PROCEEDINGS, 50th Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 10-12, 2025
SGP-TR-229

Techno-Economics of Direct Use Geothermal Energy in Gippsland, Australia

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Keywords: Australia, Gippsland, direct use, levelized cost of heat

ABSTRACT

The highly productive Lower Tertiary Aquifer (LTA) underlies 6000 square kilometers of the Gippsland region in southeast Australia. Hundreds of meters of lignite and marl of low thermal conductivity cause high thermal gradients above the aquifer, raising the aquifer temperature to above 70°C at less than 1000 meters depth in some locations. The LTA therefore represents a world-class geothermal energy source which could provide low-grade heat for a wide range of industrial processes currently consuming natural gas in Gippsland. But only one geothermal heating system is currently drawing energy from the LTA.

The University of Melbourne has been working with state and municipal governments to investigate the cost, value and barriers to replacing natural gas with geothermal energy for low-grade heat, and to identify potential users and uses for geothermal energy. A techno-economic assessment framework developed by UoM incorporates an assumption of 100% reinjection of cooled groundwater, bespoke drilling cost estimation, pump and (if necessary) heat pump selection, predicted migration of the injected cool plume, likely electricity consumption by pumps and heat pumps, load-following system models, and anticipated maintenance costs to predict the lifetime levelized cost of geothermal heat for comparison against natural gas supply contracts.

Results to date indicate that the only operating geothermal heating system—at a municipal aquatic center where the aquifer is 68°C—provides heat at significantly lower cost than natural gas, and that credible engineering solutions incorporating heat pumps could provide geothermal energy at a levelized cost lower than natural gas at another aquatic center where the aquifer may be only 25°C. The results furthermore demonstrate the techno-economic viability of multi-client heating systems with shared production and injection bores. One barrier to greater uptake is a prevailing regulatory framework that did not anticipate large-scale reinjection of cooled groundwater.

1. INTRODUCTION

1.1 Gippsland and the Lower Tertiary Aquifer

The region of Gippsland in the state of Victoria in southeast Australia has historically been a center for coal mining and electricity generation, agriculture, forestry and natural gas production (DJPR, 2022). Gippsland is divided into six local government areas (Bass Coast, Baw Baw, South Gippsland, Latrobe, Wellington, and East Gippsland) with their main administrative centers at Wonthaggi, Warragul, Leongatha, Morwell, Sale and Bairnsdale, respectively (Figure 1). The Gippsland Basin, named after the region, is an extensional sedimentary basin initiated in the Mesozoic during the breakup of Gondwana (Powell *et al*., 2020). The basin lies mostly offshore but extends onshore beneath about 14,600 km^2 of southeastern Victoria (Yates *et al*., 2015; Figure 1). About 6,000 km^2 of the onshore basin sequence hosts the Traralgon Formation, an Eocene–Oligocene, non-marine sequence primarily comprising highly porous and permeable sands and gravels towards its base; coal seams and clays in its middle; and sand, clay and minor coal at the top (Yates *et al*., 2015). The Traralgon Formation lies unconformably above Lower Cretaceous non-marine arkose and volcaniclastic rocks of the Strzelecki Group, and unconformably beneath Oligocene–Pliocene sediments dominated by thick lignite seams (brown coal) in the west and marls and carbonates in the east (Holdgate *et al*., 2021). The entire region is capped by a thin layer of Holocene gravels (Figure 2).

The Traralgon Formation hosts an extensive regional aquifer defined as the Lower Tertiary Aquifer (LTA) in the Victorian Aquifer Framework (GHD, 2012). The overlying Oligocene–Pliocene lignite deposits provide hundreds of meters of exceptional thermal insulation, which elevates the temperature in the LTA by as much as 30–40°C relative to average geothermal gradients (Rawling *et al*., 2013). Government geologists in Victoria have long pointed to natural hot groundwater in the LTA as a possible source of geothermal energy for industrial heat processes (e.g. Jenkin, 1962; King *et al*., 1987; Driscoll, 2006; Taylor *et al*., 2010; O'Neill *et al*., 2022). Jenkin (1962) was the first to draw attention to "many occurrences of high temperature waters [in boreholes] in East Gippsland", including 70°C water from the LTA at 525 m depth at Maryvale, now within the City of Latrobe (Figure 1). The natural transmissivity of the LTA supports production of at least 100 liters per second from individual bores, as demonstrated by numerous coal mine dewatering systems.

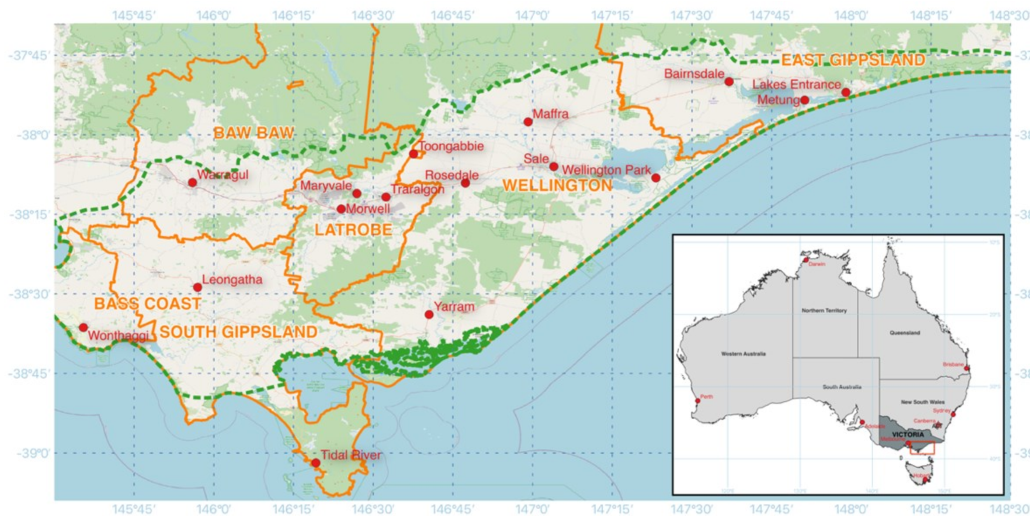

Figure 1: Gippsland in southeast Victoria, Australia, showing cities and towns (red dots), local government areas (orange), and the onshore extent of the Gippsland Basin (green dashes).

1.2 Economic drivers for decarbonization

The state of Victoria, and Gippsland in particular, has historically enjoyed access to cheap and plentiful energy sources in the form of lignite (brown coal) and natural gas. The former has provided most of Victoria's electricity and the latter has delivered industrial heat. The aging fleet of coal-fired power stations is now being retired and the domestic price of natural gas has risen sharply since Australia entered the global liquified natural gas (LNG) market in 2016 (Figure 3). Added to the price increase, gas production from offshore Gippsland is in decline, placing a question mark over long-term energy supply. Several established industries in Gippsland, built under conditions of cheap energy, were therefore already under financial pressure from increased energy prices when Victoria legislated CO_2 emission reduction targets in May 2021 (updated in May 2023); namely emissions reduction of 28–33% by 2025, 45–50% by 2030, 75–80% by 2035, and net zero by 2050, relative to 2005 levels (DEECA, 2023). Industries under the most pressure are those connected with coal mining and combustion for power generation, and those that have historically relied on cheap natural gas as a fuel for industrial heating processes.

The combined pressures of energy price increases, supply risk and legislated emission reduction targets amount to a strong incentive to identify cost-effective, reliable, secure alternative sources of industrial heat. With no government subsidies available for renewable heat projects in Australia, consumers' decisions about heat sources are strongly based on financial considerations. Geothermal energy from the LTA is an obvious contender, but there is little experience or knowledge of geothermal energy utilization within the Gippsland stakeholder community. Burns *et al*. (1995) reported only a single historical use of the geothermal resource in a paper manufacturing mill in Maryvale during the 1950s, which was discontinued in the 1960s when nearby open-pit lignite mining operations greatly lowered the water level in the LTA. Further uses of the LTA as a geothermal heat source were not seriously pursued until Latrobe City Council made the bold decision to provide heat for a new municipal recreational facility—the Gippsland Regional Aquatic Centre (GRAC)—in Traralgon using a geothermal well doublet with 100% reinjection of heat-depleted water. The GRAC opened in early 2021 (Figure 4). In 2022, a private hot spring spa resort—Metung Hot Springs—opened at Metung in the Shire of East Gippsland near the eastern limit of the basin (Figure 1). Metung Hot Springs consumes both heat and water from a single geothermal bore. Successful extraction of geothermal energy from the LTA for those projects, however, has not yet translated into widespread commercial developments of other geothermal energy projects.

1.3 Low grade heat consumers in Gippsland

Our advocacy and research work in Gippsland has identified many existing and potential consumers whose heating requirements could be met by the known LTA geothermal energy source. These include food processing facilities, protected cropping operations, healthcare providers, other aquatic recreation centers, mineral processing plants, chicken farms, meat works, fertilizer plants, and others. Many of those consumers express interest in geothermal energy as a substitute for natural gas in their operations, but wish to know the predicted cost of the heat. That is, will geothermal heat be cheaper than natural gas, biofuels, or other sources of heat over a project lifetime? Prior to the opening of the GRAC in 2021, there were no local examples of geothermal energy production from which to draw conclusions. Even now, there are still just the GRAC and Metung Hot Springs examples with their own characteristics, which cannot be directly extrapolated to other uses.

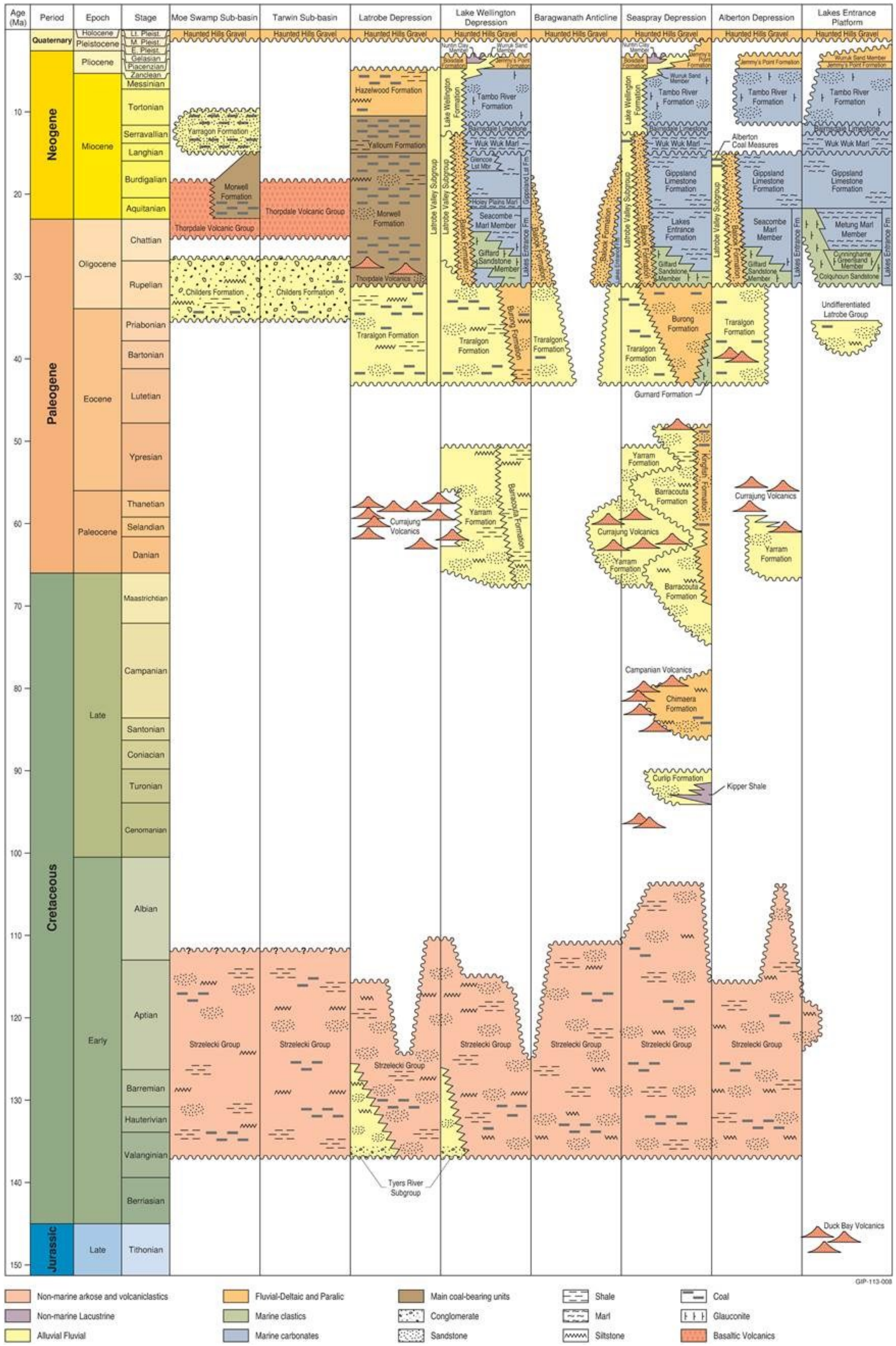

Figure 2: Gippsland Basin onshore stratigraphy. The Lower Tertiary Aquifer is equivalent to the Eocene–Oligocene Traralgon Formation. After Yates *et al*. (2015). Copyright Commonwealth of Australia (http://www.bioregionalassessments.gov.au), reproduced under Creative Commons license CC BY 4.0 (https://creativecommons.org/licenses/by/4.0/legalcode).

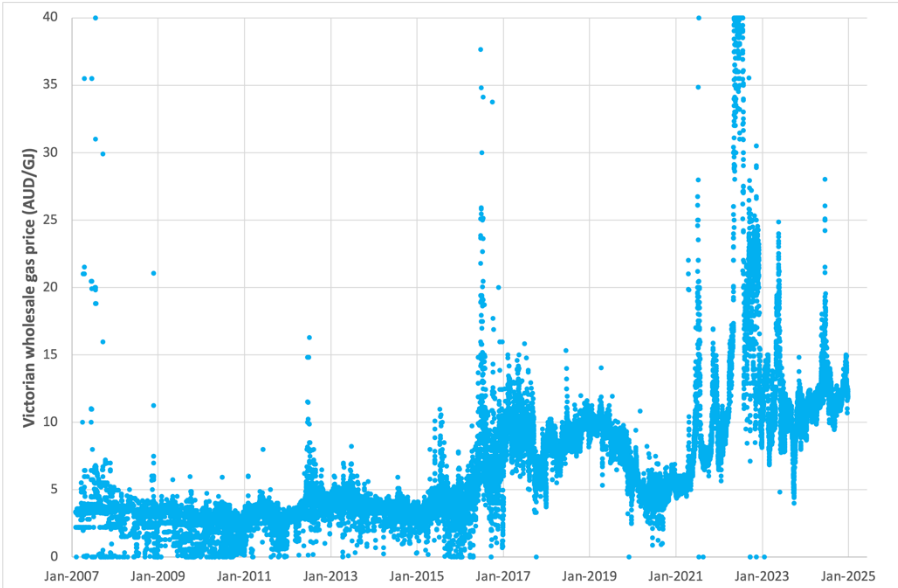

Figure 3: Victorian wholesale natural gas price history since 2007. Data from the Australian Energy Market Operator, accessed 30 January 2025.

Figure 4: The Gippsland Regional Aquatic Centre (GRAC) opened in Traralgon in early 2021. Copyright Destination Gippsland (https://eventvenuesgippsland.com.au/venues/gippsland-regional-aquatic-centre/#gallery), reproduced under Creative Commons license CC BY 4.0 (https://creativecommons.org/licenses/by/4.0/legalcode).

2. TECHNO-ECONOMIC ASSESSMENT FRAMEWORK

2.1 Levelized cost of heat (LCoH)

Given the interest in geothermal energy as a renewable heat source in Gippsland, but the understandable reluctance of potential consumers to make financial commitments to locally unproven geothermal applications, there was a need for a robust, regionally applicable, techno-economic assessment framework to identify technically feasible pathways and estimate the cost of geothermal heating projects across a wide range of locations and possible end-uses. A team to perform such analyses needs to cover subsurface characterization and modelling; borehole design and costing; above-ground engineering and component selection; demand-side energy consumption estimation and modelling; and regulatory compliance. With funding from the State Government of Victoria through the Latrobe Valley Authority and Regional Development Victoria, the University of Melbourne assembled the authors of this paper into a team that spans most of these fields.

The levelized cost of heat (LCoH) provides an objective standard method for comparing the lifetime cost of producing and delivering thermal energy (e.g. gigajoules (GJ) or thermal megawatt hours) from different sources. The heat source with the lowest predicted LCoH based on the knowledge available at the present time effectively represents the most cost-effective heat source. The LCoH calculation employs a discounted cash flow methodology to compare the total cost of a project against the total heat to be produced by the project over its lifetime, with values for future years discounted for the time-value of money and energy (Eq 1).

$$LCoH = \frac{Discounted\ lifetime\ cost}{Discounted\ lifetime\ output} = \frac{\sum_{t=1}^{n} \frac{C_t + M_t + F_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+r)^t}} \quad (1)$$

where t is the year of the project (integer between 1 and n); n is the lifetime of the project (years); C_t, M_t and F_t are the capital costs, operation and maintenance costs, and fuel costs ($), respectively, in year t; H_t is the quantity of heat produced by the project (joules) in year t; and r is the discount rate. The meanings and implications of these parameters are discussed further below.

2.2 Defining a project

All LCoH assessments should be based on well-defined actual or notional projects for which the geothermal energy to be produced and/or consumed by the project over its lifetime can be quantified. The variables for a LCoH calculation for a geothermal heating system can be divided into capital expenses, operations and maintenance expenses, the predicted quantities of heat to be consumed by the consumer(s), and project-specific parameters such as lifetime and cost-of-capital. Each of these can only be confidently estimated after careful consideration of the nature of the geothermal energy source (a role for geoscientists); the characteristics of the energy consuming process (a role for thermal engineers); the design of an appropriate project to deliver the energy where, when and at the rate required (a role for infrastructure engineers); and the required lifetime and likely source of capital for the infrastructure (decisions for the end user.) Our team covers all these domains in consultation with the end users.

Our process begins by understanding the heat demand profile of the process(es) under consideration. This often includes visits to existing sites to examine installed plant components and heat delivery networks if geothermal energy is to replace pre-existing fuel sources. We use energy system modelling software such as nPro Energy (https://www.npro.energy/) and TRNSYS (http://www.trnsys.com/; Figure 5) to design surface systems to deliver geothermal heat from a bore to where the heat is required at the time and rate at which it is required, and to discard cooled water to an injection bore. The software allows us to identify and itemize optimally-sized system components; to define and model their performance including electricity consumption; and to understand the rate at which geothermal water must be produced and injected to meet the project requirements under different injection temperature scenarios.

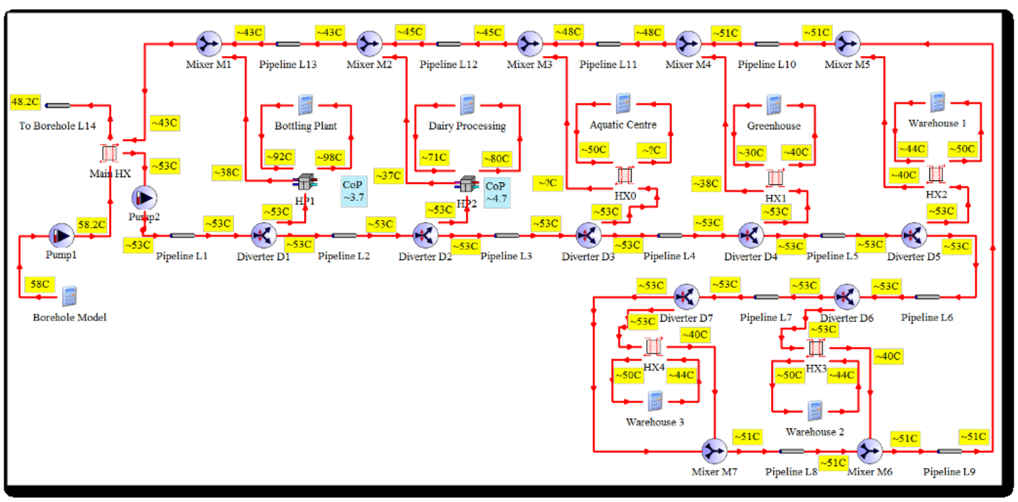

Figure 5: An example of a model constructed in the TRNSYS software, showing system components and predicted fluid temperatures at different locations throughout the geothermal energy delivery network.

In parallel with the surface investigations and modelling, we also examine existing geoscientific information about the Lower Tertiary Aquifer at the location of interest. The Geological Survey of Victoria (GSV) collated and published maps and datasets of the temperature, depth, hydraulic conductivity, thickness and other characteristics of the LTA as part of a major geothermal initiative in 2022 (O'Neill *et al*., 2022; Figure 6). Along with other extensive primary geoscientific datasets in the public domain, GSV's datasets underpin our development of numerical aquifer models. Using software such as DoubletCalc 2D (Veldkamp *et al*., 2015), we interrogate the aquifer models to understand the optimal bore-doublet production and injection screen depths, diameters, lengths and lateral separation to meet the energy production requirements of the project under different assumptions for reinjection temperature.

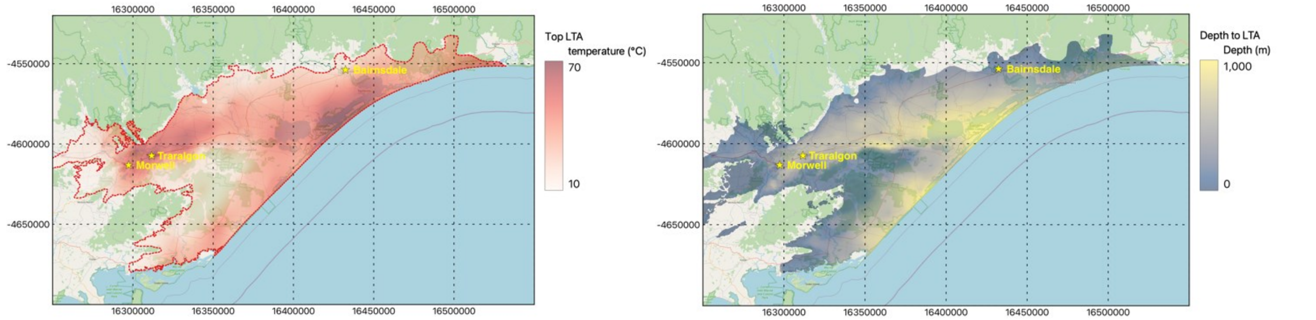

Figure 6: Locations of three case studies on maps of temperature (left) and depth (right) predicted at the top of the Lower Tertiary Aquifer by the Geological Survey of Victoria. Data from O'Neill *et al*. (2022). Coordinates in GDA94 / MGA zone 55.

The outcome of our joint investigations is a design of an interconnected bore doublet and heat delivery system with both surface and subsurface performance modelled for the lifetime of the project. The models predict future heat production and electricity consumption above-ground, and the likely impacts on temperature and pressure within the aquifer over the project lifetime. The outcomes of the coupled models provide values for several of the input parameters for LCoH calculations.

2.3 Lifetime heat demand

LCoH cannot be estimated based only on the characteristics of the geothermal energy source. The LCoH calculation is project-based, so the total amount of thermal energy (heat) to be consumed by the specific process or operation over the project lifetime has a major influence on the LCoH calculation. So, too, does the demand *profile* for the heat; that is, the variation in the demand for heat over different time-scales for the lifetime of the project. A consumer with a relatively constant heat demand (for example, an industrial process operating 24/7 at 60°C) may invest capital on a heat delivery system much more efficiently than a consumer who must build a system capable of meeting peak demand for a process with high daily or seasonal variation (for example, constant heating of an outdoor pool to 28°C). A reliable assessment of LCoH must, therefore incorporate detailed knowledge of the process(es) to which the geothermal energy will be applied. This includes the temperature (°C) and rate (W) at which thermal energy is required by the processes, when the energy is required, and whether there are any constraints on the degree by which the geothermal water can be cooled before reinjection. For example, a process that requires constant heating of 45°C feed-water to 60°C at a constant rate using 65°C geothermal water reinjected at 45°C will have a different engineering solution and geothermal energy demand profile to a process that requires heating of varying-temperature feed-water to 60°C if the reinjected geothermal water must remain above 45°C to manage a risk of scaling. Understanding the thermal energy demands of projects under investigation is the role of thermal engineers within our team.

2.4 Capital costs

2.4.1 General considerations

The cash flow for many renewable energy projects, including geothermal energy projects, is distinguished by high up-front capital investment because intermittent renewable energy sources and geothermal energy sources provide very low cost energy once the initial infrastructure is built and operating. A large proportion of the total cost of a geothermal heating project must be invested at the beginning of the project to build the infrastructure, after which relatively low ongoing costs are incurred to keep the geothermal energy flowing. The main capital expenses for geothermal heating projects include designing, drilling, casing, testing and completing the production and injection bores; purchasing and laying surface pipework; purchasing and installing one or more borehole pumps; purchasing and installing filters if required; purchasing and installing heat exchangers and/or heat pumps if thermal energy is to be transferred to a secondary medium (e.g. water or air) and/or raised to a higher temperature; and designing and constructing facilities to house the equipment. Each of these components can vary markedly in cost depending on the characteristics of the geothermal energy source (depth, temperature, chemical composition, productivity), the nature of the consuming process (size and time of heat demand, temperature of industrial process relative to the geothermal energy source), the planned lifetime of the project, and the location.

2.4.2 Drilling costs

The GSV maps of depth, thickness, temperature and hydraulic conductivity of the LTA (O'Neill *et al*., 2022) provide the geological framework for estimating the drilling cost for production and injection wells into the LTA. As part of the broader state-government-funded investigation of geothermal energy in Gippsland, the University of Melbourne worked with commercial groundwater consultants (EarthEon, Rockwater and GlobalGW) and a Gippsland-based drilling company (DrillTec) to develop an as-yet unpublished algorithm for estimating the cost of drilling into the LTA for any given location and required production rate. The algorithm first estimates the length and diameter of screen required in the LTA to meet the maximum production (or injection) rate for the specific project under consideration. Production and injection wells are considered separately due to different requirements with respect to maximum fluid flow velocities into and out of the formation. The algorithm then determines the design of an appropriate well including intermediate casing sections and pump chamber (if required), and identifies specific cost items for the design. Maximum, minimum and best estimate costs are itemized and added together for drilling, casing, cementing, mobilization/demobilization, materials, labor and fuel, for an estimated total cost range.

2.4.3 Surface pipework

Insulated or uninsulated high-density polyethylene (HDPE) pipe can be used for surface piping when geothermal source water is relatively cool for projects requiring relatively low temperatures or incorporating heat pumps. Such pipes are readily available in Australia. Based on our experience, we estimated the cost to purchase and install such pipework at 500 AUD per meter (1.00 AUD = 0.63 USD in mid-February 2025) for insulated pipe and 100 AUD per meter for uninsulated pipe. Pipework stable at higher temperatures for multi-decadal project lifetimes, however, is currently less-readily available in Australia, so the price must be estimated on a case-by-case basis by direct approach to international suppliers. Such costs are generally significantly higher than the standard local HDPE.

2.4.4 Borehole pumps

Australia enjoys a relatively healthy competitive domestic market for groundwater pumps covering a wide range of production capacities. The choice of pumps is widest for modest production temperatures (<30°C) and production rates (<50 liters per second), but still reasonably broad for higher temperatures and production rates. The market at the higher end is driven by Australia's mining and petroleum industries for dewatering mines and wells. Given the wide range of temperatures and production rates required by different potential geothermal energy projects in Gippsland, borehole pump prices are best sought from suppliers on a case-by-case basis.

2.4.5 Filters, heat exchangers and heat pumps

Similar to pumps, these components can be sourced from open competitive markets in Australia. For example, based on our experience, a standard industrial plate heat exchanger to transfer geothermal energy from groundwater to a secondary circuit would cost about 2000 + (48 x W_{max} x ΔT) AUD, where W_{max} is the maximum geothermal water flow rate (kg/s) and ΔT is the temperature drop (°C) across the heat exchanger. That is, a plate exchanger to take 10°C from a flow of 25 L/s of geothermal water would cost about 14,000 AUD (about 8,800 USD in mid-February 2025). Our experience of the heat pump market allows us to make similar estimates for those components on a case-by-case basis.

2.5 Operation, maintenance and fuel costs

2.5.1 General considerations

Once constructed, operation and maintenance (O&M) costs for geothermal heating projects are relatively low. O&M costs include regular inspection and/or cleaning of bores, filters, heat exchangers and surface pipes; regular inspection and maintenance of borehole pumps; maintenance of surface facilities; unscheduled maintenance; and regulated monitoring and reporting. Like the capital expenses, these O&M costs can vary markedly from project to project depending on size, number and type of physical components, licensing conditions, water quality and other factors. However, they are generally insignificant relative to capital costs and can be estimated as one or two percent of total capital cost on an annual basis.

2.5.2 Electricity costs

The main operational cost for a geothermal heat project is often the electricity to run pumps and/or heat pumps. Electricity consumption is relatively continuous, although it can vary upwards and downwards with heat demand. The components which consume the most electricity are borehole pumps and (if included in a project) heat pumps. The cost of the electricity is a function of the total electricity requirement and the contract the project operator has with the electricity provider. Unlike geothermal power generation projects, geothermal heat projects typically purchase electricity from a third party, so the tariff and terms of the supply contract have a big impact on the total operations cost. The retail electricity market in Australia is regulated to ensure supply, but it is also competitive—the retail price for electricity is not fixed by the government. That means different geothermal heat consumers can (and generally will) pay different rates for the electricity required to run pumps and heat pumps. A robust assessment of LCoH must take into account the details of the electricity supply contract which a consumer has or will have with the electricity retailer. As for other cost components discussed above, these must be considered on a case-by-case basis, usually in consultation with the end-user.

2.5.3 Fuel costs

The variable F_t in Equation 1 represents the cost of combustible fuel. F_t is usually zero for geothermal energy projects, for which no external source of combustible fuel is required. F_t does, however, become relevant for a techno-economic comparison of geothermal energy with other technology options for industrial heat. The most relevant alternative option in Gippsland is natural gas, which is delivered by energy retailers under supply contracts with a wide range of tariffs. Biofuels are also a credible option in some cases.

2.6 Project-specific parameters

We assign appropriate values to project-specific parameters in consultation with the project owners/end users. As evident from Eq 1, LCoH calculations are very sensitive to the values of n (lifetime of the project) and r (discount rate). For projects with similar capital costs, those with longer lifetimes (larger values of n) tend to have lower LCoH values because more energy is produced relative to projects with shorter lifetimes. For the purpose of a LCoH calculation, the lifetime of a project might be constrained by the design life of major capital items, the period of a license to access the geothermal energy resource, a notional period for infrastructure renewal, or some other parameter. 20-, 25- or 30-year lifetimes are typical notional values for 'open ended' projects.

The discount rate (r) has a big impact on LCoH. The discount rate can be thought of as 'weighted average cost of capital' with higher values equating to more expensive capital (e.g. equity partners needing a high rate of return, debt with a high interest rate, public funds diverted from high-value alternative projects, etc.) High discount rates reduce the value of future costs and energy production relative to the initial costs and early production, heighten the financial impact of upfront costs, and result in higher LCoH for projects with high initial capital costs.

The financial structure of a project also affects LCoH from the perspective of individual investors if the costs and energy are shared between different partners. A grant that offsets part of the initial capital cost, for example, would reduce the financial investment required by the developer and/or owner for the same amount of delivered energy, thus lowering the LCoH from their perspective.

2.7 Techno-economic assessment and comparison

Integrating thermal engineering, infrastructure engineering and geoscientific investigations to develop designs and modelling outcomes with project specific parameters delivers many benefits. The process is a virtual pre-feasibility study that provides the developer with confidence that the project is (or is not!) technically feasible, and delivers an effective blueprint for the project. Specific equipment models and/or service providers are identified for key components such as boreholes, pumps, heat exchangers, heat pumps, filters and pipework. Credible LCoH calculations can be completed and compared with LCoH calculations for other industrial heat options.

3. CASE STUDIES

3.1 Gippsland Regional Aquatic Centre (GRAC)

As an operating facility, the GRAC in Traralgon provided an opportunity in 2022 to calculate LCoH and compare it against the price of natural gas for a real geothermal energy project. The pools and buildings of the GRAC are heated by a hydronic system circulating 60°C water. The water circulating in the hydronic system is reheated each cycle by 68°C water from the LTA via a heat exchanger, requiring no heat pumps. Three natural gas furnaces provide a back-up heat source for the hydronic system for times when the geothermal source is offline. A 'SCADA' system continuously monitors and records temperatures at various points in the network (Figure 7).

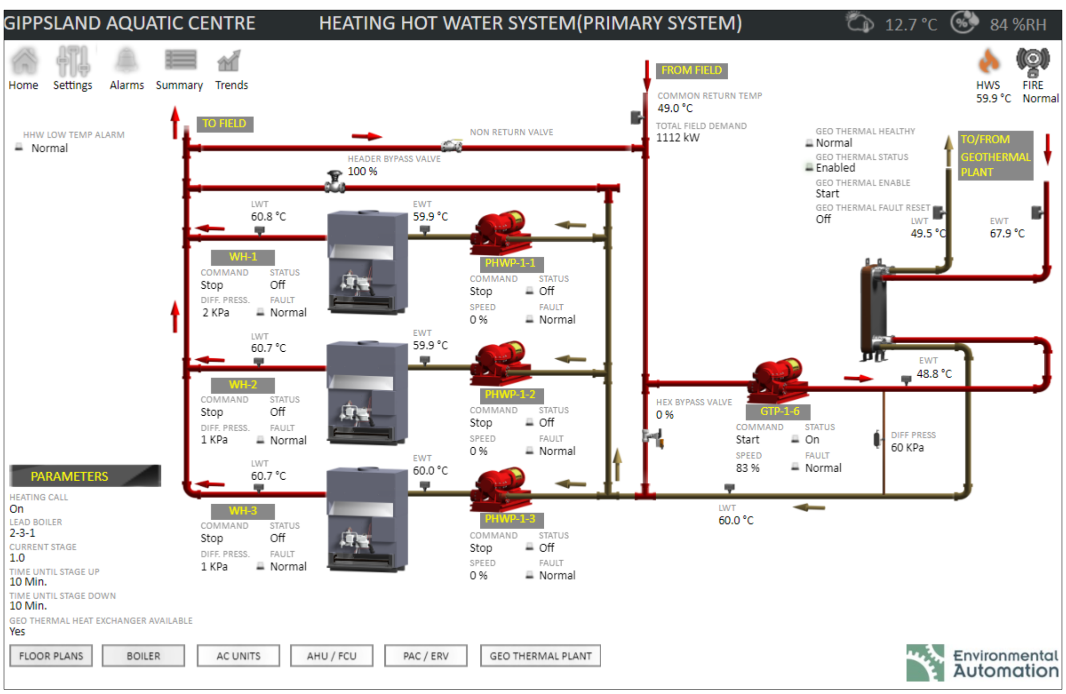

Figure 7: Image from the supervisory control and data acquisition (SCADA) system of the GRAC heating network. The outdoor temperature at the time was 12.7°C, and the geothermal doublet ("geothermal plant") was producing 67.9°C water and reinjecting 49.5°C water. The geothermal energy delivered via a heat exchanger was sufficient to maintain 60.0°C supply to the GRAC's hydronic heating network ("field"). Note the three natural gas water heaters WH-1, WH-2 and WH-3, which were all "Off" at the time.

The Latrobe City Council (LCC) provided the University of Melbourne with expenditure records from construction, twelve full months of heat and electricity consumption data after the GRAC commenced operation, and details of its contracts with energy supply companies, to assess the geothermal doublet's economic performance relative to the averted cost of natural gas combustion. Fu *et al.* (2023) published a description of the economic assessment. Table 1 provides additional details about the values for variables in Eq 1 and other relevant parameters.

Table 1: Values for the LCoH calculation for the GRAC, as published by Fu *et al*. (2023).

Variable	Value	Comment
n (project lifetime)	30 years	
C_t (capital cost)	3,855,396 AUD in Year 0	Actual expenditure by LCC
M_t (annual maintenance cost)	15,000 AUD	Small-scale maintenance every year
M_t (decadal maintenance cost)	125,000 AUD	Large-scale maintenance every 10 years
M_t (electricity cost)	45,068 AUD in Year 1	Based on actual consumption and contract tariff
H_t (annual heat produced)	23,540 GJ	Based on recorded flows and temperatures
r (discount rate)	8%	Based on other Australian renewable energy projects
General inflation	2.5%	Based on long term trend
Electricity and gas inflation rate	5%	Based on long term trend
Natural gas tariff	31.03 AUD/GJ in Year 1	Based on actual supply contract
Greenhouse gas emissions offset	51.53 kg.CO_2-e / GJ	Based on national greenhouse gas reporting standard

The key conclusions by Fu *et al*. (2023) were: (a) LCoH discounted over the 30-year lifetime of the project and incorporating inflation was 19.16 AUD/GJ; (b) the effective cost of geothermal energy in Year 1 was 10.80 AUD/GJ—about one third the natural gas tariff paid by LCC; (c) the geothermal doublet ran at >95% availability over its first year of operation; (d) the internal rate of return (IRR) on LCC's investment is 23%; (e) the payback time for the geothermal doublet is 4.94 years; and (f) the geothermal doublet offsets 914 metric tons of CO_2-equivalent greenhouse gas emissions per year by avoiding natural gas combustion.

The findings of Fu *et al*. (2023) clearly validated LCC's decision to heat the GRAC with geothermal energy. The economics of geothermal heating at the GRAC, however, are specific to that project and not necessarily applicable to other projects. For example, geothermal energy economics are favorable at the GRAC because the application operates at a temperature similar to that at which the geothermal energy is produced from the LTA at that location, eliminating the need for any heat pump, which would add extra capital and running costs to the project. The LTA is also relatively hot and shallow beneath Traralgon, minimizing the drilling and completion costs for the well doublet relative to other locations. Furthermore, LCC pays relatively high retail rates for natural gas for a consumer of its size, making it easier for alternative sources of heat to compete on cost. However, the GRAC geothermal doublet only operates at a capacity factor between 0.40–0.45, indicating a relatively inefficient return on the invested capital. As all these factors can vary widely across different users and locations, the findings of Fu *et al*. (2023) for the GRAC do not necessarily represent the likely economic performance of geothermal heat supply systems for other consumers at other locations.

3.2 Smart Geothermal Industrial Loop ('SGIL')

The positive economic performance of the geothermal doublet at the GRAC led LLC to consider a geothermal energy district heating network for the Gippsland Logistics Precinct ('GLP'), a new industrial park being developed by LLC at Morwell about 13 km WSW of the GRAC (Figure 8). The GLP is a cluster of industrial lots of various sizes, mostly between 1–3 Ha. At the time of writing in mid-February 2025, no specific tenants have been confirmed for any of the lots, although the authors expect confirmation from LCC of occupants for the first few lots within weeks. Regional Development Victoria, a department of the Victorian State Government, funded our team to design an appropriate and credible geothermal energy distribution network for the GLP and to assess its techno-economic feasibility. We refer to the project as the Smart Geothermal Industrial Loop ('SGIL').

The challenge was to design an optimal geothermal energy distribution network to provide thermal power to end users who are yet to be identified. The peak power and total energy demand profiles, and hence the optimal parameters for a geothermal energy supply system, can vary widely for different users. Our task, therefore, was to investigate whether a SGIL could provide all the heat required by a notional group of users. The approach we took was to identify a set of possible heat consuming tenants for the GLP who represented different heat demand profiles and for whom we had or could source credible heat consumption data. The industries we chose were a dairy processing facility, a greenhouse, an aquatic center, a bottling plant, and warehouses. Of those, the greenhouse, aquatic center and warehouses could use the geothermal energy at the temperature at which it is produced, while the dairy processing facility and bottling plant (and maybe the aquatic center also) would need to boost the temperature of the energy using heat pumps. We estimated the heat demand for facilities sized to fit within the 1–2 Ha lots to which they were assigned. Table 2 summarizes the supply temperatures, peak thermal power demand, and annual heat requirements for the users. Figure 9 shows the industries on their assigned lots, the notional route of the SGIL delivering heat at uniform temperature to offtake substations, and the modelled annual heat demand profiles for each user at one-hour resolution.

From amongst several options for network configuration, we selected an indirect, double-pipe option whereby geothermal energy is delivered to a secondary heating circuit via a heat exchanger at or near the production bore, with cooled geothermal water immediately reinjected. The secondary circuit comprises a 'hot' pipe delivering constant-temperature water to offtake substations at each lot, with a second pipe collecting and returning cooled water to the heat exchanger for reheating. The TRNSYS model illustrated in Figure 5 represents this option.

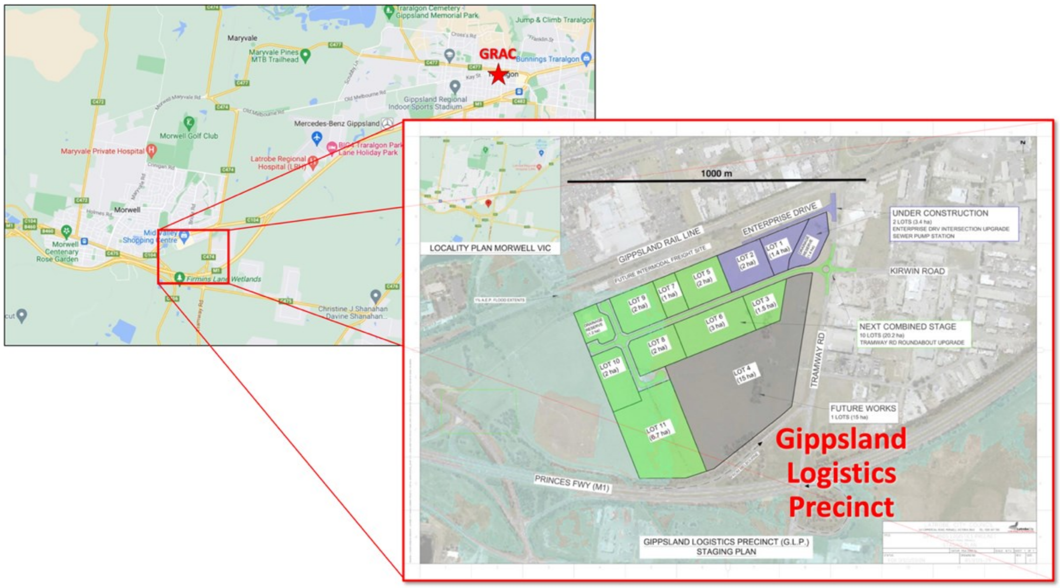

Figure 8: The Gippsland Logistics Precinct under development by Latrobe City Council at Morwell, 13 km WSW of the GRAC.

Table 2: Notional users of the SGIL with their assigned lots, assumed process temperatures, estimated peak thermal power demands, and annual heat requirements.

User	GLP lot	Interface	Supply/return temperature	Peak load (MW_t)	Annual heat demand (GWh_t)
Dairy processing	1 (1.4 Ha)	Heat pump	80/70°C	1.734	5.695
Greenhouse	2 (2 Ha)	Heat exchanger	50/40°C	0.463	1.269
Aquatic center	5 (2 Ha)	Heat exchanger or heat pump	60/50°C	1.073	3.903
Bottling plant	7 (1 Ha)	Heat pump	97/94°C	1.157	4.114
Warehouses	Lots 8–10 (2 Ha each)	Heat exchangers	40/30°C	1.228	5.459

In parallel with the heat demand and distribution modelling, we also assessed available geoscientific information about the Lower Tertiary Aquifer beneath the Gippsland Logistics Precinct. We refined existing public domain regional geological and groundwater models within Seequent software ‘Leapfrog Energy’ using legacy lithology and temperature data from coal and groundwater exploration boreholes within a radius of several kilometers of the GLP. Our refined geological model suggested the Lower Tertiary Aquifer spans a depth interval 590–705 m beneath the GLP and would produce at a temperature of 58°C (Figure 10; this is approximately the same depth but about 10°C cooler than the section of the LTA providing heat to the GRAC at Traralgon 13 km to the ENE.) Subsequent numerical modelling of production scenarios by Pujol (2023) using DoubletCalc 2D (Veldkamp *et al*., 2015), assuming the production and injection bore locations in Figure 9, indicated with high confidence that the LTA could sustainably supply heat to the SGIL with <0.5°C drop in production temperature for at least 100 years (the maximum length of the numerical simulation.)

An independent project that received grant funding from the Australian Renewable Energy Agency (ARENA) in 2024, on which one of our team collaborated, developed a larger reservoir model centered on Maryvale about 6 km northeast of Morwell (see Figure 1 for location) but encompassing the SGIL site. That project used the Waiwera reservoir modelling code developed by the University of Auckland (Croucher *et al*., 2020) to investigate the impact of lateral throughflow, ongoing nearby mine dewatering, and local geological structures on the probable initial and long-term production temperatures from the LTA on a proposed geothermal project at Maryvale. Public domain results from that modelling predicted the temperature of the LTA at the SGIL site to be 57.0–60.5°C ± 2.0°C, in good agreement with the prior work of Pujol (2023). The ARENA-funded project concluded that the LTA at Maryvale (where the temperature of the aquifer has been measured in historical bores at 70°C) could support 15 MW_t production (Pujol and Poessé, 2024) confirming the potential of the LTA in the Morwell-Maryvale-Traralgon general region.

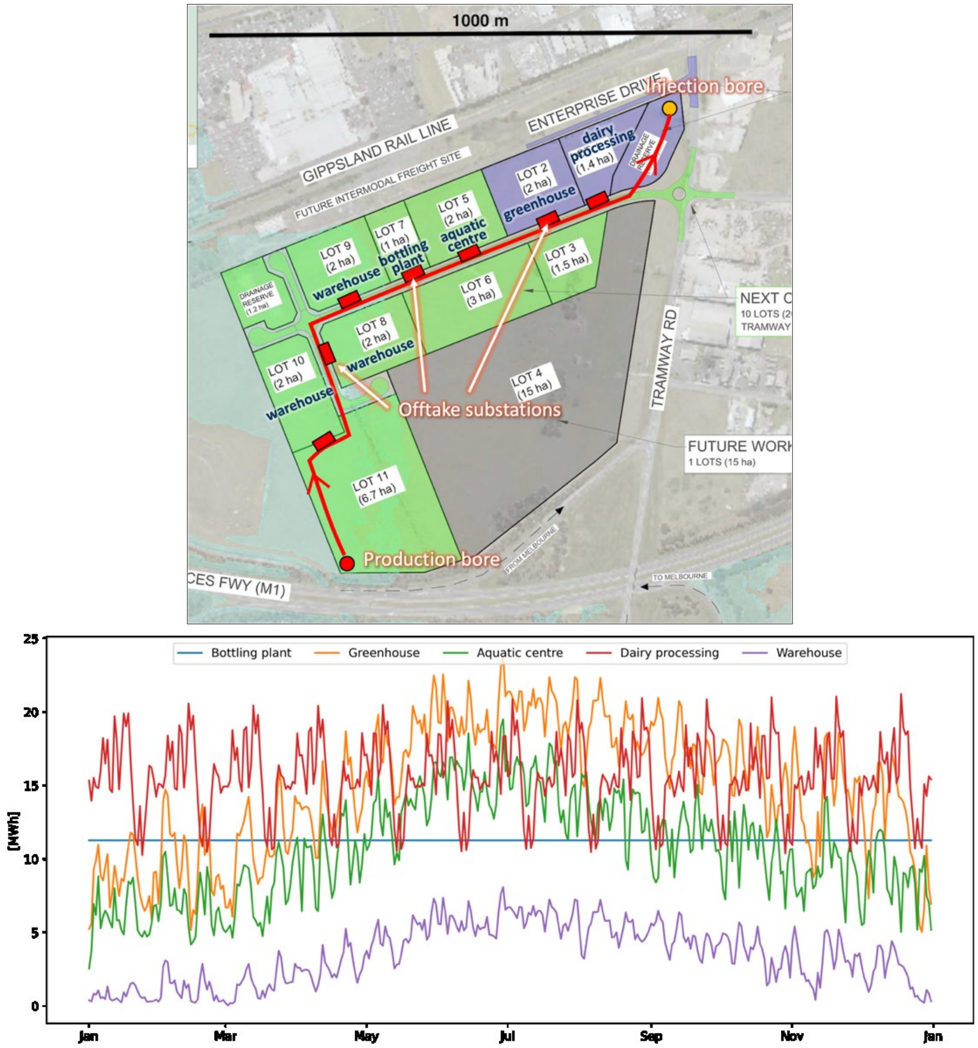

Figure 9: Top: Assignment of notional industrial heat consumers to GLP lots, and route of the SGIL delivering heat at uniform temperature to offtake substations at each lot. Bottom: Estimated hourly heat demand for notional industrial consumers.

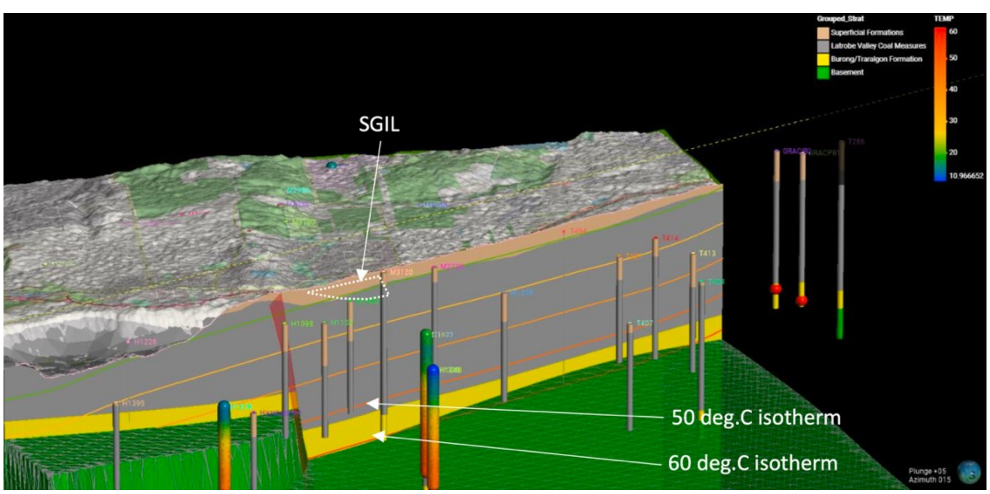

Figure 10: Leapfrog geological and thermal model around the SGIL site, showing cross-section and regional bores. The LTA is represented by the yellow Traralgon Formation. From Pujol (2023).

The combined findings of the geoscience, infrastructure engineering and thermal engineering teams provided high confidence that a Smart Geothermal Industrial Loop to distribute geothermal energy to a range of end users in the Gippsland Logistics Precinct is technically feasible. From the components itemized on the TRNSYS model of the SGIL, estimates of the drilling depths and production rates for the Lower Tertiary Aquifer, predictions of electricity consumption to run the pumps, and communication with Latrobe City Council, we constrained values for the parameters of the LCoH equation (Table 3). Our assessment was framed from the perspective of a future owner/operator of the SGIL acting as an energy retailer delivering heat to offtake substations. Under our assumed business model, end users will couple heat exchangers or heat pumps to individual substations to regulate the heat to the temperature at which they require it. Our economic assessment assumed the capital and running costs for any heat pumps would be borne by the end user rather than the owner/operator of the SGIL. That is, the capital cost item in Table 3 includes drilling and bore completions, siteworks, pipelines, diverters, mixers, pumps and the main heat exchanger, but no secondary heat exchangers or heat pumps.

Table 3: Values for the LCoH calculation for the SGIL.

Variable	Value	Comment
n (project lifetime)	25 years	Design lifetime of bores
C_t (capital cost)	5,320,000 AUD	Expenditure in Year 0
M_t (annual maintenance cost)	15,750 AUD	Compliance and small-scale maintenance every year, indexed for inflation
M_t (decadal maintenance cost)	28,000 AUD	Large-scale maintenance every 10 years, indexed for inflation
M_t (electricity cost in Year 0)	151,680 AUD	Indexed by inflation
H_t (annual heat produced)	47,880 GJ	Production at 58°C, reinjection at ≥40°C
r (discount rate)	8%	Based on assumption for GRAC
General inflation rate	2.5%	Based on long term trend
Electricity inflation rate	5%	Based on long term trend
Greenhouse gas emissions offset	51.53 kg.CO_2-e / GJ	Based on national greenhouse gas reporting standard

We determined an LCoH of 16.81 AUD/GJ and an offset of 1608 metric tons of CO_2-equivalent greenhouse gas emissions per year by avoiding natural gas combustion for our specific SGIL project. In spite of the lower predicted temperature of the LTA and the shorter lifetime for the SGIL relative to the GRAC, the predicted LCoH is 12% less than the LCoH for the GRAC. This is because the modelled SGIL operates at a capacity factor between 0.70-0.75 due to the efficient and effective sharing of the infrastructure across users with different demand profiles.

Our techno-economic evaluation of the SGIL demonstrated that the technology exists to sustainably produce and distribute geothermal energy through a district heating network at the Gippsland Logistics Precinct at a relatively low cost for at least a century. Those findings alone, however, are insufficient to trigger construction of the SGIL. The SGIL will only be financially attractive if the GLP is populated with low grade industrial heat consumers who can benefit from cheap geothermal energy. One option is for Latrobe City Council to preferentially target such heat consumers on the assumption that the SGIL will be built and will operate as modelled. The municipal government may viewed this as a relatively high risk strategy. A strategy of much lower financial risk for LCC is to attract any tenant willing to move into the GLP, most of which will not be significant low-grade heat consumers. The SGIL may become redundant if the GLP is populated with such tenants. As of mid-February 2025, no tenants for the Gippsland Logistics Precinct have been confirmed and the LCC has not committed to build the SGIL.

3.3 Bairnsdale Aquatic and Recreation Centre

The third case study is again for a municipal government facility, but some of the key parameters are different to the two cases above. The success of the GRAC geothermal energy supply for Latrobe City Council has raised awareness of geothermal energy as a possible renewable heat supply for other municipal councils in Gippsland. East Gippsland Shire Council ('EGSC') is considering geothermal energy as a substitute for natural gas burners for the Bairnsdale Aquatic and Recreation Centre ('BARC') and adjacent Forge Theatre complex (Figure 11) at Bairnsdale at the eastern end of the onshore Gippsland Basin (see Figure 1 for location.) The BARC/Forge complex currently operates a gas-fired burner that delivers 79°C water into a hydronic distribution network to heat swimming pools and building spaces (Figure 12). Both the BARC and Forge facilities also consume natural gas to provide domestic hot water at a delivery temperature of 65°C. We were tasked with assessing the techno-economic viability of replacing natural gas with geothermal energy as the heat source for these systems and to compare the results with 'business as usual' (natural gas) and air-source heat pumps (ASHPs), with the default assumption that delivery temperatures and demand profiles would remain the same.

Figure 11: Members of our team visiting the BARC and Forge facilities in November 2023.

Figure 12: Existing gas burner for hydronic heating of the swimming pool and buildings at the BARC

A productive, sustainable source of geothermal water is a key requirement for the provision of geothermal energy to any project. Access to such a source near the BARC/Forge precinct presents a key risk because the existence, depth and temperature of the LTA has not yet been verified beneath Bairnsdale. All Gippsland Basin stratigraphic units are known to be shallower and thinner towards the northern margin of the basin at Bairnsdale's location. Maps of the geothermal properties of the LTA published by O'Neill *et al*. (2022; Figure 6) suggest that the top of the LTA below the BARC/Forge site might lie at about 220 m depth at a temperature of about 25°C, but no existing bores of that depth exist near the site to provide confidence. The maps are based on extrapolation and interpolation of sparse data over 6000 km^2 of Gippsland, mostly to the south and west of Bairnsdale. The maps are, however, broadly consistent with records from a handful of historical bores drilled near Bairnsdale. For example, a 275 m deep borehole drilled in 1938 encountered a productive source of "hot" groundwater three kilometers to the south of the BARC, according to a hand-written record by the driller at the time. This is consistent with the state government maps if 30–35°C can be considered "hot." On the clear understanding that the existence of the LTA represents a key risk, we proceeded with our techno-economic assessment on the assumption of the existence of a 25°C geothermal energy source over the depth interval 220–249 m (the estimated depth to basement.)

It was immediately obvious that a geothermal heating project would need to incorporate heat pumps to deliver 79°C and 65°C water to the BARC and Forge Theatre, respectively, from a 25°C geothermal energy source. We modelled two different options whereby the geothermal source water was cooled by 10°C or 20°C before reinjection into the LTA. The results indicated 10°C cooling as the more effective option. Although less thermal energy is extracted from each unit volume of the geothermal source water compared to 20°C of cooling, lower capital and electricity costs required to run the less powerful heat pump more than compensated for the efficiency penalty. Figure 13 illustrates the geothermal energy network design for our subsequent modelling and comparison with air-source heat pump systems and a 'business as usual' natural gas furnace. Our design anticipates drawing 25°C water from a production well, immediately transferring geothermal energy from the water to a secondary circuit via a heat exchanger, and reinjecting 15°C water. The secondary circuit delivers 25°C water to 'water source heat pumps' (WHHPs) powered by electricity at the BARC and Forge Theatre, which boost the temperature of the thermal energy to 79°C and 65°C, respectively, and return 15°C water for reheating at the heat exchanger.

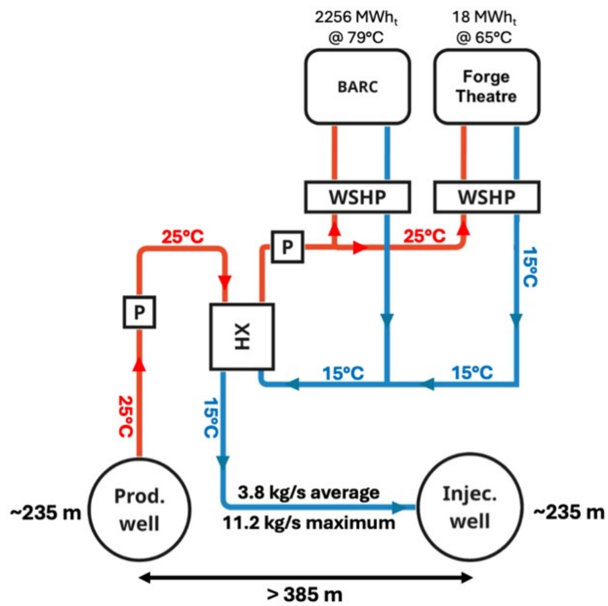

Figure 13: Schematic representation of our proposed geothermal heat pump solution for heating in the BARC/Forge precinct. 'Prod' = production, 'Injec.' = injection, 'P' = pump, 'HX' = heat exchanger, 'WSHP' = water source heat pump. Annual thermal energy demand (MWh$_t$) for BARC and Forge Theatre are shown at top.

We simulated the proposed geothermal network and modelled its ability to deliver heat to the BARC and Forge Theatre facilities at the rate and time currently provided by natural gas furnaces, and the electricity required to run the pumps and heat pumps. We also investigated the viability of drawing the required heat directly from ambient air using air-source heat pumps (ASHPs). For the modelling, we used 'nPro Energy' software by nPro Energy GmbH, Germany (https://www.npro.energy/), a tool designed for planning and simulating building and district energy systems with a focus on district heating networks, renewable energy systems, and geothermal energy.

Results from our nPro Energy modelling indicated that all three 'fuel' sources (geothermal, air, gas) could technically deliver the required heat at the required times, and allowed us to quantify the electricity and fuel requirements for each scenario. The results also gave us the average (3.8 kg/s) and peak (11.2 kg/s) production rates for 25°C water which would be required to sustain the geothermal system. On the basis of those production rates, we solved an analytical equation by Gringarten and Sauty (1975) to estimate the minimum recommended distance between production and injection bores to prevent the risk of thermal breakthrough over the 30-year design-life of the system—385 m. We then designed and estimated the cost of appropriate production and injection bores using the algorithm described in Section 2.4.2 above, obtained a quote for an appropriate borehole pump from a supplier, and estimated costs for pipelines, heat exchanger and water-source heat pumps. That gave us a credible basis for estimating capital and running costs for the geothermal network, and we completed equivalent costing exercises for the ASHP and natural gas furnace options.

East Gippsland Shire Council requested that we use plausible estimates of future gas and electricity prices in our LCoH calculations. To assist us with that task, EGSC provided 15 years of their historical energy price records. From those records, we inferred separate average historic inflation rates for electricity and gas, and extrapolated those historical trends to predict possible future price rises over the 30-year lifetime of the project. We maintained an assumption of 2.5% inflation on non-energy expenditure consistent with our other case studies. The refined assumptions about energy price inflation was a variation from the two case studies described above, in which we assumed a generic 5% annual gas and electricity inflation rate.

Table 4 summarizes the input parameters for our LCoH calculations for the geothermal energy scenario at the BARC/Forge precinct. The ASHP and 'business as usual' gas furnace scenarios had their own C_t and M_t cost structures, but other parameters were the same.

Table 4: Values for the LCoH calculation for the geothermal energy and comparison scenarios at the BARC/Forge site.

Variable	Value	Comments and assumptions
n (project lifetime)	30 years	Design lifetime of bores
C_t (capital cost)	1,366,229 AUD	Expenditure in Year 0
M_t (annual maintenance cost)	13,662 AUD	1% of initial C_t every year, indexed for inflation
M_t (7-year maintenance cost)	23,000 AUD	Replacement of water pumps every 7 years, indexed for inflation
M_t (15-year maintenance cost)	706,277 AUD	Replacement of heat pump after 15 years, indexed for inflation
M_t (electricity cost in Year 0)	198,178 AUD	Indexed by inflation
H_t (annual heat produced)	8186 GJ	Production at 25°C, reinjection at ≥15°C
Gas tariff in Year 0	24.28 AUD/GJ	Based on energy supply contract
Electricity tariff in Year 0	0.198 AUD/kWh	Based on energy supply contract
General inflation rate	2.5%	Based on long term trend
Electricity inflation rate	3.3%	Based on 15 years of tariff history
Gas inflation rate	6.9%	Based on 15 years of tariff history
r (discount rate)	8%	Based on assumption for GRAC
Cost of capital for 'business as usual'	3.5%	
Greenhouse gas emissions offset	51.53 kg.CO_2-e / GJ	Based on national greenhouse gas reporting standard

On the basis of the assumptions in Table 4, we determined LCoH values of:

- 55.77 AUD/GJ for the proposed geothermal energy network;
- 69.31 AUD/GJ for the ASHP scenario; and
- 68.16 AUD/GJ for the 'business as usual' natural gas scenario.

EGSC purchases zero-emissions power from its energy retailer, so the geothermal and ASHP scenarios also reduce greenhouse emissions by about 422 metric tons per year relative to the 'business as usual' gas furnace scenario.

The first observation is that the LCoH value for the geothermal scenario is significantly higher than those derived for the first two case studies. This is a result of the relatively low capacity factor (~0.34), the significant annual electricity consumption to run the heat pumps, and the relatively low heat extraction (10°C) from each unit mass of geothermal water.

The next observation is that, in spite of 1.341 million AUD upfront investment required for a geothermal heat pump system, the lower running costs and less exposure to inflating electricity and gas prices for the geothermal scenario over the 30-year project life deliver the lowest LCoH value, even without factoring in any value for the offset greenhouse gas emissions. The comparative financial performances of the three scenarios can be seen in a chart of cumulative (non-discounted) predicted costs over the 30-year lives of the projects (Figure 14). Predicted running costs are similar for the first five years, but the geothermal and ASHP scenarios require up-front investments in excess of one million AUD. Beyond year 5, the inflating electricity and gas prices impact the running costs of the ASHP and gas furnace scenarios to an increasingly greater degree than the geothermal energy scenario. The geothermal scenario reaches cost parity with the gas furnace scenario in year 20, but the modelled cash outlay to replace the geothermal heat pump in year 15 delays the payback time by several years. Payback time for the geothermal scenario is year 16 if the replacement of the heat pump is deferred until year 20.

In summary, our techno-economic investigation into heating options for the BARC/Forge facility indicates that a geothermal heat pump scenario is technically feasible and may be cost-competitive with alternative systems, but the biggest risk is the unverified existence, temperature and productivity of a geothermal aquifer. As of mid-February 2025, our results for this project remain preliminary and East Gippsland Shire Council remains uncommitted to any given course of action.

4. DISCUSSION

Our objective techno-economic assessments repeatedly indicate that geothermal energy from the Lower Tertiary Aquifer is now a technically viable and economically competitive low-emissions substitute for natural gas for low-grade industrial heat in Gippsland. While the existence of the vast reservoir of natural hot water in the Traralgon Formation beneath Gippsland has been known for over 50 years, the heat contained within that water has only emerged as a competitive energy source since eastern Australia began exporting liquified natural gas in 2016, as illustrated above in Section 1.2.

Our investigations have highlighted that the LCoH calculated for a geothermal energy project is highly dependent on the characteristics of the geothermal energy source (depth, temperature, productivity, sustainability); the nature of the process to which the energy will be applied; the capacity factor of the project; assumptions about inflation; and the values assigned to parameters such as discount rate and project lifetime. LCoH is best used as a comparative, rather than absolute, measure of relative financial favorability between different energy options with broadly similar subjective assumptions. In the cases that we have investigated under the sets of assumptions we have imposed in consultation with the potential end users, the geothermal energy options have emerged as the most economically favorable on the basis of LCoH. Small changes in assumptions—about project lifetime or discount rate, for example—can, however, tilt the LCoH result in favor of other energy options. We would therefore not recommend selecting one energy option over another purely on the basis of an LCoH calculation without critical examination of the underlying assumptions.

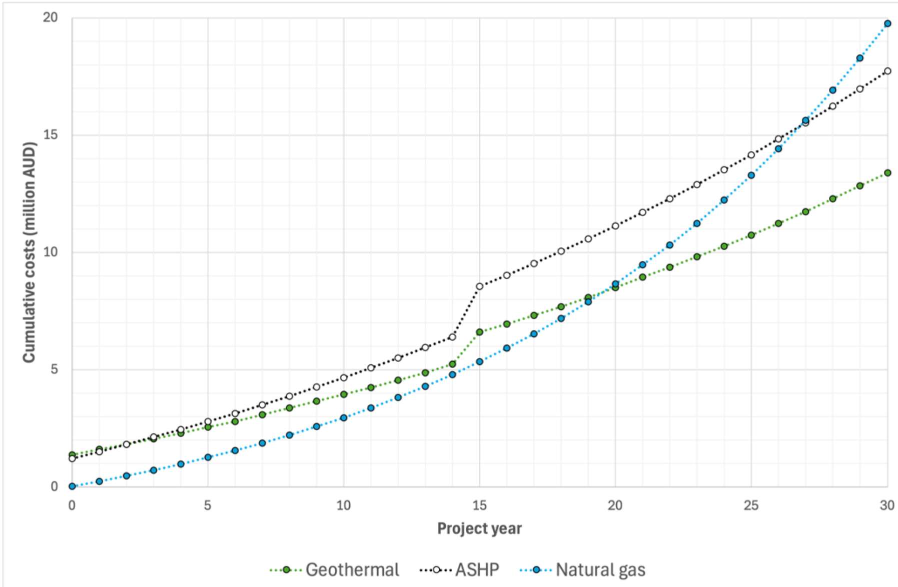

Figure 14: Predicted cumulative costs (non-discounted) for the three energy source scenarios at the BARC/Forge Theatre site. 'ASHP' = air-source heat pump.

Existing regulatory frameworks are being challenged by increasing interest in geothermal energy development in Gippsland. Geothermal energy resources less than 70°C or shallower than 1,000 m depth are regulated in Victoria under groundwater legislation that did not anticipate situations in which water would be produced and then reinjected without net consumption. Injection of cooled groundwater also triggers sections of the Environmental Protection Act, which introduces additional regulation and compliance requirements. The state government, however, recognizes the exciting potential to either amend or work within existing regulations to facilitate the safe, effective and sustainable development of a geothermal energy economy in Gippsland. Our investigations which repeatedly demonstrate the techno-economic viability of geothermal energy provide a strong argument for such amendments.

5. CONCLUDING REMARKS

Our team has now completed several investigations into the technical and financial feasibility of displacing natural gas industrial heating systems with systems delivering geothermal energy in Gippsland. Most cases we investigate indicate that the geothermal energy scenario is technically feasible and financially competitive, even in the absence of subsidies or incentives. While geothermal energy may not be as cheap as gas once was, it is now cost competitive and largely insulated from future price increases. These conditions in Gippsland appear favorable for the near-future development of the region into a major new geothermal energy province based on delivering sustainable, low-emissions, low-grade industrial heat. Our team is in discussions with several major heat consuming industries in Gippsland to identify pilot projects for geothermal industrial heat systems. We expect to see the first of those pilot projects commence in the next 12–24 months.

6. ACKNOWLEDGEMENTS

The University of Melbourne and our partners' work on characterizing and raising awareness of the geothermal energy potential in Gippsland has progressed over the past decade largely through generous financial support from the Government of Victoria through the Latrobe Valley Authority and Regional Development Victoria, and from East Gippsland Shire Council. Graeme Beardsmore's position at the University of Melbourne is partially funded by the Australian Government Department of Education NCRIS Program through AuScope Ltd. Modelling around Maryvale reported in this paper was supported by the Australian Renewable Energy Agency (ARENA) as part of ARENA's Advancing Renewables Program. Many other organizations and individuals have contributed, and continue to contribute, employee time and in kind resources to our ongoing investigations. Notable amongst these are the Latrobe City Council, Southern Rural Water and Federation University. The views expressed herein are not necessarily the views of the Australian Government. The Australian Government does not accept responsibility for any information or advice contained within this document.

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