most attractive coal-fired power station(s) for GAPG implementation were identified and the obstacles for those unfavourable coal plants were discussed. Through the established advanced economic tool and life cycle assessment, the viability, economic and environmental benefits of GAPG integration across the NSW coal-fired power plants have been quantified and, where possible, visualised. The research also shed light on the superiority of GAPG techonology over SAPG counterpart using benchmarking analysis. The impact of government policy on the profitability of GAPG technology was assessed, which provide insight to the power generation industry, coal producers, and government agencies. Milestone tasks were completed in time and key results have been submitted for publication in a prestigious journal. The following table outlines the detailed milestone progress and the associated project achievements so far.

Table 1: Milestone progress and project achievements

Milestone ID	Milestone Title	Status	Relevance to project and achievement
M1	Characterisation of geothermal resource and thermal power cycle of NSW coal-fired power plants	100% Completed	NSW coal-fired power plants and their surrounding geothermal resources were characterised. A merit index was developed, and the results facilitate the selection of the two most favourable coal plants for GAPG deployment and detailed evaluation.
M2	Thermodynamic study and optimisation of retrofit options and operation modes	100% Completed	Thermodynamic study was conducted mainly to investigate various pipeline configurations, insulation options, retrofit options, and operation modes. The overall performance forecast for NSW coal-fired power stations were obtained. The detailed technical analysis of GAPG system was completed using the developed correlations derived from the thermodynamic analysis. In addition, a detailed benchmarking study between SAPG and GAPG technologies was completed from both technical and economic points of view, which showed SAPG as a less favourable business option.
M3	Techno-economic assessment of the two selected coal-fired power stations to be retrofitted with GAPG system	100% Completed	An advanced economic tool was successfully developed for evaluating GAPG and SAPG systems based on any given coal-fired power station. A cash flow analysis was completed for the two selected coal plants and net present value and their payback periods were obtained. In addition, a sensitivity analysis was conducted to examine the impact of different operating and economic parameters on the performances of GAPG system. A government policy evaluation was

			also conducted to provide insight to the role of government organisation on GAPG deployment. A life cycle assessment for GAPG system was completed and the calculated environmental benefits were shown to outperform both the EGS system and coal-fired power plant.
M4	Summarisation of all findings, dissemination of results, and composition of the final report	100% Completed	A final report was completed with recommendations made for any future work. The key results have been submitted to a prestigious journal for publication.

3 Method

This section describes the methods employed in this study to conduct simulation and modelling study, technical and economic analyses, benchmarking study, and life cycle assessment.

3.1 Technical Analysis

3.1.1 Aspen model development

In this study, the 500 MW unit of Liddell bituminous coal-fired power plant was used as the reference power cycle for evaluating GAPG performances across the NSW coal-fired power stations. The reference power cycle employs a typical seven-stage regenerative steam Rankine cycle consisting of a boiler, a reheater, a condenser, pumps, and a series of turbines and feedwater heaters. This was modelled using Aspen HYSYS v10 according to the detailed heat and mass balance of the plant [18]. General information about the reference power cycle is presented in Table 2.

Figure 2 presents the schematic diagram of the GAPG system simulated in this study. The GAPG system consists of three major components namely (i) a conventional bituminous coal-fired power plant, (i) a geothermal plant without a power block, and (iii) a geothermal pipeline system connecting the two resources. As shown in Figure 2, the geothermal pipeline system transports a fraction of the feedwater flow (“feedwater outlet” in Figure 2) from the power station, passing the heat exchanger unit, and returns to the power station (“feedwater inlet” in Figure 2). During this process, geothermal heat is transferred from the geothermal fluid to the feedwater within the heat exchanger unit. Similarly, in the geothermal field brine is transported from the production wells through geothermal pipelines to the heat exchanger, where the thermal energy from the brine is passed onto the feedwater. The cooled brine is then directed back to the injection wells for underground reinjection.

The heat exchanger is used because geothermal fluids are not suitable for direct use in the boiler as feedwater due to the dissolved chemical impurities in the fluid. Moreover, the use of a heat exchanger minimises the heat losses and scaling problems associated with the long-distance transportation of high-temperature brine. The details of simulating a geothermal plant can be referred to the researchers’ earlier works [3, 19, 20].

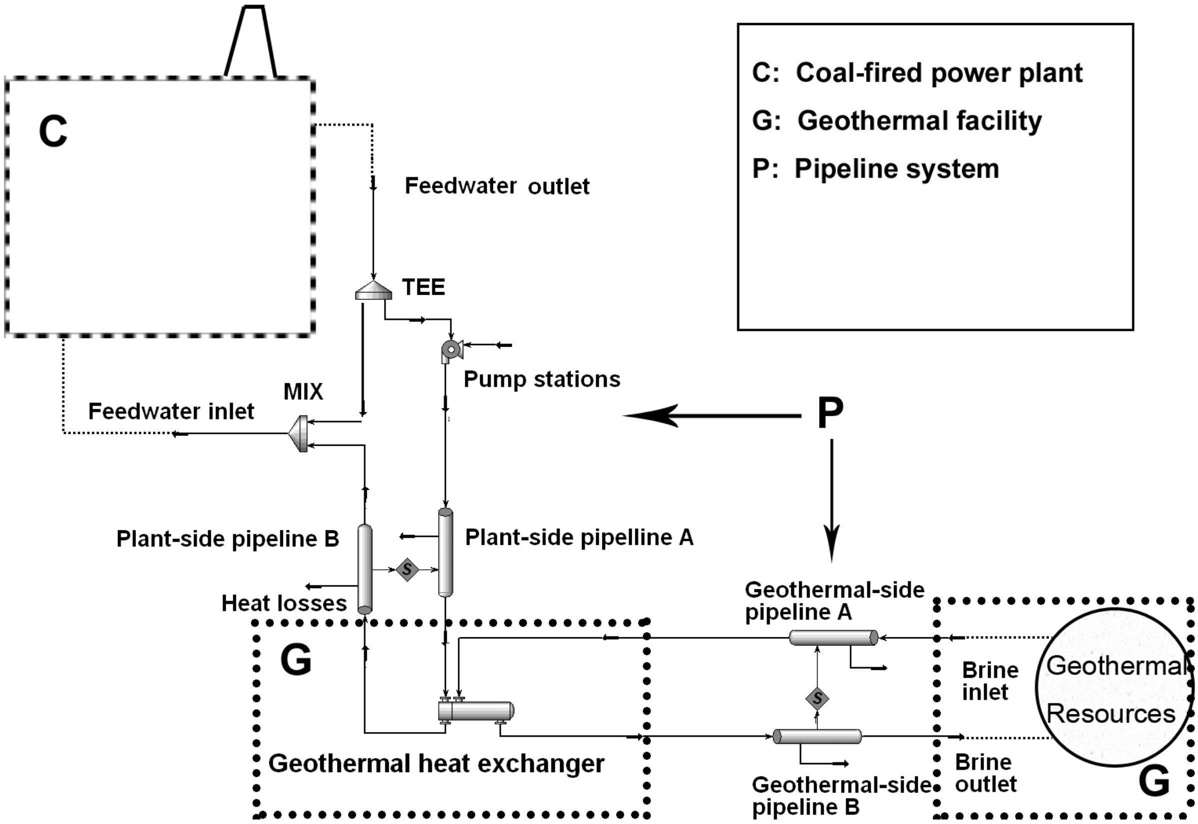


Figure 2: Schematic diagram of the GAPG system.

Table 2: Reference plant

Gross capacity	518.3 MW [18]	Fuel heating value	20.9 GJ/ tonne [21]
Auxiliary consumption	5 % of gross capacity [22]	Fuel consumption rate	251 tonne/hour
Auxiliary consumption	25.9 MW	Fuel consumption (annual)	1.95 million tonnes of black coal
Net capacity	492.4 MW	Availability factor	0.8849 [22]
Total emission intensity	1.08 t/MWh [22]	Unit fuel cost	1.41$/GJ [23]
Annual CO_2 emissions	4,122,179 tonne /year	Unit fuel cost	29.57 $/tonne
Thermal efficiency (generation)	35.6 % [22]	Unit fixed operational and maintenance (FOM) cost	52,000 $/MW/year [22]
Thermal efficiency (sent out)	33.8 % [22]	Unit varied operational and maintenance (VOM) cost	1.19 $/MWh [22]

3.1.2 Development of merit index for GAPG technology

A merit index was developed using multicriteria weighted objective matrices to evaluate NSW coal-fired power stations in terms of their potential for a successful GAPG integration. The multicriteria analysis was based on the methodology provided in [24]. This method was based on a percentage weighting of the properties of each criteria component. The total percentage weighting was 100%. Twelve components were considered for the multicriteria analysis in this evaluation including: the age of coal plant, capacity factor, quality of nearby geothermal resources, distant of the best geothermal resource, availability of coal reserves, plant thermal efficiency, maximum achievable GAPG capacity, greenhouse gas reduction potential, water scarity, environmental aspects, land use, and sesmic activity. Table 3 lists the assigned weighting percentages and explanation of those components used in the development of the merit index. The weighting percentages are given by the following criteria:

- 0-5% if it is considered to have a minor impact on the technical and economic performance of the GAPG system.
- 6-10% if it is considered to have a moderate impact on the technical and economic performance of the GAPG system.
- 11-16 if it is considered to have a significant impact on the technical and economic performance of the GAPG system.

Table 3: Weighting percentages of the components used for merit index development

Merit indexes	Weight	Comments
Age of coal plant	13%	Newer plants are more likely to have a more advanced control system and thus allows easier integration and operation of the hybrid plant. Also, any plant that are more than 40 years old are closer to shut down and thus has fewer operating hours to recoup the investment.
Quality of nearby geothermal resources	16%	The quality of geothermal resource near the coal plant determines the extent of hybridisation, generation output, and capital cost. Therefore, it is a critical factor that can impact the feasibility of GAPG concept.
Distant of the best geothermal resource	12%	The best geothermal resource located near the coal plant is a significant merit which determines the cost of geothermal pipeline and heat losses when transporting geothermal fluid.
Availability of coal reserve	11%	Is the remaining coal reserve enough to allow for a sustainable operation of the hybrid plant? This rating also considers the quality of the coal reserves nearby.
Plant thermal efficiency	8%	The efficiency of the coal plant can determine how efficiently the geothermal energy can be utilised.
Capacity factor	5%	Does the plant undergo frequent maintenance which would interrupt the operation of the hybrid system? Also, the coal plant that runs at a low capacity factor usually have lower commercial drive and thus the annual electricity production will be adversely affected. Nevertheless, most coal plants can adjust the capacity factor under better economic conditions, thus it is given a low weight score.
Water scarcity	3%	Abundant water resources nearby may help to greatly reduce pipeline cost (i.e. downsize the return pipeline to a one-way pipeline system). It

		also allows for an efficient cooling of the hybrid plant and easier operation of geothermal reservoir.
Maximum achievable GAPG capacity	11%	The maximum GAPG capacity including power generation or fuel saving potential of the GAPG system determines the size of the hybrid plant and thus the effectiveness and economics of the integration. This is largely based on the nominal capacity of the coal-fired power station.
Greenhouse gas reduction potential	5%	The potential greenhouse gas reduction at the coal plant after GAPG integration is closely related to the emission intensity of the coal plant.
Environmental aspects	5%	This criterion considers if the areas within 40 kms of the coal plant have any flood or fire prone zone, or any known protected ecological areas that may be affected by geothermal exploration.
Land use	3%	Is there any known land use confliction based on the existing tenements? (This study uses the public title search tools available at: https://nswtitles.minerals.nsw.gov.au/nswtitles/).
Seismic activity	8%	Assess the potential impact of seismic activities on the surrounding industry and public based on the geology of the area and any history of seismic activity. This is given a moderate rating since a foreseeable seismic activity may prevent the drilling exploration being approved.
Total	100%	-

3.1.3 Thermodynamic analysis

The thermodynamic analyses were performed based on the first and second laws of thermodynamics. It was assumed that kinetic and potential energies are negligible. The governing equations used in the thermodynamic analysis are summarised in Table 4.

Table 4: Governing equations for thermodynamic analysis [19].

Energy analysis

The energy balance for each operating unit of the hybrid power plant,

$$Q - W = m_{wf} \times (h_{out} - h_{in}) \quad (1)$$

The total heat input,

$$Q_{in} = Q_{geo} + Q_{coal} \quad (2)$$

The net power output and first-law thermal efficiency,

$$W_{net} = Q_{in} - Q_{out} = W_T - W_P \quad (3)$$

$$\eta = \frac{W_{net}}{Q_{coal} + Q_{geo}} \quad (4)$$

The fossil fuel-based thermal efficiency and geothermal conversion rate,

$$\eta_{coal} = \frac{W_{net}}{Q_{coal}} \quad (5)$$

$$\eta_{geo} = \frac{\Delta W_{BT}}{Q_{geo}} \quad (6)$$

Exergy analysis

The second-law thermal efficiency (also known as the utilisation efficiency or exergetic efficiency),

$$\eta_u = \frac{W_{net}}{\sum_{i=1}^{n} E_i} \tag{7}$$

Exergy content of given energy resources,

$$E_i = m_i \times [(h_i - h_0) - T_0 \times (S_i - S_0] \tag{8}$$

Exergy content of geothermal resources,

$$E_{geo} = m_{geo} \times \left[(h_{geo} - h_0) - T_0 \times (S_{geo} - S_0\right] \tag{9}$$

Exergy content of fossil fuels [25],

$$E_f = m_f \times [(h_0(R) - h_0(P) - T_0 \times (S_0(R) - S_0(P))] \tag{10}$$

$$E_f = m_f \times [G(R) - G(P))] = -m_f \times \Delta G_f \simeq -m_f \times \Delta H_f \tag{11}$$

The fossil fuel-based exergetic efficiency and geothermal utilisation efficiency,

$$\eta_{u,f} = \frac{W_{net}}{E_f} \tag{12}$$

$$\eta_{u,geo} = \frac{\Delta W_{BT}}{E_{geo}} \tag{13}$$

The geothermal heat exchanger unit was assumed to have a minimum temperature approach of 10°C and an overall heat transfer coefficient of 852.5 W/m^2C for water-brine heat transfer [2]. The efficiency of all pumps was taken as 70%. Other simulation conditions for the pipeline system are summarised in Table 5. For the choice of pipe size, the optimum nominal pipe diameter was estimated based on the pipe flow rate using Equation (14) [26]:

$$D_{optimum} = 293 m^{0.53} \rho^{-0.37} \tag{14}$$

where m is the mass flow rate of the pipe fluid, kg/s, ρ is the fluid density, kg/m^3.

The pipeline pressure drop was calculated using Beggs and Brill [27] correlation assuming negligible hydrostatic pressure loss with pipe elevation of 0 m:

$$\frac{dp_F}{dl} = \frac{2 f_{tp} \rho_m m^2}{g_c D} \tag{15}$$

where P_F is the friction pressure loss, l denotes the pipe length, f_{tp} denotes the two-phase friction factor, ρ_m denotes the density of the two-phase mixture, g_c denotes the gravitational constant and D denotes the pipe inner diameter.

Table 5: Simulation conditions for the pipeline system

Ambient temperature	25°C	Air velocity	5 m/s
Pipe material	Carbon steel	Pipe wall conductivity	45 W/m·K

Pipeline elevation	0 m	Roughness:	4.572×10^{-5} m
Insulation thickness	0 - 101.6 mm (0 - 4 inches)	Pipe diameter	Specified value or the optimum size determined by the current pipe flow rate [26]
Insulation materials	Mineral wool	Pipe schedule	40
Thermal conductivity of the insulation materials	0.04 W/m·K		

In this study, geothermal energy was mainly used to preheat the feedwater in the steam Rankine cycle of the coal plant so that a fraction of turbine-bled steam can be returned for power generation. Such operation would end up with either an additional amount of power output, called the booster mode (BT), or a reduced fuel consumption in the boiler, called the fuel saving mode (FS). The additional amount of power production (ΔW_{BT}) is the difference between the net electrical power production of the hybrid plant and the reference coal-fired power plant.

For the purpose of thermodynamic analysis, eight hybridisation modes using hypothetical geothermal resources were investigated, including: BT1, BT2, BT3, BT4, FS1, FS2, FS3, and FS4. The detailed information of these hybridisation modes is summarised in Table 6. The brine flow rates were determined in a way that can help the hybrid plant to achieve the maximum possible hybridisation for a given quality of geothermal resource.

For the techno-economic analysis of GAPG system, six hybridisation modes using actual geothermal resources with wellbore temperature data at drilling depths of 2 km, 3 km, and 5 km were examined, including: BT-2km, BT-3km, BT-5km, FS-2km, FS-3km, and FS-5km. The brine flow rates for these six hybridisation modes were also determined by realising the maximum possible hybridisation.

For the benchmarking study of SAPG system, three hybridisation modes corresponding to the replacement of heating demands from low-pressure, intermittent-pressure, and high-pressure feedwater heaters using solar energy resources were examined, including: BT1-Solar, BT2-Solar, and BT3-Solar. The size of solar field was adjusted to allow the maximum possible hybridisation at the design point.

Table 6: Definitions of the hybridisation modes under investigation

Applications	Hybridisation modes	Geothermal resource temperature (°C)	Brine flow rate (kg/s)
Thermodynamic analysis	BT1 (FS1)	90	276 (264) *
	BT2 (FS2)	110	298 (285) *
	BT3 (FS3)	120	340 (318) *
	BT4 (FS4)	150	338 (310) *
Techno-economic analysis for GAPG system	BT-2km (FS-2km)	Wellbore temperature at 2 km depth	The minimum flow rates

	BT-3km (FS-3km)	Wellbore temperature at 3 km depth	to achieve the maximum possible hybridisation
	BT-5km (FS-5km)	Wellbore temperature at 5 km depth	
Techno-economic analysis for SAPG system	BT1-Solar	All stages of the low-pressure feedwater heaters are replaced by solar preheating	Solar field is sized to allow the maximum possible hybridisation at the design point
	BT2-Solar	All stages of the intermittent-pressure feedwater heaters are replaced by solar preheating	
	BT3-Solar	All stages of the high-pressure feedwater heaters are replaced by solar preheating	

*. Based on GAPG integration at a 500 MW power unit.

The net boosted power under the booster mode is calculated by the gross boosted power from all turbines, at a resource distance of 0 km, minus the pumping power demands from both the geothermal production and injection wells as well as the pipeline system. The net fuel saving under the fuel saving mode is calculated by the gross fuel saving of the boiler, at a resource distance of 0 km, minus the heat losses in the pipeline.

The minimum required brine flow at a given resource temperature is the brine flow rate that can satisfy the maximum possible hybridisation extent or synergy under a certain hybridisation mode. For example, the minimum required brine flow at a resource temperature of 112°C in the Bayswater power station for achieving the maximum hybridisation extent under the booster mode was calculated to be about 1,283 litre/s, above which no further hybridisation synergy can be realised.

The number of wells required is the sum of the number of production and injection wells considering a ratio of one injection well for every two production wells. Geothermal energy fraction is defined as the fraction of geothermal heat to that of the total energy input of the hybrid system.

3.1.4 Other correlations employed

Apart from developing sophisticated model for calculating the key technical parameters under various conditions including the use of simulation package Aspen HYSYS V10, we also employed correlations derived from Geothermal Electricity Technology Evaluation Model (GETEM) to predict the values of some technical parameters including: the theoretically dissolved silica concentration in the brine, Equation (16), and its saturation temperature for silica, Equation (17). This is used to determine the minimum reinjection temperature for the injection well. This helps minimise silica scaling, fouling and mineral deposition in geothermal facilities such as reinjection wells, piping, heat exchangers and other production equipment. The minimum reinjection temperature is obtained by calculating both the minimum temperature to prevent silica precipitation (taken as 0.5°C greater than the saturation temperature) and the minimum temperature achievable in the geothermal heat exchanger, whichever is greater.

$$\begin{aligned}\text{Dissolved silica concentration (ppm)}\\ &= -0.0000001334837 \times T_{\text{geo}}{}^{4} + 0.0000706584462 \times T_{\text{geo}}{}^{3} \\ &- 0.0036294799613 \times T_{\text{geo}}{}^{2} + 0.3672417729236 \times T_{\text{geo}} \\ &+ 4.205944351495\end{aligned} \tag{16}$$

$$\begin{aligned}\text{Temperature achieving saturated silica (°C)}\\ &= 0.0000000000249634 \times ppm^{4} - 0.00000000425191 \times ppm^{3} \\ &- 0.000119669 \times ppm^{2} + 0.307616 \times ppm - 0.294394\end{aligned} \tag{17}$$

Due to the cooling of geothermal fluid when travelling through the well path, the bottom-hole or borehole temperature is usually greater than the wellhead temperature. Figure 3 gives the three developed correlations used in this study to estimate the temperature losses in the well bore before brine reaching the well head, ΔT_{geo}, as a function of geothermal resource temperature for three different drilling depths. The raw data points were obtained in GETEM model under the specific conditions. The GETEM model was also used for determining the pumping power demand of the production and injection wells by multiplying the actual brine production rate with the unit pump power demand obtained from GETEM, which was estimated to be 0.5 – 4.0 kW per kg/s of brine depending on the actual well depth, resource temperature and brine flow rate.

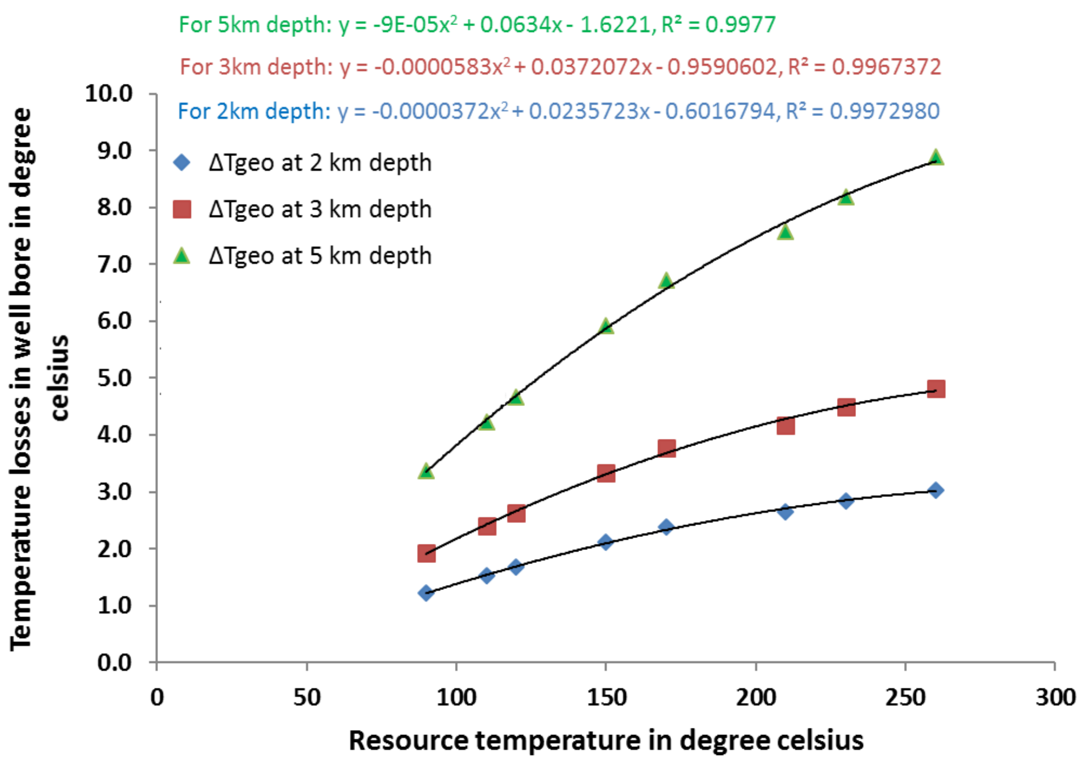


Figure 3: Temperature losses in well bore (ΔT_{geo}) as a function of geothermal resource temperature.

Equation (18) is the rule-of-thumb used to estimate brine effectiveness for the purpose of a life cycle assessment. Since there is no data available for GAPG system when performing the LCA assessment, we used the data from a stand-alone geothermal EGS plant and the calculated equivalent power plant capacity to back calculate the energy, materials and emission data for the GAPG system.

$$\begin{aligned}\text{Brine effectiveness (kWe per kg/s)}&\\ &= 3.6 \times (-0.0000000335559 \times T_{\text{geo}}{}^{4} + 0.000012204486 \times T_{\text{geo}}{}^{3}\\ &+ 0.0001765735 \times T_{\text{geo}}{}^{2} - 0.182542 \times T_{\text{geo}} + 9.41376)\end{aligned} \quad (18)$$

3.2 Economic Analysis

The economic analysis examined both the levelized cost of electricity (LCoE) and net present value (NPV) for each scenario. The methodology used was based on the established economic practices. The cost of electricity was calculated by Equation (19):

$$LCOE = \frac{\sum_{t=1}^{T}(I_{\text{t}} + M_{\text{t}} + F_{\text{t}})/(1+i)^{t}}{\sum_{t=1}^{T} P_{\text{t}}/(1+i)^{t}} \quad (19)$$

I_t : investment expenditures in the year t

M_t : operations and maintenance expenditures in the year t

F_t : fuel expenditures in the year t

P_t : electrical energy generated in the year t

i : discount rate

T : expected lifetime of system

The study also calculates LCoE for geothermal conversion only, LCoE_{geo}, to indicate the cost of clean energy production. This is by treating P_t as the net boosted electricity in the year t and all other parameters to be associated with the geothermal part only (e.g. F_t is reduced to 0 and M_t is reduced to operations and maintenance expenditures attributed by geothermal resources only, which is estimated as 0.8% of the plant cost of GAPG system deduced from the GETEM model).

The NPV approach presents a more advanced tool to evaluate different investment options. The cumulative net cash flow—namely, the NPV at year *T*—was calculated using Equation (20):

$$CV = -E_0 + \sum_{t=0}^{T} \frac{(R_t - E_t)}{(1+i)^t}, \quad t = 1, \ldots\ldots T \quad (20)$$

where *CV* denotes the capital value (NPV of future accumulating costs), R_t is the total revenue per year, and E_t is the total expenditure per year, including fixed and varied operating and maintenance costs, feedstock costs and auxiliary power costs. When the cumulative net cash flow reaches zero, the initial capital investment is fully recovered, and the payback period can be obtained by solving such a mathematical equation with $CV = 0$.

3.2.1 Capital cost

The capital cost of the project is obtained by estimating the total equipment cost and then apply the established cost estimation guidelines to estimate other cost components such as labour and installation costs. When a cost is obtained from a reference in a different year, capacity, or currency, the Chemical Engineering Plant Cost Index (CEPCI), economics of scale, and currency conversion rates on 31/12/2018 will be used to convert the reference cost to the equivalent Australian dollars. Specifically, for some components with a historical quote per unit capacity, the current cost can be obtained by:

$$C = C_P \times Q \times \frac{CEPCI}{CEPCI_0} \tag{21}$$

where C is the current cost of the equipment with a capacity of Q; C_P is the unit price of the equipment; Q is the capacity of the equipment; CEPCI refers to the Chemical Plant Cost Index for the current year; $CEPCI_0$ is the Chemical Plant Cost Index for the reference year.

For equipment with different capacity to the reference, the corresponding cost can be estimated using the economics of scale equation:

$$C = C_0 \times (\frac{Q}{Q_0})^M \times \frac{CEPCI}{CEPCI_0} \tag{13}$$

where C_0 is the reference purchase cost of the equipment with a capacity of Q_0; M is a constant which varies for different equipment. Where possible, the cost data in this report have been cross checked with the data from the open literature and independent sources such as industry suppliers. The accuracy of the total project cost is expected to be within ±20%. The total project cost will include an owner's cost of 3% and a project contingency of 15%. The effects of other economic factors including insurance, inflation, taxes and tariffs, and fluctuating revenues on the electricity sale are not covered in this study.

Depending on the distance between the fossil fuel power plant and geothermal resource, the major development costs of GAPG technology consist of the costs of well development, pipeline system, coal plant modification, feedwater pump, production and injection system, and geothermal heat exchanger.

3.2.1.1 Well development

Geothermal well cost is the most significant cost in a geothermal system, which is typically difficult to predict due to the complexity associated with the geographical and geologic conditions of geothermal reservoirs [28, 29]. The access to available geothermal drilling cost is also highly limited. However, the well cost can be estimated using the Wellcost Lite model developed by Livesay and his co-workers [30]. Figure 4 shows the comparison between the well cost predicted by the Wellcost Lite model and the actual costs of oil, gas, hydrothermal and HDR reservoirs. In this study, the well cost was estimated according to the Wellcost Lite model for a range of drilling depths. More specifically, the following cost components were also considered including a non-well exploration cost of HDR resources at $3.0 million [31] and a reservoir stimulation cost at $2.5 million per injection well [32].

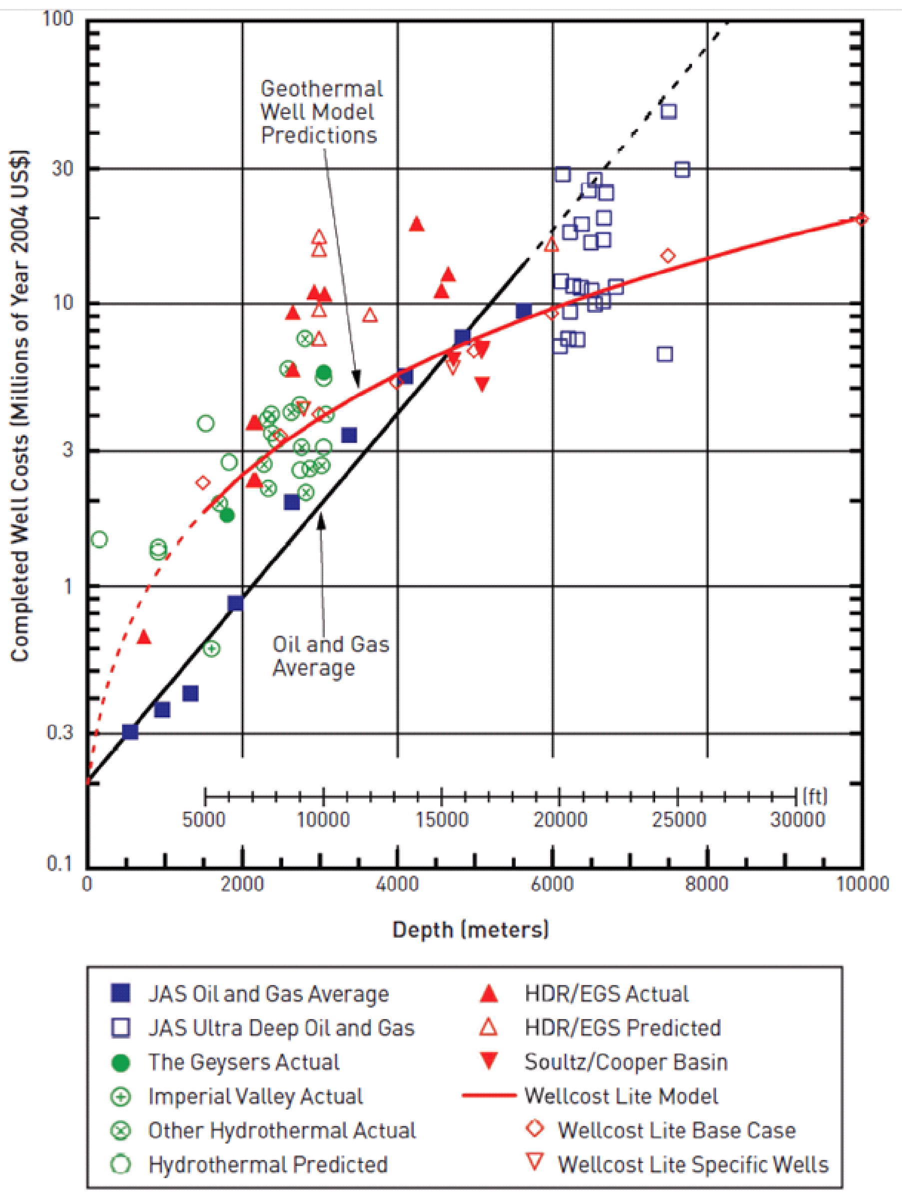


Figure 4: Well cost predicted by Wellcost Lite model, compared with the actual costs of oil, gas, hydrothermal and HDR reservoirs. Source: US Department of Energy, 2006.

3.2.1.2 Pipeline system

A variety of pipe construction materials, including carbon steel, polypropylene, polybutylene, and plastics etc., can be potentially considered for the geothermal pipeline in the hybrid system, which is subject to the maximum allowable temperature of the transported fluid. The cost variation of material can result in a large difference in the total cost of the pipeline system especially for a long resource distance. In this article, however, carbon steel was selected as the most appropriate material because of its long-term high-temperature resistance in the range of 150°C to 250°C [33]. Mineral wool, as widely used in the geothermal district heating industry, was selected as the pipe insulation material. The cost of pipe insulation is given by:

$$C_{insulation} = C_{pipe} \times S \times L \tag{22}$$

where S is the cross-section surface area of the pipe insulation layer in m^2, L is the total pipe length in km, and C_{pipe} was the unit cost of mineral wool using the quotes from Block White Construction Materials Corp. Pty Limited.

The unit bare pipeline cost (i.e. without insulation) was estimated using the cost data obtained from natural gas transmission pipelines [34]. This approach was adopted because the cost of geothermal pipeline is limited in public, and there is a high level of similarity between the natural gas pipeline and geothermal pipeline. However, the difference between the two is that geothermal fluid can be transported at a much lower pressure than natural gas. The total geothermal pipeline cost—including material ($C_{materials}$), labour (C_{labour}) and miscellaneous (C_{misc}) costs (excluding insulation costs)—was calculated by, respectively:

$$C_{materials} = C_f \times [(330.5d_{pipe}^2 + 687d_{pipe} + 26960) \times l_{pipe} + 35000] \tag{23}$$

$$C_{labour} = C_f \times [(343d_{pipe}^2 + 2074d_{pipe} + 170013) \times l_{pipe} + 185000] \tag{24}$$

$$C_{misc} = C_f \times [(8417d_{pipe} + 7324) \times l_{pipe} + 95000] \tag{25}$$

where C_f denotes the cost conversion factor considered both currency conversion and CEPCI index, d_{pipe} denotes the pipe diameter in inches and l_{pipe} denotes the total pipe length in miles.

3.2.1.3 Geothermal heat exchanger

The cost of heat exchanger was calculated considering both the unit cost per surface area (C_{unit}) and the total required heat transfer area (A), given by:

$$C_{heat\ exchanger} = C_{unit} \times A \tag{26}$$

where, the unit cost per surface area was determined based on a guideline FOB (free-on-board) cost of a stainless-steel shell and tube heat exchanger at \$502,776 for a heat transfer area of 2,000 m^2. The fixed capital investment of the heat exchanger was then calculated after considering the rules of thumb for determining labour, materials, physical and bare module costs in the reference [35]. The obtained unit cost per surface area was \$837/m^2 and the overall heat transfer coefficient of the brine-water heat exchanger was fixed at 852.5 W/m^2 °C [36].

3.2.1.4 Feedwater circulation pump

Similarly, the cost of feedwater circulation pump was determined based on a guideline FOB cost of a centrifugal water pump at \$53,564 for a duty of 250 kWe [35]. After labour, materials and other costs, the unit capital cost of the feedwater circulation pump was estimated at 317\$/kWe.

3.2.1.5 Production and injection systems

The cost of production and injection systems in the geothermal site includes the necessary costs involved with brine production activities such as production piping, injection piping, production pumps, injection pumps, corrosion inhibition systems, and other surface devices. The GETEM model was used for estimating the cost of the production and injection pumps by multiplying the concerned brine production rate with the unit pump cost obtained from GETEM at specific technical conditions. The cost of other surface equipment and indirect costs were taken as 15% of the total cost of the production and injection systems.

3.2.1.6 Plant modification

Similar to retrofitting a post combustion unit to a coal-fired power plant, the plant modification for GAPG integration also involves the treatment of turbine bled steam between intermediate pressure and low-pressure systems with the same goal of minimal intrusion to the existing power cycle. The combustion system may or may not be significantly affected depending on the hybridisation mode employed.

The retrofit cost can include the cost of modifying the main power generation components such as feedwater heaters, turbine and/or boiler, as well as the need for extra pipe work such as new fittings, joints and welding. Obviously, this cost is highly site-specific and depends on the extend of the hybridisation, age of plant, and quality of incoming geothermal fluid. During modification, any refurbishment or minor upgrading work may also need to be done to boost the performance of the coal plant. This part of the cost is even more variable. It was estimated in a report that a boiler and turbine upgrade for the post combustion retrofitting system including rearranging steam extraction would cost approximately 200$/kW [37]. In terms of GAPG system, however, retrofit may be simpler due to the nature of the technology. The boiler would remain the same for the booster mode yet require modification under the fuel saving mode due to a reduced heat duty. In this study, we assume that for the booster mode operation a constant $40/kW is the minimum retrofit cost, while for the fuel saving mode $120/kW is employed to also account for the modification of the boiler system. In addition, an extra 20$/kW is considered for plants that are older than 30 years.

3.2.1.7 Capital expenditure structure

Table 7 shows the capital spending structures of the key activities in the pre-operation period, including exploration, permitting, licencing, drilling, pipeline construction, and plant modification. It can be seen that the majority of investment takes place in the third year.

Table 7: Duration and investment structure of the activities in the pre-operation period

Project Activity	Activity intensity in the pre-operation period			
	1st year	2nd year	3rd year	4th year
Permitting, license & leasing	60%	30%	10%	-
Exploration and drilling test	100%	-	-	-
Drilling	-	40%	60%	-
Production and injection system	-	30%	70%	-
Geothermal pump Installation	-	-	50%	50%
Engineering	-	50%	50%	-
Pipeline construction	-	20%	50%	30%
Plant construction and modification	-	-	30%	70%
Capital expenditure structure	10%	24%	43%	23%

3.2.2 Typical operating and economic conditions

Table 8 lists the typical operating and economic conditions used in this work to assess the techno-economic performance of the GAPG system based on today's market conditions, with either actual or assumed values. However, it should be noted that any variation of future conditions, including the cost of electricity, fuel price, carbon price, and renewable energy certificates (RECs)/feed-in-tariff etc., would significantly affect the overall performances. The established economic model can incorporate any forecast data of those key variables and predict the impact. Due to the lack of those data and for the purpose of this report, a comprehensive sensitivity analysis was conducted, which examines how deviations of key variables in the expected range would affect system profitability.

Table 8: Typical operating and economic conditions used in the analysis

Key Assumptions	Unit	Values
Geothermal fluid heat capacity, C_p	kJ/kg K	4.2
Overall heat transfer coefficient between brine and feedwater	$W/m^2°C$	852.5
Geothermal fluid density, ρ	kg/m^3	962
Successful rate of well development	%	100
Temperature approach of geothermal heat exchanger	°C	10
Feedwater temperature	°C	36.2
Ambient temperature	°C	25
Air velocity	m/s	5
Resource thermal drawdown	°C/year	0
Insulation thickness	mm	101.6
Single well productivity	kg/s per well	50
Injection well flow rate	kg/s per well	100
Unit Cost of CO_2 Emissions #	$/t	20
RECs or Feed-in-tariff #	$/MWh	50
Electricity sale price	cents/kWh	8
Coal plant modification period for the BT-2km mode*	Weeks	4
Plant availability		0.85
Discount factor	%	6.5
Project contingency		0.15
Compensations (free permits)	$/t	0
Pre-operation period (exploration, testing, and construction)	years	4
Plant lifetime for calculating LCoE	years	25
Forecast		
Annual electricity price increase		0%
Annual fuel price increase		0%

*. Assuming 2 extra weeks for BT-3km and 4 extra weeks for BT-5km; all fuel saving modes have an additional 2 weeks to be allocated for boiler side modification.

#. Although carbon price and RECs are abolished/expired in Australia, they are considered as conventional economic means for subsidising and promoting clean energy technologies and therefore are still employed in this study for purely evaluation purposes.

3.2.3 Limitations of the advanced economic model

An advanced economic model was developed for assessing both the technical and economic performances of GAPG system for any given coal-fired power station across Australia. The estimated results obtained using the advanced model, however, are based on the equations/correlations developed over an anticipated range of conditions. And while the model may provide estimates outside of those ranges, those estimates may not be correct or much less accurate. For example, the geothermal pipeline cost equations are based on a maximum resource distance of 40 km. While a pipeline cost of even longer distance can be estimated, there is no basis for those estimates. In addition, the model was developed based on a closed loop geothermal cycle like a binary plant, it may not be suitable for providing estimate for those geothermal sites that involve brine flash operation.

Although the current version of the model, called GAPG V1.0, was created to predict acceptable results in the studied range of conditions, the model can be further expanded to include more widely applicable conditions and improved in technical details by using more rigorous equations and correlations. This then becomes a potential subject of the future studies.

3.3 Benchmarking Study with Solar Assisted Power Generation

Considering the significantly different nature of solar and geothermal energy resources, a simple technical analysis would not be enough to reveal the true benefits and drawbacks each technology holds. Therefore, the advanced economic tool for GAPG assessment was also extended to include the functionality of SAPG assessment. Some basic simulation parameters and assumptions employed for evaluating the SAPG system are listed as follows:

- Ambient temperature: 25°C
- Average solar peak irradiation over one year: 800 W/m^2
- Capacity factor: 0.145
- Optical-thermal conversion efficiency of the solar collectors: 0.7
- Feedwater preheating using solar energy is employed[3]
- Installed cost of solar collectors: 183-261 AUD$/$m^2$ depending the required temperature of solar working fluid. A low temperature requirement of the heated working fluid (e.g. <150 °C as in the BT1-solar operating mode) implies that cheaper solar collector technology and materials could be employed and thus a reduction of the total cost of solar collectors is expected.
- The annual operations and maintenance expenditures of solar field was taken as $66 per kW of the installed capacity of a stand-alone solar CSP plant [38]
- Capital investment is expensed over the typical three-years construction periods for a solar CSP plant with an expenditure structure of 20%, 55%, and 25% for the 1st, 2nd, and 3rd year, respectively.
- The retrofit process of SAPG will cause a loss of capacity in the coal plant of 4 weeks, 6 weeks, and 8 weeks for BT1-Solar, BT2-Solar, BT3-Solar modes, respectively
- Other operating and economic conditions use the typical values listed in Table 8

The technical analysis was performed based on the design-point conditions and, where possible, the annual techno-economic performances were calculated considering the low capacity factor of solar energy. It should be noted that, for both SAPG and GAPG technologies, the benchmarking study was conducted based on the best achievable hybridisation scenario using the optimum renewable energy resources that was practically available. Only in this way should the study allow for an fair "apple-to-apple" comparison.

3.4 Life Cycle Assessment

A life cycle Assessment (LCA) of the GAPG system was conducted under the principles of (i) ISO 14040:2006 and ISO 14044 environmental management – life cycle assessment, and (ii) ISO 14064:2006 – greenhouse gases. Material and energy balances are used to quantify key process parameters (e.g. emissions, resource and energy consumptions) associated with converting raw materials into useful final products as well as the disposal of all products. The environmental impacts of these processes are then evaluated. The results can be used to facilitates the decision maker to identify the processes that create significant environmental burdens and find solutions to mitigate such negative effects.

[3] Using solar collector to produce steam of the same quality that matches the coal-fired steam turbine cycle is not impossible, but it can be a great engineering challenge. Instead, using a heat exchanger to transfer solar heat to preheating the feedwater before it entering the boiler is a more widely practiced option.

The system boundary, defined as the delimitations of operations that are included in the LCA of the GAPG system, include coal mining, coal transportation, geothermal fluid production and injection, feedwater/brine transportation, energy and emissions related to the construction of GAPG infrastructures, all operations at the coal-fired power plant, and power transmission to the end users. The LCA methodology calculates performance per unit of product/activity, also called the functional unit for the LCA. One MWh of electricity delivered to the users' wall outlet by the GAPG system was the functional unit for this study, that is the extra power produced in the coal plant due to GAPG integration under the booster mode minus all auxiliary power demands attributed to GAPG integration. Figure 5 illustrates the system boundary and functional unit for GAPG system. To produce one extra MWh of electricity, the total emissions and energy consumption associated with this activity in both the geothermal site and coal plant was analysed.

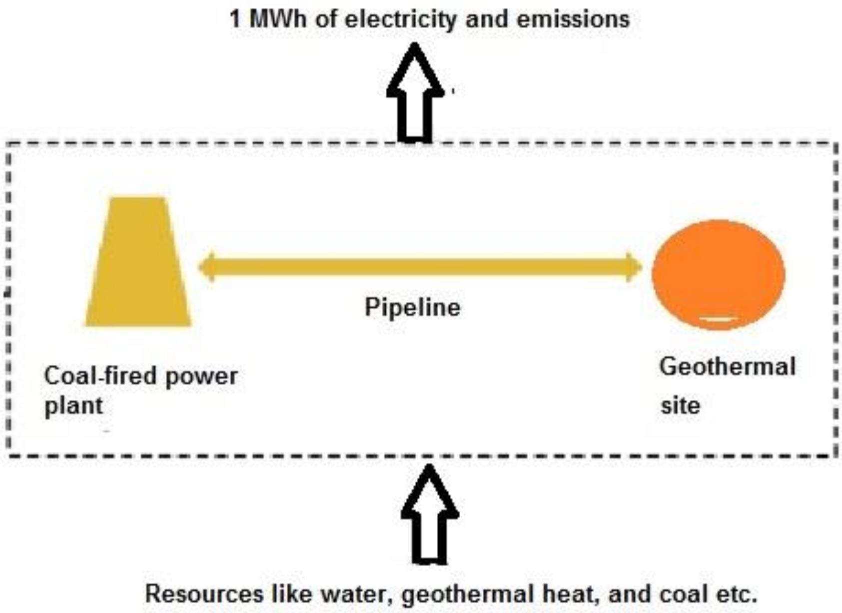


Figure 5: System boundary and functional unit for GAPG system.

Because no power production occurs in the geothermal site and the GAPG system shares the same power transmission infrastructure as the coal plant, no further infrastructure materials to connect power to the grid is required. In addition, if the thermal drawdown of geothermal resources is considered, the geothermal pipeline may be required to be relocated/extended at an interval of about every 15 years. We neglect such effect in the current LCA assessment. With data retrieved from the literature regarding the materials requirement for an EGS plant, the infrastructure materials for the GAPG system can be estimated and the associated energy and emissions data can be obtained using the Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET, version 2019) for the EGS case (GREET is a software developed by Argonne National Laboratory).

4 Results and Discussion

Results of the technical and economic analyses are presented and discussed in this section. A benchmarking study against SAPG technology and a life-cycle assessment of the GAGP plant are also completed.

4.1 Technical Analysis

4.1.1 Characterisation of NSW coal-fired power plants

Table 9 summarises the key plant data of eight major coal-fired power plants that have a power capacity of greater than 100 MW in NSW, which were obtained from various sources [21, 39]. The combined capacity is calculated to be 11,750 MW. The fuel properties for these power plants are listed in Table 10. These power stations are featured by burning bituminous coal to power steam turbines that generate some or all electricity. As of today, however, three of the eight coal-fired power plants have been either stopped operation or demolished due to poor economics of operation and/or out of service lifespan. This leaves only five coal-fired power plants to be examined under the GAPG concept, which are Liddell, Vales Point B, Eraring, Bayswater, and Mount Piper power plants. These plants also have scheduled closure dates ranging from 2022 to 2043 subject to further extension depends on the age of the plant, market condition, and future refurbishment plan.

Table 9: Basic plant data for the eight major coal-fired power plants in NSW.

Parameters	**Bayswater**	**Eraring**	**Liddell**	**Mt Piper**	**Munmorah**	**Redbank**	**Vales Point B**	**Wallerawang**
Operator	AGL Energy	Origin Energy	AGL Energy	Energy Australia	Delta Electricity.	National Power	Delta Electricity.	Delta Electricity.
Commencement year	1984	1982	1971	1992	1969	2001	1978	1976
Boiler type*	PF	PF	PF	PF	PF	CFBC	PF	PF
Maximum capacity (MW)	2640	2640	2000	1400	600	150	1320	1000
Send out electricity (GWh)	15955	13859	8070	7921	226	1027	6671	5458
Number of units	4	4	4	2	2	1	2	2
Unit capacity (MW)	660	660	500	660	300	150	660	500
Condenser cooling	Natural draft cooling towers	Natural draft cooling towers	Custom built lake	Evap. cooling towers	Evap. cooling towers	Evap. cooling towers	Evap. cooling towers	Evap. cooling towers

Cooling medium	Fresh water (Hunter river)	Salt water (lake Macq.)	Fresh water (Hunte r river)	Fresh water (Cox river)	Salt water (lake Mun mora)	Fresh water (Hunte r river)	Salt water (lake Macq.)	Fresh water (Cox river)
Annual average thermal efficiency (HHV basis)	36.5%	36.4%	32.7%	37.2%	32.0%	32.0%	35.6%	33.2%
Fuel	Coal	Coal	Coal	Coal	Coal	Coal tailing	Coal	Coal
Annual fuel consumption (Mt)	7.23	5.63	4.16	3.1	0.1	0.53	2.82	2.27
CO_2 emission intensity (kg/MWh)	879	870	949	843	984	978	896	893

* PF : Pulverised Fuel ; CFBC : Circulating Fluidised Bed Combustor

Table 10: Fuel properties for the eight major coal-fired power plants in NSW.

Components	Bayswater	Eraring	Liddell	Mt Piper	Munmorah	Redbank	Vales Point B	Wallerawang
C (%)	53.5	59.0	49.7	59.3	63.6	51.8	58.2	59.1
H (%)	3.5	3.7	3.3	3.7	4.0	3.3	3.7	3.7
N (%)	1.2	1.2	1.1	1.4	1.2	2.2	1.2	1.3
S (%)	0.5	0.4	0.5	0.5	0.4	0.3	0.4	0.5
O (%)	6.4	6.6	6.3	6.1	7.3	5.4	6.3	5.8
Ash (%)	24.7	21.0	30.4	21.2	19.0	8.0	22.2	21.7
Moisture (%)	10.1	8.2	8.8	8.0	4.5	30.0	8.0	8.0
Calorific Value (MJ/kg)*	22.4	24.3	20.9	24.7	26.3	21.6	23.8	26.0

* HHV basis

Figure 6 shows the established Aspen HYSYS model of a typical subcritical bituminous coal-fired power plant using detailed heat and mass balance data. However, due to the private nature of the thermal power cycle data of NSW power stations, obtaining the detailed heat and mass balance of all the five coal-fired power stations was found unsuccessful except for Liddell power plant. Hence, the power cycle data for the Liddell power station was used as the nominal cycle to represent other NSW coal-fired power plants considering that the same type of fuel and power cycle are used.

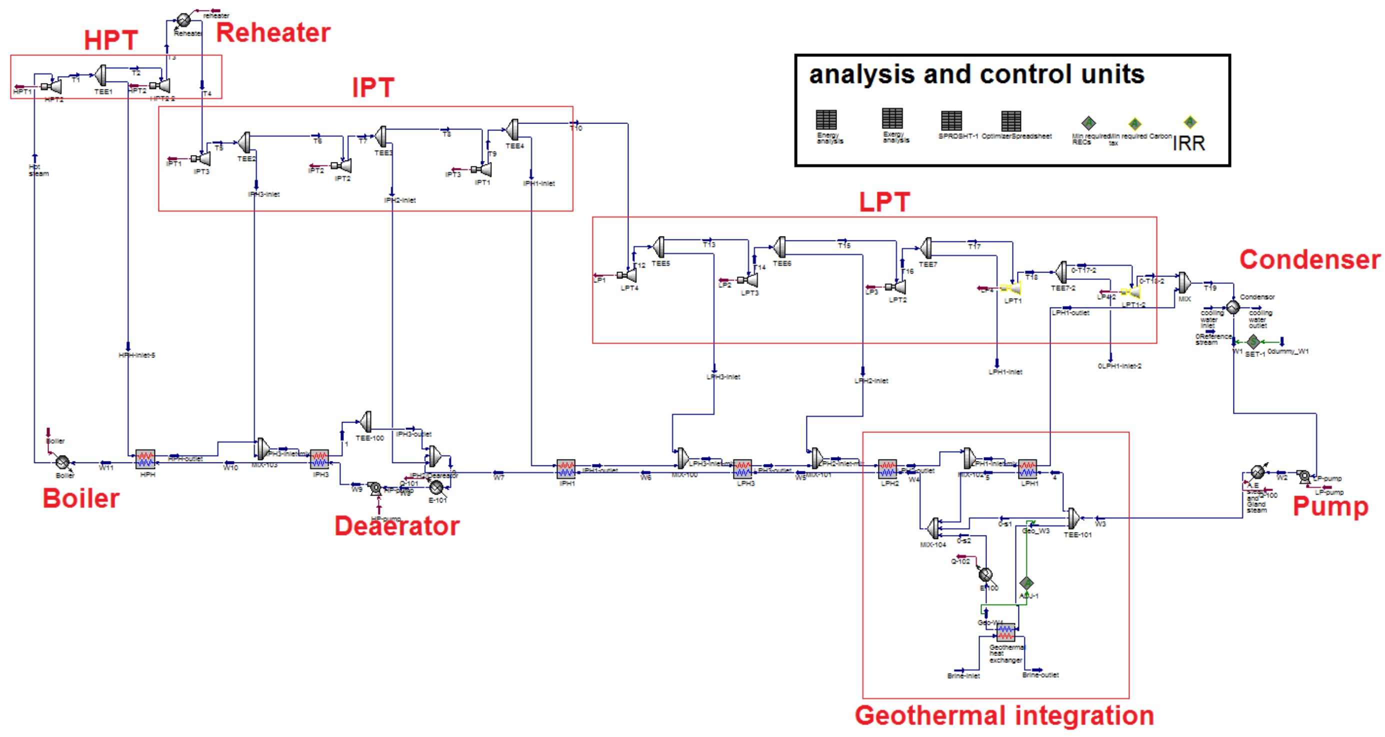


Figure 6: HYSYS model of the thermal power cycle of a typical bituminous coal-fired plant plant (HPT: high-pressure turbine; IPT: intermediate-pressure turbine; LPT: low-pressure turbine).

4.1.2 Characterisation of NSW geothermal resource

Geothermal resources near the NSW coal-fired power stations were identified and the wellbore temperature profiles at 2 km, 3 km, and 5 km depths were quantified using the existing well data at various depths (see Figure 7 for all the raw drilling data points). Figure 8, Figure 9, and Figure 10 gives the geothermal resource maps for drilling depths of 2km, 3 km, and 5km, respectively. It can be seen in the three resource maps that the geothermal gradient across the area is unevenly distributed and not always linear with drilling depth. Although geothermal resource temperature is generally linear with depth, its temperature profile along depth varies with geographical location and rock type. It is possible that geothermal heat is trapped within a specific depth range, for example, covered by a coal seam acting as the insulation layer. Hence, this work does not use fixed geothermal gradients in the analysis, but rather the extrapolated resource temperature data at various depths (2km, 3km, and 5km) according to the geothermal resource maps.

Our previous investigation suggests a technical and economic limit on the maximum distance between geothermal resource and coal-fired power plant at no more than 40 km [19]. The consideration is that above 40 km the heat losses and cost of pipeline can balance out the benefit of a hybrid plant over two stand-alone plants. Thus, this work adopts such limitation as the boundary of geothermal resource investigation around the coal plants. Specifically, geothermal resources at 0 km, 5 km, 10 km, 15 km, 20 km, 25 km, 30 km, 35 km, and 40 km along various radius directions of the five coal plants were characterised in detail, which are used for the detailed evaluation of GAPG performance.

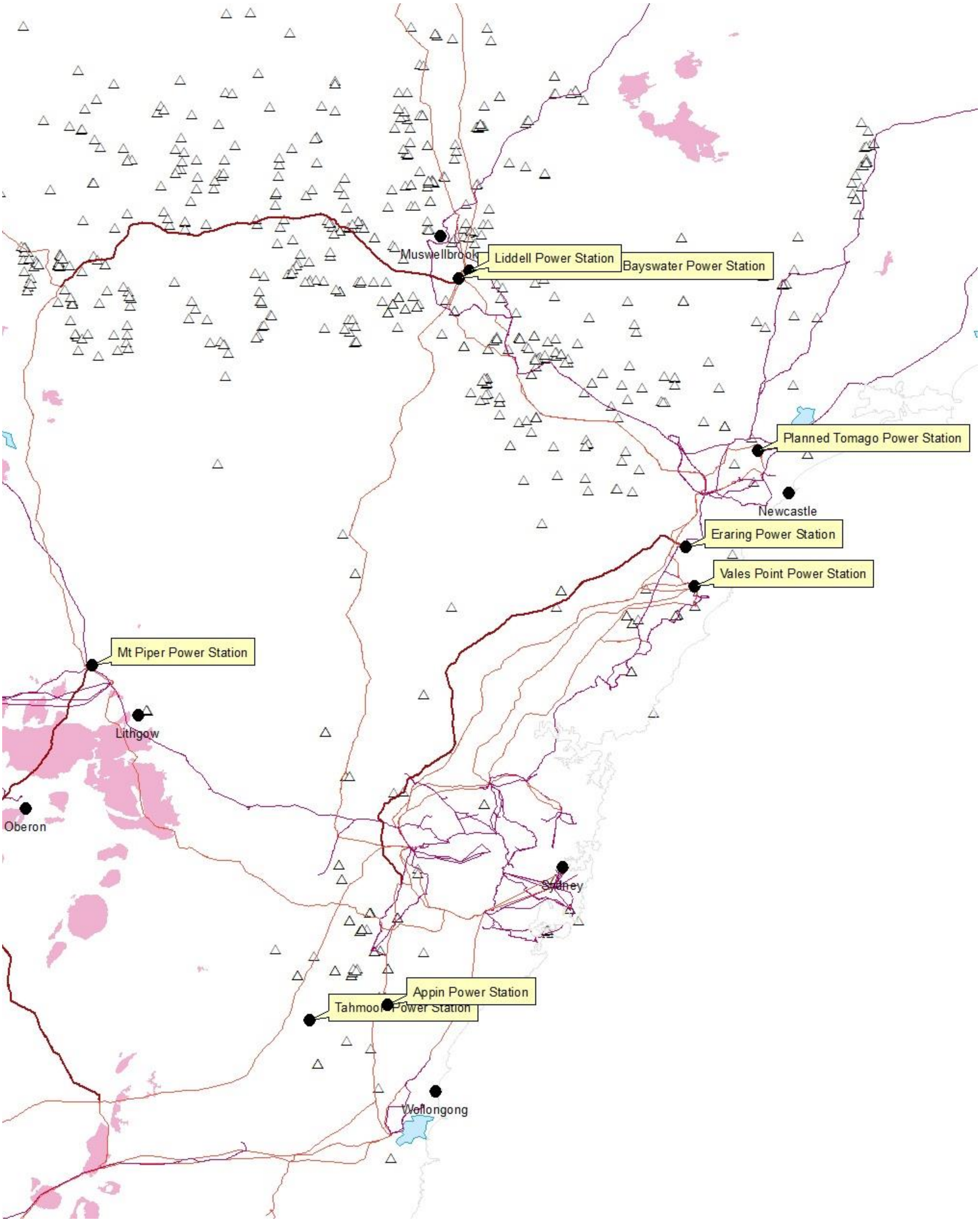


Figure 7: Well drilling data points around the NSW coal-fired power stations [40].

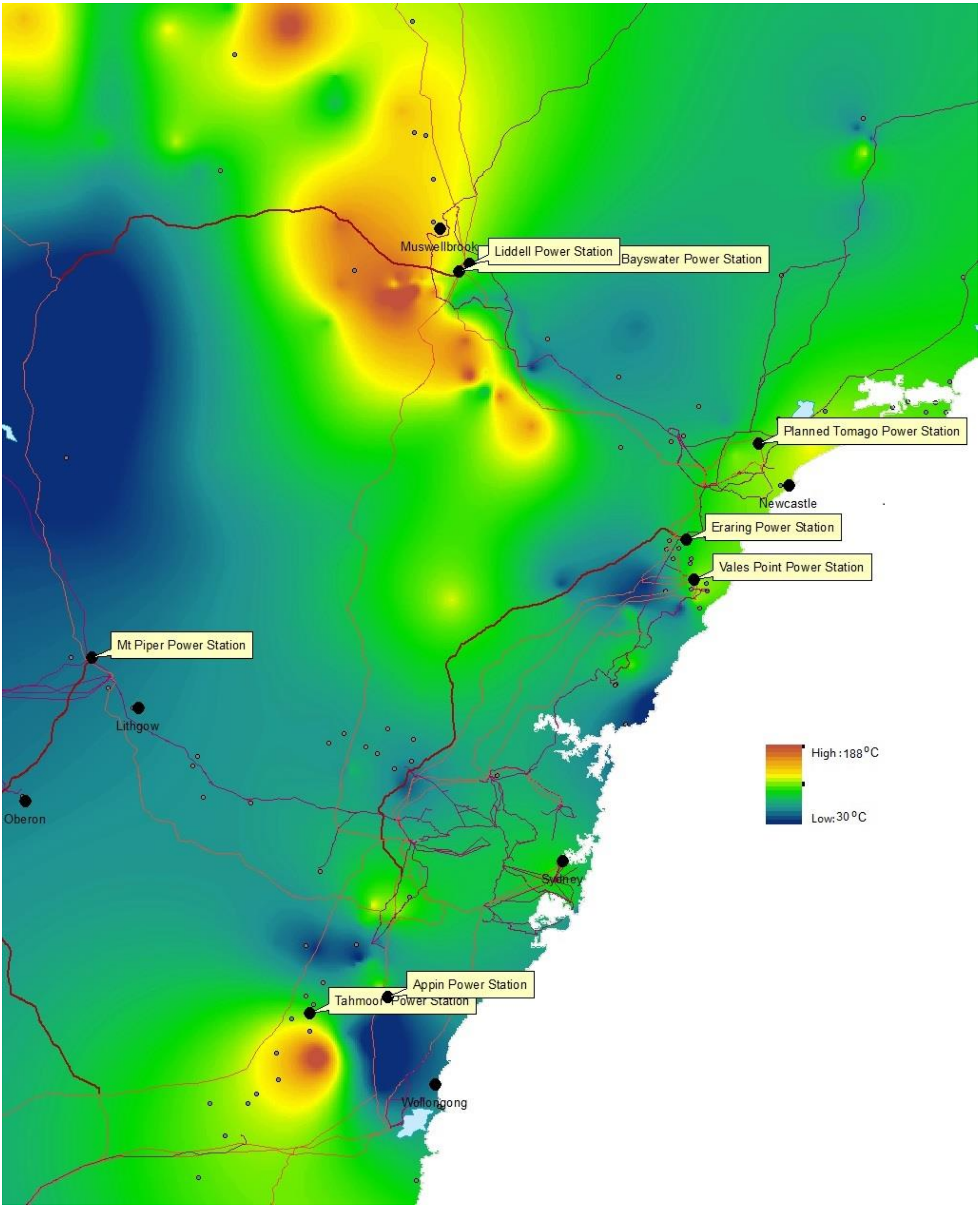


Figure 8: Geothermal resource map near the NSW coal-fired power stations at a drilling depth of 2 km [40].

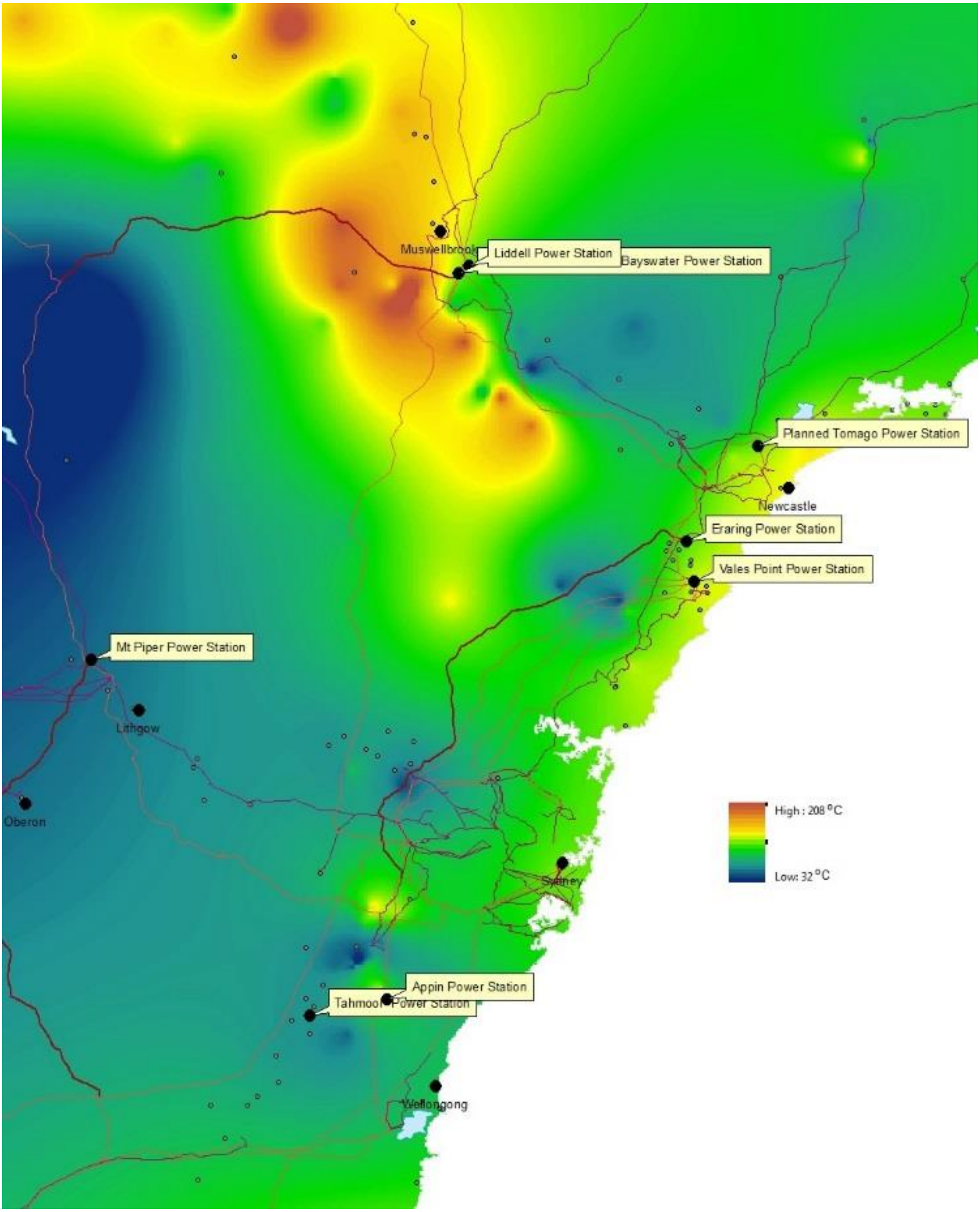


Figure 9: Geothermal resource map near the NSW coal-fired power stations at a drilling depth of 3 km [40].

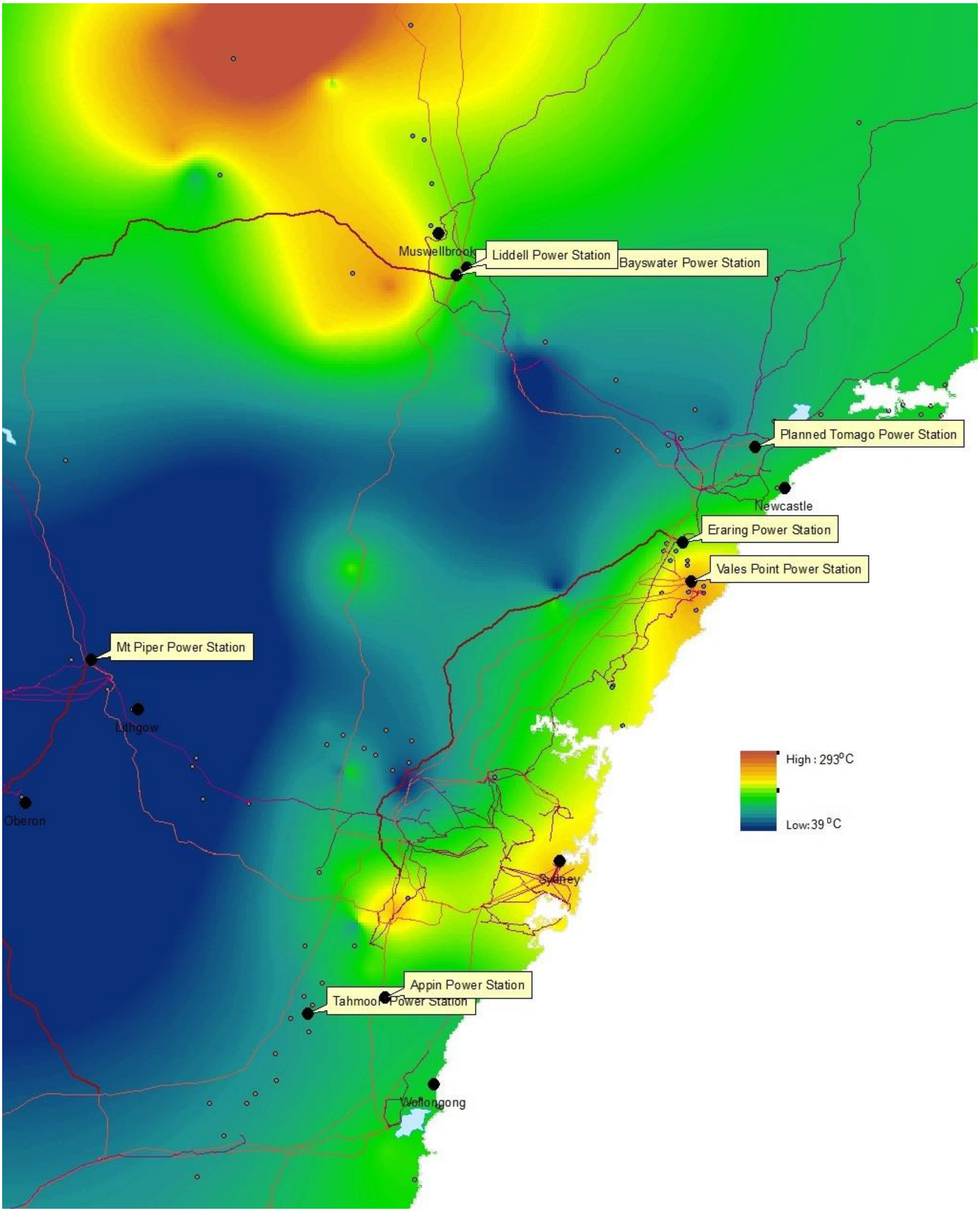


Figure 10: Geothermal resource map near the NSW coal-fired power stations at a drilling depth of 5 km [40].

4.1.3 Merit index for the major NSW coal-fired power stations

Table 11 shows the index criteria created for calculating the GAPG merit index for the five remaining NSW coal-fired power stations. Although efforts are made to quantify all the index criteria, some indexes have to use a qualitative approach due to the lack of precise data. With the data presented in the previous two sections, the quantifiable indexes include the age of coal plant, capacity factor, quality of nearby geothermal resources, distant of the best geothermal resource, plant thermal efficiency, maximum GAPG capacity, and greenhouse gas reduction potential.

Regarding the availability of coal reserves, Figure 11 gives the main NSW coalfields around the major coal-fired power plants. It is reported that NSW recoverable coal reserves total over 7 billion tonnes which include conceptual mine resources in both mining leases and exploration licence areas. Coal mines in NSW were found to produce about 194 million tonnes of saleable coal in 2017–2018, of which 161 million tonnes was exported overseas [9]. Most of the examined coal plants sit on the major coalfields with about 36 years of reserve if the export and consumption are kept the same level as 2017-2018. However, the Mt Pipe coal plant was found to sit outside of the coalfield and has been restricted by a volatile coal supply from the surrounding coal mines. For instance, in May 2019 the power output of Mt Pipe coal plant was reduced to 58% of its last year's output due to the reduced coal suppliers from six mines to one [41]. Therefore, only the Mt pipe coal plant was given a low coal reserve rating in this study.

Also considerred are the petroleum tenements and title maps (available at https://nswtitles.minerals.nsw.gov.au/nswtitles/), NSW flood data portal (www.environment.nsw.gov.au) and NSW bush fire prone land mapping tool (www.rfs.nsw.gov.au/) for determining other index criteria. For example, it was found that for the Liddell and Bayswater plants a substantial area for coal mining tenements exist. And national parks/reserves exist at the 20-40 km southwest of both Liddell and bayswater plants. The area of 10-15 km east of the Liddell and bayswater plants is national forest. The 20-40 km northeast area of the Liddell and Bayswater plants is Tamworth moratorium area. Considering that high-grade geothermal resources are located at 20-30 km south and southwest of the plant, the land use conflict and environment concerns for Liddell and Bayswater plant are rated as significant.

For Eraring power plant, it was found that a substantial area of coal tenure within 40 km and a small mineral tenure at the 17km south of Eraring power station exist. The gosford north area is a general restricted area which is located at 20-30 km southwest of Eraring power station. A small wetland area between 2-3 km southwest of Eraring power station is also presented. State forests and national parks/reserves exist across the 10-20 km north and west areas. Considering that high-grade geothermal resources are located at 10-15 km south and 20-40 km northeast of the Eraring plant, its land use conflict is rated moderate with limited environment concerns. On the other hand, for the Vales Point B plant it was found that high-grade geothermal resources is locate between 0-5 km south and 0-5 km southeast of the Vales Point B plant. A moderate rating was given to its land use conflict and a limited rating was given to the environment concerns.

The Mt piper power station was found to have national parks/reserves between 10-40 km north and 10-40 km east, state forests within 20 km radius, mineral tenure at 10 km west and 20-40 km southwest, and coal tenures within 10 km north, 10-20 km east and 10-20 km southeast. Since high-grade geothermal resources are located at 30-40 km north and east of the plant, the land use conflict is rated as limited with moderate environment concerns.

Table 11: The index criteria for calculating merit index

Assigned scores	0	2	4	6	8	10
Age of coal plant	>50 years	40 - 50 years	30 - 40 years	20 - 30 years	10 - 20 years	<10 years
Capacity factor	<40%	40 - 50 %	50 - 60 %	60 - 70 %	70 - 80 %	>80%
Quality of nearby geothermal resources	<25°C/km within 40km	25 - 35°C/km within 40km	35 - 40°C/km within 40km	40 - 45°C/km within 40km	45 - 50°C/km within 40km	> 50°C/km within 40km
Distant of the best geothermal resource	>40 km	30 - 40 km	20 - 30 km	10 - 20 km	5 - 10 km	<5 km
Availability of coal reserves	<5 years	5 - 10 years	10 - 15 years	15 - 20 years	20 - 25 years	>30 years
Plant thermal efficiency	<25%	25 - 30%	30 - 32%	32 - 34%	34 - 36%	36 - 38%
Coal plant nameplate capacity (i.e. maximum GAPG capacity)	<500 MWe	500 - 1000 MWe	1000 - 1500 MWe	1500 - 2000 MWe	2000 - 2500 MWe	>2500 MWe
Emission intensity of the coal plant (i.e. greenhouse gas reduction potential)	<820 kg CO_2 /MWh	820 - 840 kg CO_2 /MWh	840 - 860 kg CO_2 /MWh	860 - 880 kg CO_2 /MWh	880 - 900 kg CO_2 /MWh	>900 kg CO_2 /MWh
Assigned scores	0		5		10	
Water scarcity	Limited water resource	-	Moderate water resource	-	Plenty of water resource	
Environmental aspects	Significant impact	-	Moderate impact	-	Limited impact	
Land use	Significant confliction	-	Moderate confliction	-	No confliction	
Seismic activity	Significant potential	-	Moderate potential	-	Limited activity	

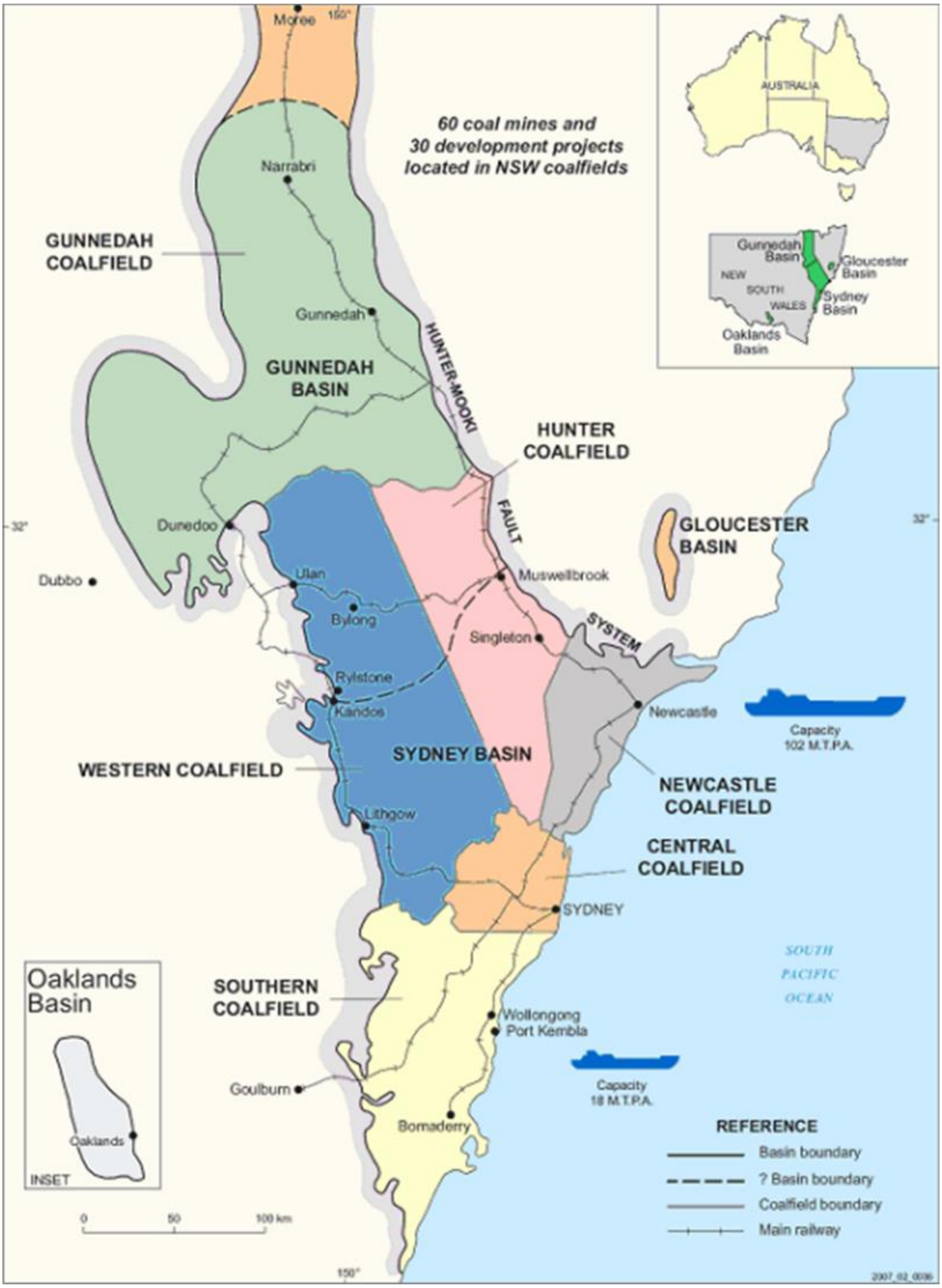


Figure 11: Major coalfields in NSW (courtesy: NSW Resources & Geoscience)

Multiplying the weigting percentages (Table 3) with the assigned scores of various index criteria (Table 11), the merit indexes were calculated and presented in Table 12 for the five coal-fired power stations. The results show that the MT Piper and Vales Point B power stations have poor performance scores lower than 6.0. Despite of a young power plant, the low merit index of the MT Piper plant is contributed by the poor geothermal and water resources nearby, a low maximum GAPG capacity, and its relatively unstable coal reserve. The Vales Point B power station is quite an old power plant aged 41 years now, and has poor geothermal resources despite that the best geothermal resource is located less than 5 km away. On the other hand, the Bayswater power plant was found to have the highest performance score followed by Eraring power plant. These two power plants are the ones that feature high quality geothermal resources within 20 km, abundant coal reserves, high plant availability and a reasonable plant lifetime. The achievable GAPG capacity is also the highest among all coal-fired power plants, attracting investment due to the economic-of-scale effect and allowing greater social-economic benefits to be realised. These two plants were, therefore, selected to be the most viable sites for the detailed techno-economic assesmeent of GAPG implementation.

Table 12: Merit index of GAPG integration in NSW coal-fired power plants

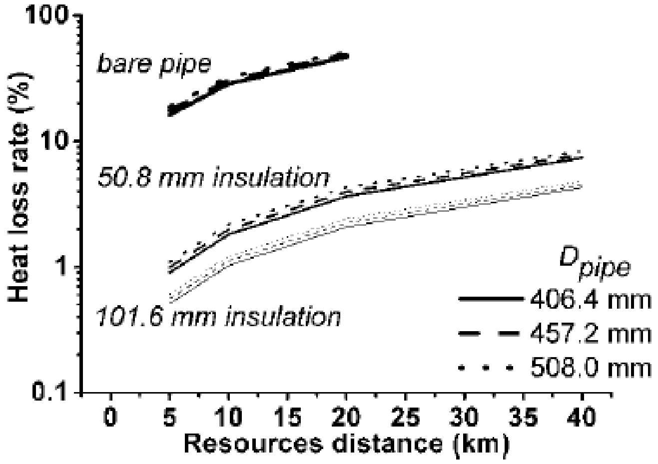
Merit indexes	Bayswater	Liddell	Eraring	Vales Point B	Mt Piper
Age of coal plant	4	2	4	2	6
Capacity factor	8	2	6	6	6
Quality of nearby geothermal resources	8	8	6	4	2
Distance of the best geothermal resource	6	6	6	10	2
Availability of coal reserves	10	10	10	10	2
Plant thermal efficiency	8	6	10	8	10
Water scarcity	5	5	10	10	0
Maximum GAPG capacity	10	8	10	4	4
Greenhouse gas reduction potential	6	10	6	4	6
Environmental aspects	0	0	10	10	5
Land use	0	0	5	5	10
Seismic activity	10	10	0	0	10
Total scores	7.0	6.3	6.8	5.7	4.8

4.1.4 Thermodynamic study and optimisation of retrofit options and operation modes

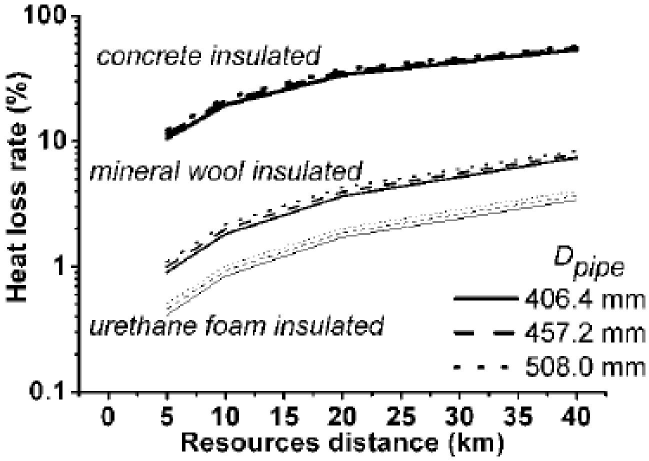
The conducted thermodynamic study was based on a single 500 MW power unit using hypothetical geothermal resources under eight operating modes as listed in Table 6, namely BT1, BT2, BT3, BT4, FS1, FS2, FS3, and FS4. Some elementary results of the thermodynamic analysis have been published in our earlier work [19]. These results are not repeated here. Nevertheless, this section will present results that deals with issues such as pipeline configuration and insulation options analyses, various retrofit options and operation modes, overall performance forecast for NSW coal-fired power stations, and correlation development that can be used for building the advanced techno-economic model of GAGP system.

Figure 12 shows the impact of using various pipe insulation materials on the total heat loss of the pipeline system as a function of resource distance and insulation thickness. The results indicate that heat loss is so significant for a bare pipe that over 20 km would render the benefit of geothemal preheating to be balanced out by pipeline heat losses. At flowing conditions, the temperature loss of the transported fluid in the insulated pipelines was found to be in the range of 0.01-0.40°C/km and, for uninsulated pipes, the temperature loss amounts up to 1-2°C/km. This is for an approximately 200-300 litre/s flow in a 400-500 mm diameter pipe. The temperature drop will be reduced for larger diameter pipes with greater flow. In addition, a four-inch mineral wool insulation (i.e. 101.6 mm) can be recommended to be employed in the

GAPG pipeline system to minimize heat losses meanwhile obtaining proper temperature resistance at medium-to-high temperatures. A typical example is the 29 km long geothermal district heating pipelines that runs from Nesjavellir to Reykjavik in Iceland with less than 2°C loss in the aboveground. This steel pipeline has a diameter of 800-900 mm and mineral wool insulation of 100 mm thick. The flow rate is around 560 litre/s and takes seven hours for the fluid to be transported to the destination [42].



(a)



(b)

Figure 12**:** Heat losses of the pipeline system using different insulation options for a resource distance of up to 40 km as a function of pipe diameter.

Energy balance calculations were also carried out to determine the optimum location of geothermal heat exchanger between the coal plant and geothermal site. The calculation, however, did not find any significant impact of the positioning of geothermal heat exchanger on the GAPG system. Nevertheless, both the concern of the corrosivity of brine and the lower temperature and pressure of the feedwater on the coal plant side suggest that the geothermal heat exchanger should be located close to the wells to minimize heat losses, pressure drop, and brine corrosion. Regarding the detailed design of the pipeline system, as shown in Figure 2, a two-way (i.e. return) pipeline system was assumed to be used to deliver the geothermal fluid. The elevation and curvature of the pipe was not considered. Therefore, the total pipe length is exactly twice of the resource distance. However, a single one-way pipeline design is also possible for deploying GAPG technology. Both designs are discussed here. In both the one-way and two-way pipeline designs, water resources are used as the energy carriers to transfer geothermal heat to the power plant. The main difference between these two pipeline designs is how the water resources are treated after arriving at the power plant. In the one-way pipeline design, upon arrival at the power plant, the water carried with geothermal heat is used to preheat the feedwater, and then disposed onsite, either as the makeup water for the cooling tower, or discharged to a nearby river. In the two-way pipeline design, unlike the one-way scenario, the water carried with geothermal heat is used to preheat the feedwater, then recycled back to the geothermal heat exchanger. It should be noted that the one-way pipeline design is only viable when there is enough water resource (such as a lake or river) near the geothermal plant, as seen in Iceland geothermal district heating plants, while the two-way design is more likely the practical design for Australia where available water resource is generally limited due to the arid climate.

Various retrofit options were examined and optimised based on the detailed thermal power cycle. However, evaluation of the quality and distance of nearby geothermal resource around the NSW coal-fired power stations suggests that the maximum attainable wellhead temperature is estimated to be around 184°C (which varies depending on the flow rate of the circulating geofluid) for a wellbore temperature of 191°C at 5 km depth and 15 km west of Bayswater power station. Although theoretically a 100% replacement of the turbine bled steam is possible if geothermal fluid temperature is high enough at a greater depth (investigated in our previous work [19]), the well head temperature poses a practical limitation on the various hybridisation options that may be achievable by GAPG concept. Therefore, the scope of the hybridisation options has to be narrowed down to mainly replace the bled steam from the last couple of stages of the intermediate turbine and all stages of the low pressure turbine. Since steam turbines can usually operate across a broad speed range and have about 10% reserve capacity for overload operation, the booster mode that yields additional power generation is expected to be more appealing for the industry than the fuel saving mode.

On the other hand, the long-distance transportation of a great amount of feedwater in the magnitude of 1,000 litre/s to the geothermal site requires careful selection of the pipe size and pipeline configuration in order to minimize pump power consumption, heat losses, and more importantly, the capital cost of circulating pump and pipeline construction. It is easily understood that a greater pipe size leads to a lower pressure drop yet a greater pipeline capital investment, however, it is not clear how the combination of these factors would translate into the economics of the whole plant, such as LCoE and NPV value. As such, an economic optimisation study was conducted to quantify these impacts, which ultimately helps to evaluate and determine the optimum pipe size and pipeline configuration.

Table 13 examines the impact of eight different pipe sizes and pipeline configurations on the LCoE and NPV of the hybrid plant. As can be seen in Table 13, for both the booster modes BT-3km and BT-5km the use of a single return pipe with a nominal diameter of 900 mm is a superior option than the use of double return pipes with smaller sizes. It turns out that the adverse effect of an increased pipeline cost due to the use of double return pipes slightly overweights the benefits of a reduced pump power consumption and a cheaper circulation pump. Therefore, in the following analysis the single return pipe configuration is employed by default. It should be noted, though, the above analysis results and conclusions are subject to change under non-typical conditions, and the double return pipe may become a sound option, e.g., when electricity sale price is significantly high and reducing pump power consumption becomes a key economic drive.

Table 13: Optimisation of pipe size and pipeline configuration

Scenario analysis	Pump power demand, kW/km	Pressure drop, kPa/km	Total pump power demand, kWe	Total pressure drops, kPa	LCoE of clean power production, cents/kWh	NPV, million $
BT-3km, T_{geo} = 118°C, resource distance = 5 km						
Single return pipe ($D_{nominal}$=900mm, schedule 40)	53	31	534	312	15.34	10,909
Double return pipe ($D_{nominal}$=800mm, schedule 30)	25	15	254	149	16.10	10,886
Double return pipe ($D_{nominal}$=700mm, schedule 30)	50	29	504	295	15.89	10,893
Double return pipe ($D_{nominal}$=600mm, schedule 30)	118	69	1181	690	15.89	10,894

BT-5km, T_{geo} = 156.6°C, resource distance = 5 km						
Single return pipe ($D_{nominal}$=900mm, schedule 40)	72	38	725	382	9.40	11,197
Double return pipe ($D_{nominal}$=800mm, schedule 30)	34	18	689	181	9.70	11,175
Double return pipe ($D_{nominal}$=750mm, schedule 30)	47	25	948	250	9.70	11,178
Double return pipe ($D_{nominal}$=700mm, schedule 30)	68	36	1366	360	9.60	11,181

Figure 13 shows the boosted power production and fuel saving as a percentage of the original capacity of the coal-fired power plant under the booster and fuel saving modes for different geothermal well head temperatures. The obtained values are used to generate two correlations (given in Figure 13) that are to be used in the advanced economic model. Similarly, Figure 14 shows the calculated geothermal energy demand for achieving the maximum possible hybridisation at a given well head temperature. This is presented in the form of unit geothermal energy demand per MW of coal plant capacity and two correlations are also produced and employed in the advanced economic model of the GAPG system.

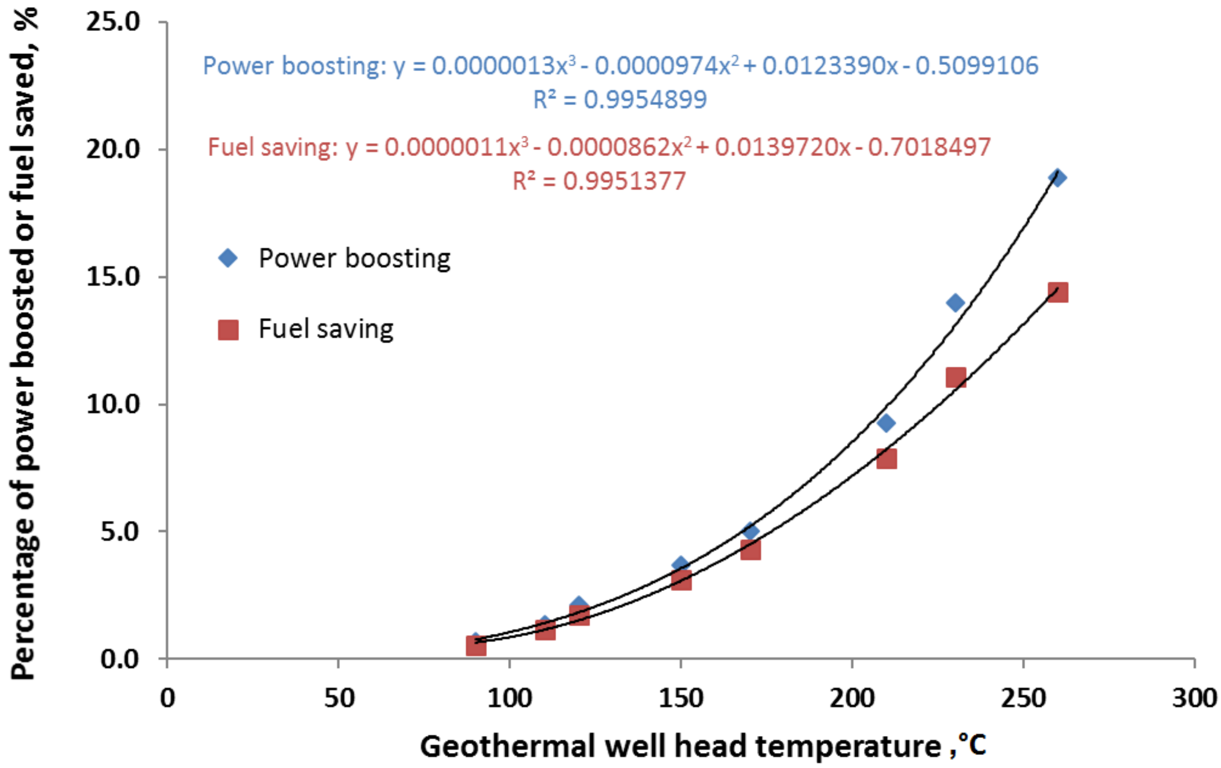


Figure 13: Percentage of power boosted, or fuel saved for GAPG integration as a function of geothermal well head temperature.

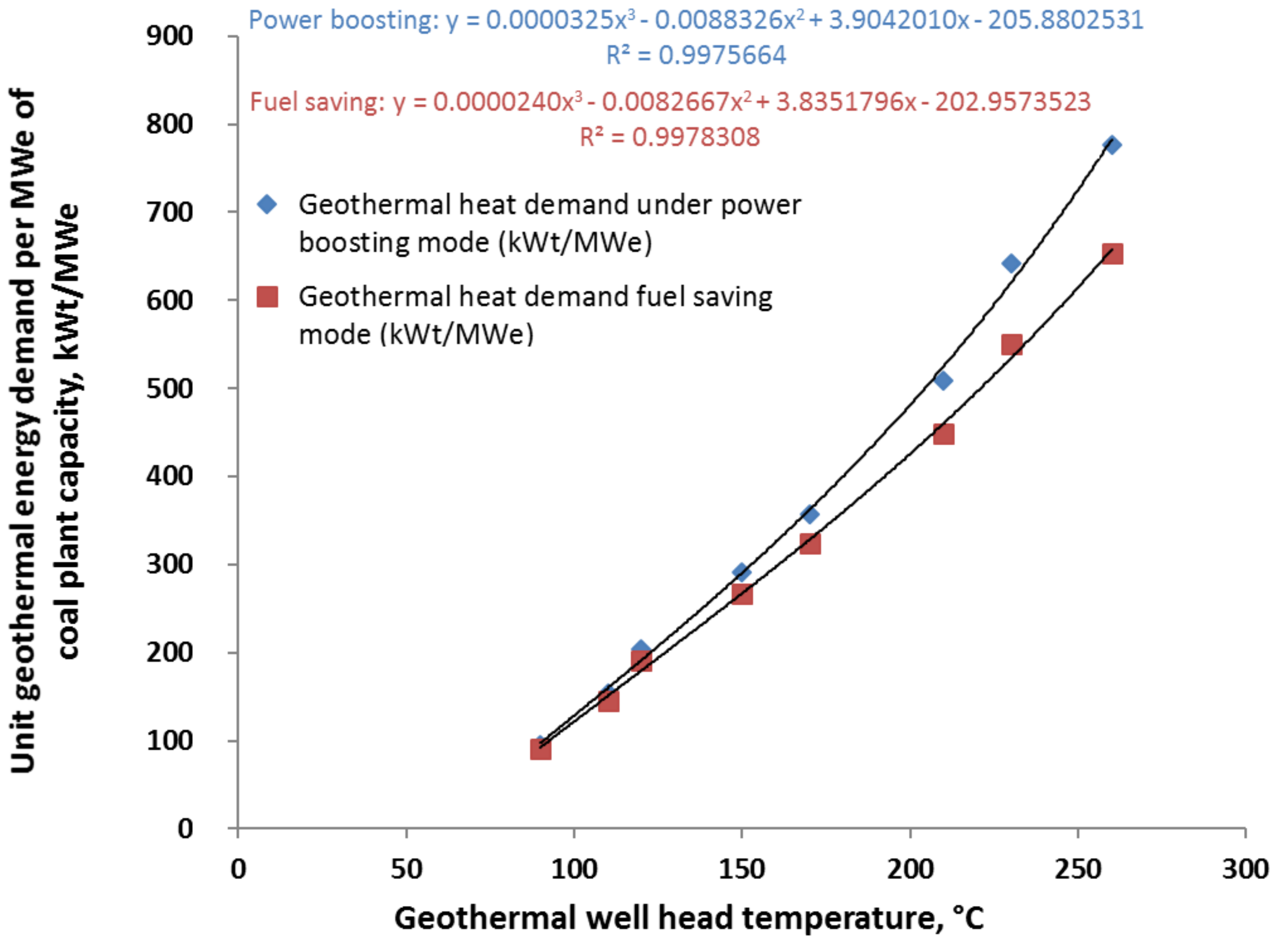


Figure 14: Unit geothermal energy demand per MWe of coal plant capacity as a function of geothermal well head temperature.

Figure 15 shows the calculated boosted power production for GAPG integration in the five major NSW coal-fired power stations under the booster modes. The columns with dotted-line borders are the theoretical maximum benefits that GAPG technology can bring to NSW coal-fired power plants based on their rated capacity and an assumed capacity factor of 85%. The figure shows that Bayswater and Eraring power plants hold the maximum potentials with up to 847 GWh/year of additional electricity generation, whilst Mt Piper and Vales Point B power plants can have up to about 413-458 GWh/year of additional electricity generation. Interestingly, though, the typical sent out electricity of NSW coal-fired power stations is usually lower than what should be based on their rated maximum capacity. This is due to the low operating capacity factor of coal plants, which is contributed by a combination of factors such as weak market demand, aging, and reliability issues. For example, Liddell power plant is reported to have been operating at just 39.6 per cent capacity in August 2017 due to frequent failures and maintenance [43]. This then has a direct impact on the maximum benefit that GAPG technology can bring since no benefit can be realised if the main power plant is not operating. In this regard, the following study including the techno-economic analysis uses only practical values, rather than theoretical ones, as the basis to calculate the benefits of GAPG system. As shown in Figure 15, the coloured columns display the practically achievable electricity generation of the GAPG system for all five coal plants. The additional power production that can be achieved practically was found to be as low as 54% of the theoretical level for

Liddell power station to 81% for Bayswater power station. This is also found to be directly proportional to the capacity factor and thermal efficiency of the coal plant.

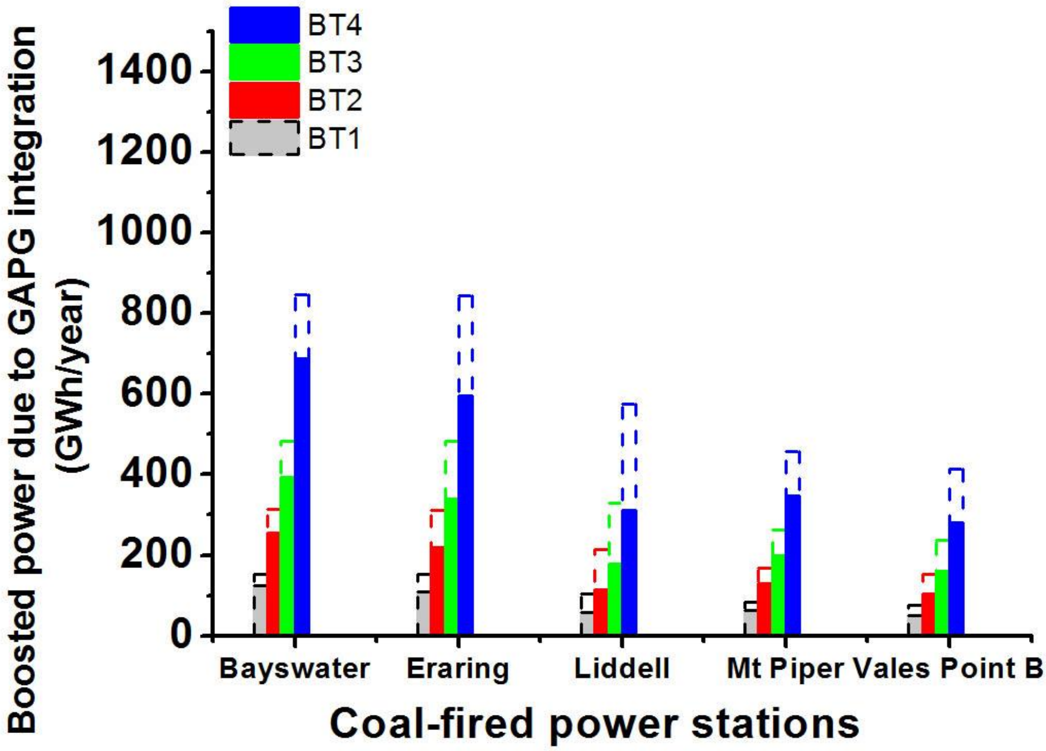


Figure 15: Potential additional power production for GAPG integration in the five major NSW coal-fired power stations under different booster operation modes (columns with dotted-line borders: theoretical maximum levels; coloured columns: practically achievable levels).

Similarly, Figure 16 shows the potential coal savings of the GAPG systems to be implemented in the five major NSW coal-fired power stations under different fuel saving operating modes. It was found that up to 325 thousand tonnes of coal per year for Bayswater power station only, and up to 1.2 million tonnes of coal per year for NSW coal plants, could be potentially saved if the GAPG system operates under the fuel saving mode. Again, the practically achievable coal savings were calculated to be only 54% - 81% of the theoretical values, which reduces the total coal savings for NSW coal plants by about 31% down to 826 thousand tonnes each year.

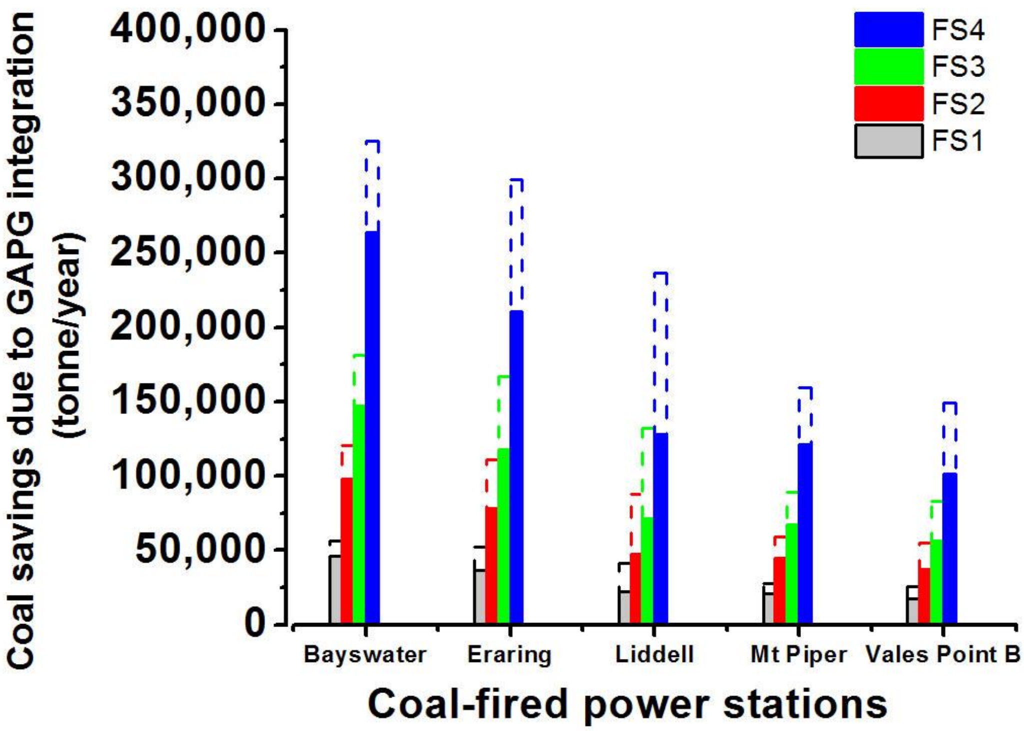


Figure 16: Potential savings of coal for GAPG integration in the five major NSW coal-fired power stations under different fuel saving operating modes (columns with dotted-line borders: theoretical maximum levels; coloured columns: practically achievable levels).

Table 14 and Table 15 summarise the key technical parameters and performances for the GAPG integration with Bayswater and Eraring power station, respectively. The results show that the temperature loss in the well bore was estimated to be 1.1 - 1.6°C for a drilling depth of 2 km and up to 6.9 - 7.1°C for a drilling depth of 5 km. The reinjection temperature for the Bayswater injection well was calculated to be 46.2°C, 47.5°C and 69.5°C for a resource temperature of 112.4°C, 156.8°C, and 188.6°C, respectively. This was largely determined by considering both the temperature to prevent silica precipitation and the minimum temperature approach in the geothermal heat exchanger. Similar values are determined for the injection well in Eraring as shown in Table 15. Also calculated are the pump power demand for geothermal production and injection wells, heat losses, pressure drop and pump power demand for the geothermal pipeline system. It is worth mentioning that the pump power demand for geothermal production and injection wells reduces from 3.5 – 4 kW per kg/s of brine to 0.5 kW per kg/s of brine as the depth of well increase from 2 km to 5 km. This is because at a greater depth of the production well the intrinsic reservoir pressure can become greater than that of the injection pressure and hydrostatic pressure heads.

With the above detailed technical data, the performances of the hybrid plant under six different hybridisation modes were obtained and compared with those of the reference plants (i.e. business-as-usual). It was found that after the GAPG integration, the Bayswater hybrid plant can produce up to 6.3% more electricity or 5.6% fuel saving when compared with the reference case. These are obtained after considering the heat losses and power consumption in the geothermal pipeline system and translate into up to a net efficiency uplift of about 6.5% and an emission intensity reduction of about 6%. Similarly, for the Eraring hybrid plant, the maximum net boosted power is 5.7% of the reference level and the fuel saving obtainable is 4.9%, resulting in a net efficiency uplift of about 5.8% and an emission intensity reduction of about 5.4%.

Table 14: Technical analysis of GAPG integration with Bayswater power station

Power Specification	Units	Reference plant	Geothermal Assisted Power Generation					
			Booster mode			Fuel Saving mode		
			BT-2km	BT-3km	BT-5km	FS-2km	FS-3km	FS-5km
Typical Gross Capacity	*MWe*	2280	2312	2365	2422	2280	2280	2280
Typical Auxiliary Consumption	*MWe*	137	143	142	143	143	141	141
Typical Net Capacity	*MWe*	2143	2169	2223	2278	2137	2138	2138
Q_{in} (coal)	*MWt*	6019	6019	6019	6019	5942	5816	5683
Thermal Efficiency	*%*	35.6	36.0	36.9	37.9	36.0	36.8	37.6
Generation (annual)	*MWh*	15,955,000	16,146,826	16,549,961	16,965,632	15,910,966	15,921,562	15,918,504
Efficiency Uplift	*%*	-	1.2	3.7	6.5	1.1	3.4	5.6
Fuel								
Fuel Consumption Rate	*t/h*	967	967	967	967	955	935	913
Fuel Consumption (annual)	*t*	7,202,799	7,202,799	7,202,799	7,202,799	7,110,302	6,959,498	6,801,284
Fuel Saved	*%*	-	-	-	-	1.3	3.4	5.6
Emissions								
Annual CO_2 Emissions	*t-CO_2-e / Year*	13,976,580	13,976,580	13,976,580	13,976,580	13,797,095	13,504,470	13,197,465
Total Emission Intensity (sent-out)	*t-CO_2-e / MWh*	0.88	0.87	0.84	0.82	0.87	0.85	0.83
Δ Emission Intensity	*%*		-1.2	-3.6	-6.0	-1.0	-3.2	-5.4
Geothermal Site								
Geothermal heat	*kWt*	-	348,302	647,865	869,859	328,278	594,273	780,376

Geothermal energy fraction	*%*	-	5.5	9.7	12.6	5.2	9.3	12.1
Drilling depth	*km*		2	3	5	2	3	5
Resource temperature	*°C*		112.4	156.80	188.60	112.40	156.80	188.60
Determined reinjection temperature	*°C*		46.2	47.5	69.5	46.2	47.5	69.5
Dissolved silica concentration	*ppm*		78.7	164.3	249.5	78.7	164.3	249.5
Temperature achieving saturated silica	*°C*		23.2	47.0	69.0	23.2	47.0	69.0
Minimum hot outlet temperature of geothermal heat exchanger	*°C*		46.2	46.2	46.2	46.2	46.2	46.2
Temperature loss in well bore	*°C*		1.6	3.4	7.1	1.6	3.4	7.1
Well head temperature	*°C*	-	110.8	153.4	181.5	110.82	153.36	181.47
Geothermal production and injection well pump power demand	*kWe per kg/s*		3.5	1.6	0.3	3.5	1.6	0.3
Geothermal production and injection well pump power demand	*kWe*		4495.3	2389.9	555.1	4236.9	2192.2	498.0
Boosted power or fuel saved	*%*	-	1.5	4.0	6.6	1.3	3.4	5.6
Gross boosted power	*MWe*	-	32.3	85.3	141.9	-	-	-
Net boosted power	*MWe*	-	25.8	79.9	135.7	-	-	-
Gross fuel saving	*MWt*	-	-	-	-	77.3	203.5	335.2
Net fuel saving	*MWt*	-	-	-	-	77.3	203.3	335.5
Required brine flow	*kg/s*	-	1283	1457	1850	1210	1337	1660
Geothermal pipeline								

Selected optimum pipe nominal diameter	*mm*		900	900	900	900	900	900
Resource distance or 50% of the total pipe length	*km*		20.0	20.0	20.0	20.0	20.0	20.0
Pipeline pressure drop	*kPa*		1205	1544	2463	1074	1305	1991
Pumping power consumption	*kWe*		2023	2995	5995	1677	2299	4403
Pipeline heat losses	*kWt*		1902	2856	3540	1902	2856	3540

Table 15: Technical analysis of GAPG integration with Eraring power station

Power Specification	Units	Reference plant	Geothermal Assisted Power Generation					
			Booster mode			Fuel Saving mode		
			BT-2km	BT-3km	BT-5km	FS-2km	FS-3km	FS-5km
Typical Gross Capacity	*MWe*	1991	2002	2025	2100	1991	1991	1991
Typical Auxiliary Consumption	*MWe*	129	133	133	132	133	133	131
Typical Net Capacity	*MWe*	1861	1869	1892	1968	1857	1858	1860
Q_{in} (coal)	*MWt*	5113	5113	5113	5113	5088	5033	4861
Thermal Efficiency	*%*	36.4	36.5	37.0	38.5	36.5	36.9	38.3
Generation (annual)	*MWh*	13,859,000	13,913,314	14,084,894	14,653,346	13,830,386	13,832,556	13,846,638
Efficiency Uplift	*%*	-	0.3	1.6	5.8	0.3	1.4	5.2
Fuel								
Fuel Consumption Rate	*t/h*	758	758	758	758	754	746	720
Fuel Consumption (annual)	*t*	5,640,619	5,640,619	5,640,619	5,640,619	5,613,156	5,551,962	5,362,704
Fuel Saved	*%*	-	-	-	-	0.5	1.6	4.9
Emissions								
Annual CO_2 Emissions	*t-CO_2-e / Year*	12,001,894	12,001,894	12,001,894	12,001,894	11,943,460	11,813,253	11,410,558
Total Emission Intensity (sent-out)	*t-CO_2-e / MWh*	0.87	0.86	0.85	0.82	0.86	0.85	0.82
Δ Emission Intensity	*%*		-0.4	-1.6	-5.4	-0.3	-1.4	-4.8
Geothermal Site								
Geothermal heat	*kWt*	-	140,037	347,754	703,508	133,085	326,432	634,910
Geothermal energy fraction	*%*	-	2.7	6.4	12.1	2.5	6.1	11.6
Drilling depth	*km*		2	3	5	2	3	5

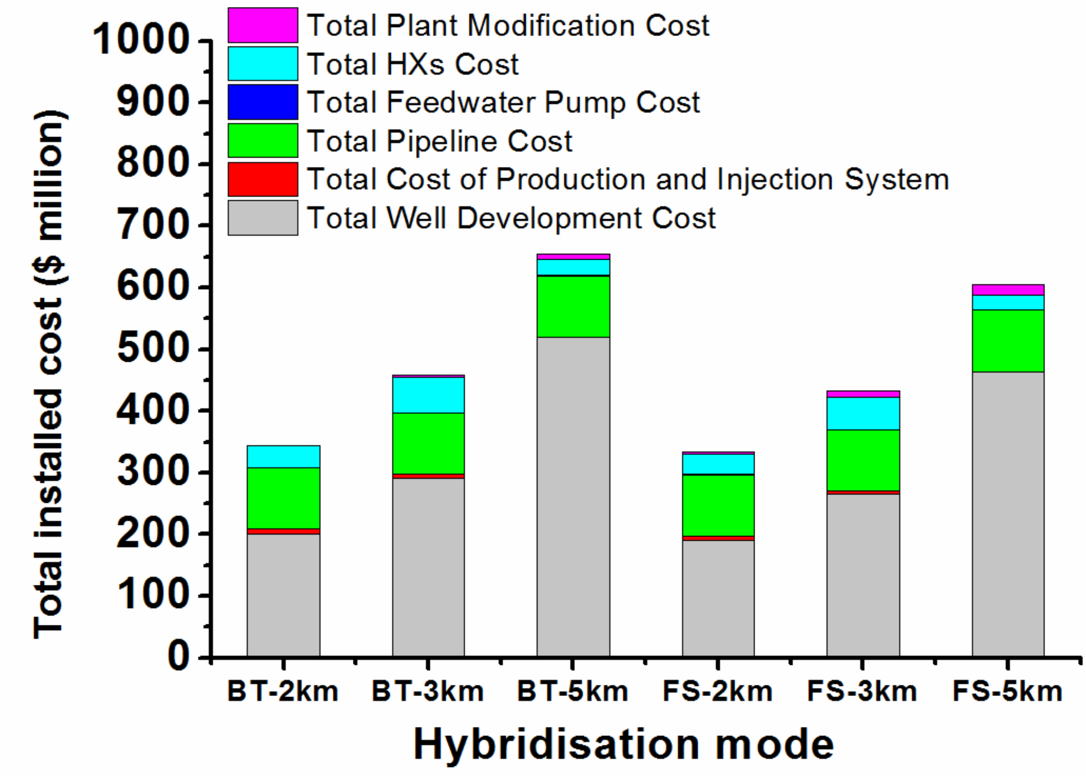
Resource temperature	*°C*		83.9	121.2	181.1	83.9	121.2	181.1
Determined reinjection temperature	*°C*		46.2	46.2	64.1	46.2	46.2	64.1
Dissolved silica concentration	*ppm*		44.6	92.4	227.8	44.6	92.4	227.8
Temperature achieving saturated silica	*°C*		13.2	27.1	63.6	13.2	27.1	63.6
Minimum hot outlet temperature of geothermal heat exchanger	*°C*		46.2	46.2	46.2	46.2	46.2	46.2
Temperature loss in well bore	*°C*		1.1	2.7	6.9	1.1	2.7	6.9
Well head temperature	*°C*	-	82.8	118.5	174.2	82.79	118.51	174.19
Geothermal production and injection well pump power demand	*kWe per kg/s*		4.1	2.8	0.3	4.1	2.8	0.3
Geothermal production and injection well pump power demand	*kWe*		3738	3173	456	3552	2978	412
Boosted power or fuel saved	*%*	-	0.6	1.8	5.8	0.5	1.6	4.9
Gross boosted power	*MWe*	-	11.4	34.2	108.8	-	-	-
Net boosted power	*MWe*	-	7.3	30.3	106.7	-	-	-
Gross fuel saving	*MWt*	-	-	-	-	25.0	80.5	252.1
Net fuel saving	*MWt*	-	-	-	-	24.9	80.4	251.9
Required brine flow	*kg/s*	-	911	1145	1521	866	1075	1373
Geothermal pipeline								
Selected optimum pipe nominal diameter	*mm*		842.4	900.0	900.0	819.9	900.0	900.0

Resource distance or 50% of the total pipe length	*km*		10.0	10.0	10.0	10.0	10.0	10.0
Pipeline pressure drop	*kPa*		310.0	482.7	839.5	280.9	426.9	687.2
Pumping power consumption	*kWe*		338	703	1704	291	573	1248
Pipeline heat losses	*kWt*		644	1045	1689	644	1045	1689

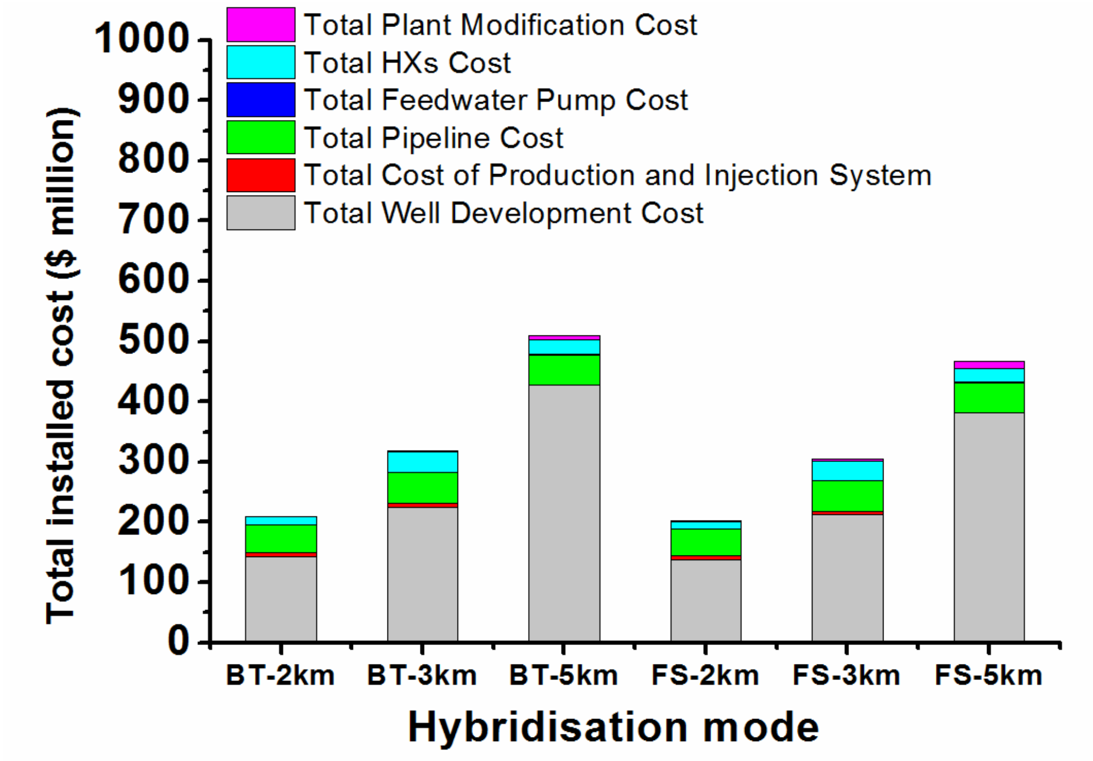
4.2 Economic Analysis

4.2.1 Capital cost analysis

Figure 17 gives the cost breakdown of the GAPG systems for Bayswater and Eraring power stations, respectively. The total installed cost was shown to range between \$350 million – \$650 million for the Bayswater plant and \$210 million – \$500 million for the Eraring plant depending on which operating mode was employed. Of the total installed cost, the well development cost is the single largest investment reaching 57% for the low hybridisation level (BT-2km or FS-2km), and up to 84% for the high hybridisation level (BT-5km or FS-5km). The second largest investment is the pipeline system, accounting for 10-22% for a resource distance of 10 km and 15-30% for a resource distance of 20 km. The heat exchanger takes the next biggest investment proportion ranging from 4-12% depending on the required heat duty of the exchanger. It also turns out that the costs of plant modification, feedwater pump, and production and injection system are insignificant compared to other major cost items and takes less than 4% altogether.



(a)



(b)

Figure 17: Breakdown of the total installed cost of the hybrid plant under various hybridisation modes for (a) Bayswater (L_{geo} = 20 km); (b) Eraring (L_{geo} = 10 km).

Table 16 and Table 17 summarise the detailed cost calculations for GAPG integration with Bayswater and Eraring power stations, respectively, under six different hybridisation modes. The results obtained here are used to plot the cost charts in Figure 17 as well as to calculate the economic performances including LCoE, NPV, and payback period, which are presented in the next section.

Table 16: Detailed cost analysis of GAPG integration with Bayswater power station

Detailed Cost Analysis	Units	Reference plant	Geothermal Assisted Power Generation					
			Booster mode			Fuel Saving mode		
			BT-2km	BT-3km	BT-5km	FS-2km	FS-3km	FS-5km
Base production cost								
Unit Fuel cost	*\$ / GJ*	1.27	1.27	1.27	1.27	1.27	1.27	1.27
Total Fuel cost	*\$ / Year*	204,905,225	204,905,225	204,905,225	204,905,225	202,273,869	197,983,806	193,482,915
Unit FOM cost	*\$/MW/Year*	49,000	49,000	49,000	49,000	49,000	49,000	49,000
Total FOM cost	*\$/Year*	104,995,299	106,257,655	108,910,570	111,673,177	104,705,522	104,775,251	104,779,533
Unit VOM cost	*\$/MWh*	1.19	1.19	1.19	1.19	1.19	1.19	1.19
Total VOM cost	*\$ / Year*	18,986,450	19,214,724	19,694,454	20,194,020	18,934,049	18,946,658	18,947,433
Total production cost	*\$ / Year*	328,886,974	330,377,603	333,510,249	336,772,422	325,913,440	321,705,716	317,209,880
Normalised production cost	*¢ / kWh*	2.06	2.05	2.02	1.98	2.05	2.02	1.99
Emission cost								
Unit cost of CO_2 emissions	*\$/t*	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Compensations (free permits)	*\$/t*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total cost of CO_2 Emissions	*\$ / Year*	279,531,600	279,531,600	279,531,600	279,531,600	275,941,905	270,089,404	263,949,291
Normalised emission cost	*¢ / kWh*	1.75	1.73	1.69	1.65	1.73	1.70	1.66
Geothermal well development								
Number of wells required			38	44	56	36	40	50
Exploration cost	*\$*		3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000

Cost of completed wells	*$*		166,317,783	251,446,400	469,868,289	157,564,216	228,587,636	419,525,258
Stimulation cost per injection well	*$/well*		2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
Cost of stimulation	*$*		31,666,667	36,666,667	46,666,667	30,000,000	33,333,333	41,666,667
Production and injection system								
Total cost of production and injection well pumps	*$*		6,754,031	5,354,802	284,509	6,365,732	4,911,849	255,241
Other surface equipment and indirect costs (15% of total system cost) [9]	*$*		1,191,888	944,965	50,207	1,123,364	866,797	45,043
Total cost of production and injection system	*$*		7,945,919	6,299,767	334,716	7,489,096	5,778,646	300,284
Geothermal pipeline								
Unit material cost of the pipeline	*2000US$/km*		291,462	291,462	291,462	291,462	291,462	291,462
Unit labour cost of the pipeline	*2000US$/km*		428,140	428,140	428,140	428,140	428,140	428,140
Unit miscellaneous costs of the pipeline	*2000US$/km*		194,619	194,619	194,619	194,619	194,619	194,619
Unit pipeline cost	*2000US$/km*		914,221	914,221	914,221	914,221	914,221	914,221
Total pipeline cost excluding insulation cost	*$*		79,441,976	79,441,976	79,441,976	79,441,976	79,441,976	79,441,976
Optimum pipe outer diameter	*inch*		35.4	35.4	35.4	35.4	35.4	35.4
Insulation thickness	*inch*		4.0	4.0	4.0	4.0	4.0	4.0
Unit cost of mineral wool	*$/m*		488	488	488	488	488	488
Pipeline insulation cost	*$*		19,519,030	19,519,030	19,519,030	19,519,030	19,519,030	19,519,030

Heat exchanger								
UA of heat exchanger	*kJ/(°C h)*		127,557,278	209,443,347	94,420,957	120,223,823	192,118,055	84,707,874
Heat transfer coefficient [36, 44]	*W/m²°C*		852.5	852.5	852.5	852.5	852.5	852.5
Required heat transfer areas	*m²*		41,563	68,245	30,766	39,174	62,600	27,601
Unit cost of heat exchanger [35]	*$/m²*		837	837	837	837	837	837
Total capital cost of heat exchanger	*$*		34,768,354	57,088,083	25,736,370	32,769,470	52,365,719	23,088,869
Feedwater transportation Pumps								
Specific power consumption	*kW/km*		51	75	150	42	57	110
Specific pressure drops	*kPa/km*		30	39	62	27	33	50
Flow rate	*l/s*		1,283	1,457	1,850	1,210	1,337	1,660
Duty	*kW*		2,023	2,995	5,995	1,677	2,299	4,403
Unit cost of pump [35]	*$/kW*		317	317	317	317	317	317
Total capital cost of pump	*$*		641,022	948,973	1,899,333	531,284	728,225	1,395,074
Plant modification								
Unit cost of plant modification	*$/kW*		40	40	40	120	120	120
Extra cost for aged plants	*$/kW*		20	20	20	20	20	20
Total cost of plant modification	*$*		1,545,741	4,794,209	8,176,993	3,852,374	10,133,137	16,722,558
Total installed cost	*$*		344,846,492	459,205,105	654,643,374	334,167,447	432,887,702	604,659,716

Table 17: Detailed cost analysis of GAPG integration with Eraring power station

Detailed Cost Analysis	**Units**	**Reference plant**	**Geothermal Assisted Power Generation**					
			Booster mode			**Fuel Saving mode**		
			BT-2km	BT-3km	BT-5km	FS-2km	FS-3km	FS-5km
Base production cost								
Unit Fuel cost	*$ / GJ*	1.67	1.67	1.67	1.67	1.67	1.67	1.67
Total Fuel cost	*$ / Year*	228,901,945	228,901,945	228,901,945	228,901,945	227,787,482	225,304,163	217,623,896
Unit FOM cost	*$/MW/Year*	49,000	49,000	49,000	49,000	49,000	49,000	49,000
Total FOM cost	*$/Year*	91,202,122	91,559,544	92,688,668	96,451,851	91,013,820	91,028,102	91,140,954
Unit VOM cost	*$/MWh*	1.19	1.19	1.19	1.19	1.19	1.19	1.19
Total VOM cost	*$ / Year*	16,492,210	16,556,843	16,761,024	17,441,526	16,458,159	16,460,742	16,481,149
Total production cost	*$ / Year*	336,596,277	337,018,333	338,351,637	342,795,322	335,259,461	332,793,006	325,245,998
Normalised production cost	*¢ / kWh*	2.43	2.42	2.40	2.34	2.42	2.41	2.35
Emission cost								
Unit cost of CO_2 emissions	*$/t*	20.0	20.0	20.0	20.0	20.0	20.0	20.0
Compensations (free permits)	*$/t*	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total cost of CO_2 Emissions	*$ / Year*	240,037,880	240,037,880	240,037,880	240,037,880	238,869,199	236,265,068	228,211,161
Normalised emission cost	*¢ / kWh*	1.73	1.73	1.70	1.64	1.73	1.71	1.65
Geothermal well development								
Number of wells required			27	34	46	26	32	41
Exploration cost	*$*		3,000,000	3,000,000	3,000,000	3,000,000	3,000,000	3,000,000

Cost of completed wells	*$*		118,173,162	194,299,491	385,963,238	113,796,378	182,870,109	344,010,712
Stimulation cost per injection well	*$/well*		2,500,000	2,500,000	2,500,000	2,500,000	2,500,000	2,500,000
Cost of stimulation	*$*		22,500,000	28,333,333	38,333,333	21,666,667	26,666,667	34,166,667
Production and injection system								
Total cost of production and injection well pumps	*$*		5,045,837	5,183,373	233,903	4,795,324	4,865,568	211,095
Other surface equipment and indirect costs (15% of total system cost)	*$*		890,442	914,713	41,277	846,234	858,630	37,252
Total cost of production and injection system	*$*		5,936,279	6,098,086	275,180	5,641,558	5,724,198	248,347
Geothermal pipeline								
Unit material cost of the pipeline	*2000US$/km*		260,277	293,212	293,212	248,031	293,212	293,212
Unit labour cost of the pipeline	*2000US$/km*		401,290	437,390	437,390	387,835	437,390	437,390
Unit miscellaneous costs of the pipeline	*2000US$/km*		187,501	199,369	199,369	182,882	199,369	199,369
Unit pipeline cost	*2000US$/km*		849,068	929,971	929,971	818,748	929,971	929,971
Total pipeline cost excluding insulation cost	*$*		36,890,209	40,405,293	40,405,293	35,572,881	40,405,293	40,405,293
Optimum pipe outer diameter	*inch*		33.2	35.4	35.4	32.3	35.4	35.4
Insulation thickness	*inch*		4.0	4.0	4.0	4.0	4.0	4.0
Unit cost of mineral wool	*$/m*		442	488	488	425	488	488
Pipeline insulation cost	*$*		8,846,840	9,759,515	9,759,515	8,504,430	9,759,515	9,759,515
Heat exchanger								
UA of heat exchanger	*kJ/(°C h)*		51,285,333	127,356,455	91,393,720	48,739,144	119,547,930	82,482,012

Heat transfer coefficient [36, 44]	*W/m²°C*		852.5	852.5	852.5	852.5	852.5	852.5
Required heat transfer areas	*m²*		16,711	41,498	29,780	15,881	38,953	26,876
Unit cost of heat exchanger [35]	*$/m²*		837	837	837	837	837	837
Total capital cost of heat exchanger	*$*		13,978,870	34,713,616	24,911,234	13,284,854	32,585,242	22,482,165
Feedwater transportation Pumps								
Specific power consumption	*kW/km*		17	35	85	15	29	62
Specific pressure drops	*kPa/km*		16	24	42	14	21	34
Flow rate	*l/s*		911	1145	1521	866	1075	1373
Duty	*kW*		338	703	1704	291	573	1248
Unit cost of pump [35]	*$/kW*		461	461	461	461	461	461
Total capital cost of pump	*$*		156,071	324,388	785,815	133,985	264,292	575,751
Plant modification								
Unit cost of plant modification	*$/kW*		40	40	40	120	120	120
Extra cost for aged plants	*$/kW*		20	20	20	20	20	20
Total cost of plant modification	*$*		437,660	1,820,261	6,428,239	1,268,683	4,095,645	12,838,710
Total installed cost	*$*		209,919,091	18,753,982	509,861,846.79	202,869,437	305,370,960	467,487,160

4.2.2 LCoE of the hybrid plant

Under the typical conditions defined in Table 8, the advanced economic model returns all cash flows data over a presumed 25-years operation for the two chosen NSW coal-fired power stations namely, Bayswater and Eraring plants. The examined resource distance is 0 – 40 km at drilling depths of 2 km, 3 km, and 5 km. The integration between the coal plant and geothermal resources is under either booster or fuel saving mode.

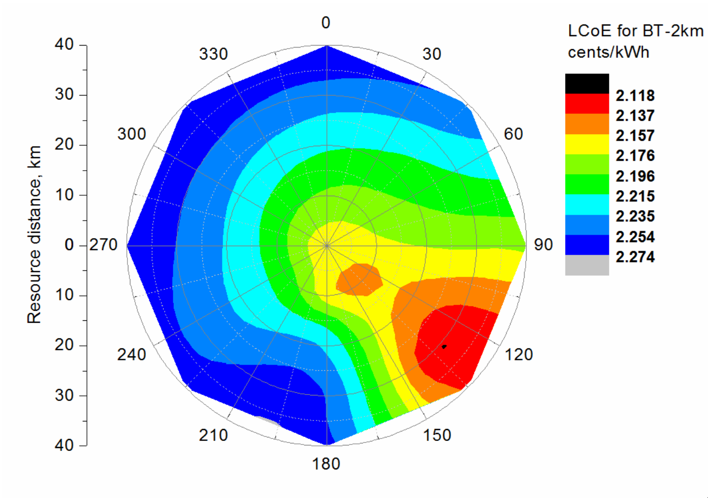
Figure 18 shows the obtained LCoE of the hybrid plants for Bayswater power station (see B-1, B-2, B-3 in Figure 18) and Eraring power station (see E-1, E-2, E-3 in Figure 18), which are integrated by the booster mode with geothermal resources at drilling depths of 2 km (B-1, E-1), 3 km (B-2, E-2), and 5 km (B-3, E-3), respectively. Comparing the results with the LCoE of the reference plants, i.e. the business-as-usual, at 2.06 cents/kWh for the Bayswater power station and 2.43 cents/kWh for the Eraring power station, the LCoE of the hybrid plants were found to be approximately 0.04 - 0.32 cents/kWh greater. This margin increases as the extent of hybridisation increases at places where geothermal resources with greater resource temperatures and drilling depths are present. The increased LCoE after hybridisation indicates that at the current conditions the business-as-usual scenario has the cheapest electricity primarily due to the significant cost associated with utilising the geothermal resource at a great depth. This finding is not surprising since base-load coal-fired power plant is still one of the cheapest ways of generating electricity at present if no emission penalty is imposed. Even after imposing a carbon tax penalty at 20$/tonne, the conclusion remains the same and the LCoE after carbon tax was found to increase by about 1.7 cents/kWh in general for both the coal plant and GAPG system.

The same trend can be found for the hybrid plants employing the fuel saving mode (figures not given here due to a high similarity with Figure 18). The variation of LCoE of the hybrid plants under the booster and fuel saving modes was found to be within 0.01 cents/kWh.

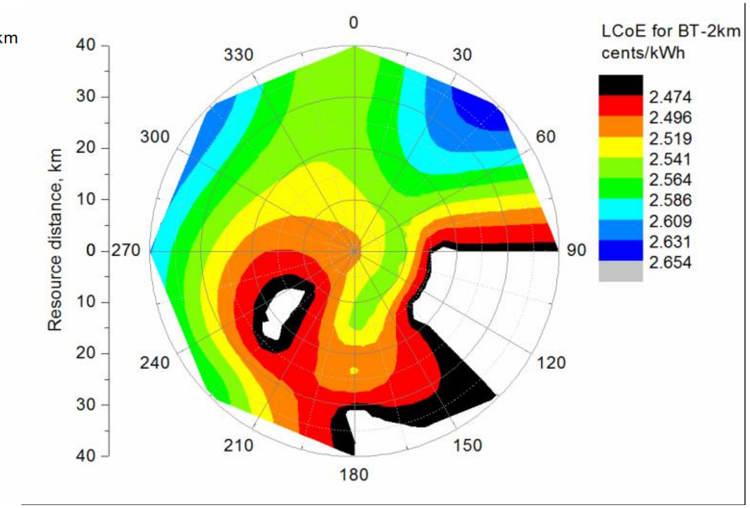
4.2.3 LCoE for geothermal conversion

Figure 19 shows the LCoE for converting geothermal energy into power using the same power cycle of the coal plant under the boost mode, namely $LCoE_{geo}$. The Bayswater results (see B-1, B-2, B-3 in Figure 19) show that the lowest $LCoE_{geo}$ was found to be between 10 – 20 km in the west and southwest of Bayswater power station, reaching 17.5 cents/kWh, 8.6 cents/kWh, and 7.1 cents/kWh for the drilling depths of 2 km, 3 km, and 5 km, respectively. On the other hands, the Eraring results (see E-1, E-2, E-3 in Figure 19) indicate that the lowest $LCoE_{geo}$ was found to be either within 10 km around the Eraring power station or along the coastal line where geothermal resources with better quality are present. And the minimum $LCoE_{geo}$ was found to be 39.5 cents/kWh, 15.0 cents/kWh, and 7.4 cents/kWh for the drilling depths of 2 km, 3 km, and 5 km, respectively, all greater than those obtainable at Bayswater station. The above results imply that the best geothermal site for implementing GAPG system is not always the one with the highest resource quality or shortest resource distance. Rather, a proper combination of high resource quality and affordable resource distance will be the best choice and these optimum areas are already highlighted as red and black[4] in Figure 19.

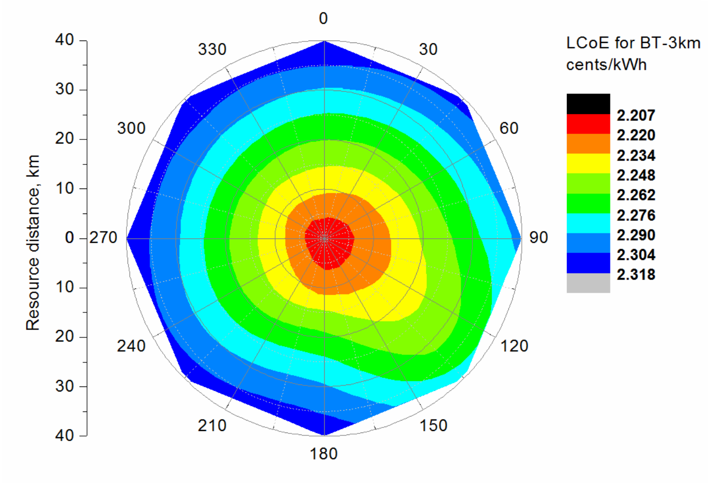
[4] Note the black areas in the figures are the extrapolated minimum regions below a certain threshold using a limited amount of data points; they do not necessarily mean that those values below the threshold are practically achievable.


LCoE for BT-2km
cents/kWh
2.118
2.137
2.157
2.176
2.196
2.215
2.235
2.254
2.274
Resource distance, km

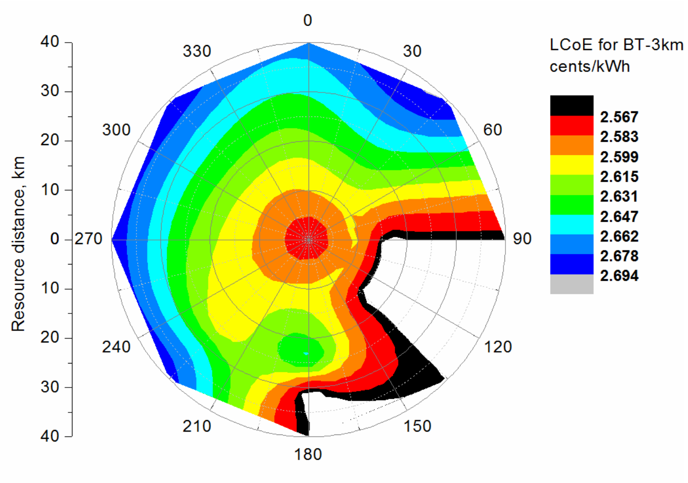
(B-1)


LCoE for BT-2km
cents/kWh
2.474
2.496
2.519
2.541
2.564
2.586
2.609
2.631
2.654
Resource distance, km

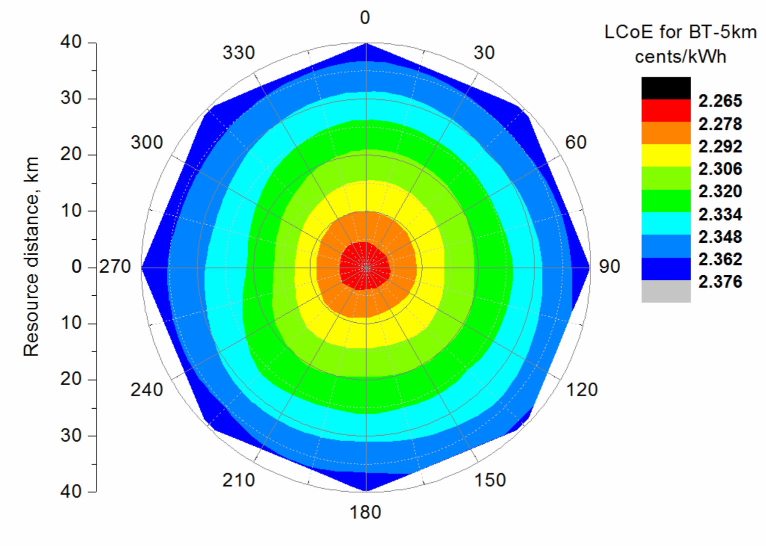
(E-1)


LCoE for BT-3km
cents/kWh
2.207
2.220
2.234
2.248
2.262
2.276
2.290
2.304
2.318
Resource distance, km

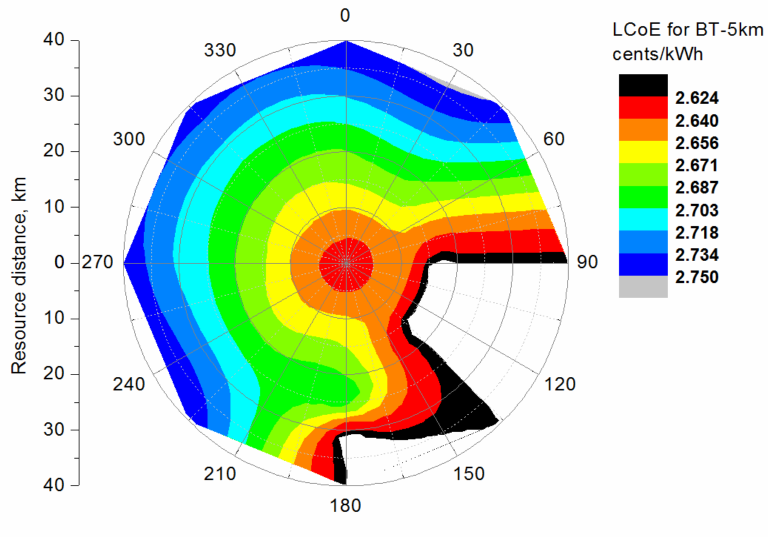
(B-2)


LCoE for BT-3km
cents/kWh
2.567
2.583
2.599
2.615
2.631
2.647
2.662
2.678
2.694
Resource distance, km

(E-2)

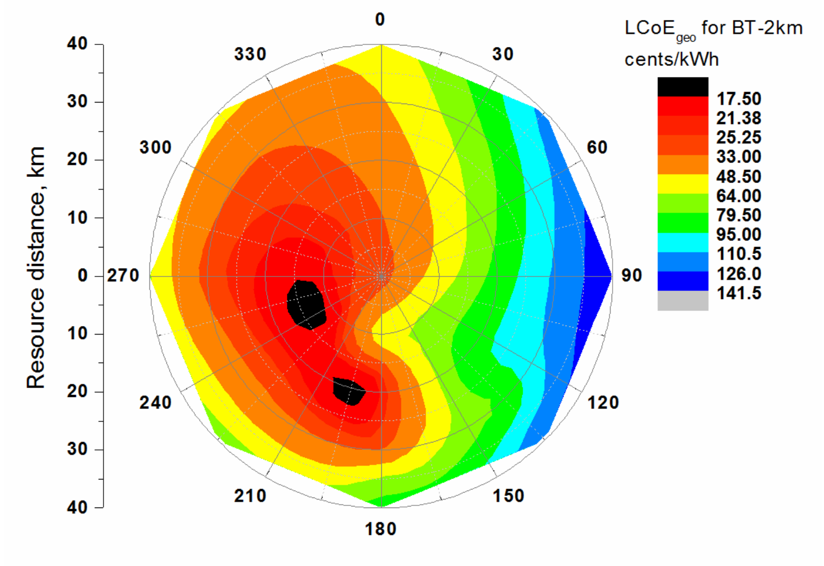


(B-3)

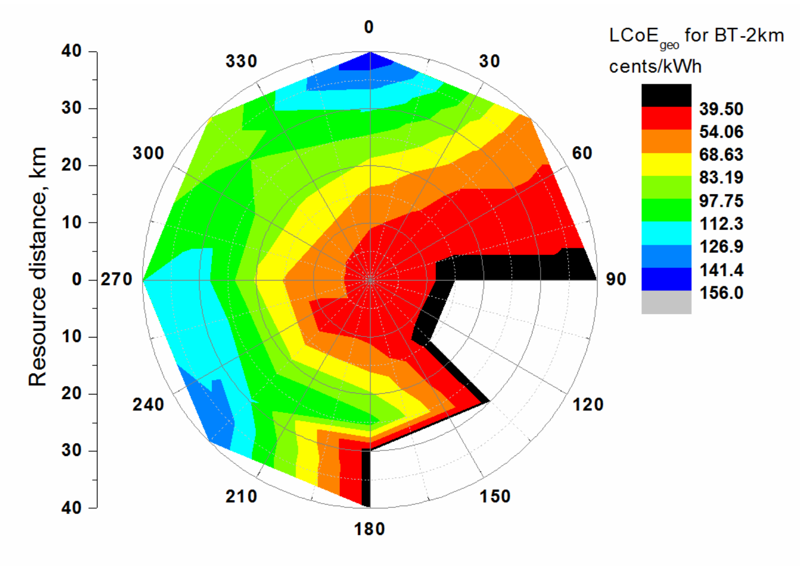


(E-3)

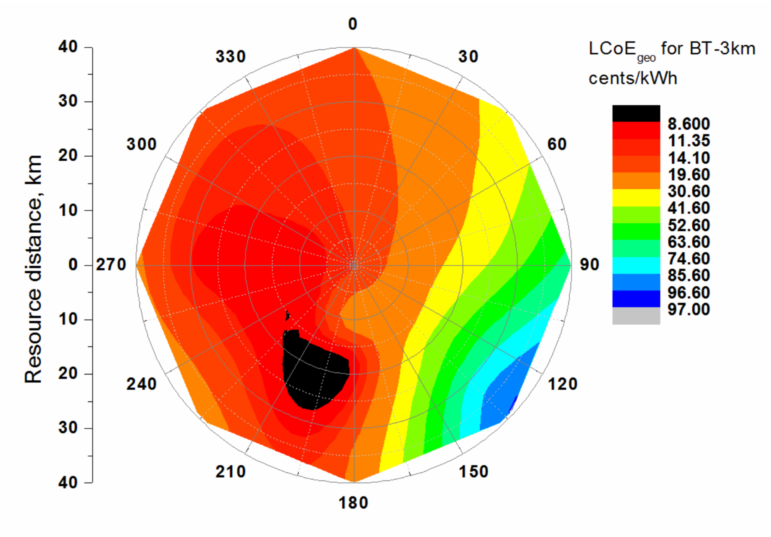
Figure 18: LCoE of the two chosen NSW coal-fired power plants (B-, Bayswater; E-, Eraring) integrated with geothermal resources at distances up to 40 km and at drilling depths of 2 km (B-1, E-1), 3 km (B-2, E-2), and 5 km (B-3, E-3) (under the booster mode and without carbon tax).


LCoE$_{geo}$ for BT-2km
cents/kWh
17.50
21.38
25.25
33.00
48.50
64.00
79.50
95.00
110.5
126.0
141.5
Resource distance, km
0
30
60
90
120
150
180
210
240
270
300
330

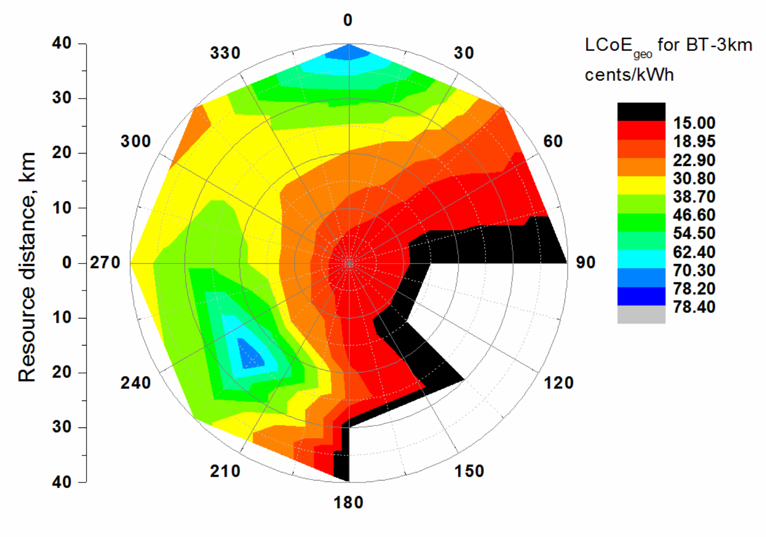
(B-1)


LCoE$_{geo}$ for BT-2km
cents/kWh
39.50
54.06
68.63
83.19
97.75
112.3
126.9
141.4
156.0
Resource distance, km
0
30
60
90
120
150
180
210
240
270
300
330

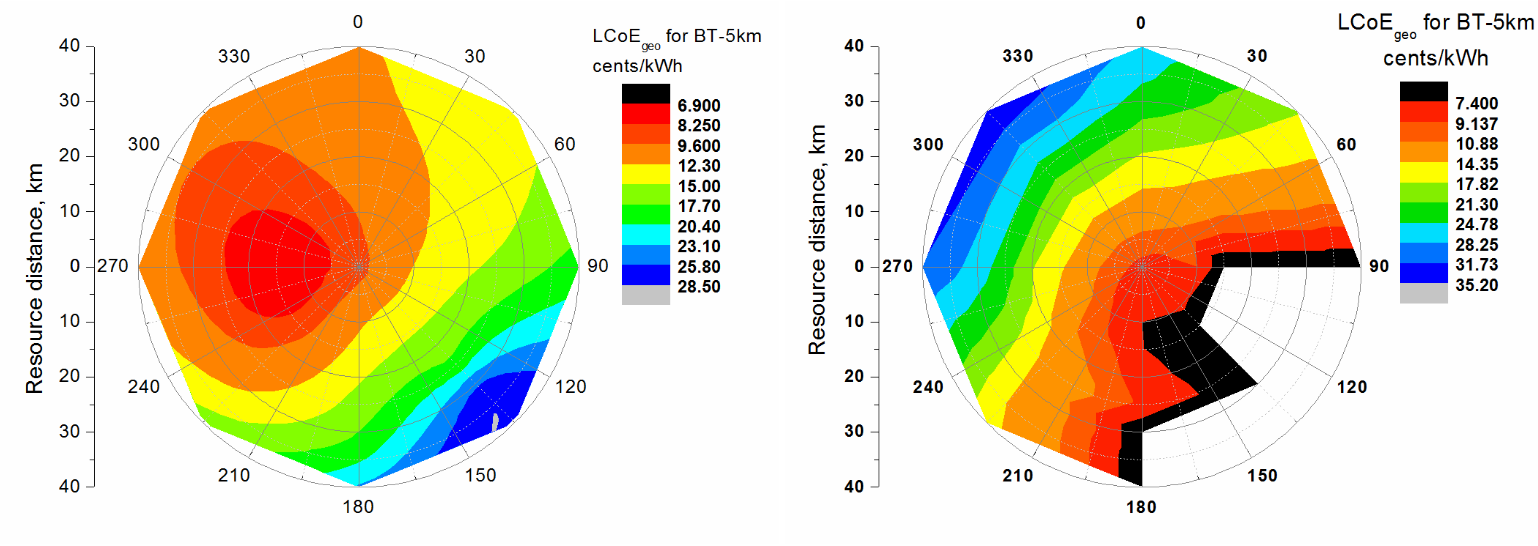
(E-1)


LCoE$_{geo}$ for BT-3km
cents/kWh
8.600
11.35
14.10
19.60
30.60
41.60
52.60
63.60
74.60
85.60
96.60
97.00
Resource distance, km
0
30
60
90
120
150
180
210
240
270
300
330

(B-2)


LCoE$_{geo}$ for BT-3km
cents/kWh
15.00
18.95
22.90
30.80
38.70
46.60
54.50
62.40
70.30
78.20
78.40
Resource distance, km
0
30
60
90
120
150
180
210
240
270
300
330

(E-2)



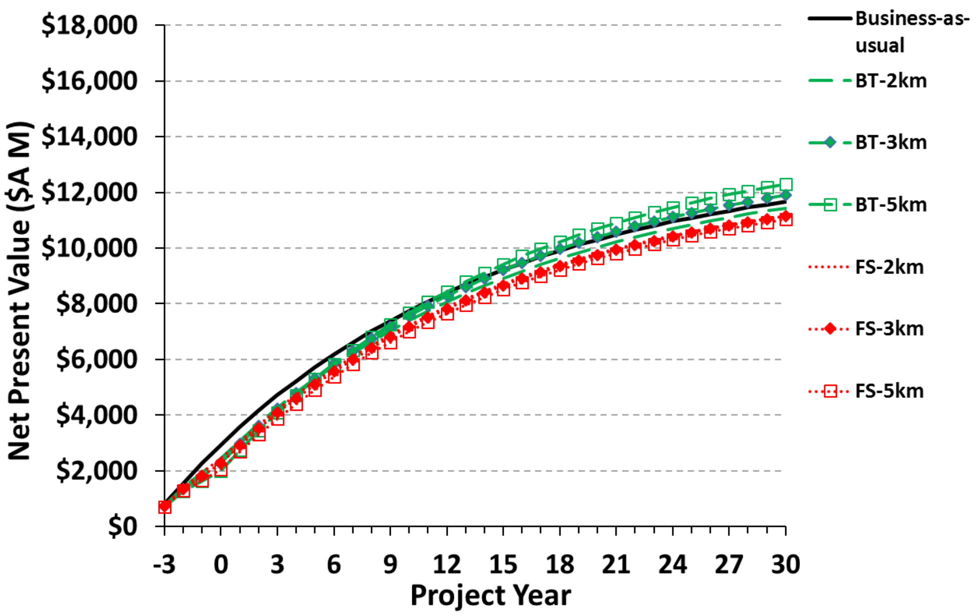
(B-3) **(E-3)**

Figure 19: LCoE$_{geo}$ of the two chosen NSW coal-fired power plants (B-, Bayswater; E-, Eraring) integrated with geothermal resources at distances up to 40 km and at drilling depths of 2 km (B-1, E-1), 3 km (B-2, E-2), and 5 km (B-3, E-3) (under booster mode).

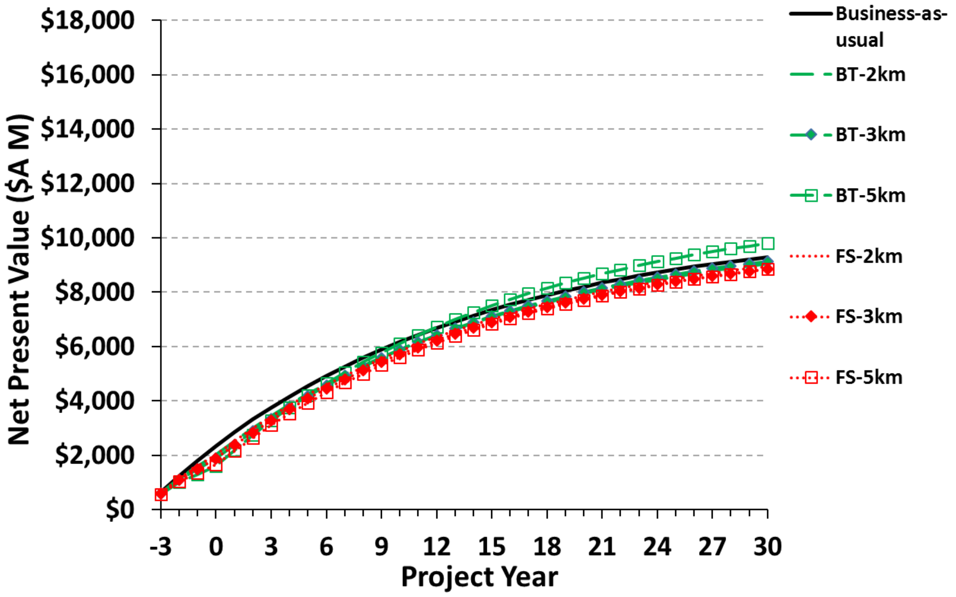
4.2.4 Cash flow and NPV

Although the above findings fail to show a LCoE lower than that of the coal plant under the typical conditions, it does not necessarily disapprove the potential benefits of GAPG technology. Indeed, with the revenues from electricity sales and proper economic incentives (e.g. RECs=50 cents/kWh), the hybrid plant could end up with a better cash position and a greater NPV at the end of the project lifetime.

Figure 20 presents the results of the accumulated cash flow analysis (i.e. NPV) of the GAPG projects for both Bayswater and Eraring power stations. It shows that with an electricity wholesale price of 8 cents/kWh and RECs at 50 cents/kWh, the NPV of all hybrid plants and coal-only plant increases dramatically with time. It means that the examined cases, either hybrid or business-as-usual, remains highly profitable even under a presumed carbon tax of 20 $/tonne. In addition, the difference between the NPVs of the hybrid plant and business-as-usual was also calculated and the results are plotted in Figure 21 for a better evaluation of the relatively performances of the various cases. As shown in Figure 21, all fuel saving cases were found to always have lower NPVs than that of the business-as-usual cases, whilst the booster modes BT-3km and BT-5km for the Bayswater power station and BT-5km for the Eraring power station were found to yield positive NPV increment (excess) after approximately 11.1 years, 15.8 years and 11.2 years, respectively. These results imply that, under the typical conditions, the hybrid plant employing the fuel saving mode is not economically viable largely due to the low cost of fuel and low emission penalty (thus making little economic sense to reduce coal consumption). This is in addition to the complexity and prolonged installation period associated with boiler modification under the fuel saving mode. The hybrid plant under the booster mode, however, can become profitable since the accumulated cash flow is lifted by a high amount of revenue coming from the excess electricity sale and incentives of RECs. At the end of the project, the Bayswater hybrid plant under the booster modes BT-3km and BT-5km was found to generate an excess NPV of $170 million and $499 million, respectively. That is about $7 million - $20 million of profit gain each year. The Eraring hybrid plant under the booster mode BT-5km was found to generate an excess NPV of $397 million, or a profit gain of $16 million/year. However, the booster mode BT-2km, due to a low hybridisation extent and thus a weak thermodynamic boost, was found to always have negative NPV increment.

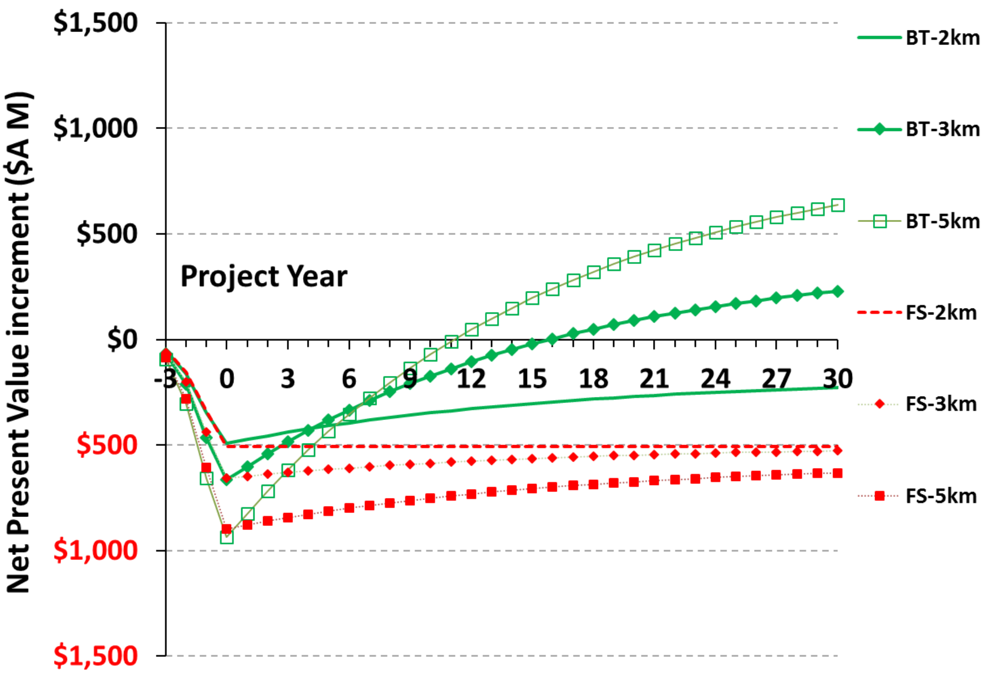


(a)

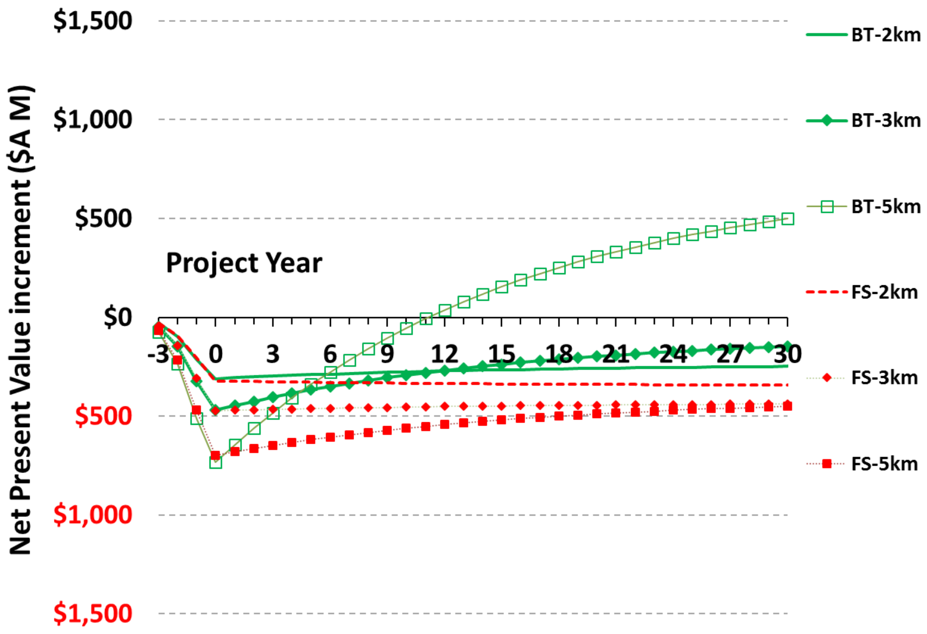


(b)

Figure 20: Net present value of the hybrid plant under six different hybridisation modes compared with that of the business-as-usual case. (a): Bayswater (L_{geo} = 20 km); (b): Eraring (L_{geo} = 10 km) (under typical conditions).



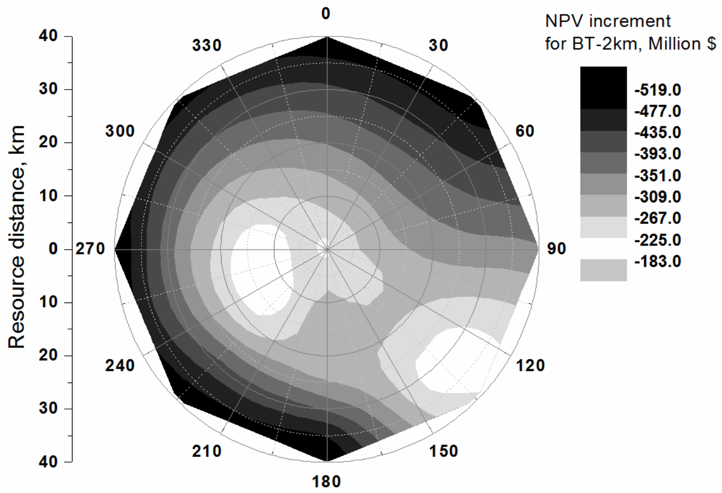
(a)



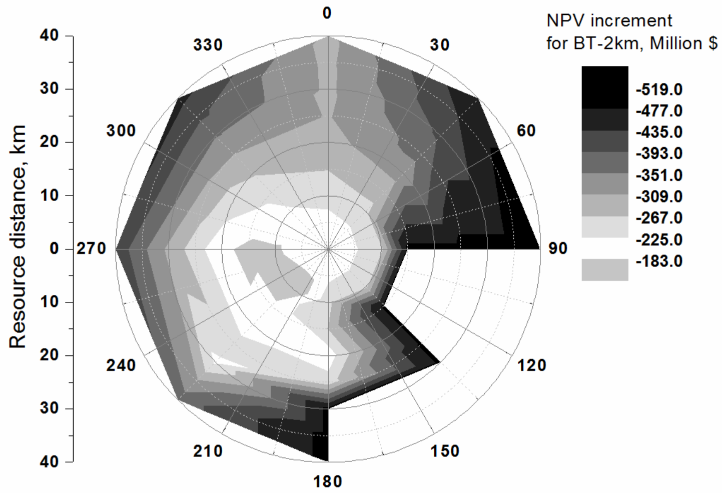
(b)

Figure 21: Net present value increment of the hybrid plant under six different hybridisation modes. (a): Bayswater (L_{geo} = 20 km); (b): Eraring (L_{geo} = 10 km) (under typical conditions).

Figure 22 presents the highlighted reference maps for the hybrid plant to achieve positive excess NPV within 40 km radius of the coal-fired power plant and by drilling up to 5 km. These areas are also the places where the GAPG technology is advised to be implemented in to gain the best chance of success in commercialising the new technology. It is again worth noting that these results were obtained under the typical conditions and all are subject to change under non-typical conditions, which will be unfolded in the sensitivity analysis section.



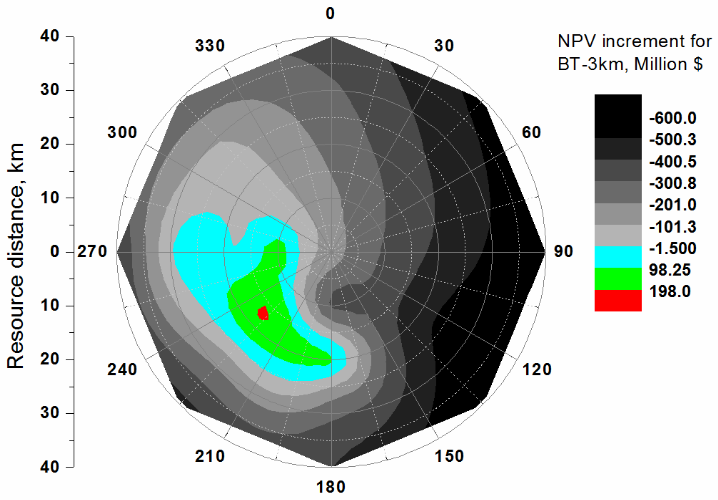
NPV increment
for BT-2km, Million $
-519.0
-477.0
-435.0
-393.0
-351.0
-309.0
-267.0
-225.0
-183.0
Resource distance, km



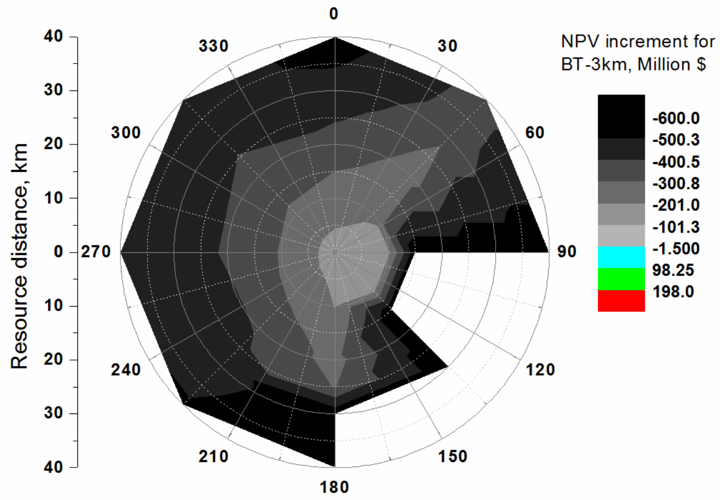
NPV increment
for BT-2km, Million $
-519.0
-477.0
-435.0
-393.0
-351.0
-309.0
-267.0
-225.0
-183.0
Resource distance, km

(B-1)

(E-1)

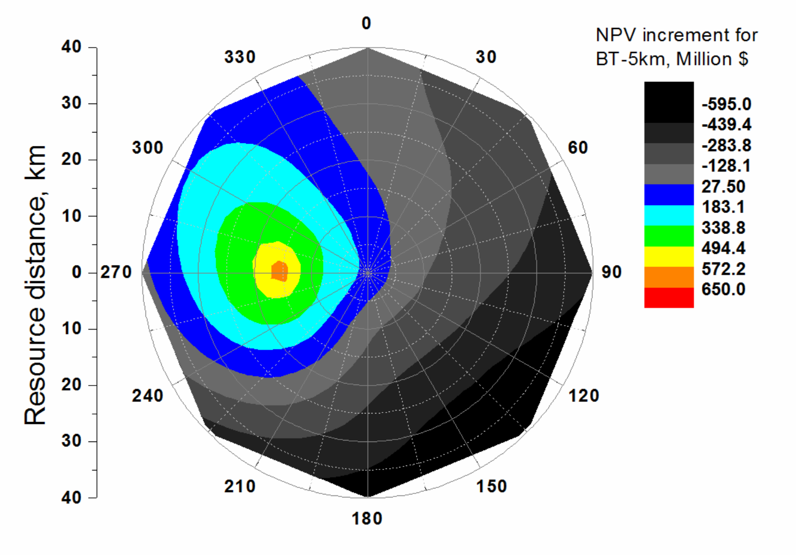


NPV increment for
BT-3km, Million $
-600.0
-500.3
-400.5
-300.8
-201.0
-101.3
-1.500
98.25
198.0
Resource distance, km

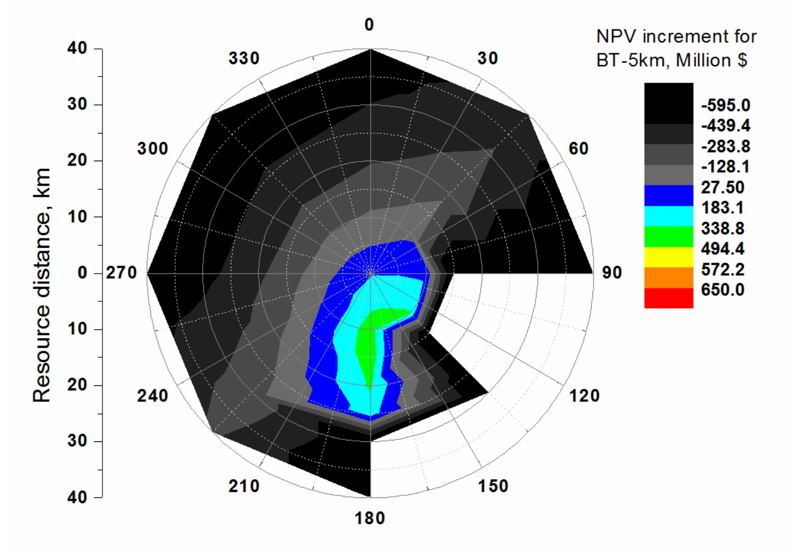


NPV increment for
BT-3km, Million $
-600.0
-500.3
-400.5
-300.8
-201.0
-101.3
-1.500
98.25
198.0
Resource distance, km

(B-2)



(E-2)



(B-3)

(E-3)

Figure 22: NPV increments of the two chosen NSW coal-fired power plants (B-, Bayswater; E-, Eraring) integrated with geothermal resources at distances up to 40 km and at drilling depths of 2 km (B-1, E-1), 3 km (B-2, E-2), and 5 km (B-3, E-3) (under the booster mode and at typical conditions).

4.2.5 Payback period

Table 18 summarises the calculated payback periods for the investment in GAPG technology for both Bayswater and Eraring power stations under the booster mode. Under the typical conditions, as shown in Table 18, most investments in the GAPG technology result in a payback period between about 10 – 20 years if neglecting the cases with low-quality geothermal resources. It was also found that drilling deeper does not always mean a longer payback period since geothermal resources with a greater quality can be present and help to increase the techno-economic synergies between the coal and geothermal plants. The minimum payback period was found to be 10.2 years for the location at 15 km west of Bayswater plant and at a drilling depth of 5 km. For the Eraring plant, such figure becomes 11.5 years for the location at 10 km south of Eraring plant and at a drilling depth of 5 km.

Table 18: Payback periods for Bayswater and Eraring power plants integrated with geothermal resources at distances up to 40 km under the booster mode and at typical conditions.

Payback period in years for Bayswater hybrid plant with a drilling depth of 3 km								
Distance, km	N	NE	E	SE	S	SW	W	NW
0	>30	>30	>30	>30	>30	>30	>30	>30
5	>30	>30	>30	>30	>30	>30	>30	>30
10	>30	>30	>30	>30	>30	25.71	15.35	>30
15	>30	>30	>30	>30	>30	14.73	23.46	>30
20	>30	>30	>30	>30	17.36	15.84	23.44	>30
25	>30	>30	>30	>30	>30	27.36	19.59	>30
30	>30	>30	>30	>30	>30	>30	26.30	>30
35	>30	>30	>30	>30	>30	>30	>30	>30
40	>30	>30	>30	>30	>30	>30	>30	>30
Payback period in years for Bayswater hybrid plant with a drilling depth of 5 km								
0	16.88	16.88	16.88	16.88	16.88	16.88	16.88	16.88
5	18.02	22.35	25.53	26.09	22.87	15.86	14.16	14.77
10	19.56	27.03	>30	>30	>30	15.54	11.98	14.12
15	21.72	>30	>30	>30	>30	15.54	10.23	14.33
20	24.43	>30	>30	>30	>30	17.86	11.61	14.85
25	26.73	>30	>30	>30	>30	21.57	13.26	15.65
30	29.47	>30	>30	>30	>30	>30	15.72	16.76
35	30.15	>30	>30	>30	>30	>30	19.24	18.09
40	>30	>30	>30	>30	>30	>30	25.91	19.52
Payback period in years for Eraring hybrid plant with a drilling depth of 5 km								
0	15.38	15.38	15.38	15.38	15.38	15.38	15.38	15.38
5	22.98	18.57	15.59	13.07	12.91	15.89	20.72	23.90
10	>30	25.50	16.93	12.35	11.48	18.88	>30	>30
15	>30	>30	-	-	11.48	22.63	>30	>30
20	>30	>30	-	-	12.89	>30	>30	>30
25	>30	>30	-	-	14.91	>30	>30	>30
30	>30	>30	-	-	-	>30	>30	>30

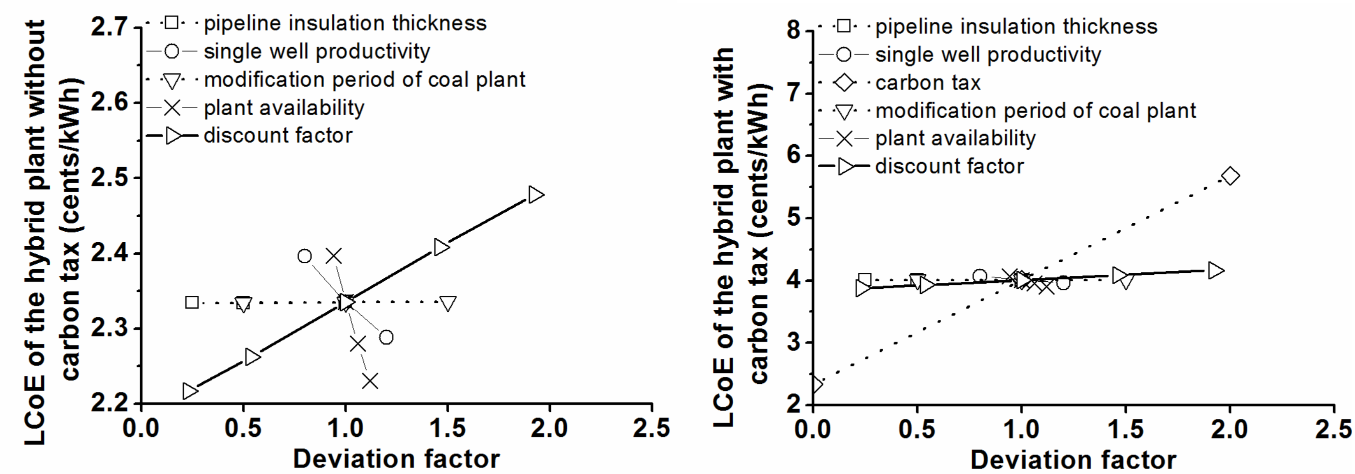
35	>30	>30	-	-	-	>30	>30	>30
40	>30	>30	-	-	-	>30	>30	>30

4.2.6 Sensitivity analysis

In this section, the optimum resource locations and drilling depths that yield the greatest profit for the investment in Bayswater and Eraring hybrid plants are selected as the finalised cases (i.e. BT-5km), which are further evaluated in the sensitivity analysis. The key technical and economic conditions to be assessed under non-typical conditions are:

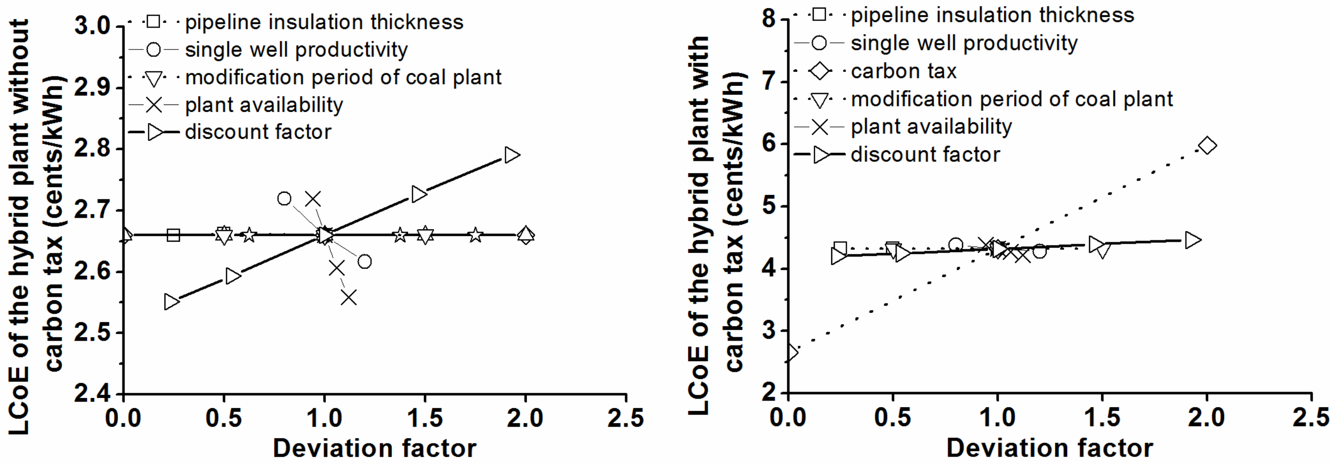
- Pipeline insulation thickness: 1, 2, 4 inches
- Single well productivity: 40, 50, 60 kg/s per well
- Modification period of coal plant for the booster mode BT-5km: 6, 8, 10 weeks
- Plant availability: 0.8, 0.85, 0.9, 0.95
- Unit cost of CO_2 emissions (also known as carbon tax): 0, 20, 40 $/tonnes
- RECs or feed-in-tariff: 0, 25, 50, 75, 100 $/MWh
- Electricity wholesale price: 5, 8, 11, 14 cents/kWh
- Discount factor: 1.5%, 3.5%, 6.5%, 9.5%, 12.5%

Figure 23 and Figure 24 show the calculated LCoE of the hybrid plant under non-typical conditions with and without carbon tax for Bayswater and Eraring power station, respectively. Without carbon tax, Figure 23a and Figure 24a indicate that plant availability is the most critical factor that affects the LCoE, followed by single well productivity and discount factor. With carbon tax, Figure 23b and Figure 24b indicate that carbon tax becomes the overwhelming factor that affects the LCoE, followed by plant availability. The rest factors such as modification period of coal plant and pipeline insulation thickness were found to have limited impact on the LCoE of the hybrid plants.



(a) (b)

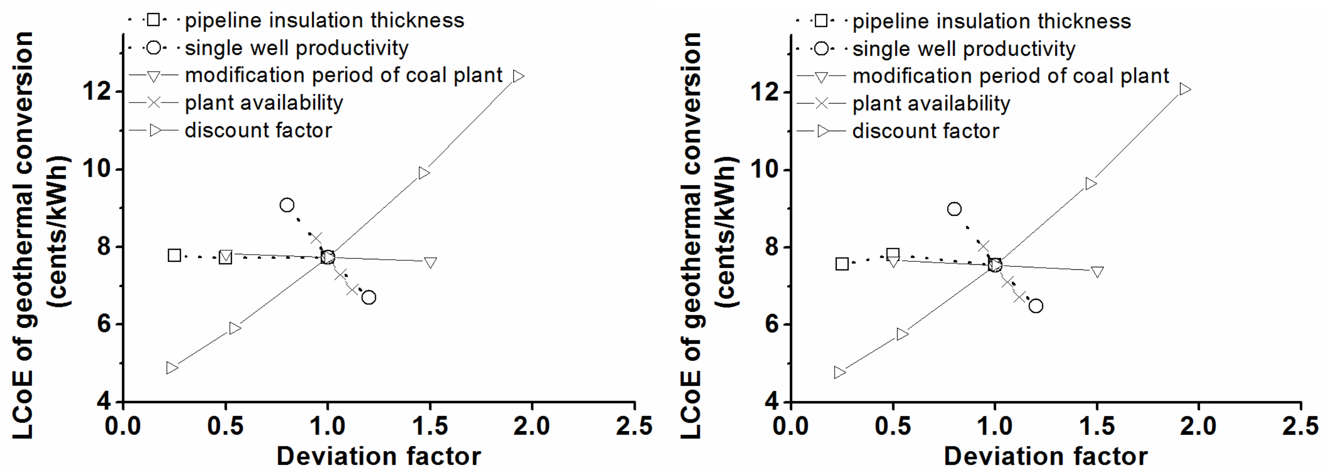
Figure 23: LCoE of the Bayswater hybrid plant under non-typical conditions: (a) without carbon tax; (b) with carbon tax.



(a) (b)

Figure 24: LCoE of the Eraring hybrid plant under non-typical conditions: (a) without carbon tax; (b) with carbon tax.

Figure 25 shows the LCoE of geothermal conversion for the Bayswater and Eraring hybrid plants, respectively, under non-typical conditions. It was found that the single well productivity, discount factor and plant availability are the three most critical factors with roughly equal level of impact on the $LCoE_{geo}$. The implication is that a low discount factor, a high plant availability and a high single well productivity are the most favourable conditions contributing to a low $LCoE_{geo}$.



(a) (b)

Figure 25: LCoE of geothermal conversion for the hybrid plant under non-typical conditions: (a) Bayswater; (b) Eraring.

Figure 26 presents the NPV increment of the hybrid plant compared to that of the business-as-usual case under non-typical conditions. The results in Figure 26 show that the sensitive parameters that have a great impact on the profitability of the investment include, from high to low, plant availability, discount factor, electricity wholesale price and RECs. The insensitive parameters are carbon tax, modification period, and pipeline insulation thickness. Here, it should be highlighted that with the absence of policy incentive for clean energy production (i.e. RECs=0 cents/kWh) or at times when discount factor increases above ~11.5%, the investment in GAPG technology will become unprofitable resulting in a reduced NPV compared to that of the business-as-usual case. That implies the GAPG project should not be approved under such disadvantaged market conditions.

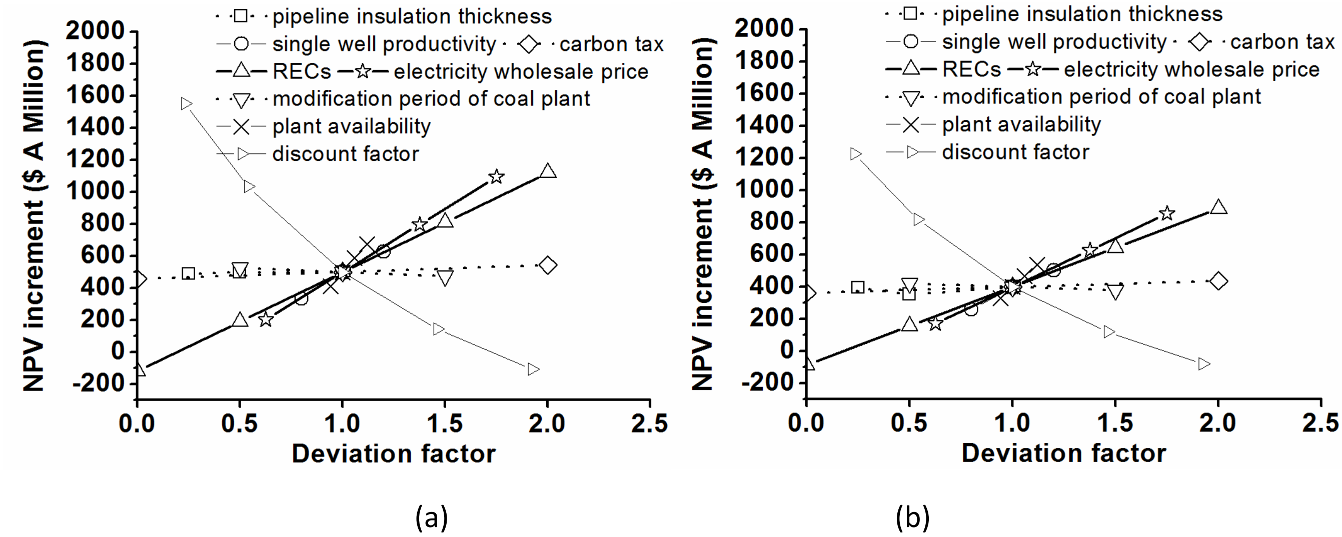


Figure 26: NPV increment of the hybrid plant under non-typical conditions: (a) Bayswater; (b) Eraring.

Figure 27 presents the calculated payback period of the hybrid plant under non-typical conditions for both Bayswater and Eraring power stations. It can be seen from Figure 27 that the conditions that yield the greatest profit (i.e. NPV increment in Figure 26) also result in the shortest payback period and hence share similar sensitivity among the examined parameters as discussed in the previous graph. However, a payback period less than 5 years was found to be less likely for GAPG technology within the examined conditions.

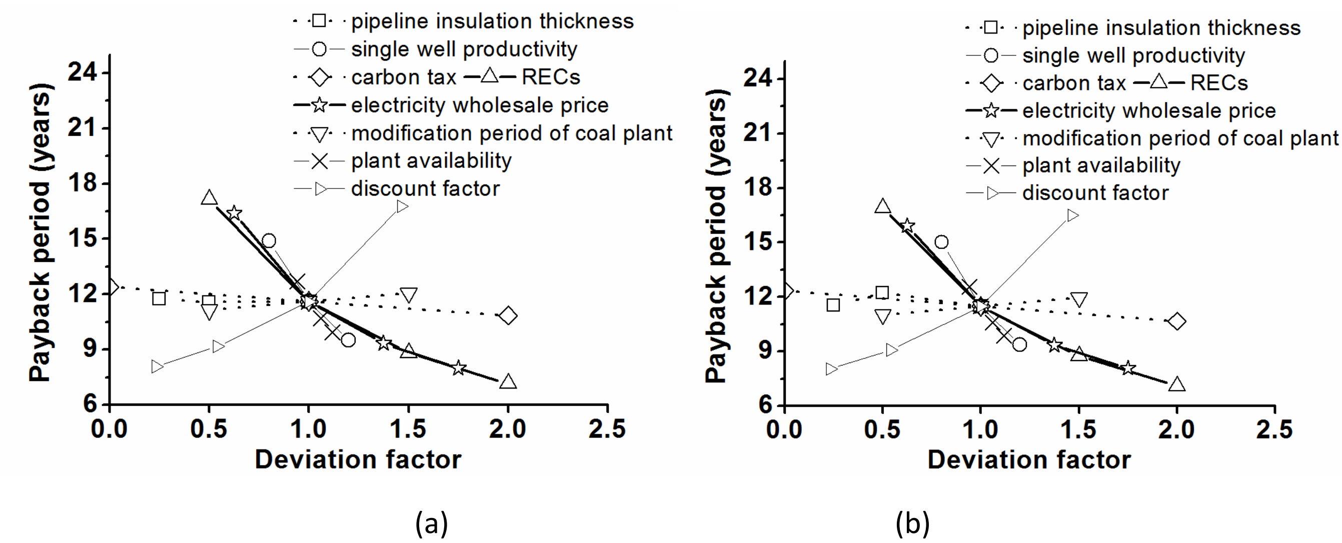


Figure 27: Payback period of the hybrid plant under non-typical conditions: (a) Bayswater; (b) Eraring.

4.2.7 Government policy analysis

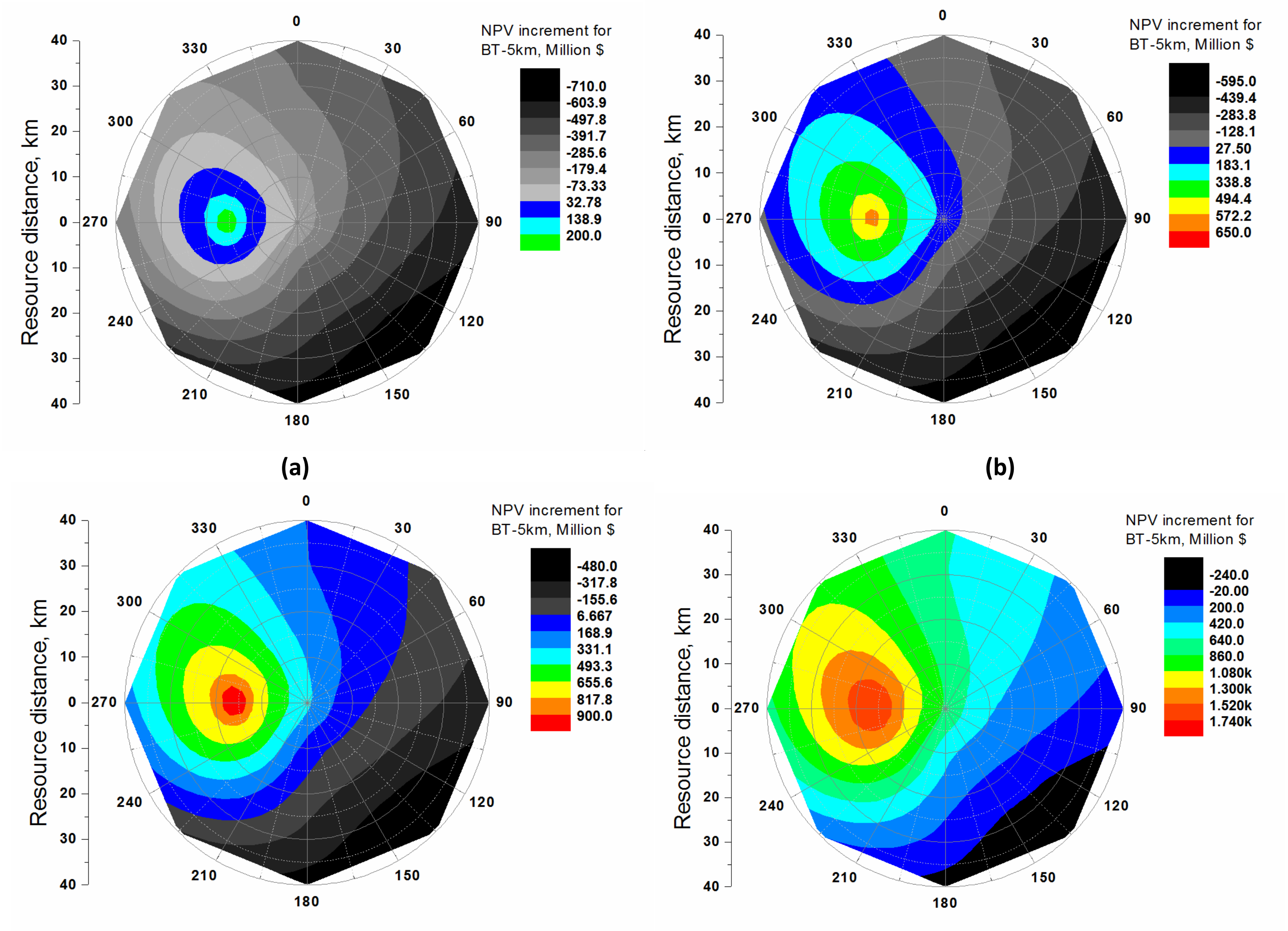
In this section, four hypothetical levels of economic policies were formulated to study the impact of government role on the feasibility of rolling out GAPG technology across NSW coal-fired power stations, including:

a) Pessimistic conditions (no carbon tax; RECs = 25 $/MWh; financial discount rate = 6.5%)

b) Typical conditions (carbon tax =20 $/tonne; RECs = 50 $/MWh; financial discount rate = 6.5%)
c) Optimistic conditions (carbon tax = 40 $/tonne; RECs = 75 $/MWh; financial discount rate = 6.5%)
d) Extremely optimistic conditions (carbon tax = 80 $/tonne; RECs = 75 $/MWh; financial discount rate = 3.5%)

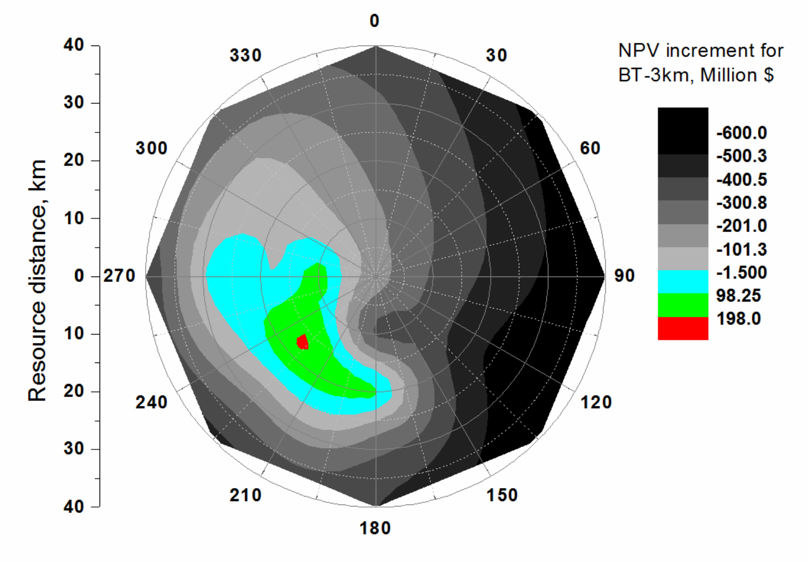
Figure 28 and Figure 29 show the NPV increment (or the net profit obtainable) under the four different levels of government policies for the Bayswater hybrid plant with drilling depths of 5 km and 3 km, respectively. The results indicate that under the pessimistic conditions the GAPG technology can marginally success in a very limited locations and drilling must be deep enough (e.g. at 5 km) to reach high quality resources. As the economic policy is enhanced from pessimistic to optimistic conditions, more areas at a lower drilling depth becomes available for an economical utilisation of the geothermal resources in the GAPG platform. The associated profit gain is also greatly increased as the policy conditions is improved and the exact profit gain can be found in Figure 28 and Figure 29 for different drilling depths and various locations within 40 km radius of the coal plant. On average, an increase of carbon tax at 20 $/tonne and RECs at 25 $/MWh was found to improve the profitability of GAPG technology by $8.4 million/year and $14.7 million/year for the booster mode operation, BT-3km and BT-5km, respectively.

Interestingly, Figure 30 shows that under the extremely optimistic conditions the fuel saving modes, FS-3km and FS-5km, also become profitable in a limited number of places. This is mostly due to the greatly amplified saving in terms of the avoided CO_2 emission under a high carbon tax of 80 $/tonne. On the other hand, the payback period of the GAPG investment at Bayswater station can be as short as 7.2 years, 5.6 years, and 12.6 years for the BT-3km, BT-5km, and FS-5km scenarios, respectively if the extremely optimistic conditions are imposed. Under the optimistic conditions, the shortest payback period was found to be 10.1 years and 7.4 years for the BT-3km and BT-5km scenarios, respectively. Under the pessimistic conditions, the shortest payback period elevates to 26.5 years and 15.9 years for the BT-3km and BT-5km scenarios, respectively. And the investment under the fuel saving modes were not found to payback itself except under the extremely optimistic conditions. The above findings clearly show the importance of government policies in leading industry on the road of emission reduction and the adoption of clean energy technologies such as GAPG concept.

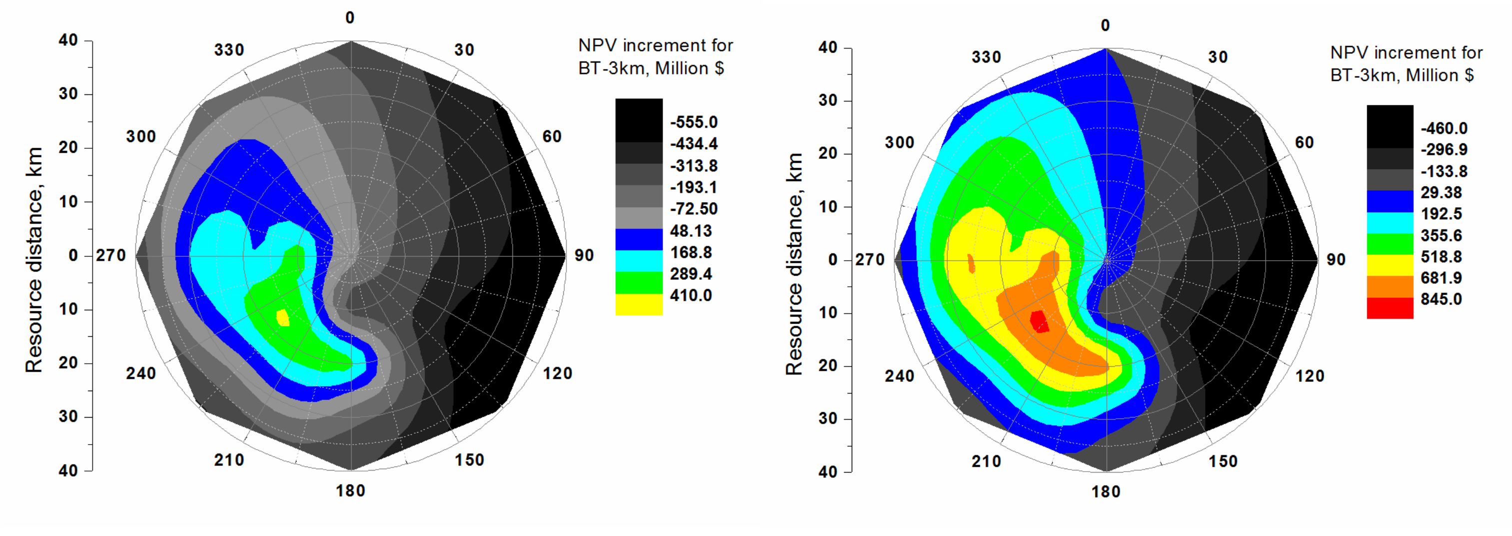

NPV increment for BT-5km, Million $
-710.0
-603.9
-497.8
-391.7
-285.6
-179.4
-73.33
32.78
138.9
200.0
Resource distance, km
(a)
NPV increment for BT-5km, Million $
-595.0
-439.4
-283.8
-128.1
27.50
183.1
338.8
494.4
572.2
650.0
Resource distance, km
(b)
NPV increment for BT-5km, Million $
-480.0
-317.8
-155.6
6.667
168.9
331.1
493.3
655.6
817.8
900.0
Resource distance, km
NPV increment for BT-5km, Million $
-240.0
-20.00
200.0
420.0
640.0
860.0
1.080k
1.300k
1.520k
1.740k
Resource distance, km

(c) **(d)**

Figure 28: NPV increments of the Bayswater coal-fired power plant integrated with geothermal resources at distances up to 40 km and at a drilling depth of 5 km under the booster mode, BT-5km, (a): pessimistic conditions; (b): typical conditions; (c): optimistic conditions; (d): extremely optimistic conditions.

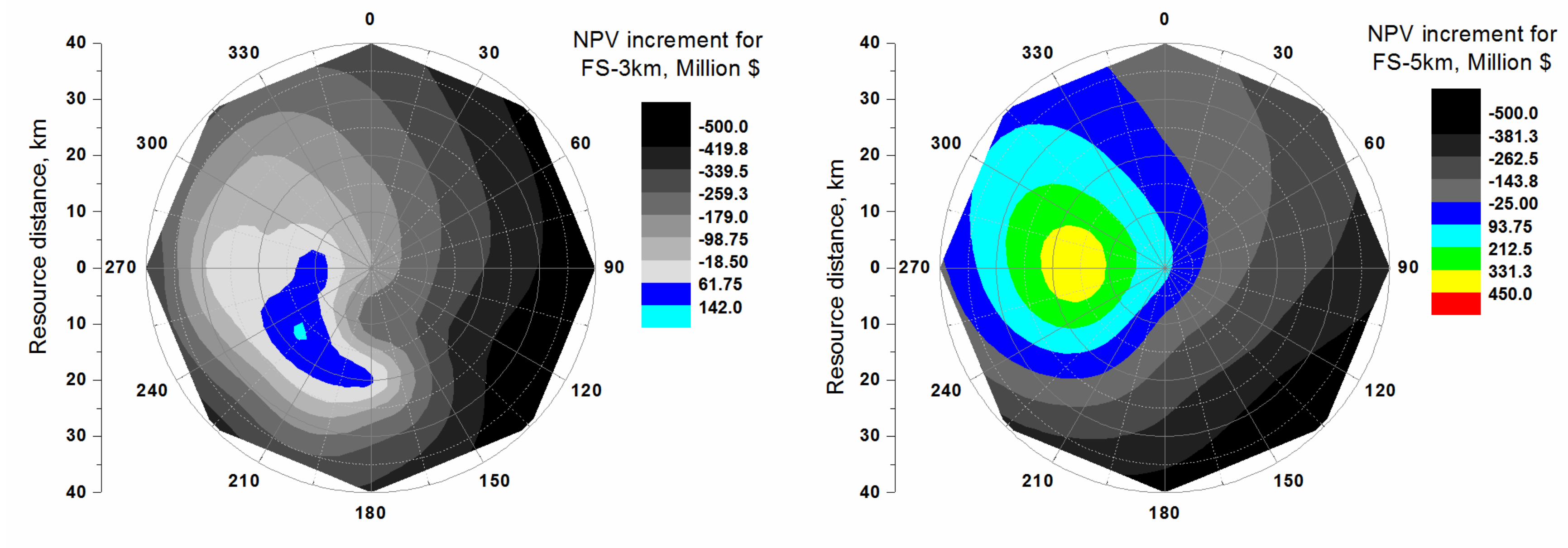


(a)



(b) **(a)**

Figure 29: NPV increments of the Bayswater coal-fired power plant integrated with geothermal resources at distances up to 40 km and at a drilling depth of 3 km under the booster mode, BT-3km, (a): typical conditions; (b): optimistic conditions; (c): extremely optimistic conditions.



(a) **(b)**

Figure 30: NPV increments of the Bayswater coal-fired power plant integrated with geothermal resources at distances up to 40 km and at drilling depths of 3 km and 5 km under the fuel saving mode, (a) FS-3km and (b) FS-5km, respectively (with extremely optimistic conditions).

4.3 Benchmarking Study with Solar Assisted Power Generation

Using the methods described in Sections 3.2 and 3.3, the technical and economic performances of a SAPG system integrated with Bayswater power station are evaluated here. The obtained results are used as benchmarks against those obtained previously for GAPG system as shown in Table 15 and Table 16.

Table 19 presents the detailed technical results of the SAPG system under the three predefined booster modes, BT1-Solar, BT2-Solar, and BT3-Solar (see definitions in Table 6). Here, the booster modes are different to those examined under the GAPG system because solar energy is a high-quality energy source and, therefore, better hybridisation modes exist for SAPG system, e.g. replacing the heating requirement for high-pressure feedwater heaters. This is otherwise not achievable using geothermal resources of low-medium quality. This advantage of SAPG system is fully realised in the current analysis as in the BT3-Solar and BT2-Solar operating modes, whilst for the BT1-Solar operating mode the lower temperature requirement of the solar field prompts the uses of cheaper solar collectors that may help to deliver better economics. Indeed, BT1-Solar turns out to be the best scenario for SAPG system, which will be discussed in a later text. Some key findings in Table 19 are listed here:

- The peak boosted power for SAGP system was found to be 37% - 95% greater than that of the GAPG system when comparisons are made between the operating modes of BT-2km (GAPG) and BT1-Solar (SAPG), BT-3km (GAPG) and BT2-Solar (SAPG), BT-5km (GAPG) and BT3-Solar (SAPG), respectively. However, with a low capacity factor at 14.5% the SAPG system was found to produce only 21%- 31% of the additional electricity achievable for GAPG system on an annual basis.
- The conversion rate of renewable energy to electricity was calculated to be 7% - 16% for GAPG system and 13% - 32% for SAPG system. The higher conversion efficiency of SAPG system is attributed by the high-quality of solar energy.
- The thermal efficiency of the coal plant is increased by 1.2% - 6.5% for GAPG system, which is compared to 2.2% - 8.7% for SAPG system at the design point.
- The emission intensity of the coal plant is reduced by 1.2% - 6% after integrating a GAPG system, which is dropped to only 0.4% - 1.5 % reduction for SAPG system. Again, this drop is attributed to the low capacity factor of solar energy.
- The solar parabolic trough area requirement was estimated to be 644,249 m^2, 1,146,999 m^2, 1,021,904 m^2 for the operating modes BT1-Solar, BT2-Solar, and BT3-Solar, respectively.

Table 19: Technical analysis of the SAPG system integrated with Bayswater power station under the three predefined booster modes.

Power Specification	Units	Reference plant	Solar Assisted Power Generation		
			Booster mode		
			BT1-Solar	BT2-Solar	BT3-Solar
Typical Gross Capacity	*MWe*	2280	2326*	2436*	2465*
Typical Auxiliary Consumption	*MWe*	137	137	137	137
Typical Net Capacity	*MWe*	2143	2189*	2299*	2329*
Q_{in} (coal)	*MWt*	6019	6019	6019	6019
Thermal Efficiency	*%*	35.6	36.4*	38.2*	38.7*
Generation (annual)	*MWh*	15,955,000	16,013,591	16,153,437	16,190,968

Efficiency Uplift	%	-	2.2*	7.3*	8.7*
Fuel					
Fuel Consumption Rate	*t/h*	967	967	967	967
Fuel Consumption (annual)	*t*	7,202,799	7,202,799	7,202,799	7,202,799
Fuel Saved	%	-	-	-	-
Emissions					
Annual CO_2 Emissions	*t-CO_2-e / Year*	13,976,580	13,976,580	13,976,580	13,976,580
Total Emission Intensity (sent-out)	*t-CO_2-e / MWh*	0.88	0.87	0.87	0.86
Δ Emission Intensity	%		-0.4	-1.2	-1.5
Solar field					
Process heat demand	*kWt*	-	360,779	642,319	572,266
Optical-thermal conversion efficiency of the solar collectors		-	0.70	0.70	0.70
Capacity factor			0.145	0.145	0.145
Solar average peak irradiance	*W/m^2*		800	800	800
Solar heat available each year	*kWh/m^2*		1,016	1,016	1,016
Solar parabolic trough area requirement	*m^2*		644,249	1,146,999	1,021,904
Peak boosted power in the coal plant	*MW*		46	156	186
Additional power production each year	*MWh/year*		58,591	198,437	235,968
Minimum required solar working fluid temperature	*°C*	-	112	201	258

*. At design point.

Table 20 presents the economic analysis results of the SAPG system for three booster modes under the typical operating and economic conditions as given in Table 8. As it shows, the total project cost was calculated to be $213 million, $484 million, and $485 million for BT1-Solar, BT2-Solar, and BT3-Solar, respectively. Of the total installed cost, about 65% - 66% is attributed to the installation of solar collectors, about 29% is related to other field infrastructure and labour cost (e.g. pipeline, site preparation, electric installations etc.), 3% - 4% is the heat exchanger cost, and 2% - 3% is the retrofit cost. The LCoE of clean power production, i.e. converting solar thermal energy to electricity, was calculated to be 23 – 39 cents/kWh. This is about twice to triple of the LCoE of geothermal-to-electricity in GAPG system.

In addition, the SAPG system operating under the BT1-Solar mode was found to achieve the greatest NPV primarily owing to its low-cost solar collectors. However, none of the investigated SAPG systems realises positive increment in NPV at the end of the project lifetime when compared to the business-as-usual scenario. The cost of solar collectors is considered too high for the relatively low figures of the annual boosted electricity, which is a key drawback of the technology attributed by the low capacity factor of solar energy. A simply mathematical calculation will reveal the problem: for the BT3-Solar mode, the $29 million/year of gross revenue from electricity sale requires 17 years to payback the $485 million investment without considering any operating and maintenance costs and interest rate etc. With all factors considered, the SAPG project was found not able to payback itself within 30 years.

The detailed cash flow analysis of GAPG versus SAPG systems are illustrated in Figure 31 and Figure 32. The key information is that the initial capital investment of SAPG system is lower than GAPG system, but its ability to recover the cost is much slower than the GAPG system due to the lower annual electricity generation. The base load characteristic of GAPG technology clearly exhibits a key advantage against its counterpart and the payback period is found to be 11 – 16 years for GAPG system under the typical conditions. In conclusion, SAPG technology was found in this benchmarking study to be an unviable and less favourable business option.

Table 20: Economic analysis of the SAPG system integrated with Bayswater power station under the three predefined booster modes.

Detailed Cost Analysis	Units	Reference plant	Solar Assisted Power Generation		
			Booster mode		
			BT1-Solar	BT2-Solar	BT3-Solar
Base production cost					
Unit Fuel cost	*$ / GJ*	1.27	1.27	1.27	1.27
Total Fuel cost	*$ / Year*	204,905,225	204,905,225	204,905,225	204,905,225
Unit FOM cost	*$/MW/Year*	49,000	49,000	49,000	49,000
Total FOM cost	*$/Year*	104,995,299	104,995,299	104,995,299	104,995,299
Unit VOM cost	*$/MWh*	1.19	1.19	1.19	1.19
Total VOM cost	*$ / Year*	18,986,450	19,056,174	19,222,590	19,267,252
Total production cost	*$ / Year*	328,886,974	328,956,698	329,123,114	329,167,777
Normalised production cost	*¢ / kWh*	2.06	2.05	2.04	2.03
Emission cost					
Unit cost of CO_2 emissions	*$/t*	20.0	20.0	20.0	20.0
Compensations (free permits)	*$/t*	0.0	0.0	0.0	0.0
Total cost of CO_2 Emissions	*$ / Year*	279,531,600	279,531,600	279,531,600	279,531,600
Normalised emission cost	*¢ / kWh*	1.75	1.75	1.73	1.73
Solar field					
Unit installed cost of solar collectors [38]*	$/m^2		183	235	261
Total installed cost of solar collectors	$		117,881,790	269,836,325	267,119,126
Other field infrastructure and labour cost (e.g. pipeline, site preparation, electric installations etc.)[45]	*$*		52,429,249	120,012,735	118,804,230
Heat exchanger					
Designed LMTD	*°C*		49.8	66.6	45.4
UA of heat exchanger	*kJ/(°C h)*		26,085,206	34,715,863	45,367,819

Heat transfer coefficient [36, 44]	*W/m²°C*		852.5	852.5	852.5
Required heat transfer areas	*m²*		8,500	11,312	14,783
Unit cost of heat exchanger [35]	*$/m²*		837	837	837
Total capital cost of heat exchanger	*$*		7,110,058	9,462,521	12,365,930
Plant modification					
Unit cost of plant modification	*$/kW*		40	40	40
Extra cost for aged plants	*$/kW*		20	20	20
Total cost of plant modification	*$*		2,767,661	9,373,492	11,146,362
Total installed cost	*$*		180,188,758	408,685,074	409,435,649
Project contingency	*$*		27,028,314	61,302,761	61,415,347
Owner's cost	*$*		6,216,512	14,099,635	14,125,530
Total project cost	*$*		213,433,584	484,087,470	484,976,526
Cash Flow Analysis Results					
LCoE of the hybrid plant without carbon tax	¢ / kWh	2.06	2.18	2.31	2.30
LCoE of the hybrid plant with carbon tax	¢ / kWh	3.81	3.93	4.04	4.03
LCoE of clean power production	¢ / kWh	-	39.24	27.41	22.84
Fuel saving	$ / Year	-	-	-	-
NPV	million $	11092	10751	10628	10732
NPV increment	million $	-	-341	-464	-360
Payback period	Year	-	>30	>30	>30

*. 30% and 10% cost reductions are applied to the solar collectors that require lower working fluid temperatures under the booster modes BT1-Solar and BT2-Solar, respectively.

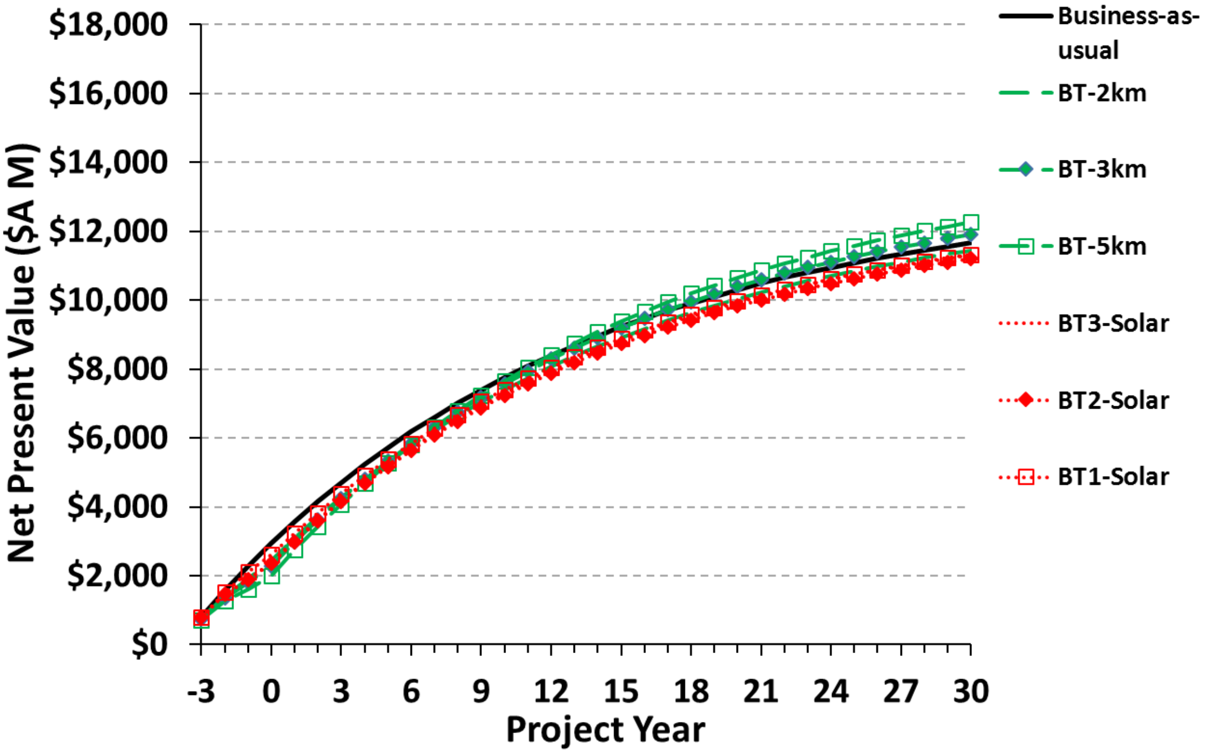


Figure 31: Net present value of GAPG system versus SAPG system under the booster modes compared with that of the business-as-usual case at Bayswater power station.

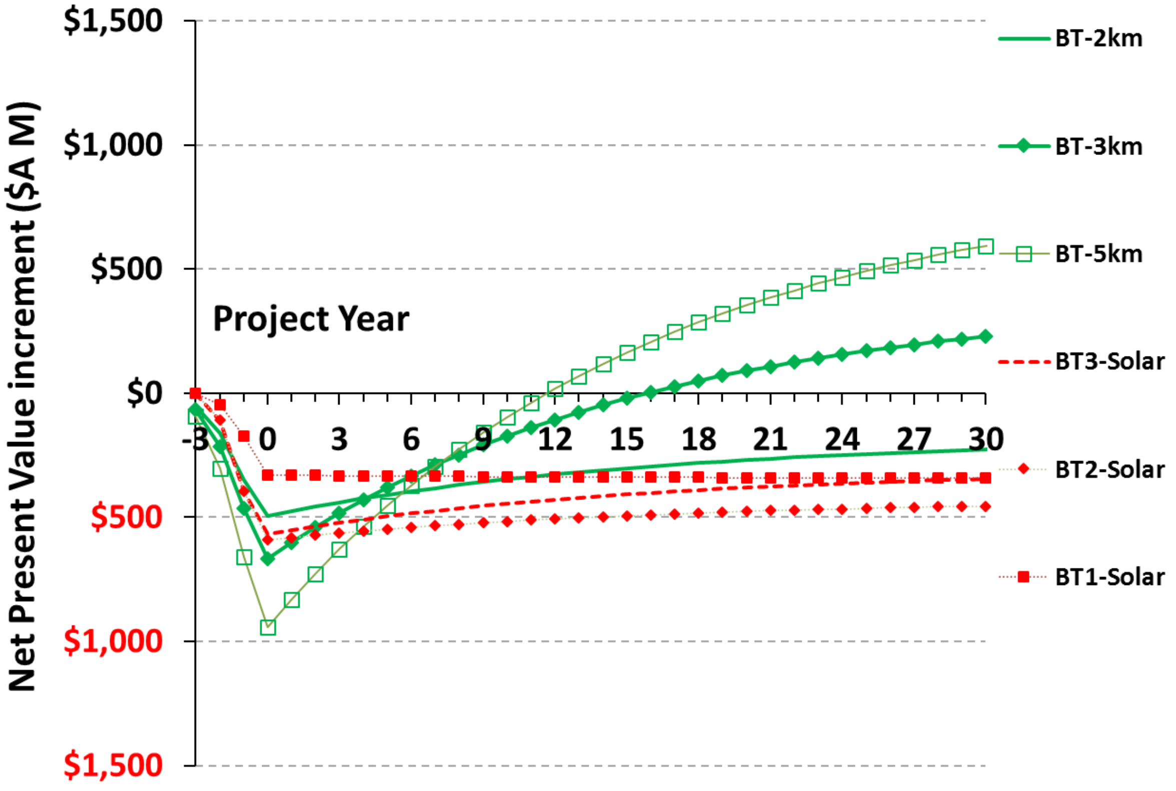


Figure 32: Net present value increment of GAPG system versus SAPG system under the booster modes.

4.4 Life Cycle Assessment

This section presents the results of an LCA assessment of GAPG system according to the method described in the Section 3.4. The Bayswater power station was selected in this analysis as the most favourable plant to implement GAPG technology across all NSW coal-fired power plants. The energy, materials requirements and emissions for both the fuel cycle (energy, fuel and feedstock for operating the plant) and plant cycle (from raw material production to the installation, construction, and commissioning of the plant) are included. The final product is the net delivered electricity available at the users' wall outlet taken into the consideration of about 4.9% electric transmission and distribution losses. The GAPG system operating under the booster mode with an optimum resource distance of 20 km, as indicated by the previous techno-economic analysis, was used in the LCA assessment (see details in Table 14 and Table 16).

GHG emissions are calculated in grams CO_2 equivalent (gCO_2e) by combining CO_2, CH_4, and N_2O scaled by their global warming potentials based on the latest assessment report (AR5 with more information on IPCC website www.ipcc.ch). Any fugitive CO_2 emissions from the geothermal fluid was considered negligible for GAPG system since it is a closed loop system. For readers information, the geothermal flash power plant has fugitive CO_2 emissions at about 91g CO_2/kWh.

4.4.1 Plant cycle

Table 21 presents the material usages for two EGS plants (20MW and 50 MW) retrieved from the literature [46]. Since the GAPG system uses very similar plant infrastructure as a geothermal EGS plant except that a longer pipeline replaces the power generation block, the data in Table 21 can be used to estimate the material requirement for the power plant infrastructure of the GAPG system. It shows that in average the steel usage of the power block accounts for 17.4% of all the steel used in the EGS plant, while 100% of aluminium, concrete, and iron usages are for constructing the power block. With these data, the material and energy requirements for the EGS plant excluding the power block was calculated and presented in Table 22 in terms of tonne per TWh of the installed capacity. The data is also compared to those of the coal plant and EGS plant. Without the power block, the EGS plant was found to reduce its material usages by 3,155 tonnes/TWh or 26.6%. Coal-fired power plant was found to use much less construction materials at about 1,183 tonnes/TWh, compared to 11,883 tonnes/TWh for EGS plant. Therefore, from the perspective of plant cycle only, renewable energy plants like EGS and GAPG has a much greater material usage and poses greater environmental impact than coal-fired power plant (note that the main environmental impact of coal plant is due to its fuel cycle, i.e. burning coal). However, GAPG system can reduce such impact by sharing the power block with the coal plant.

Table 21: Detailed material usages for two EGS reference plants

Materials	20MW EGS plant, million tonnes/MW	50MW EGS plant, million tonnes/MW	Calculated average materials usage for the power block only (%)
Aluminium	45.2	42.6	100
Cement	988	987	0
Concrete	460	460	100
Iron	3.9	2.8	100
Steel	1206	1175	17.4
Diesel	263930 (litres/MW)	240500 (litres/MW)	0

bentonite	283	282	0

Table 22: Material and energy requirements for the EGS plant excluding the power block compared with those of the coal plant and EGS plant.

Materials	Unit	Coal-fired power plant	Geothermal-EGS plant	Geothermal-EGS plant excluding the power block*
Aluminium	tonne/TWh	2.73	193.83	0
Cement	tonne /TWh	0	4,370.39	4,370.39
Concrete	tonne/TWh	866.54	2,030.99	0
Copper	tonne/TWh	0.64	2.96	2.958
Iron	tonne/TWh	1.44	14.75	0
Steel	tonne/TWh	311.89	5,270.65	4,354.86
Diesel	GJ/TWh	0	36,516.00	36,516.00

*. This column is based on the equivalent installed capacity of a geothermal EGS plant.

The amount of steel required for constructing a return pipeline with a nominal diameter of 900 mm was estimated to be 16,818 tonnes (with the pipe schedule 40 weighting at 420.45 kg/m). The mineral wool for pipeline insulation at an insulation thickness of 101.6 mm was computed to be 197 tonnes. Adding these with other major GAPG infrastructures including wells, transportation pump, and geothermal heat exchanger etc., Table 23 gives the calculated total energy and material requirements for the infrastructure of the GAPG system under three booster modes, BT-2km, BT-3km, and BT-5km.

Table 23: Energy and material requirements for the infrastructure of the GAPG system under three booster modes.

Energy and material requirements for GAPG infrastructure	Unit	BT-2km	BT-3km	BT-5km
Brine effectiveness	kWe per kg/s	10.45	39.71	67.12
Theoretical power output of a stand-alone EGS plant	MWe	13.41	57.87	124.20
Installed capacity over the plant lifetime	TWh	3.00	12.93	27.74
Geothermal wells and production/injection systems				
Cement	tonne	13,090	56,493	121,254
Copper	tonne	9	38	82
Steel	tonne	13,044	56,292	120,823
Diesel	GJ	109,371	472,019	1,013,115
Pipeline				
Steel	tonne	16,818	16,818	16,818
Mineral wool	tonne	197	197	197
Cement	tonne	855	855	855
Diesel*	GJ	58,175	58,175	58,175

Geothermal heat exchanger [47]				
Steel	tonne	650	1,067	481
Feedwater transportation pump [48]				
Steel	tonne	2.0	2.3	2.9
Total energy and material requirements				
Cement	tonne	13,945	57,348	122,109
Copper	tonne	9	38	82
Steel	tonne	30,513	74,179	138,125
Diesel	GJ	167,546	530,194	1,071,290
Mineral wool	tonne	197	197	197

*. in average 40,557 litre of diesel is required to complete the installation of a 1000m-long pipeline [46].

Table 24: Summary of energy consumption and emissions of material products for power plant infrastructure.

	Aluminium	Cement	Concrete	Copper	Mineral wool	Glass	Iron	Lead	Oil	Plastic	Silicon	Steel
Energy use: GJ per tonne												
Total energy	134.18	4.35	0.49	40.12	25,046	13.55	31.40	24.29	48.88	73.25	3343.66	27.95
Fossil fuels	84.97	3.84	0.44	34.76	22,505	12.68	30.94	23.30	48.62	70.67	2428.06	25.23
Coal	30.67	1.91	0.18	11.96	7,417	2.87	22.51	20.48	0.53	5.39	1004.54	18.09
Natural gas	38.51	1.07	0.12	15.87	25	9.49	6.70	1.95	5.56	56.88	1336.39	7.22
Petroleum	15.78	0.86	0.13	6.93	114	0.32	1.73	0.87	42.52	8.40	87.13	0
Water consumption, litre per tonne	240478	1057	554	11805	364	2958	1161	1889	3890	5239	2605279	4863
Total emissions: gram per tonne												
VOC	966.22	100.18	73.95	326.98	0	138.22	2014.95	1682.94	1169.07	1283.53	22219.05	2378.90
CO	2717.70	1143.17	122.13	2303.42	0	594.65	890.49	618.27	1177.33	4772.14	77503.53	17139.30
NO_x	5860.96	1246.47	152.41	6045.49	10	1613.62	1448.65	1095.63	7980.52	3112.53	154172.85	2162.22
PM_{10}	4790.61	213.44	69.86	576.49	0	99.15	1002.84	4645.46	1456.11	309.83	21886.64	1368.31
$PM_{2.5}$	2381.70	116.34	24.37	309.61	0	65.95	458.48	2281.47	700.85	126.54	10685.98	651.99
SO_x	29307.39	378.81	42.97	131836.58	12	1090.38	2953.68	27726.93	26254.92	23319.47	315951.48	8411.52
BC	48.87	3.87	1.02	84.72	0	8.32	7.09	12.09	51.46	19.34	1086.49	10.39
OC	79.64	14.18	2.34	56.00	0	16.37	17.56	11.73	46.68	34.44	2281.04	22.96
CH_4	12628.16	336.87	41.00	5130.69	5	2194.01	4234.34	6619.31	4462.78	24854.27	382855.53	3876.88
N_2O	113.55	6.31	0.68	47.96	0	19.16	14.67	7.16	77.23	85.12	3656.10	22.24
CO_2	7728132	855909	86673	2570491	713	1065870	797544	542386	3947253	1835912	177494631	2236042
CO_2 (w/ C in VOC & CO)	7735414	858018	87096	2575129	713	1067235	805223	548603	3952747	1847411	177685671	2270389
GHGs	8144349	869795	88505	2741759	1971	1138132	936140	749080	4107097	2615597	190140203	2392589

Table 24 summarises the energy consumption and emissions of various material products for power plant infrastructure, mainly retrieved from the GREET model. The mineral wool data was obtained from [49]. With these data, the plant cycle energy demand and emissions for the GAPG system were calculated in Table 25 and compared with those of the coal-fired power plant and stand-alone EGS plant. The results show that the infrastructure of GAPG system and EGS plant incurs much greater emissions and energy consumption than the coal plant. In addition, compared with EGS plant, the GAPG system infrastructure requires 58% - 65% less water and produces 17% - 29% less GHGs emission.

4.4.2 Fuel cycle

For the fuel cycle of GAPG system, its energy usage is mainly geothermal heat calculated at 24.3 – 51.2 GJ/MWh with a water consumption at 3,781 litres/MWh and zero emissions (See Table 26). Therefore, it can be said that GAPG system is an even cleaner energy technology than EGS plant primarily owing to the less emissions related to the infrastructure. Table 26 also compares the fuel cycle energy usage and emissions of the GAPG system with those of the coal-fired power plant and stand-alone EGS plant. It can be seen that the total energy input of the GAPG system under the booster mode BT-3km is about 28% less than the stand-alone EGS plant given a similar resource temperature of 150°C, yet about 3 times as much as that of the coal plant. This is due to the greater geothermal-to-power conversion efficiency of the GAPG system than EGS plant. Also, the coal plant uses a higher quality fuel (coal) than the GAPG and EGS plants, whose fuel (geothermal heat) is of substantially lower quality. However, fuel cycle emissions are much greater for coal plant and negligible for GAPG and EGS plant.

Table 25: The plant cycle energy usage and emissions for the GAPG system per MWh of electricity available at user sites (wall outlets).

Energy and emissions associated with plant cycle	GAPG system			EGS plant	Coal-fired power plant
Energy Use: GJ per MWh	BT-2km	BT-3km	BT-5km		
Total energy	0.24	0.20	0.23	0.25	0.010
Fossil fuels	0.22	0.19	0.21	0.22	0.009
Coal	0.13	0.11	0.12	0.12	0.006
Natural gas	0.05	0.04	0.04	0.06	0.003
Petroleum	0.04	0.04	0.05	0.05	0.000
Water consumption, litre per MWh	35.79	29.82	33.36	85.28	2.799
Total Emissions: gram per MWh					
VOC	16.23	12.88	14.19	14.34	0.854
CO	118.17	94.52	104.34	102.31	5.743
NO_x	18.29	16.40	18.78	22.21	0.871
PM_{10}	9.81	8.04	8.95	10.07	0.528
$PM_{2.5}$	4.72	3.89	4.34	4.95	0.244
SO_x	57.70	46.00	50.73	55.27	2.974
BC	0.08	0.07	0.08	0.12	0.005
OC	0.20	0.18	0.20	0.28	0.010
CH_4	26.98	21.71	24.02	29.86	1.355

N_2O	0.17	0.15	0.16	0.22	0.008
CO_2	17,583	15,203	17,212	21,452	837
CO_2 (w/ C in VOC & CO)	17,818	15,392	17,421	21,660	849
GHGs	18,673	16,081	18,184	22,614	892

Table 26: The fuel cycle energy usage and emissions for the GAPG system per MWh of electricity available at user sites (wall outlets).

Energy and emissions associated with fuel cycle	GAPG system			Coal-fired power plant	EGS plant (T_{geo} = 150°C)
Energy Use: GJ per MWh	BT-2km	BT-3km	BT-5km		
Total energy	51.2	30.7	24.3	10.73	42.4
Fossil fuels	0	0	0	10.73	0
Coal	0	0	0	10.53	0
Natural gas	0	0	0	0.03	0
Petroleum	0	0	0	0.16	0
Water consumption, litre per MWh	3,781	3,781	3,781	1,667	3781
Total Emissions: gram per MWh					
VOC	0	0	0	83.59	0
CO	0	0	0	87.23	0
NO_x	0	0	0	2,294.41	0
PM_{10}	0	0	0	107.57	0
$PM_{2.5}$	0	0	0	59.52	0
SO_x	0	0	0	4,898.18	0
BC	0	0	0	2.82	0
OC	0	0	0	6.34	0
CH_4	0	0	0	1,482.78	0
N_2O	0	0	0	16.08	0
CO_2	0	0	0	904,260	0
CO_2 (w/ C in VOC & CO)	0	0	0	904,662	0
GHGs	0	0	0	953,407	0

It should be mentioned that the energy and emission data in Table 26 for the coal plant was calculated by considering both feedstock and fuel. The detailed energy and emission data associated with feedstock and fuel consumption for the coal plant is given in Table 27 [21, 50].

Table 27: Detailed energy and emission data for coal plant including both feedstock and fuel consumption.

Parameters	Feedstock	Fuel
Total energy, kJ per MWh	227,106	10,506,641
Fossil fuels	218,986	10,506,641
Coal	23,642	10,506,641
Natural gas	33,366	0

Petroleum	161,977	0
Water consumption, litres per MWh	146.77	1,520
Emissions, grams per MWh		
VOC	74.63	8.96
CO	28.77	58.46
NO_x	134.41	2160
PM_{10}	87.57	20
$PM_{2.5}$	14.46	45.06
SO_x	68.18	4,830
BC	0.88	1.94
OC	2.69	3.65
CH_4	1,472.28	10.50
N_2O	0.32	15.76
CO_2	16,260	888,000
CO_2 (w/ C in VOC & CO)	16,538	996,301
GHGs	60,790	1,000,792
Solid waste	-	117,000

4.4.3 Overall performances and implication

Table 28 shows the total energy, water and emission data of the GAPG system including both the plant and fuel cycles, which are compared to those of the coal plant and stand-alone EGS plant. The results show that the GAPG system operating under the booster modes BT-3km and BT-5km consumes less geothermal energy per MWh of the delivered electricity than the stand-alone EGS plant. And it requires about 2.3 times of the water demand of a coal-fired power plant. The total GHGs emissions of the GAPG system, however, were found to be up to 29% less than the emissions in the stand-alone EGS plant and 98.3% less than the emissions in a coal plant. This thus becomes a clear evidence that leaves GAPG system to be the technology with the least impact on the environment. Specifically, if the geothermal resources are to be utilised in a GAPG system in replace of an EGS plant, the following environmental benefits can be realised: a reduction of about 6.3 kg/MWh of CO_2 emission; a reduction of about 7.8 g/MWh of CO emission; a reduction of about 5.8 g/MWh of NO_x emission; a reduction of about 9.0 g/MWh of SO_x emission; a reduction of about 2.0 g/MWh of PM_{10} particulate matter; a reduction of about 1.0 g/MWh of $PM_{2.5}$ particulate matter; and a reduction of about 8.1g/MWh of CH_4 emission.

Table 28: Total energy, water and emission data of the GAPG system compared to those of the coal plant and stand-alone EGS plant.

Summarised LCA performances	GAPG system			Coal-fired power plant	EGS plant (T_{geo} = 150°C)
Energy Use: GJ per MWh	BT-2km	BT-3km	BT-5km		
Total energy	51.42	30.89	24.49	10.74	42.63
Fossil fuels	0.22	0.19	0.21	10.73	0.22
Coal	0.13	0.10	0.11	10.54	0.12
Natural gas	0.05	0.04	0.05	0.04	0.06
Petroleum	0.04	0.04	0.05	0.16	0.05
Water consumption, litre per MWh	3,817	3,811	3,815	1,670	3,867
Total Emissions: gram per MWh	-	-	-	-	-
VOC	16.22	12.88	14.19	84.44	14.34
CO	118.17	94.52	104.34	92.97	102.31
NO_x	18.29	16.41	18.78	2,295.28	22.21
PM_{10}	9.81	8.04	8.95	108.10	10.07
$PM_{2.5}$	4.72	3.89	4.34	59.76	4.95
SO_x	57.69	46.00	50.73	4,901.15	55.27
BC	0.08	0.07	0.08	2.82	0.12
OC	0.20	0.18	0.20	6.35	0.28
CH_4	26.98	21.71	24.02	1,484.13	29.86
N_2O	0.17	0.14	0.16	16.09	0.22
CO_2	17,582	15,203	17,212	905,097	21,452
CO_2 (w/ C in VOC & CO)	17,819	15,392	17,421	905,511	21,660
GHGs	18,672	16,081	18,184	954,299	22,614

On the other hand, there are even more significant environmental benefits if the electricity we consumed from the wall socket is produced from GAPG system rather than coal-fired power plants. Table 29 illustrates the energy and emission saving potentials of the GAPG system compared to coal-fired power generation using Bayswater power station as a showcase. According to the technical analysis, the GAPG system implemented in Bayswater power station can produce about 191,826 MWh/year, 594,961 MWh/year, and 1,010,632 MWh/year for the booster modes, BT-2km, BT-3km, and BT-5km, respectively. This would translate into the potential savings in terms of energy and emissions cut, as presented in Table 29, when compared to the electricity generated using coal.

Table 29: Energy and emission savings if electricity is sourced from GAPG technology rather than coal.

Potential saving	GAPG system		
Energy Use: TJ per year	BT-2km	BT-3km	BT-5km
Total energy	-7,802	-11,989	-13,890
Fossil fuels	2,017	6,276	10,637
Coal	1,997	6,208	10,534
Natural gas	-3	-4	-11
Petroleum	24	72	114

Water consumption, tonne/year	-411,977	-1,274,219	- 2,168,039
Total Emissions: tonne/year			
VOC	13	43	71
CO	-5	-1	-11
NO_x	437	1,356	2,301
PM_{10}	19	60	100
$PM_{2.5}$	11	33	56
SO_x	929	2,889	4,902
BC	1	2	3
OC	1	4	6
CH_4	280	870	1,476
N_2O	3	9	16
CO_2	170,249	529,453	897,325
CO_2 (w/ C in VOC & CO)	170,283	529,587	897,533
GHGs	179,478	558,203	946,068

*. Negative value means either more energy and resources are needed or more emissions are produced.

For a better understanding of the life-cycle environmental impact of the GAPG technology on NSW power grid, it can be further calculated from Table 29 that, over a 10-year period, the GAPG concept will likely lead to the following benefits for the Bayswater power plant alone: (i) avoided fossil fuel consumptions including up to 4.7 million tonnes of coal and 1,140 TJ equivalent petroleum; (ii) cost savings of about $147.5 million due to reduced coal usage, (iii) an estimated reduction in GHGs emissions of up to 9.5 million tonnes, and a revenue of the associated carbon tax/credit at $238 million assuming a carbon price of $25/tonne, (iv) reduction in sulphur dioxide emissions of up to 49,020 tonnes, nitrogen oxide emissions of up to 23,010 tonnes, methane emissions of up to 14,760 tonnes, nitrous oxide emissions of up to 160 tonnes, combined PM10 and PM2.5 particulate matter of about 1,560 tonnes as well as reductions in heavy metals, volatile organic compounds, black carbon, and organic carbon of up to 800 tonnes in total.

5 Conclusions

In this study all major NSW coal-fired power stations were investigated regarding their potentials for a successful GAPG integration using geotheraml HDR resources via the merit index evaluation. The project also enables the identification and quantification of technoeconomic and environmental benefits of GAPG technology for NSW, Australia. It was found that Bayswater and Eraring power stations held the best potentials for GAPG technology primarily due to the high quality geothermal resources within 20 km, abundant coal reserves, high plant availability, large achievable GAPG capacity and reasonable plant lifetime. In contrast, the MT Piper, Liddell and Vales Point B power stations were found to be less favorable owing to either an aging plant, an unstable coal reserve, or a poor geothermal resource quality. Geothermal energy resources in NSW especially surrounding the coal-fired power plants were characterised for three specific drilling depths, 2km, 3km, and 5km. The geothermal gradient across the area was found to be unevenly distributed and not always linear with drilling depth. The maximum acheiveable well head temperature was estimated to be about 184°C for a wellbore temperature of 191°C at 5 km depth and 15 km west of Bayswater power station.

Thermodynamic study shows that the optimum pipeline configration is the use of a single return pipeline with a 101.6 mm-thick mineral wool insulation. The geothermal heat exchanger was found to be better located near the geothermal field, rather than the coal plant, to minimize heat losses, pressure drop, and brine corrosion. At flowing conditions, the temperature loss of the transported fluid in the insulated pipelines was found to be in the range of 0.01-0.40°C/km and, for uninsulated pipes, the temperature loss amounts up to 1-2°C/km. In addtion, the maximum achievable well head temperature poses a practical limitation on the various hybridisation options that may be achievable by GAPG concept. The scope of the hybridisation options has to be narrowed down to mainly replace the bled steam from the last couple of stages of the intermediate turbine and all stages of the low pressure turbine. The booster mode that yields additional power generation is expected to be more appealing for the industry than the fuel saving mode.

Both the practical and theoretical maximum benefits that GAPG technology can bring to NSW coal-fired power plants were calculated. Under the fuel saving mode, up to 325 thousand tonnes of coal per year for Bayswater power station only, and up to 1.2 million tonnes of coal per year for NSW coal plants, could be potentially saved. However, the practically achievable coal savings were calculated to be only 54% - 81% of the theoretical values, which reduces the total coal savings for NSW coal plants by about 31% down to 826 thousand tonnes each year. This is owing to the low operating capacity factor of coal plants, which is contributed by a combination of factors such as weak market demand, aging, and reliability issues. Under the booster mode, the total additional clean power generation was calculated to be up to 3,139 GWh/year. Again, the practically achievable figure is only 71% of the theoretical value, namely, 2,224 GWh/year.

The technical analysis showed that after the GAPG integration, the Bayswater hybrid plant can produce up to 6.3% more electricity or 5.6% fuel saving when compared with the reference case. These are obtained after considering the heat losses and power consumption in the geothermal pipeline system and translate into up to a net efficiency uplift of about 6.5% and an emission intensity reduction of about 6%. Similarly, for the Eraring hybrid plant, the maximum net boosted power is 5.7% of the reference level and the fuel saving obtainable is 4.9%, resulting in a net efficiency uplift of about 5.8% and an emission intensity reduction of about 5.4%.

The economic analysis consists of a capital cost analysis, a LCoE calculation, and a cash flow analysis. The capital cost analysis showed that the total installed cost of GAPG system was between \$350 million – \$650 million for the Bayswater plant and \$210 million – \$500 million for the Eraring plant depending on which operating mode is employed. Of the total installed cost, the well development cost is the single largest investment reaching 57% for the low hybridisation level (BT-2km or FS-2km), and up to 84% for the high hybridisation level (BT-5km or FS-5km). The second largest investment is the pipeline system, accounting for 10-22% for a resource distance of 10 km and 15-30% for a resource distance of 20 km. The heat exchanger takes the next biggest investment proportion ranging from 4-12% depending on the required heat duty of the exchanger. It also turns out that the costs of plant modification, feedwater pump, and production and injection system are insignificant compared to other major cost items and takes less than 4% altogether.

With an assumed plant lifetime of 25 years, the LCoE of the hybrid plant and the LCoE of geothermal conversion were obtained. The LCoE of the hybrid plant were found to be approximately 0.04 - 0.32 cents/kWh greater than that of the coal plant regardless of carbon price. This finding is reasonable since the costly HDR resources, rather than low-cost hydrothermal resources, were involved in GAPG system. This directly contributed to a lifted LCoE of the whole plant and the coal plant itself was still the cheapest way of generating electricity owing to the low marginal cost of coal resources. Even after imposing a carbon tax penalty at 20$/tonne, the conclusion remains the same and the LCoE after carbon tax was found to increase by about 1.7 cents/kWh. On the other hand, the minimum LCoE of geothermal conversion for the Bayswater power station was found to be 17.5 cents/kWh, 8.6 cents/kWh, and 7.1 cents/kWh for the drilling depths of 2 km, 3 km, and 5 km, respectively. These numbers increase to 39.5 cents/kWh, 15.0 cents/kWh, and 7.4 cents/kWh, respectively for Eraring power stations. The locations of the geothermal resources for achieving those minimum LCoE were also identified.

The cash flow analysis told a different story by showing that with revenues from electricity sales and proper economic incentives, the Bayswater hybrid plant under the booster modes BT-3km and BT-5km was found to generate an extra NPV of $170 million and $499 million, respectively at the end of the project lifetime when compared to that of the business-as-usual case (i.e. the coal plant). That is about $7 million - $20 million of profit gain each year. The Eraring hybrid plant under the booster mode BT-5km was also found to generate an excess NPV of $397 million, or a profit gain of $16 million/year. Nevertheless, the booster mode BT-2km, due to a low hybridisation extent and thus a weak thermodynamic boost, was found to be uneconomical. Under the fuel saving modes, the hybrid plants were also found to be unviable largely due to the low cost of fuel and low emission penalty (thus making little economic sense to reduce coal consumption). This is in addition to the complexity and prolonged installation period associated with boiler modification under the fuel saving mode. At last, the areas where the GAPG technology could produce excess net profit gain were visualised in several reference maps for both Baywater and Eraring power stations within the 40 km range. These areas are also the recommended places to deploy GAPG system in order to gain the best chance of success in commercialisation.

Under the typical operating and economic conditions, the minimum payback period for GAPG technology was found to be 10.2 years for the location at 15 km west of Bayswater plant with a drilling depth of 5 km, and 11.5 years for the Eraring plant at the location of 10 km south with a drilling depth of 5 km. Under non-typical conditions, a sensitivity analysis was performed to evaluate the impact of each key parameter on the performances of GAPG technology. It was found that within the examined range of conditions a payback period less than 5 years was found to be less likely for GAPG technology. In addition, plant availability was found to be the most critical factor that affects the LCoE of the hybrid plant, followed by single well productivity and discount factor. With a carbon tax imposed, the carbon tax then becomes the overwhelming factor that affects the LCoE of the hybrid plant, followed by plant availability. Other factors such as modification period of coal plant and pipeline insulation thickness were found to have limited impact on the LCoE of the hybrid plant. For the LCoE of geothermal conversion, the study suggested that the three most critical factors are the single well productivity, discount factor and plant availability. Therefore, a low discount factor, a high plant availability and a high single well productivity can be the most favourable conditions for the GAPG technology to success. The profitability or payback period of GAPG technology was found to be greatly affected by, from high impact to low impact, plant availability, discount factor, electricity wholesale price and RECs. Other parameters like carbon tax, modification period, and pipeline insulation thickness were found to be less influential on the project.

We also simulated the GAPG system for Bayswater power station under four levels of government policy support, mainly through the carbon price and RECs, from pessimistic to extremely optimistic conditions. The reference maps for viable GAPG deployment within the 40 km range of Baywater power station were obtained for three booster modes. The results showed the profitable areas expanded greatly when the level of government policy support is enhanced. On average, an increase of carbon tax at 20 $/tonne and RECs at 25 $/MWh was found to improve the profitability of GAPG technology by $8.4 million/year and $14.7 million/year for the booster mode operation, BT-3km and BT-5km, respectively. The findings clearly indicate the importance of government policies in leading industry on the road of emission reduction and the adoption of clean energy technologies such as GAPG concept.

The research also shed light on the superiority of GAPG techonology over SAPG counterpart using benchmarking analysis based on their integrations with the Bayswater power stations. Although using solar as a high-quality energy source, the SAPG system was found to produce only 21% -31 % of the additional electricity achievable for GAPG system on an annual basis. The intermittent nature of solar energy and the high cost of solar field were identified as the key drawbacks of the SAPG technology, and with a capacity factor of only 14.5% the SAPG system was found to be unable to payback itself within even 30 years. The base load characteristic of GAPG technology clearly exhibits a key advantage against its counterpart and the payback period was found to be 11 – 16 years for GAPG system under the typical conditions. The LCoE of clean power production, i.e. converting solar thermal energy to electricity, was calculated to be 23 – 39 cents/kWh. This is about twice to triple of the LCoE of geothermal-to-electricity in GAPG system. In conclusion, SAPG technology was found in this benchmarking study to be an unviable and less favourable business option.

Lastly, a life cycle assessment was performed for the GAPG system to evaluate its energy, materials consumptions and environmental impact. It consists of plant cycle and fuel cycle assessments. The plant cycle assessment deals with the processes from raw material production to the installation, construction, and commissioning of the plant. The GAPG system was found to reduce the material usages by 3,155 tonnes/TWh or 26.6% compared to that of the equivalent stand-alone EGS plant. This is owing to the 17.4% reduction of steel usage and 100% reduction of aluminium, concrete and iron usages that would otherwise be required for constructing the power block. This translates into 58% - 65% less water consumption and 17% - 29% less GHGs emission compared to the EGS plant. Nevertheless, the infrastructure of both the GAPG system and EGS plant was found to incur much greater emissions and energy consumption than the coal plant. On the other hand, the fuel cycle assessment that deals with energy, fuel and feedstock when operating the plant showed that the GAPG system consumed about 24.3 – 51.2 GJ/MWh of geothermal energy, 3,781 litres/MWh of water resources, and produced zero emissions. This is compared to the great GHGs emission obtained for the coal plant as a result of both feedstock and coal consumption. Overall, the total water demand of the GAPG system was calculated to be about 3,814 litres per MWh, which is about 2.3 times of that of the coal plant and 1.4% less than that of the stand-alone EGS plant. This is mainly owing to the water requirement in the hydraulic fraction process, while the Bayswater plant uses much less water since it can source water from the Hunter river. In addition, the total GHGs emissions of the GAPG system were found to be up to 29% less than the emissions in the stand-alone EGS plant and 98.3% less than the emissions in a coal plant. This thus testifies that GAPG is the technology with the least impact on the environment. Specifically, when compared to a EGS plant, the GAPG technology can help to achieve a series of environmental benefits, including a reduction of about 6.3 kg/MWh of CO_2 emission; a reduction of about 7.8 g/MWh of CO emission; a reduction of about 5.8 g/MWh of NO_x emission; a reduction of about 9.0 g/MWh of SO_x emission; a reduction of about 2.0 g/MWh of PM_{10} particulate matter; a reduction of about 1.0 g/MWh of $PM_{2.5}$ particulate matter; and a reduction of about 8.1g/MWh of CH_4 emission. When compared to the power produced from a coal-fired power plant, using GAPG technology can help to achieve even greater environmental benefits: namely, for the Bayswater power plant alone and over a 10-year period: (i) avoided fossil fuel consumptions including up to 4.7 million tonnes of coal and 1,140 TJ equivalent petroleum; (ii) cost savings of about $147.5 million due to reduced coal usage, (iii) an estimated reduction in GHGs emissions of up to 9.5 million tonnes, and a revenue of the associated carbon tax/credit at $238 million assuming a carbon price of $25/tonne, (iv) reduction in sulphur dioxide emissions of up to 49,020 tonnes, nitrogen oxide emissions of up to 23,010 tonnes, methane emissions of up to 14,760 tonnes, nitrous oxide emissions of up to 160 tonnes, combined PM10 and PM2.5 particulate matter of about 1,560 tonnes as well as reductions in heavy metals, volatile organic compounds, black carbon, and organic carbon of up to 800 tonnes in total.

6 Recommendations

The following recommendations are made for any future work:

- Benchmarking study with SAPG system can extend to employ cost-effective energy storage system to increase the capacity factor for solar and thereby increase energy output at a reasonable price.
- The GAPG advanced economic model can be further expanded to include more widely applicable conditions and improved in technical details by using more rigorous equations and correlations
- A demonstration project is essential for GAPG concept and, upon successful, it can provide risk relief for investors and help initiate more GAPG projects.
- A critical factor when operating the GAPG system is to ensure the reliability and security of the existing asset. The GAPG system should be operated as independently as possible, be easily integrated and isolated, and allow for a reverse of operation back to the original plant when things go wrong.

7 References

[1] Geoscience Australia. Onshore energy security program. 2008. Available from: http://www.ga.gov.au/energy/geothermal-energy-resources.html.

[2] DiPippo R. Geothermal power plants: principles, applications and case studies. UK: Elsevier Advanced Technology; 2005.

[3] Zhou C, Doroodchi E, Moghtaderi B. An in-depth assessment of hybrid solar-geothermal power generation. Energy Conversion and Management. 2013;74:81-101.

[4] Geoscience Australia and ABARE. Australian energy resource assessment. 2010. Available from: Http://adl.brs.gov.au/data/warehouse/pe_aera_d9aae_002/aeraCh_07.pdf.

[5] White DH, Goldstone LA. Potential of hybrid geothermal/coal fired power plants in Arizona [Internet]. Research report [OSTI ID: 6549806; Legacy ID: DE83005310]. 1982. Available from: http://www.osti.gov/energycitations/servlets/purl/6549806-qJSmT3/native/.

[6] Anno GH, Dore MA, Grijalon RL, Lang GD, Thomas FJ, editors. Hybrid geothermal/fossil power plants: a site specific analysis. Greater Los Angeles Area Energy Symp; 1978 May 23; USA.

[7] Dipippo R, Kestin J, Khalifa HE. Hybrid fossil-geothermal power plants. Technical paper: American Society of Mechanical Engineers; 1977. Report No.: 77 -WA/Ener-2. Contract No.: 04021215.

[8] Erlingsson T, Thorhallsson S, editors. Long distance transmission pipelines for geothermal waters in iceland (20-60 km). Workshop for Decision Makers on Direct Heating Use of Geothermal Resources in Asia; 2008 May 11-18; Tianjin, China.

[9] International Geothermal Association. What is geothermal energy. 2004. Available from: http://www.geothermal-energy.org/geothermal_energy/what_is_geothermal_energy.html.

[10] Parsons Brinckerhoff, ARENA. Hybridisation of Fossil Fuel Energy Generation in Australia; 2013. Contract No.: 2158936A-POR-RPT-002 RevG.

[11] Johnson LH, Couchman RS, Spencer Jr. RC, Booth JA, Holman RJ, inventors; General Electric Company. Method for operating a steam turbine with an overload valve. United States. 1983.

[12] Kestin J, DiPippo R, Khalifa HE. Hybrid geothermal-fossil power plants. Mechanical Engineering. 1978;100(12):28-5.

[13] Khalifa HE, DePippo R, Kestin J. Hybrid fossil-geothermal power plants. Proceedings of the 5th Energy Technology Conference; 1978 Feb 27-Mar 1; Washington, DC, USA. Gov Inst, Inc; 1978. p. 960-70.

[14] Bruhn M. Hybrid geothermal-fossil electricity generation from low enthalpy geothermal resources: geothermal feedwater preheating in conventional power plants. Energy. 2002;27(4):329-46.

[15] Bruhn M. Power production from geothermal-fossil hybrid power plants may help the environment. Elektrizitaetswirtschaft. 1999;98(24):36-8.

[16] Buchta J, editor. Green power from conventional steam power plant combined with geothermal well. 2009 IEEE International Conference on Industrial Technology; 2009 Feb 10-13; Gippsland, VIC, Australia. Piscataway, NJ, USA: IEEE; 2009.

[17] Buchta J, Wawszczak A, editors. Economical and ecological aspects of renewable energy generation in coal fired power plant supported with geothermal heat. 4th IEEE Electrical Power and Energy Conference: "Sustainable Energy for an Intelligent Grid", EPEC 2010; 2010 Aug 25-27; Halifax, NS, Canada. IEEE Computer Society; 2010.

[18] Hu E. Original design of the heat and mass balance of the Liddel power cycle. Via personal communication. 2013 [cited]. Available from.

[19] Zhou C, Doroodchi E, Moghtaderi B. Assessment of geothermal assisted coal-fired power generation using an Australian case study. Energy Conversion and Management. 2014;82:283-300.

[20] Zhou C, Doroodchi E, Moghtaderi B, editors. Geothermal assisted coal-fired power generation: an Australian case study. World Renewable Energy Congress 2013 proceedings; 2013; Perth, Australia.

[21] Brown P, Cottery A, Searles M, Wibberley L, Scaife P. A life cycle assessment of the New South Wales electricity grid (year ending 2003). Pullenvale, Qld; 2006. Available from: http://nla.gov.au/nla.cat-vn4397247.

[22] ACIL Tasman, Fuel resource, new entry and generation costs in the NEM-final report. 2009. Available from: http://www.aemo.com.au/planning/419-0035.pdf.

[23] ACIL Tasman, Preparation of energy market modelling data for the Energy White Paper. 2010. Available from: http://www.aemo.com.au/planning/0400-0019.pdf.

[24] Higginson K, Lachlan A, Zambelli V, Boyle J, Cartmill I. Feasibility Study For a Parabolic Trough Solar Collector to Drive a 10kW Electricity Generator; 2010. Contract No.: N/A. University of Queensland.

[25] Khalifa HE, DiPippo R, Kestin J, editors. Geothermal preheating in fossil-fired steam power plants. Proceedings of the 13th Intersociety Energy Conversion Engineering Conference; 1978 Aug 20-25; San Diego, CA, USA. Warrendale, PA, USA: Soc. Automotive Engrs; 1978.

[26] Sinnott RK. Coulson and Richardson's chemical engineering volume 6 - chemical engineering design. 4th ed.: Elsevier; 2005.

[27] Beggs HD, dan Brill JP. A Study of Two Phase Flow in lnclined Pipe. Journal of Petroleum Technology. 1973;May:607-17.

[28] California Energy Commission. New geothermal site identification and qualification- final report. California Energy Commission, Sacramento, CA; 2004. Available from: http://www.osti.gov/energycitations/servlets/purl/897111-uaYN4E/.

[29] U.S. Department of Energy. The future of geothermal energy-impact of enhanced geothermal systems (EGS) on the United States in the 21st century. U.S. Department of Energy; 2006. Available from: http://www1.eere.energy.gov/geothermal/future_geothermal.html.

[30] Renewable Energy and Power Department, Idaho National Laboratory. The future of geothermal energy-impact of enhanced geothermal systems (EGS) on the united states in the 21st century. U.S. Department of Energy; 2006. Available from: http://www1.eere.energy.gov/geothermal/future_geothermal.html.

[31] Young KR, Augustine C, Anderson A, editors. Report on the U.S. DOE geothermal technologies program's 2009 risk analysis. Thirty-Fifth Workshop on Geothermal Reservoir Engineering; 2010 February 1-3, 2010; Stanford University, Stanford, California, USA.

[32] Dunn P. Baseline system costs for 50.0 MW Enhanced Geothermal System - a function of: working fluid, technology, and location. 2011; Available from: http://smu.edu/geothermal/Oil&Gas/2011/Dunn_BaselineSystemCosts50MWEGS_2011.pdf.

[33] Rafferty KD. Piping. 1998; 19(1)Available from: http://geoheat.oit.edu/ghcindex.htm#geores.

[34] Parker NC. Using natural gas transmission pipeline costs to estimate hydrogen pipeline costs. Institute of Transportation Studies, University of California; 2004. Available from: http://pubs.its.ucdavis.edu/publication_detail.php?id=197.

[35] Donald RW. Appendix D: Capital Cost Guidelines. Rules of Thumb in Engineering Practice; 2007. p. 376-436.

[36] Dagdas A. Heat exchanger optimization for geothermal district heating systems: a fuel saving approach. Renewable Energy. 2007;32(6):1020-32.

[37] MIT Energy Initiative. Retrofitting of Coal-Fired Power Plants for CO_2 Emissions Reductions: Massachusetts Institute of Technology; 2009. Contract No.: N/A.

[38] National Renewable Energy Laboratory. Parabolic Trough Collector Cost Update for the System Advisor Model (SAM). United States. Office of the Assistant Secretary of Energy Efficiency and Renewable Energy; 2015.

[39] Zhou C, Shah K, Moghtaderi B. Techno-Economic Assessment of Integrated Chemical Looping Air Separation for Oxy-Fuel Combustion: An Australian Case Study. Energy & Fuels. 2015;29(4):2074-88.

[40] Wade SL, Barry CM, Nelson MD, Gammridge L. Renewable energy map of New South Wales, Version 1.2 (Digital Dataset). Geological Survey of New South Wales, Maitland. Geological Survey of New South Wales, Maitland; 2017. Available from: http://www.resourcesandenergy.nsw.gov.au.

[41] Hadley R. Energy Minister fighting to keep coal fired powered stations going. 2019. Available from: https://www.2gb.com/energy-minister-fighting-to-keep-coal-fired-powered-stations-going/.

[42] Lund JW. Hitaveita reykjavikur and the nesjavellir geothermal co-generation power plant. Geo-Heat Center Quarterly Bulletin. 2005.

[43] Hannam P. Liddell power plant operating below 40 per cent capacity, faces 'mammoth' woes. 2017. Available from: https://www.smh.com.au/environment/liddell-power-plant-operating-below-40-per-cent-capacity-faces-mammoth-woes-20170907-gycij7.html.

[44] Sukaryadi D, Marza S, F. Dictus B. Heat Exchanger Design on the Geothermal Binary Cycles in Dieng Geothermal Area, Indonesia. Proceedings World Geothermal Congress; 2015 19-25 April 2015; Melbourne, Australia. 2015.

[45] International Renewable Energy Agency. Renewable energy technologies: cost analysis series - concentrating solar power; 2012. Contract No.: N/A.

[46] Sullivan JL, Clark CE, Han J, Wang M. Life-cycle analysis results of geothermal systems in comparison to other power systems; 2010. Contract No.: DE-AC02-06CH11357.

[47] ChemEng Software. Heat exchanger excel model based on Rules of Thumb for Chemical Engineering 5th edition. 2019. Available from: www.chemengsoftware.com.

[48] Lenntech. Goulds 3409 medium capacity, single stage, double suction pump. 2019. Available from: https://www.lenntech.com/Data-sheets/Goulds-3409-L.pdf.

[49] Schmidt A, Clausen AU, Kamstrup O, Jensen AA. Life cycle assessment of three insulation materials. Available from: https://www.irbnet.de/daten/iconda/CIB2853.pdf.

[50] Argonne National Laboratory - Systems Assessment Center. The greenhouse gases, regulated emissions, and energy use in transportation model (GREET model). 2019. Available from: https://greet.es.anl.gov/.

8 Appendices

The following paper has been submitted to Energy Conversion and Management:
Zhou C., Doroodchi E., Moghtaderi B., Techno-economic study of New South Wales coal-fired power plants integrated with geothermal resources within 40 km, 2020, Energy Conversion and Management, under review.
This work was completed by Dr. Cheng Zhou under the supervision of Associate Prof. Elham Doroodchi and Prof. Behdad Moghtaderi. No academic/ professional qualifications were obtained during this project.

SIGN OFF:

I, the undersigned, being a person duly authorised by the Grantee, certify that:
(a) the above information is true and complete:
(b) the expenditure of the Funding received to date has been used solely on the Project; and
(c) there is no matter or circumstances of which I am aware that would constitute a breach by the Grantee or, if
applicable the End Recipient and Subcontractors', of any term of the Funding Deed.

Signature:

Cheng Zhou

Position: Research Associate
Name: Dr. Cheng Zhou (and on behalf of Associate Prof. Elham Doroodchi)
Date: 31/12/2019