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UK Geothermal Review and Cost Estimations

Final Report

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		Changes made	Hurdle rates were updated for deep geothermal technologies for both LCOH and LCOE. Changes have been made to the main report, annex B and C.		

Department for Energy Security and Net Zero note for the following report.

This report has been produced by Arup, and updated by DESNZ in May 2025, which updated the hurdle rates for deep geothermal technologies for heat and power generation, following a DESNZ commissioned research project across renewable power generation technologies, which included geothermal energy and is expected to be published in due course. This research report has an accompanying cover note written by DESNZ which aims to outlining the research's purpose, scope, and assumptions, explore areas for future updates to this research and outline its intended use.

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Contents

Tables

Figures

Appendices

Annexes

Annexes are separate to this document.

Glossary

ABEX	Decommissioning (Abandonment) Costs
AFPG	Association Française des Professionnels de la Géothermie
AGS	Advanced Geothermal Systems
ASHP	Air Source Heat Pump
ATES	Aquifer Thermal Energy Storage
BEIS	Department for Business, Energy & Industrial Strategy
BGS	British Geological Survey
BH	Borehole
BHT	Bottomhole Temperature
BSI	British Standards Institution
CAPEX	Capital Costs
CCC	Committee on Climate Change
CfD	Contracts for Difference
CHP	Combined Heat and Power
DEFRA	Department of Environment, Food and Rural Affairs
DESNZ	Department for Energy Security and Net Zero
DEVEX	Development Costs
DHN	District Heat Network
DLE	Direct Lithium Extraction
EA	Environment Agency
EGEC	European Geothermal Energy Council
EGS	Enhanced Geothermal System
EPC	Engineering, procurement, and construction
EPD	Environmental Product Declaration
ESP	Electrical submersible pump
FES	Future Energy Scenarios (National Energy System Operator (NESO))
Fm	Formation
FOAK	First of a Kind
FORGE	Frontier Observatory for Research in Geothermal Energy
GHG	Greenhouse gas
GSHP	Ground Source Heat Pump
GSNI	Geological Survey of Northern Ireland
GWP	Global Warming Potential
HIA	Hydrological Impact Assessments
HP	Heat pump
HSA	Hot Sedimentary Aquifer
ICE	Inventory of Carbon and Energy
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Heat
LHV	Lower Heating Value
NOAK	Nth of a Kind
NESO	National Energy System Operator
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&G	Oil and gas
O&M	Operations and Maintenance
ONS	Office for National Statistics
OPEX	Production cost
ORC	Organic Rankine Cycle
RICS	Royal Institute of Chartered Surveyors
SPF	Seasonal Performance Factor
ULF	Utilisation-Linked Finance
US DOE	US Department of Energy
US OEERE	U.S. Office of Energy Efficiency & Renewable Energy
WFS	Water Feature Surveys
WLC	Whole Life Carbon
WSHP	Water Source Heat Pump

Executive Summary

This report provides electricity generation and heat supply cost estimates from geothermal energy in the UK. The study was commissioned by Department of Energy Security and Net Zero (DESNZ) and undertaken by Ove Arup & Partners Limited (Arup). The geothermal technologies considered here range from shallow ground source heat pumps (GSHP) (less than 500m depth) to deep geothermal systems for heat and power (up to 5km depth). Deep geothermal technologies can provide direct baseload heat (and in some cases power) where other renewable energy technologies cannot generate continuous baseload energy.

This report presents the methodology, the levelised cost calculations and their associated technical assumptions, and a review of carbon intensity of geothermal technologies. The findings provide cost estimates for geothermal heat (for the first time by DESNZ), geothermal power (updated with new data, since an earlier 2016 report[1]), and the potential for lithium production and revenue.

Note that the following aspects were outside of scope for this study:

- A UK-wide review of resource potential for geothermal (instead seven areas were evaluated).
- An evaluation of the impact of hurdle rates[2] on project costs.
- An evaluation of wider/indirect system costs and benefits (e.g. supply chain development and skills).

Methodology

The methodology consisted of a three-phase process: 1) data collection from literature and stakeholders, 2) UK deep geothermal modelling across selected locations, 3) levelised cost of energy (heat and electricity) modelling informed from the data collection and geothermal modelling work. In addition, a whole life carbon assessment, lithium revenue assessment, and indicative modelling of funding mechanisms was undertaken.

The amount of data used to inform each levelised cost parameter varied from more than ten for development costs, to less than three for decommissioning and plant operating costs. Given the current relatively undeveloped nature of deep geothermal in the UK, limited data was available for deep geothermal technologies compared to shallow systems. International data was therefore also used to supplement UK data for deep geothermal.

Assessed Technologies and Context

Open systems are systems which require the ability of the geological target to be able to produce fluids and are thus more sensitive to geological conditions. Closed systems are systems with thermal fluids isolated from surrounding rock and are less sensitive to geological condition. Shallow geothermal technologies evaluated include vertical closed loop boreholes (<500m), open loop wells (<500m) and mine water systems. Deep geothermal technologies in this study include oil and gas (O&G) converted coaxial wells (closed systems between 1 and 2km), O&G converted wells (open systems between 1 and 2km), purpose build coaxial wells (closed systems between 1 and 4km) and deep geothermal for heat (open systems between 2 and 3km) and deep geothermal for heat and power (between 4 and 5km).

[1] Arup, 2016. Review of Renewable Electricity Generation Cost and Technical Assumptions, Study Report. Prepared for the UK Department of Energy and Climate Change (now the UK Department for Energy Security and Net Zero). https://assets.publishing.service.gov.uk/media/5a80a790e5274a2e8ab51667/Arup_Renewable_Generation_Cost_Report.pdf

[2] Hurdle rates refer to the minim rate of return required on a project of investment. The greater the risk involved in an investment, the higher the hurdle rate. The hurdle rate for deep geothermal is greater than shallow geothermal.

UK Deep Geothermal Assessment

The UK deep geothermal assessment focused on seven geographic locations[3] selected to provide a range of both geothermal potential and geographic location. Geothermal modelling at these seven locations was undertaken to provide geography – specific thermal and power capacity estimates. These estimates were then averaged to inform the levelised cost models.

Levelised Cost Modelling

Levelised cost modelling assessed geothermal technologies as either First-of-a-kind (FOAK) or Nth-of-a-kind (NOAK) systems. The levelised cost of electricity (LCOE) modelling method was adopted from existing DESNZ methods, and the LCOE model was adapted for the levelised cost of heat (LCOH) assessment. Note that levelised costs include pre-development, construction, operational, and decommissioning costs. Costs presented in this executive summary are 'Medium' costs and for projects which begin development in 2024 leading to commissioning dates of 2026 (for shallow geothermal) and 2030 to 2032 (for deep geothermal).[4] The full modelled results are presented in the main report and annexes and include 'Low', 'Medium', and 'High' values and a wide range of variables and start dates.

Whole lifecycle carbon modelling, undertaken by capturing embodied carbon values and multiplying activity data with an appropriate emissions factor at each lifecycle stage, was used to evaluate carbon emissions for selected geothermal technologies.

UK Levelised Cost of Heat (LCOH) Results

Shallow systems were modelled to supply heat and cooling, and deep geothermal systems were modelled supplying heat only. Twenty different scenarios were assessed, across different technologies, depths, and end heating (and cooling) users. The assessed end users included district heat networks (DHN) with two supply temperatures, 55°C and 85°C, and an "ideal" hospital with an assumed annual load profile of 60% heating (over 5,260hrs), and 20% cooling (over 1,750hrs) annually. LCOH outputs are presented for the maximum generation capability for an averaged heat output at a given depth utilising a given technology.

Shallow Geothermal LCOHs

For geothermal heat, shallow technologies were found to provide the lowest geothermal levelised costs (Figure 1). Shallow geothermal technologies are established and therefore benefit from reduced construction costs, a developed supply chain, and contractor competition.

Shallow geothermal systems used for heating only have levelised costs ranging from around £18 to £56 per MWh (assuming the technology is a NOAK, 2024 project start). Heating and cooling LCOH scenarios have been considered and the cooling revenue is based on an avoided costs methodology and is represented only for the ideal hospital scenario. The levelised costs decrease further when the system is used for both heating and cooling.

The LCOH is significantly influenced by the choice of hurdle rate (with 7.5% assumed for shallow geothermal), which is lower than deep geothermal systems (assumed 10.1%) due to shallow systems and ground source heat pumps being more developed and therefore include less risk. Assuming a higher hurdle rate for shallow systems would lead to costs estimates increasing. For example, if we assume a 10% hurdle rate, a heating only shallow mine water DHN 85°C this increase would be from the £30/MWh (NOAK, project start in 2024) to £36/MWh.

Compared with deep geothermal systems, shallow geothermal systems also benefit from decreased drilling costs, however, incur additional costs associated with the need to uplift the heat extracted to the required temperature for the end heat user (via the use of heat pumps).

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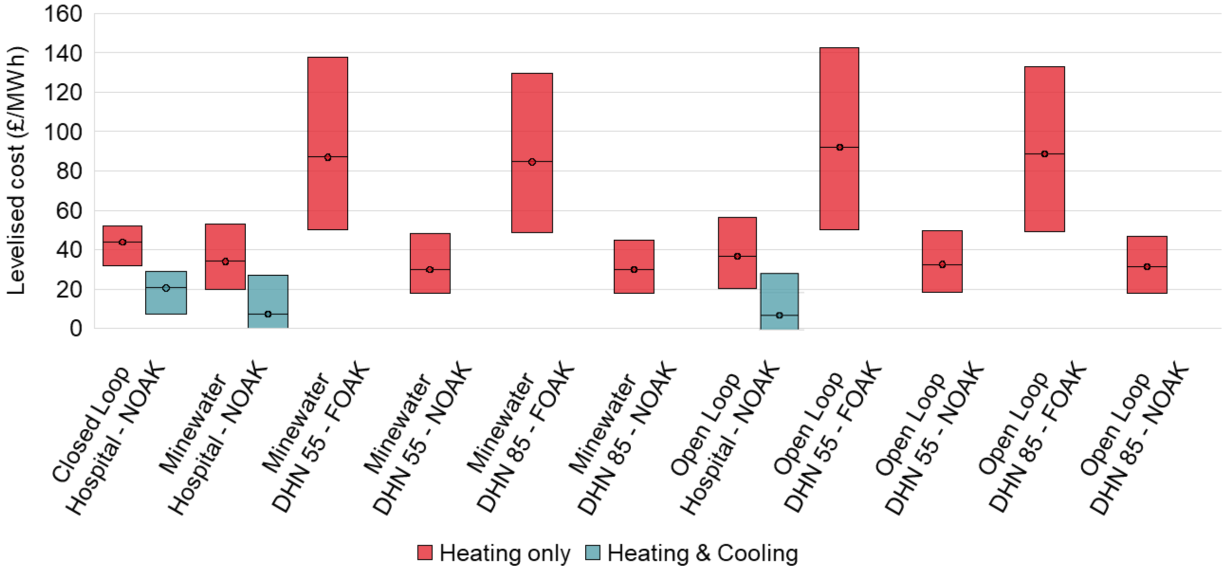
[3] Wessex Basin (Portsmouth), Cheshire Basin (Manchester Airport), Northumberland & Solway Basin (Newcastle), Glasgow & Clyde Basin (Western Edinburgh), Northern Ireland Sedimentary Basin (Loch Neagh Basin, Antrim), Cornish granites (Cornwall) and North Scotland granites (Western Aberdeen)

[4] Commissioning dates are based on average project durations for planning, construction, and commissioning of around 2 years for shallow systems, and 6 to 8 years for deep geothermal systems.



* Maximum value represents the 'High' cost, the inner point marks the 'Medium' costs and the minimum represents the 'Low' cost.
* Blue bars show the LCOH after deduction of cooling revenues, assumed to be equal to the cost of provision of cooling separately. Cooling revenues are likely overestimations. Lower bound LCOH for cooling have been truncated to zero.
* Levelised costs are related to their end user (hospital or district heating network (DHN) at 55°C or 85°C).

Figure 1: Levelised cost of heat for shallow geothermal systems

Deep Geothermal LCOHs

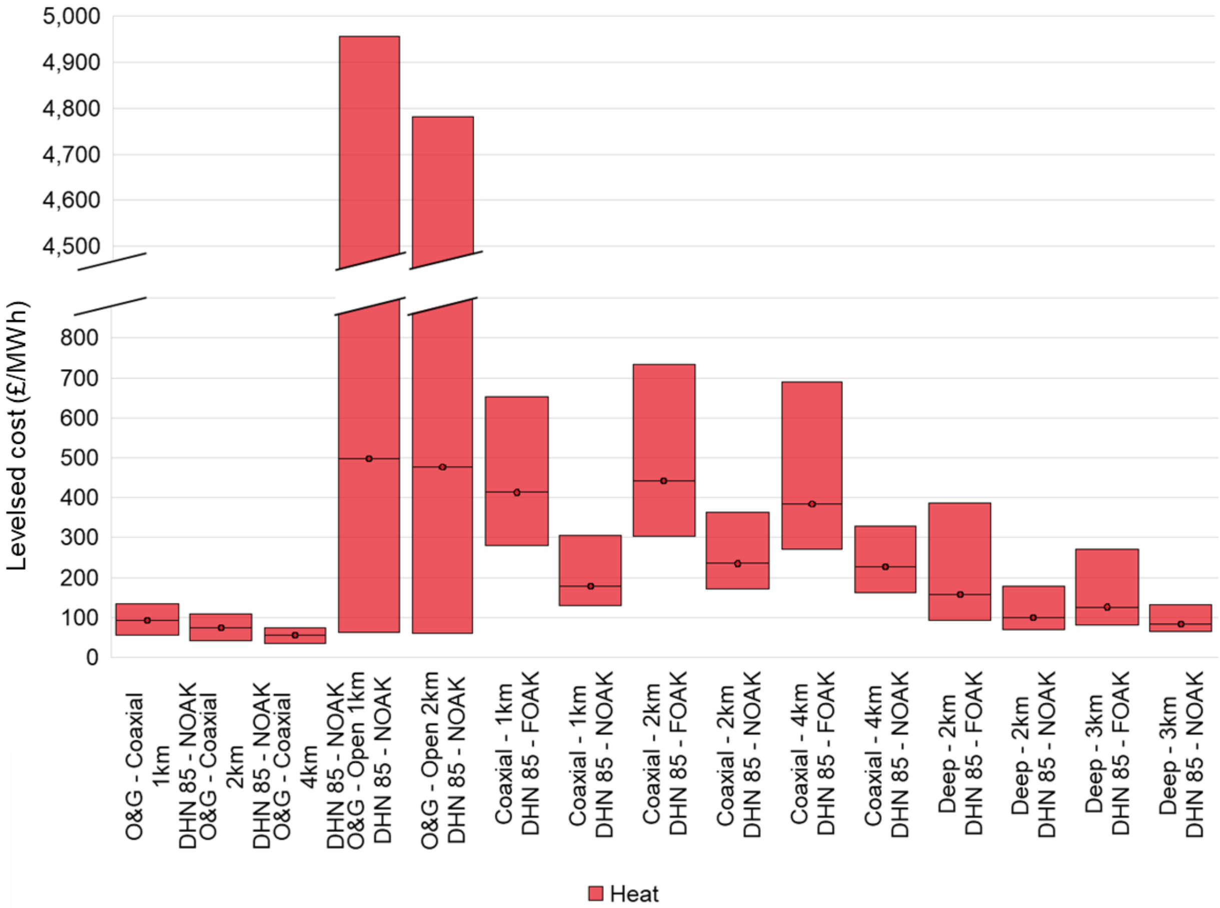
Of the deep geothermal technologies considered, deep geothermal doublets and O&G converted coaxial wells have the lowest of the deep technology levelised costs of heat (Figure 2). O&G coaxial have levelised costs of £55 to £100 per MWh (assuming the technology is NOAK) for medium values, and deep geothermal doublets of £84 to £172 per MWh (for FOAK and NOAK systems) for medium values. The levelised costs for deep geothermal doublets factor in their high heat capacities, with high construction (drilling) costs. The levelised cost for O&G coaxial systems have lower construction costs, given the wells have already been drilled and only need repurposing, however, also have lower heat capacities. Deep geothermal doublet technologies are widely utilised across Europe and globally and have high thermal capacities which are orders of magnitude greater than O&G converted coaxial systems (which are also less established technologies relative to deep geothermal doublets).

As with shallow systems, for deep systems the LCOH is also significantly influenced by the hurdle rate, which is assumed to be 10.1%, reflecting a higher drilling risk than shallow systems. Hurdle rates have significant uncertainty, as they can vary significantly from project to project and across a geothermal systems lifespan, e.g. higher hurdle rates are experienced during the drilling phase (exploration phases) but once exploration demonstrates success, the hurdle rate reduces. A hurdle rate for deep geothermal heat generation was assumed for this study to be the same as the hurdle rate for deep geothermal power generation (10.1%)[5]. This is considered to be representative of a whole life hurdle rate for deep geothermal power generation and is consistent with 2025 DESNZ commissioned research [116]. Assuming a higher hurdle rate of 18.8%[6], for example, that could be more reflective of risk during the drilling phase, would lead to costs estimates increasing for a deep doublet at 3km from £126/MWh to £264/MWh (FOAK, medium scenario, 2024 project

[5] The same hurdle rate is assumed for both deep geothermal for power and for heat. Deep geothermal for power takes into consideration the Contracts for Difference (CfD) scheme. Deep geothermal for heat may have greater price risk due to no CfD (noting potential for Government grants) but reduced construction risk due to shallower depths which may largely balance out.

[6] 18.8% is considered to be representative of a hurdle rate for the drilling phase of geothermal only (European Economics, 2018). The drilling phase is the period of highest risk within a geothermal project.

start, 2023 price base). For deep geothermal systems if risks can be reduced then hurdle rates may reduce leading to improved cost-effectiveness.



* Maximum value represents the 'High' cost, the inner point marks the 'Medium' cost, and minimum value represent the 'Low' cost.
* O&G converted open loop systems have very high upper bound levelised cost estimates (owing to inferred very low flow rates / capacities)
* For visual clarity, only the 85°C DHN end user values have been presented. The 55°C DHN values and trends are broadly comparable

Figure 2: Levelised costs of heat for deep geothermal systems (2024 project start, 2023 price base)

Comparative Technology LCOHs & European Markets

Comparative technologies such as gas boilers and air source heat pumps (ASHPs) were found to have levelised costs across Europe of £75/MWh to £160/MWh (2024 equivalent costs) for ASHPs; and £75/MWh to £130/MWh for gas boilers. The comparative technology assessment was conducted at a higher level than the geothermal technology assessment, and therefore should be considered as an indicative comparison only.

There are limited publications on shallow geothermal LCOHs. Available GSHP LCOHs from Germany ranged from £126 to £210/MWh. Deep geothermal LCOH values from the US and Germany ranged from £9.4 to £273/MWh; comparable to the NOAK geothermal doublet and O&G converted coaxial systems.

Levelised Cost of Electricity (LCOE) Results

The LCOE models assessed sedimentary and granite deep geothermal targets at various depths. Deep geothermal was treated as a combined heat and power (CHP) system. Unless specified otherwise, the LCOEs presented include a heat revenue of £143/MWh (for a 2024 project start date) based on an avoided cost methodology[7].

Deep granites, at depths of 4 to 5 km, have levelised costs, without assuming any heat revenue, ranging from £609/MWh (FOAK, high scenario, 2024 project start) to £60/MWh (NOAK, low scenario, 2050 project

[7] Noting that heating revenue varies with the start date (e.g. £143 for 2024, and £151 for 2030), and the assumed revenue could be less (e.g. if the heat is priced to significantly undercut gas or electricity prices) or more (e.g. assuming maximum heat production and that all heat is sold).

start). Sedimentary targets, at depths of 3 to 4 km, have levelised costs ranging from £3251/MWh (FOAK, high scenario, 2024 project start) to £73/MWh (NOAK, low scenario, 2050 project start). Heat revenues can further reduce the overall levelised cost (Figure 3).

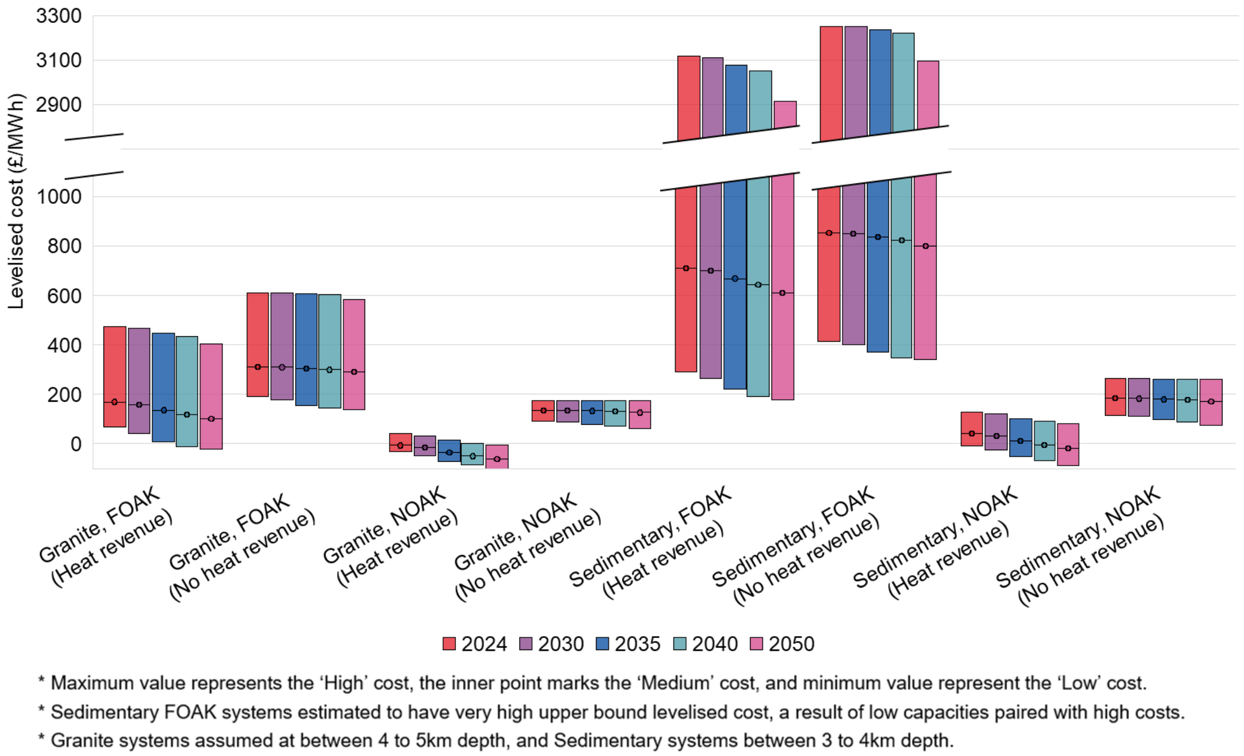


Figure 3: Levelised costs of electricity from deep geothermal systems (2024 project start, 2023 price base)

The LCOE model is sensitive to system heat and power capacities. Owing to their higher inferred capacities, granite targets have lower LCOEs. The levelised cost models are also sensitive to hurdle rates. A hurdle rate of 10.1% was assumed for deep geothermal power generation. If a higher hurdle rate was assumed of 18.8%, for example this would lead to costs estimates increasing from £169/MWh to £453/MWh for central assumptions (Granite FOAK, heat revenues, 2024 project start, medium scenario).

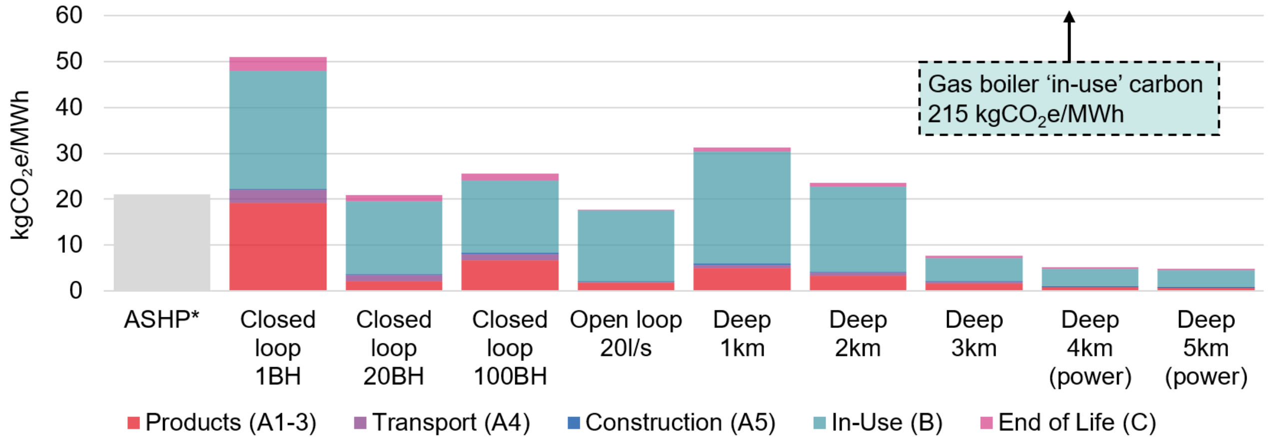
The high FOAK levelised costs primarily reflect high drilling costs. Similar to the LCOH scenarios, an assumed NOAK technology leads to reduced drilling costs, development of larger-scale facilities, and better economies of scales.

The LCOEs found in this research were compared to LCOE benchmarks from other relevant counties across Europe and the U.S. From 2010 to 2022 the yearly global weighted average of LCOEs of installed geothermal plants ranged from £68 to £117/MWh (IRENA (2022) [73]). US LCOE values from two separate reports suggest LCOEs from £51.3 to £590 per MWh (FOAK) and £34 to £192 per MWh (NOAK).

Lithium extraction from geothermal brine fluids has recently gained interest in the UK. Lithium extraction, in conjunction with geothermal energy is currently in a pre-pilot phase in the UK with limited examples worldwide. Arup's high-level assessment looked at three scales of development, from pilot to commercial scale (100s tonnes of lithium product to 10,000s tonnes of lithium product sold per annum respectively). At the pilot and semi-commercial scales, lithium returns remain limited. However, once the plant is at a commercial scale, lithium returns can have a material impact to improve the economics for a combined geothermal and lithium plant. Given the high-level nature of the assessment presented in this report, we recommend that the evaluation of lithium presented is further reviewed when more commercial data becomes available.

Carbon

Geothermal systems are considered to be low carbon technologies. The carbon assessment for this study was in line with benchmarked published data, and outlined that deep geothermal systems, used for direct heating (i.e., without a heat pump), provide the lowest whole life carbon intensities. The whole life carbon intensities of shallow geothermal systems, and deep systems with heat pump use, are comparable to the operational carbon of ASHPs, and a magnitude less than the operational carbon of gas boilers (Figure 4). As the UK grid decarbonises, operational carbon will reduce, further reducing geothermal (and other electrical system) carbon intensities.



* ASHP embodied carbon from CIBSE TM65.1 Embodied carbon in building services: residential heating (2021) [115]. Arup converted the reported 55.2 $kgCO_2e/kW$ to 21 $kgCO_2e/MWh$, assuming the system is used for heating for 60% of the year (5256hrs), to be comparable with the shallow geothermal systems. The full reported range is from 34.5 to 71.3 $kgCO_2e/kW$ (c. 13.1 to 27.1 $kgCO_2e/MWh$). This is a residential value and therefore may not be suitable for direct comparison.

* Gas boilers excluded from graph. Gas boilers have an 'in-use' carbon value of 215 $kgCO_2e/MWh$, exceeding the axis of this graph.

* Carbon costs: A1-3, Products (piping, pumps, cement); A4, Transport (haulage); A5, Construction (enabling works, water disposal); B, In-Use (maintenance, equipment replacement, operational energy consumption); C, End of Life (demolition, transport, recycling).

Figure 4: Whole life carbon assessments for geothermal systems and 'in-use' carbon for comparator technologies

1. Introduction

1.1 Project Context

The Department of Energy Security and Net Zero (DESNZ) has appointed Ove Arup & Partners Limited (Arup) to update electricity generation cost and heat cost estimates in addition to technical assumptions for geothermal energy in the UK.

This document presents the findings of the study. It describes the methodology adopted, assesses geothermal potential in selected areas across the UK, and describes how generation costs and carbon emissions have been calculated. The report consolidates data from the following tasks, highlighting key insights in detailed appendices and annexes, such as emissions data for comparing different geothermal systems.

- Task 1: Methodology Report: desk study of methodology and literature research
- Task 2: Technical Note: definition of scope of geothermal technologies and UK geothermal targets
- Task 3: Draft levelised cost chapter (Power) including Raw cost data, assumptions and calcs for power
- Task 4: Draft levelised cost chapter (Heat) including Raw cost data, assumptions and calcs for heat
- Task 5: Final Spreadsheets

1.1.1 Navigating this report

This report addresses the following research questions (Table 1), which are explored in detail in the report appendices, annexes and models.

Table 1: Research Questions

Research Question		Location
RQ 1	What is the current technology and delivery landscape for: geothermal for power and geothermal for heat, including a summary of what has changed in costs and technologies since the Arup (2016) report.	All Sections Annex B
RQ 2	What are the costs and technical assumptions that make up the levelised cost of electricity (LCOE) and the levelised cost of heat (LCOH) and combined power and heat?	Section 3 & 4 Annex B Annex C
RQ 3	How are those costs and assumptions likely to evolve over time, up until 2050 and including learning rate forecasts?	
RQ 4	How will the likely technological capabilities change, up until 2050 (e.g. Enhanced Geothermal Systems, combining heating and cooling, including lithium extraction)? How will these impact costs?	Section 4 Annex C
RQ 5	What are the costs and technical assumptions that currently underpin ability to support geothermal electricity generation combined with heat and combined with lithium extraction.	Section 4 Annex C
RQ 6	What are the costs for geothermal power and heat and combined heat and power in different geographic locations (including Manchester Basin, Portsmouth basin, Norfolk, and Cornwall), at different depths (e.g. 300m, 1km, 2km, 4km for heat and 4km and 5km for power).	Section 2 Annex A
RQ 7	What are the costs and technological capabilities of related geothermal projects e.g. mine water heat and repurposing oil and gas boreholes	Section 3 Annex B
RQ 8	For geothermal heat what costs of funding mechanisms depending on LCOH calculated (including feed-in tariffs, Insurance scheme, capital grant) along with an assessment of hurdle rates across the different types of geothermal projects?	Section 3 Annex B
RQ 10	Compare LCOH and carbon footprint of geothermal with comparable dispatchable heat sources (e.g. CHP, waste heat from industrial site, WSHP).	Annex D

Research Question		Location
RQ 11	What are the total emissions for the different geothermal systems considered and include an assumption of costs based on a variable carbon price.	Section 5 Annex D
RQ 12	What are the cost benefits of wider system impacts (e.g. dispatchable heat source, land use, cost risk associated with public information campaign or ceasing a project due to seismic activity for EGS)?	Section 6
Note. RQ number 09 was not included in the specification.		

1.1.2 Costing year

The costs presented in this report use a cost base of £2023 costs, unless otherwise stated.

1.1.3 Limitations

This report, along with the models and assessments conducted, is based on reasonable assumptions derived from stakeholder and literature data. However, the LCOH and funding mechanism models for geothermal are pioneering efforts in the UK. There is room for critical review, parameter adjustments, and re-modelling. The models are extensive, offering significant potential for further trend analysis and expansion of the assessments presented. The funding mechanisms model currently applies a single model at a time; simultaneous application of multiple models could reveal compounded impacts. Additionally, with the models established, more specific and localised assessments could be conducted.

1.2 Project Background

Many governments in Europe and worldwide have recognised the potential of geothermal energy to make a significant contribution to the decarbonisation of heat and power as well as to energy security and job creation. While geothermal energy has not been a focus for UK policy support to date, in June 2022 the House of Commons Environmental Audit Committee recognised that geothermal energy could transform the UK's capacity to meet climate goals, use homegrown energy and grow the economy.

Shallow and deep geothermal energy is a proven low carbon source of heat and power globally and has the potential to make a significant contribution to decarbonisation and energy security.

In the UK, heating and hot water currently constitute 40% of the energy consumption and is responsible for nearly 20% of greenhouse gas emissions [1]. Heat is therefore a critical component of the UK's strategy to meet its decarbonisation targets.

POSTbrief 46 [2] confirms that the UK government has not yet factored deep geothermal into its carbon budget or strategies due to a lack of information about the application of the technology in the UK. Shallow systems are currently supported via heat pump incentives. The development of geothermal projects is hindered by high upfront capital costs and project risk. Without long-term strategies and policies, there are more challenges for the development of geothermal energy in the UK compared to some other European (and global) countries. For example Germany [109], the Netherlands [110], Italy [111], the United States [112], and France [113], and the European Union [114] have public-access geothermal data repositories and funding campaigns to acquire new data [108]; and select policies include ambitions to cut permitting time in half in France, separate legal procedures for geothermal in Netherlands, permissions to develop geothermal in protection zones in Japan, and treating geothermal as strategic investments in the Philippines [108]. This research project provides an evidence base for geothermal costs and feasibility to inform the governments decisions about future geothermal funding support schemes.

1.2.1 What is levelised cost?

The key outputs of this project were the technical and cost assumptions. They were used as inputs for estimating the Levelised Cost of Heat ('LCOH') and Levelised Cost of Electricity ('LCOE'). Levelised cost can be defined as the discounted lifecycle cost of building and operating an energy generation asset, expressed as a cost per unit of electricity or heat (£/MWh). It reflects all relevant costs faced by an energy generator over its lifetime. Levelised cost can be expressed as the ratio of the total cost of an average generation plant to the total amount of energy generated over a plant's lifecycle. Both LCOE and LCOH are expressed in net present value terms.

Levelised cost allows consistent comparisons of different energy generation technologies to be made. It is an approach that captures the cost, technical performance, cost of finance and technology risk (via the discount rate). As new cost and technical performance data becomes available, levelised cost estimates can be updated and the change in cost can be observed over time. For example, DESNZ (DECC, BEIS) has periodically published reports which allow comparison over time to be made and change in assumptions to be observed.

Key benefits of applying a levelised cost method is that it allows comparisons of different generation technologies and the levelised cost output can be compared with market prices (e.g. electricity wholesale). There are however some limitations with the approach. These could include:

- Estimates are based on information available at a specific point in time. An update of assumptions should be made on a regular basis to ensure up-to-date estimates are available;
- Forecast of levelised cost is subject to uncertainty e.g. fuel input prices. A range of levelised costs should therefore be prepared.

Both LCOH and LCOE estimates include pre-development costs, the capital cost of the equipment installation; operating expenditures and regular maintenance; and decommissioning costs. In order to consider the cost to a developer of producing heat or power (which also produce cooling, and heat as secondary products respectively), LCOH and LCOE calculations net off the estimated revenues received from the supply of cooling and heating respectively.

1.3 Methodology

The research methodology for this study involves several key steps, each contributing to a comprehensive and more detailed understanding of geothermal energy in the UK. These steps include assessing potential geothermal targets, conducting a literature review, engaging with stakeholders, validating findings, analysing costs, and making informed forecasts for the future of the UK geothermal sector. The outlined project methodology is presented in Table 2.

Table 2: Methodology of the Study

Process Step	Description
Literature Review	The literature review had three main objectives. Firstly, it aimed to identify relevant literature and guidance related to the technical performance of geothermal combined heat and power (CHP), and heat only plants. Secondly, it sought to collect data on development costs (capital expenditures or CAPEX) and operational expenses (OPEX) for use in analysis and benchmarking. Lastly, it ensured that literature from global geothermal systems was included, providing a valuable reference point for understanding the UK's position in the global market.
Stakeholder Consultation	The stakeholder consultations were divided into two distinct parts. 1. A main stakeholder survey; – Arup conducted an online stakeholder survey, distributing it to a diverse group of stakeholders worldwide numbering over 448 (survey live 09 February – 01 March 2024). – A secondary survey was provided to the Ground Source Heat Pump Association (GSHPA) (survey live 23 February – 15 March 2024). 2. One to One Meetings; – These meetings provided a much deeper level of insight and focussed on organisations with direct experience of geothermal well installation and operation. – Data from these engagements was recorded in a standardised format, allowing for meaningful comparisons. The purpose of the stakeholder consultation was to gather reasonable and representative data on technical assumptions, system costs across the life of each system type, and carbon data. Further detail on data collection and the output is included in the following section.

UK Geothermal target assessment (Task 2)	An assessment of the geothermal potential for heat and power was undertaken across seven UK geographical locations; these included two granitic, and five sedimentary basin settings. The comprehensive review outlined geological stratigraphy, inferred hydrogeology and thermogeology, while detailing the power and heat capacity within each region. The targeted assessments were integral to the LCOH and LCOE models. The complete findings of this assessment are included in Section 2 and Annex A.
Validation and Benchmarking	Literature was predominantly used to inform the global benchmarking exercise.
Cost analysis and data ranges	The literature review contributed valuable European and American data ranges related to various technical and cost data. This information was further enhanced by the stakeholder engagement process. Due to the commercial sensitivity of the data provided, stakeholder data was generalised and presented as ranges as detailed in the following sections. The combination of stakeholder input with existing literature resulted in reasonable datasets for the model inputs. However, certain inputs had limited available data, this is elaborated on in each relevant section and the model assumptions log.
Forecast	Stakeholder data was used to inform the forecasting exercise, the primary sources for technical and cost data were derived from the U.S. Department of Energy and European publications. The specific references are detailed in the relevant annex (Annex A – D).

1.4 Summary of technologies

The project encompasses a broad range of geothermal technologies, as detailed in Table 3. These technologies include both shallow systems (less than 500 meters deep) and deep systems (greater than 500 meters deep), which are illustrated in Appendix A.

Appendix B presents a technology prioritisation matrix, offering visual ranking criteria for geothermal technologies used in this study based on their depths and geology, and whether they were assessed for heat and/or power.

Table 3: Geothermal technologies covered by the Study

Technology	Description
Closed loop (Shallow)	Vertical loops/pipes are installed in boreholes typically between 50 and 200 meters deep below ground level. They are arranged in arrays/lattice patterns. The system comprises an underground heat exchanger and piping network, heat pump/heat exchanger, and building distribution system. Manifolds are used to connect the borehole arrays.
Open loop (Shallow)	Typically, two water wells (boreholes) 100 to 200m depth; one for abstraction and at least one for discharge of groundwater to and from the same aquifer. The water is pumped from the abstraction borehole and piped to the heat exchanger where heat is transferred to the heat pump prior to being returned to the aquifer. These systems can be used reversibly, as Aquifer Thermal Storage (ATES). In these instances one well, part of a doublet (2-well system) could be used to abstract for one season, and reinject in another season over a single annual period. The aquifer is used as a thermal store inter-seasonally. Likely benefits are improved heat pump performance (COP). The potential performance increase is not considered within this study.
Minewater (Shallow)	Mine water energy systems utilise heat in abandoned mine systems. Both open and closed loop systems are possible. This study looks at open loop Minewater systems only. Open loop systems utilise boreholes installed into the mine workings to abstract mine water, which is then passed through a heat exchanger/heat pump before being returned to the mine workings via another borehole. Existing mine water abstraction schemes can provide an opportunity for an open loop system.
Coaxial well (Deep)	A single borehole is fitted with an inner insulated liner, forming an annulus between the liner and the borehole wall/casing. The base of the well can either be 'open'/perforated, referred to as a standing column well, or 'closed' referred to as a coaxial well. Warm water is brought up from the base of the well within the inner insulated liner, and the heat is transferred at the surface via a heat exchanger before being returned down the borehole via the outer annulus. Deep coaxial wells operate as closed-loop system, while standing column wells operate as an open-loop system; with low volumes of formation fluid being incorporated in the system, and often discharged at the surface, a process known as bleeding.
Oil and gas conversion	One approach is to install an insulated liner to create a deep coaxial single well/standing column well, which is an adaptation of established shallow geothermal technologies. Another approach is to connect two existing wells

Technology	Description
	and set up a hot sedimentary aquifer system. This system requires at least two wells: one for abstraction and at least one for discharge of groundwater to and from the same aquifer Repurposing wells benefits from reduced CAPEX costs (as the well(s) are already built). However, consideration must be given to the handling of co-produced gas and/or oil.
Deep geothermal doublet	Hot sedimentary aquifer (HSA) systems target deep reservoirs (>500m depth) and can provide water at higher temperatures relative to shallower systems in favourable geological conditions. Enhanced geothermal systems (EGS) are implemented in hot rocks where there is potential for natural permeable pathways that can be enhanced for circulating geothermal fluids. Once operational, both HSA, and EGS systems circulate fluid between wells through a permeable pathway (natural or engineered fracture network), and therefore have been assessed in the same way within the modelling, as 'deep geothermal'. HSA work in a similar way to an open-loop system, utilising a well doublet (i.e., abstraction and discharge borehole). Abstraction requires a pump, and a second pump may be required to discharge water back into the aquifer. With sufficiently high temperatures, these systems can be used for direct heating (not requiring a heat pump) but do require a heat exchanger to transfer heat to buildings or district heating networks. EGS involves drilling an abstraction borehole and a discharge borehole into an impermeable rock or existing fracture/fault system (benefitting from existing permeability). A fracture network can then be established or modified through stimulation to enhance their permeability and allow geothermal fluid to move from the discharge well to the abstraction well. The fluid is heated as it permeates through the fractures. Hydraulic stimulation may result in additional costs (not captured as part of this study).

1.5 Stakeholder Engagement

Stakeholder engagement was a significant contribution to the research for this project. It was important to obtain accurate data related to costs and technical assumptions for geothermal parameters. Information was obtained directly from developers and suppliers, focusing on both UK-specific sources and international data to supplement UK evidence, where there was limited experience. This ensured the study presented a balanced assessment of data.

The key steps undertaken before, during, and after the stakeholder engagement are described below;

Data collection and review

- An extensive data collection exercise was undertaken to ensure that existing and varied published data was used; and to allow stakeholders (globally) a chance to input into the task. See 0.
- Published datasets were reviewed and key data, including costs, technical data, and financing information was extracted and used in the LCOE data model. See Annex C.
- Published data ranged in currency and publication date. Currency conversion was applied to ensure consistent representation in 2023 Sterling costs.
- During the analysis, a detailed review of published datasets (referenced within individual model assumptions) was undertaken, focusing on critical information such as costs, technical data, and financing details.

Integration into models

- These key data points were then integrated into the Levelised Cost models.
- To standardise the data, an index for currency conversions[8] was based on the 2024-06-01 date.
- The GDP deflator was applied to present costs in a consistent basis (from ONS - last updated 15 February 2024).
- This approach ensured accurate and consistent data representation within the models.

Stakeholder Surveys and Discussion

[8] Currency conversions set to 2024-06-01 values, as per: https://www.xe.com/en-gb/currencytables/

- As discussed in Table 2, two stakeholder surveys were conducted;
- A main stakeholder survey covering both shallow and deep geothermal technologies.
- A secondary survey was provided to the Ground Source Heat Pump Association (GSHPA) solely focusing on shallow technologies.
- For each technology, detailed technical assumptions were provided, inviting stakeholders to share their insights. Additionally, questions related to capital expenditure (CAPEX), operational expenditure (OPEX), and financing were posed.

External Outreach Efforts

- We engaged additional stakeholders through external outreach efforts:
- Project overview delivered to the National Geothermal Taskforce on February 15th.
- Commentary during a Geological Survey of Northern Ireland (GSNI) Webinar on February 22nd.
- QR code links distributed during the All-Party Parliamentary Group on deep geothermal at the House of Lords on January 23rd.
- Increased visibility at the UK Geothermal Symposium in November 2023.

1.5.1 Summary of the stakeholder data

A total of 448 industry stakeholders were contacted across the global geothermal industry using a standardised questionnaire (included in 0). Of these, 18 responded in the main questionnaire, while an additional 8 engaged in the secondary GSHPA-specific survey. Stakeholder engagement numbers are shown in Figure 5.

Among the returned questionnaires:

- Seven stakeholders had experience with deep geothermal systems.
- Twelve stakeholders had experience with shallow geothermal systems.
- Three stakeholders had experience with both systems.
- A total of four stakeholders provided their opinions on the research via the questionnaire but did not comment on the technology details.
- Additionally, five stakeholders directly emailed their opinions on the research without responding to the questionnaire.
- Notably, two stakeholders initially started the survey but later withdrew their consent.

Figure 5: Stakeholder engagement

After conducting the questionnaire and reviewing relevant literature, Arup took a proactive approach by engaging in individual one-on-one interviews with stakeholders. A total of 23 such interviews were conducted with manufacturers, supply chain, developers, and operators. The primary goal was to collect stakeholder insights regarding anticipated cost and specific technical performance for construction, operation, maintenance, and decommissioning of the geothermal systems. Additionally, the stakeholder engagement process delved into potential factors influencing future cost adjustments.

- Nine of the one-on-one sessions were conducted with respondents who completed questionnaires.
- Among the fourteen new interviewees:
  - Five stakeholders had experience with deep geothermal systems.
  - Five stakeholder had experience with shallow geothermal systems.
  - Two stakeholders had experience with both systems.
  - Two stakeholders shared their opinions on the research but did not provide comments on the technology specifics due to either commercial sensitivities or limited experience.

The data collection process included a reasonable balance between developers, trade associations, supply chain contractors and asset owners as shown in Figure 6.

The stakeholders who engaged were from various countries. While the majority were from the UK, there were also 9 from wider Europe, 6 from the Americas, 4 from Africa, 2 from Oceania, and 4 from Asia. Additionally, one stakeholder identified their location as global. This diverse representation was essential for gaining perspectives, expertise, market insights, technology innovation, policy alignment, and financing aspects.

This current study draws on substantially more data than the previous LCOE model, which was completed in 2016 and incorporated geothermal energy [45]. The 2016 study engaged with manufacturers, developers, trade associations, and utility companies, but only 11 data points, with an average installed capacity of 3.0 MW, were deemed robust, representative, and valuable for the analysis. Notably, the stakeholder engagement process for the current study involved five times the number of stakeholders compared to the 2016 review.

Annex B and Annex C each include a data collection table which summarises the stakeholder data collected for each model.

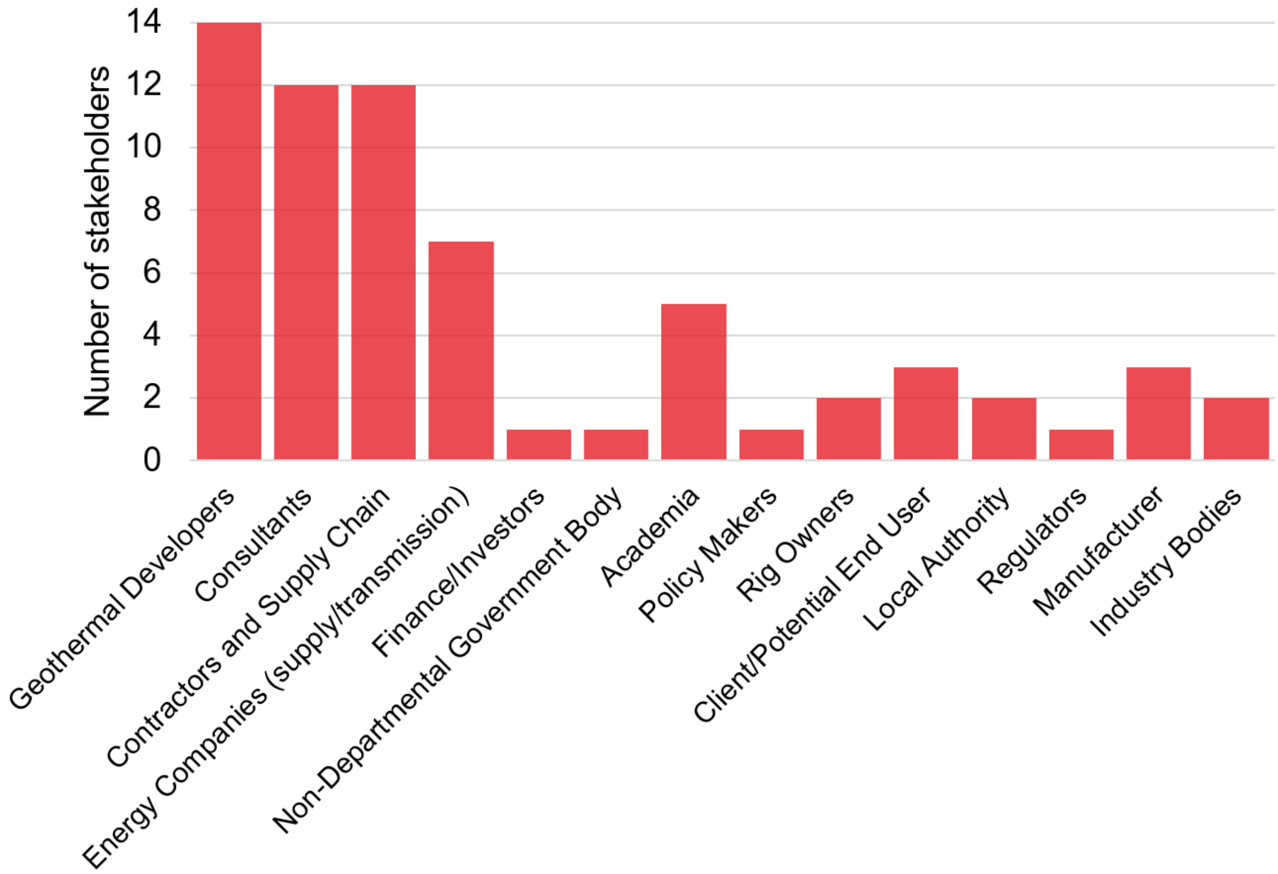


Figure 6: Stakeholder roles and group distribution

2. UK Geothermal Assessment

2.1 Introduction

This section summarises Task 2, the assessment of heat and power outcomes that was conducted for the target geothermal locations in the UK.

Full details of the approach, methodology, and assessment outcomes are presented in Annex A. This annex includes discussion of the geology, hydrogeology, and thermogeology for each of the assessed UK regions, and discussion of the modelling approach. The UK geothermal assessment pertains exclusively to heat and power from various geothermal technologies. The assessment has been used to feed into the LCOH and LCOE assessments.

2.2 Approach

2.2.1 Geological characterisation

A literature review and modelling exercise was undertaken to infer the geological stratigraphy and produce ground models at seven selected sites in the UK. Further details of how the geological characterisation was completed for each location are presented in Annex A.

Considering the geographical spread, a specific target location was used for each geology as shown in brackets:

1. Wessex Basin (Portsmouth)
2. Cheshire Basin (Manchester Airport)
3. Northumberland & Solway Basin (Newcastle)
4. Glasgow & Clyde Basin (Western Edinburgh)
5. Northern Ireland Sedimentary Basin (Loch Neagh Basin, Antrim)
6. Cornish granites (Cornwall)
7. North Scotland granites (Western Aberdeen)

Then for each of the geothermal targets (sedimentary basin and granite bodies), a target depth (see Table 4) inferred temperature, and estimated permeability ranges were determined. These values were used to inform the heat assessment and power assessment, further detail is presented in Annex A.

Note for the hydrothermal targets, only reservoirs which were estimated with a bottom hole temperature (BHT) of greater than 100°C were considered.

Table 4: Geological summary for each target location

Parameter	Value
Wessex Basin (Portsmouth)	
Geothermal gradient	Between 35 to 40°C/km
Potential deep geothermal reservoirs	Great Oolite Group – Principal aquifer – 1150 to 1300m depth
	Inferior Oolite Group – Principal aquifer – 1300 – 1440m depth
	Sherwood Sandstone Group – Principal aquifer – 1800 to 1920m depth
Cheshire Basin (Manchester)	
Geothermal gradient	Between 25 to 35 °C/km

Parameter	Value
Potential Shallow open loop aquifer	Sherwood Sandstone Group – Principal aquifer – 350 to 1250m depth
Potential deep geothermal reservoirs	Appelby Group (Collyhurst Sandstone Fm.) – 1500 to 2000m depth
	Craven Group – 3100 to 4850m depth
Northumberland & Solway Basin (Newcastle)	
Geothermal gradient	35 to 40 ºC/km
Potential deep geothermal reservoirs	Fell Sandstone – Principal aquifer – 2000 to 3000m depth (Kingston Park)
	Fell Sandstone – Principal aquifer – 1420 to 1795m depth (Science Central)
Glasgow & Clyde Basin (Edinburgh)	
Geothermal gradient	Between 28 to 32 ºC/km
Potential deep geothermal reservoirs	Kinnesswood Fm. – Secondary A – 1700 to 2000m depth
	Know Pulpit Fm. – Secondary A – 2000 – 2150m depth
Northern Ireland Sedimentary Basin (Lough Neagh Basin, Antrim)	
Geothermal gradient	Between 30 to 34 ºC/km
Potential deep geothermal reservoirs	Sherwood Sandstone Group – Principal – 2000 to 2650m depth
	Lower Permian Sandstones – Principal – 2900 to 3200m depth
Cornish Granites	
Geothermal gradient	Between 33 to 35 ºC/km
Potential deep geothermal reservoirs	Cornwall granite – Unclassified – 4000m depth
	Cornwall granite – Unclassified – 5000m depth
North Scotland Granites (Aberdeen)	
Geothermal gradient	Between 28 to 32 ºC/km
Potential deep geothermal reservoirs	Scottish granite – Unclassified – 4000m depth
	Scottish granite – Unclassified – 5000m depth

2.3 Summary of findings

Table 5 and Table 6 present a summary of the geothermal heat assessments.

Table 7 presents a summary of the geothermal power assessment. The heat and power capacities presented were used to inform the levelised cost models. Further detail is presented in Annex A.

Permeability[9] and effective aquifer thickness are the two most important geological parameters which impact upon modelled thermal output. The difference between input and exit temperature of the delivery fluid at the heat exchanger, ΔT, is the most important operational parameter for modelled thermal output.

[9] The ability, or measurement of a rock's ability, to transmit fluids, measured in millidarcies for this report.

Thermal outputs vary significantly based on location across the UK and depth of the reservoir, as shown in Table 5 and Table 6. The limited data on deep geology requires aquifer thicknesses to be estimated in some locations impacting the thermal output. For example, an aquifer may be 300m thick, however if only 50% of the unit is sufficiently permeable to contribute flow, then it would be inappropriate to model the full 300m thickness. This has been captured within the DoubletCalc models; with net-to-gross set at 0.4, 0.5, and 0.8 for low, medium, and high respectively. Based on our assessment of the data these numbers were considered appropriate to represent UK reservoirs. Further geological assessment could be undertaken, including reservoirs not considered in this study, to improve the accuracy of the calculated thermal outputs.

Unsurprisingly, granites (in Cornwall and West Aberdeen), with their greater depths and elevated geothermal gradients, offered the highest thermal and power potential;

Sedimentary Basins:

- Target Depths: Ranging from 1,150 to 4,350 metres
- P10 Thermal Capacity: 1.0 – 13.6 MWe

Granites:

- Target Depths: Assessed at 4,000 and 5,000 metres
- P10 Thermal Capacity: 17.1- 23.3 MWe

The inferred ground models and double calc inputs and output graphs for each target location are provided in Annex A.

The following tables include an indication on relative confidence. Deep geothermal systems are inherently uncertain until a well has been drilled and tested. The productivity of a given geothermal well may underperform or overperform from modelled estimates.

Table 5: Summary of Sedimentary aquifer geological parameters and thermal and power capacity estimates

Setting	Location	Aquifer / granite	Depth (m)	Thickness (m)	Gradient (°C/km)	Permeability (mD)[1] [most likely]	Flow (l/s)			Thermal Capacity (MWth)[2]			Confidence[3]
							P90	P50	P10	P90	P50	P10	
Wessex Basin	Portsmouth	Great Oolites	1150 - 1300	150	35 – 40	1 – 400 [150]	6.4	14.4	24.3	0.7	1.7	2.9	Low-medium
		Sherwood Sandstone	1800 - 1920	120	35 – 40	1 – 400 [150]	7	15.7	27.6	0.8	2.2	3.9	Medium-high
Cheshire Basin	Manchester Airport	Collyhurst Sandstone Formation	1600 - 1900	300	25 – 35	1 – 300 [100]	9.2	20.5	35.6	0.9	2.25	4.05	Medium
		Early Carboniferous Limestone	3850 - 4350	500	25 – 35	1 – 400 [150]	38.1	49.9	56.1	8.2	11.2	13.6	Low-medium
Northumberland & Solway Basin	Newcastle, Science Central	Fell Sandstone	1420 - 1795	375	35 – 40	1 – 250 [100]	13.9	28.4	42.8	1.8	4.0	6.2	Medium-high
	Newcastle, Kingstone Park	Fell Sandstone	2000 - 2375	375	35 – 40	1 – 250 [100]	17.5	33.8	47.5	2.7	5.4	8.0	Medium
Glasgow & Clyde Basin	Western Edinburgh	Kinnesswood Fm.	1700 - 2000	300	28 – 32	1 – 100 [50]	5.3	11.5	17.6	0.5	1.3	2.2	Low
		Know Pulpit Fm.	2000 - 2150	150	28 – 32	1 – 100 [40]	2.2	5.1	9.3	0.1	0.4	1.0	Low
Northern Ireland Sedimentary Basin (Lough Neagh Basin)	Antrim	Sherwood Sandstone	2200 - 2650	450	30 – 34	1 – 400 [150]	30.9	55.6	74.3	4.2	8.2	11.5	Low
		Lower Permian Sandstones	2900 - 3200	300	30 – 34	1 – 300 [100]	17.4	32.9	46.3	2.6	5.4	8.0	Low

[1] Permeability is a very challenging parameter to assess. Core measurements can be used where available; however, these only reflect primary permeability, ignoring fracture influence. Owing to their depth, deep geothermal reservoir permeability is often dominated by secondary (fracture) permeability. Therefore, the permeability estimates presented are often an order of magnitude greater than core measurements recorded in literature. Permeability is reported in mD (Millidarcy).

[2] The calculated thermal capacity estimates are high level used to inform the levelised cost models only. The values are not to be relied upon for more detailed site assessments.

[3] Relative confidence based on geological data availability. Many locations have ‘low’ confidence, which reflects the lack of literature, deep well data, or seismic data available in the area.

Table 6: Summary of granite body geological parameters and thermal capacity and power capacity estimates

Setting	Location	Depth (m)	Gradient (°C/km)	Permeability (mD) [most likely]	Flow (l/s)			Thermal Capacity (MWth)			
					P90	P50	P10	P90	P50	P10	Confidence
Cornwall Granites	Cornwall	4000	33 – 35	1 – 5000 [200]	37.6	57.3	67.6	9.5	15.0	19.4	Low
		5000	33 – 35	1 – 5000 [150]	37.5	59.9	70.9	10.6	17.9	23.3	Low
North Scotland Granites	West Aberdeen	4000	28 – 32	1 – 5000 [100]	17	40.9	64.3	3.5	10.3	17.1	Low
		5000	28 – 32	1 – 5000 [100]	20.9	47.7	67.3	5.7	14.9	22.4	Low

Table 7: Power assessment summary

Setting	Location	Aquifer / granite	Depth (m)	Gradient (°C/km)	Bottom-hole Temperature estimate (°C)	Flow (l/s)			Power Capacity (MWe)			Confidence
						P90	P50	P10	P90	P50	P10	
Cheshire Basin	Manchester Airport	Early Carboniferous Limestone[1]	3850 - 4350	25 – 35	109 – 149	38.1	49.9	56.1	<0.1	0.4	1	Low
Northern Ireland	Antrim	Lower Permian Sandstones[1]	2900 - 3200	30 – 34	106 – 119	17.4	32.9	46.3	<0.1	0.3	0.8	Low
Cornwall	Cornwall	Granite[2]	4000	33 – 35	142 – 173	40	60	80	1.3	1.9	2.5	Low
		Granite[2]	5000	33 – 35	175 – 185	40	60	80	2.2	3.3	4.2	Low
North Scotland Granites	West Aberdeen	Granite[2]	4000	28 – 32	122 – 138	20	50	70	0.5	1.3	1.4	Low
		Granite[2]	5000	28 – 32	150 – 170	20	50	70	0.9	2.1	2.9	Low

3. Levelised Cost of Heat (LCOH)

This section summarises the Levelised Cost of Heat Assessment for geothermal projects across the UK. It addresses Task 4: *Draft levelised cost chapter (Heat) including Raw cost data, assumptions and calcs for heat.* The full set of input and outputs data tables and assumptions are presented in Annex B.

3.1 Introduction

Across Europe there are over 19,000 district heating networks supplying heat to over 77.3 million citizens. Geothermal energy currently provides 2.5% of district heating across Europe, but this percentage is significantly higher in certain countries: Iceland and France (80%), Germany (50%), Poland (15.6%), and Hungary (11%). In the UK, only 2-3% of heat is currently supplied by district heating networks (DHNs), of which geothermal provides a small portion, with only a handful of geothermal DHN systems in operation (e.g., Gateshead supplies around 6.2MW [78]). It is estimated that DHNs will need to supply 20% of heat by 2050, with geothermal energy potentially being a major contributor [48].

Globally, geothermal deployment for heating and cooling grew at an average rate of around 9% annually between 2015 and 2020 to reach 107 GWth in 2020 [76]. Geothermal heat is predominantly used to heat buildings; which comprises around 86% of geothermal heat use globally in 2024 [77].

As the UK strives to achieve its ambitious net-zero emissions targets, geothermal energy offers a good opportunity to deliver clean, reliable heating and cooling. This chapter describes the LCOH assessment for shallow and deep geothermal technologies across the UK.

Within the UK, the following funding support schemes are available: Green Heat Network Fund (GHNF), Heat Networks Delivery Unit (HNDU), and Public Sector Decarbonisation Scheme (PSDS); these funds are generally applicable to shallow/ surface renewable heat systems. Therefore the funding mechanisms explored as part of this study focus on deep geothermal for heat.

The LCOH model required the assessment of generalised heating capacity estimates for all of the ground source heat pump (GSHP) and deep geothermal technologies. For GSHP technologies, heat pumps can, and often are, operated in heating and cooling modes seasonally. If thermal loads are imbalanced, for example heating only (e.g. for residential buildings), or cooling only (e.g. data centres); then the ground is more susceptible to becoming thermally depleted, which detrimentally impacts upon GSHP efficiency. Following discussions with stakeholders, it was decided to include the option to toggle on the 'cost of cooling' within the model as a discounted cost. The shallow systems within the LCOH model therefore consider heating only, and heating and cooling scenarios. This model represents the first Levelised Cost of Heat model of geothermal heat undertaken in the UK.

Conversely, deep geothermal systems, typically targeting multiple kilometre depths, have high temperatures. Deep geothermal systems can provide heat directly (if temperatures are sufficient to meet demands) or boosted (e.g. with use of high temperature heat pumps). Deep geothermal cooling is possible with adsorption or absorption chillers; however, these have not yet been extensively commercially deployed. Therefore, the deep geothermal systems within the LCOH model consider heating only.

Levelised costs are specific to the assessed scenarios. The LCOH and LCOE models use assumed values for heat capacity, costs, and heat users. Levelised costs developed in this study allow direct comparison between technologies but are not appropriate for direct application to a specific site. Thus, site specific cost assessments are necessary to appraise individual developments. The models and reported findings outline the functionality of the models, provide indicative levelised costs, and highlight the potential impact of various funding mechanisms.

A summary of the assessed technologies is provided in Table 8, a summary diagram is also included in Appendix A.

Table 8: Summary of assessed technologies

Technology	Summary
Shallow GSHP technologies	
Closed loop vertical boreholes	Vertical loops/pipes are installed in boreholes between 50 and 200 meters deep below ground level. They are arranged in arrays/lattice patterns and are more common than horizontal systems due to their space efficiency, especially in cities with limited space and high energy demands. The system comprises an underground heat exchanger and piping network, heat pump/heat exchanger, and building distribution system. Manifolds are used to connect the borehole arrays.
Open loop wells – Traditional	Open-loop geothermal wells require at least two water wells (boreholes): one for abstraction and at least one for discharge of groundwater to and from the same aquifer. The water is pumped from the abstraction borehole, usually using an electrical submersible pump (other pumps may be possible) and piped to the heat exchanger where heat is transferred to the heat pump prior to discharge.
Minewater systems	Mine water energy systems utilise heat in abandoned mine systems. Both open and closed loop systems are possible. Open loop systems utilise boreholes installed into the mine workings to abstract mine water, which is then passed through a heat exchanger/heat pump before being returned to the mine workings via another borehole. Existing mine water abstraction schemes can provide an opportunity for an open loop system. Closed loop systems work by installing the closed loop into the mine workings via boreholes. Heat is transferred to/from the mine workings to the geothermal fluid within the closed loop.
Deep Geothermal technologies	
Advanced Geothermal Systems (AGS)	AGS is an emerging technology. There is insufficient practical data to competently derive an LCOH/LCOE estimate. This technology has been excluded from the levelised cost models.
Repurposing oil & gas wells	Oil and gas wells are often drilled deep into permeable geologic strata. Repurposing these wells can be a cost-effective way to harness geothermal energy. One approach is to install an insulated liner to create a deep coaxial single well/standing column well, which is an adaptation of established shallow geothermal technologies. Another approach is to connect two existing wells and set up a hot sedimentary aquifer system. This system requires at least two wells: one for abstraction and at least one for discharge of groundwater to and from the same aquifer Both options have been considered in the assessment.
Deep single coaxial well / standing column well	A single borehole is fitted with an inner insulated liner, forming an annulus between the liner and the borehole wall/casing. The base of the well can either be 'open'/perforated, referred to as a standing column well, or 'closed' referred to as a coaxial well. Warm water is brought up from the base of the well within the inner insulated liner, and the heat is transferred at the surface via a heat exchanger before being returned down the borehole via the outer annulus. Deep coaxial wells operate as closed-loop system, while standing column wells operate as an open-loop system; with low volumes of formation fluid being incorporated in the system, and often discharged at the surface, a process known as bleeding.
Hot sedimentary aquifer (HSA) – termed 'Deep geothermal' in models	Deep geothermal systems target deep reservoirs (>500m depth) and can provide water at higher temperatures relative to shallower systems but require favourable geological conditions. They work in a comparable way to an open-loop system, utilising a well doublet (i.e., abstraction and discharge borehole). Abstraction requires a pump (typically an electrical submersible pump), and a second pump may be required to discharge water back into the aquifer. With sufficiently high temperatures, these systems can be used for direct heating (not requiring a heat pump) but do require a heat exchanger to transfer heat to buildings or district heating networks.

3.2 Methodology

Levelised cost can be defined as the discounted lifecycle cost of building and operating an energy generation asset, expressed as a cost per unit of electricity or heat (£/MWh). LCOH represents the break-even tariff, i.e. the price per MWh that stakeholders need to recover their costs. The calculation averages the cost of production over the life of a plant and allows both cost and generation to be converted into a single value. For the analysis there are two important aspects of the definition which need to be considered:

- What assets are included within the cost; and,
- The operational time period over which the levelised costing will take place.

For consistency with previous studies, the definition of levelised cost applied in this study only takes into account the costs borne by developers in relation to construction and operation of a renewable geothermal generation project. It does not take account of the wider capital and operational costs of the wider DHN. It includes costs up to the point to heat/coolth generation only; i.e., includes costs of installing heat pumps or construction of a heat plant. It excludes costs of distribution district heating networks or other piping infrastructure. Distribution is excluded because this is highly site-specific, and it was considered inappropriate to generalise this and include it within the model.

The models assume that 100% of generated heating and cooling is sold to off-takers. For shallow systems, which are often purpose built for a given heat/cooling user, this assumption is reasonable as the system is unlikely to be operated unless the energy demand is present. Deep geothermal systems are assumed to deliver heat to DHNs. This is dictated by the demands of the DHN. Should deep geothermal systems be geographically isolated, alternative heat users, such as distilleries or greenhouse agriculture may be suitable off-takers. The assumption that 100% of generated thermal energy is sold to off-takers is used for simplicity and idealised scenarios; in reality this may be an oversimplification (resulting in more favourable LCOH values).

Project duration is a critical factor in the development, delivery, and operation of geothermal projects. The following were factored into the calculation:

- The estimated time it takes for a project to go through design, construction, and delivery.
- The expected operational life of the technology in question.
- The hurdle rate is applied as the discount rate which allows the valuation of future values to be brought back to present values i.e. the value today of a future stream of costs.

The reported costing year in this report reflects the project start year i.e. the year the model, and system development (pre-development), starts. For example, '2024 costs' refer to pre-development starting in 2024, not system operation. Different technologies have different development timescales. Commissioning dates are based on average project durations for planning, construction, and commissioning of around 2 years for shallow systems, and 6 to 8 years for deep geothermal systems. Therefore, assuming a 2024 start date, a shallow system may be operational in 2026, and deep geothermal system may be operational in 2030 to 2032. A summary of generalised timescales is presented in Table 9.

A summary of generalised timescales is presented in Table 9.

Table 9: General timescales for shallow and deep system types

System	Shallow systems	Deep systems
Pre-development	0.5 to 2 years	0.5 to 2 years
Construction	1 to 2 years	1 to 6 years
Operation	20 to 40 years	20 to 40 years
Decommissioning	Not required	0.5 to 1 year

3.2.1 Components of Levelised Cost

Table 10 provides a summary of the components of levelised cost models.

Table 10: Cost Definitions for geothermal

Cost Items	Description
Development Costs ('DEVEX')	
Pre-licensing cost	Development costs including planning, submission fees, survey costs etc.
Technical development cost	Technical design associated with the development of a geothermal projects
Planning cost	Covers regulatory costs, licensing, public enquiry, 'local community engagement' costs.
Capital Costs ('CAPEX')	
Capital (overnight) cost	Capital cost covers the projected design, procurement, and construction costs e.g. Engineering, procurement, and construction (EPC) costs if applicable (e.g. well drilling, equipment, plant). It also covers the full capital cost excluding interest costs during construction and land costs.
Owner's cost	Includes procurement cost, project management, owner's engineer etc.
Construction, inclusive of infrastructure costs	Includes costs up to the point to heat/coolth generation only; i.e., includes costs of installing heat pumps or construction of a heat plant. It excludes costs of distribution district heating networks or other piping infrastructure. Distribution is excluded because this is highly site-specific and it was considered inappropriate to generalise this and include it within the model.
Decommissioning costs	The cost to decommission the well assets to meet regulatory requirements and the cost to decommission surface plant. Well decommissioning requirements vary with technology (e.g. open loop systems are more onerous than closed loop).
Operational Costs ('OPEX')	
Fixed O&M cost	Costs such as labour, planned and unplanned maintenance, spares and consumables.
Variable O&M cost	Calculated on a per MWh of generation basis. These are output related expenditures, such as electrical submersible pump (ESP), heat pump, or surface plant pumping costs.
Insurance Cost	Excluded from models.
Financial	
Hurdle rate	The minimum rate of return required on a project of investment. The greater the risk involved in an investment, the higher the hurdle rate. The hurdle rate for deep geothermal has been assumed to be greater than shallow due to the greater drilling depth.
Timescales	
Pre-development	Time period for completing desk-based assessments, surveys, designs, planning, and permitting
Development	Time period for drilling the well assets and constructing the surface plant
Operation	Time period of system operation
Decommissioning	Time period for decommissioning the well assets and surface plant

Arup collected generation cost and technical data for all geothermal heating systems, with the aim to provide DESNZ with an updated view on the commercial and technical aspects crucial for project development. Additionally, Arup conducted a review of learning rate forecasts for construction and operating costs.

3.2.2 Data Collection

This section provides a more detailed breakdown of the type and volume of data collected for each of the key LCOH model inputs. A summary of the data collection is presented in Table 11 and Table 12.

Table 11: Geothermal, Cost Data Collection

Data Item	Overview of Data Collected		Confidence[1]
	Stakeholders	Literature / Reports	
Closed loop Open loop Minewater Coaxial Deep geothermal O&G geothermal conversion	We collected data from 9 companies through questionnaires and conducted one-on-one interviews with an additional 3 companies, resulting in a total of 12 data points. The questionnaire provided structured responses, while interviews allowed for open-ended discussions, revealing nuances and details. There is data on factors such as system timescale and costs per phase, data on installed systems, and heat pump efficiencies. These are crucial for LCOH modelling. Insights from the interviews highlighted the need to consider cooling within shallow systems; and complexities around selecting reasonable representative numbers to generalise these systems. This qualitative information complements quantitative data. The dataset also includes geographical diversity (from different countries), which enhances its usefulness. Geothermal resources vary by location, and this diversity ensures a more robust model. The dataset represents a cross-section of the geothermal industry. They cover a spectrum of project sizes, technologies, and operational contexts. Emerging trends and perspectives were captured. These additional data points enhance the dataset's representativeness. While no dataset can fully encapsulate every scenario, this approach struck a balance between breadth and depth, making it a credible and relevant sample for LCOH modelling.		
Development costs ('DEVEX')			
Pre-licensing costs	6 stakeholders, 7 data points.	None	High
Construction Costs ('CAPEX')			
Capital (overnight) costs – drilling	5 stakeholders, 7 data points (general values rather than project costs).	Deep drilling: same as LCOE assumptions (see Annex C)	High
Capital (overnight) costs – plant	3 stakeholders, 3 data point (general values rather than project costs).	IRENA [50], Publications [86] [87]	Medium
Operational Costs ('OPEX')			
Fixed O&M costs	None	IRENA [50], Publications [86] [87]	Low-Medium
Variable O&M costs	None	IRENA [50], Publications [86] [87]	Low-Medium
Decommissioning (Abandonment) Costs ('ABEX')			
Well decommissioning	3 data points from 1-to-1 discussions		Medium
Plant decommissioning	1 stakeholder, 1 data point (project value)		Low
[1] Relative confidence is determined by the availability and reliability of data sources, whether from stakeholders or publications. Low confidence indicates parameters derived from only a few number of sources. Medium confidence reflects a combination of limited stakeholder data and some published information. High confidence reflects parameters supported by numerous stakeholder inputs and literature sources that are broadly consistent with each other.			

Table 12: Geothermal, Technical Data Collection

Data Item	Overview of Data Collected		Confidence[1]
	Stakeholders	Literature	
Timing			
Pre-development period	6 stakeholders, 7 data points.	Publication [86]	High
Construction period			High
Plant operating period			High
Heating & cooling output			
Heat output	Informed from Arup assessment (see Annex A)		See Table 5
Cooling output	Informed from Arup assessment (see Annex A)		High
Operational Assumptions			
Seasonal Performance Factor (SPF)	9 stakeholders, 9 data points		High
Availability profile (inclusive of load profile)	3 stakeholders	Publications [86]	High
Other			
Hurdle rates	Shallow geothermal: Consistent with previous DESNZ internal analysis (2024)[10] Deep geothermal: Consistent with 2025 DESNZ commissioned research [116].		Low
Learning rates	None	Publications [80][81]	Low-Medium
[1] Relative confidence is determined by the availability and reliability of data sources, whether from stakeholders or publications. Low confidence indicates parameters derived from only a few number of sources. Medium confidence reflects a combination of limited stakeholder data and some published information. High confidence reflects parameters supported by numerous stakeholder inputs and literature sources that are broadly consistent with each other.			

As presented in Table 11 and Table 12; a large volume of published data and stakeholder data has been used to inform the assessment. The data between stakeholders and published literature shows good agreement, and therefore is considered to be a reasonable basis for the values used in the LCOH model. However, it is important to note that certain parameters have more data points than others.

3.2.3 Stakeholder Feedback

Arup carefully examined stakeholder responses and one-on-one feedback to gain insights into stakeholder perspectives on the potential evolution of future costs, technical performance, and the geothermal systems market. A concise summary of these findings is provided in Table 13.

[10] The internal DESNZ analysis (2024) was not specific to geothermal and is being reviewed. Hurdle rates were not assessed as part of this report and used as an input assumption only.

Table 13: Summary of Key Stakeholder Feedback

Key Highlights
System variability: stakeholders highlighted that use of generalised parameters is challenging, as each geothermal system will vary on a site-by-site basis. Despite this variability, for the purposes of the study, stakeholders found the implemented technical assumptions generally reasonable. This was done by asking the stakeholders to directly comment within the questionnaire and during the 1-to-1 meetings. **Cooling**: stakeholders highlighted that omission of cooling as part of ground source heat pump systems would strongly negatively impact the LCOH (acting to increase the value); and critically, not be representative of the system. Arup have taken this on board and included discounted cooling revenue within the model. It should be noted that heating only and heating and cooling scenarios have been modelled, this is to reflect the fact that GSHP systems are typically used for heating only, however, are increasingly being used for heating and cooling. **Hybrid solutions**: stakeholders highlighted that geothermal and ground source heat pump systems are often used in conjunction with other heating/cooling systems. For example, a shallow closed loop borehole system may provide 1MW baseload capacity (covering 60% of the annual heating demand) with a similarly sized air-source-heat-pump system used in conjunction to provide the 'top-up' (or back-up) heating (or cooling) supply. This improves overall system resilience. **Heat pump design**: heat pumps can used with various heat transfer fluids (e.g. carbon dioxide, hydrocarbons, ammonia, etc.). Each fluid is suited to a different operating window (e.g. 50 to 70°C). In instances where a low-temperature geothermal system needs to be boosted in temperature to a high delivery supply (e.g. 20 degrees from the geothermal system, boosted to 75 degrees); heat pumps can be 'cascaded' (e.g. boost to 30°C, then 50°C, then 75°C, being undertaken by different heat pumps and transfer fluids) to improve efficiency. Stakeholders acknowledged that this level of detail and assumptions is too great for the purpose of this study. Per technology, the models assume operation of a single heat pump with a single seasonal performance factor (SPF). The selected SPF is based on the supply temperature and deliver temperature. **Government support**: heat pumps and geothermal systems are used across Europe and globally, however the UK is slow with its uptake. Stakeholders identify that a contributing factor may be the UK's 'spark gap' (the price difference between gas (cheap) and electricity (expensive)). In the UK this factor is around 4. So, if we assume a typical heat pump SPF of 4 (suitable for shallow GSHP systems in heating mode) the heat pump is 4 times more efficient than a gas boiler; however, given the spark gap factor of around 4; fuel costs are the same, and savings are not realised.

Additional stakeholder feedback, generally relating to the deep geothermal systems, is presented within Section 4.2.3.

3.2.4 Assumptions

Given LCOH sensitivity to the underlying assumptions such as load factor, discount rates, capital, and operating cost, the LCOH adopted the standard practice which considers a range of costs (low, medium, high) rather than a single point. This approach allows the modelling process to account for uncertainty and variability. Further details of the selected low, medium, and high values are provided in Annex B. For each variable, low, medium, and high values were selected based on a P10, P50, and P90 values where there is more than 10 data points; minimum, average, and maximum value where there is less than 10 data points; and selection of most reasonable value based on professional judgement where only a few points are available.

Arup undertook an extensive literature review and engaged stakeholders via a questionnaire and 1-to-1 discussion (see Section 1.5 and Annex E). The data gathered was used to inform the LCOH model.

The LCOH model was developed to focus on select system designs and operational heat users. As a result, some data had to be generalised to provide representative values. Table 14 presents a summary of key assumptions used to inform the LCOH model.

Table 14: Summary of key assumptions

Variable	Summary
Heat User	The scope of works comprised an assessment of District Heat Network connections for 55°C and 85°C temperatures with the intention to see how varying temperature impacts LCOH outcomes. These temperatures were selected to reflect high temperature 3rd generation DHN assumed at 85°C; and 4th Generation low temperature at 55°C DHN. These are assumed to be more commonplace in the future. Following stakeholder engagements, and from internal consideration; an additional use case which demonstrates and considers cooling revenue was also added into the model. Many shallow systems can be configured to deliver both heating and cooling. This arrangement generally benefits operational performance, can increase capacity, and extend system life (by avoiding thermal depletion of the resource with imbalanced use, e.g., heating only operation).

Variable	Summary
	Inclusion and discounting of cooling revenue within the model also acts to reduce LCOH values; as the system is operational for longer periods of the year and delivers more thermal energy. Following stakeholder engagements, and from internal consideration, an additional use case ('Hospital') which demonstrates and considers cooling revenue was also added into the model. Generalisation of system operational parameters, such as operational hours, and heating and cooling balance is very challenging to implement as every building/heat user has unique requirements. Regardless, assumptions were made to inform the model.
Operational Hours	Operational hours: For the DHN options, the system was assumed to run in heat only mode for 2000 hours for FOAK, and 6000 hours for NOAK. The difference in operational hours for the DHN is based on current FOAK systems in the UK, e.g., Gateshead, with 2000 run-hours [78]. The NOAK assumption of 6000 hours is based on a Danish Energy Agency assumption [79]. For the Hospital options, the system was assumed to run continuously all year round (8760 hours), with a 60% heating (c. 5,250 hours) to 20% cooling ratio (1,750 hours). This hospital scenario is likely an oversimplification and may represent an idealised use case. However, it serves the purpose of demonstrating the benefits of having balanced systems.
Learning rate	Learning rates: Deep geothermal learning rates were consistent with the LCOE model, at 3.3%, 0.5%, and 0.1% for high, medium, and low (see Section 4) and based on drilling rates at Fervo [13]. Drilling is the greatest capital cost component of deep geothermal systems. These learning rates are for drilling capital costs only. Learning rates for capital costs of plant were not applied, nor for system operation. Ground source heat pump (GSHP) learning rates were applied to all other systems which did not require deep well (>500m) drilling. Rates used for low, medium, and high were 0.8% to -0.2%, inferred from published data, and estimated heat pump growth rates [80][81][82] (see Annex B). These were based on published learning rates for heat pumps only. These learning rates exclude consideration of shallow drilling, plant development and system operation.
Back up heat source	The LCOH model includes a back-up heat source. This is because heating systems require resilience should the geothermal system fail or need boosting to meet peak demands. For all systems this was assumed to comprise a gas boiler, scaled to meet 100% of the geothermal system heating capacity (i.e., a 3MW geothermal system, would have a 3MW gas boiler back up). Construction costs included the cost for the boiler(s), pump(s), and mains connection. Construction costs excluded piping to/from the DHN. This is because the back-up boilers are assumed to connect to an existing network, so no additional piping is required. All costs are based on recent Arup experience. The costs are representative for 1MW to 10MW scale systems. Variable O&M costs and carbon costs are excluded. This is a back-up system and assumed to be built and maintained (fixed O&M) only; it is not assumed to be used and therefore variable O&M is obsolete.
Cooling revenue	Arup estimated cooling revenues based on a method that aligned with DESNZ's approach to estimating heat revenue. It is based on an estimate of avoided cost, i.e., the cost that a cooling customer avoids from installing and operating a stand-alone cooling system. The approach Arup applied estimated what cost would have been incurred by a cooling customer (buyer of cooling via a geothermal system), if the customer had produced the same amount of cooling using a stand-alone cooling system. The approach assumes that 100% of the cooling is purchased by the customer. The customer pays retail electricity prices to operate its cooling system, system maintenance and replacement costs which are avoided as a result of buying cooling via a geothermal generator. Please note that in the LCOH 'funding' model, cooling revenue can be turned on and off as required. (discussed further in Section 3.2.5)
Funding Model	Funding model: The purpose of the funding model Arup prepared was to test at a high-level the impact of different funding mechanisms on levelised cost. The assumptions used within the indicative funding modelling were based upon a high-level literature review of international examples of funding mechanisms for geothermal.
Hurdle Rates	A hurdle rate of 10.1% has been assumed for all deep systems. This value is consistent with 2025 DESNZ commissioned research [116]. Hurdle rates have been updated in comparison to the Arup 2016 values [83], and Europe Economics study [27]. The updated hurdle rate for deep geothermal is lower than previous figures (18.8%). The lower hurdle rate is reflective of the risk across the lifespan of the geothermal system which is comparable to the evaluation of levelised costs for other technologies. The higher hurdle rate of 18.8% is inferred to be reflective only of the risk associated with the drilling phase (exploration) of the geothermal system. Shallow systems and ground source heat pumps are more developed and therefore include less risk. Therefore, a lower hurdle rate was used. Due to limited data available on hurdle rates a hurdle rate of 7.5% was assumed, which agrees with internal DESNZ analysis (2024).

3.2.5 Discussion

3.2.5.1 Cooling Revenue

Cooling has been assumed for the Hospital scenarios, where shallow systems are used for heating and cooling. LCOH models which exclude cooling revenue from systems which deliver cooling are unrepresentative of the system as a whole and therefore discounted cooling revenue has been included as an option within Arup's LCOH model.

The potential for geothermal projects to earn cooling revenues was explored by Arup. Stakeholders indicated that cooling could become an important source of future revenue. Therefore, to test the potential impact of cooing revenue on levelised cost, the approach Arup applied was consistent with the methodology used to estimate heating revenue. In the Arup model, cooling revenue was estimated on a discounted present value basis and then net off the final LCOH estimate. Please note that Arup's estimate should only be seen to be indicative. It is based on internal assumptions but does not reflect stakeholder views or a wider study of prices in the cooling market. It is recommended that cooling revenue is a further area of research.

Arup's approach to estimating cooling revenues aligns with DESNZ's historic approach to heat revenue as discussed in Table 14.

3.2.5.2 Thermal Capacities

The LCOH model assesses 2km and 3km sedimentary systems. The UK geothermal assessment assessed reservoirs at specific depths (see Annex A); therefore, similar depths were used to inform the '2km' and '3km' levelised cost. For the 2km depth system, an average heat output of Wessex Basin Sherwood Sandstone (1920m), Cheshire Basin Collyhurst Sandstone (2000m), Northumberland & Solway Basin Fell Sandstone (1795m) and Glasgow & Clyde Basin Kinnesswood Formation (2000m) was used. For these, each P90 value was averaged, each P50 value averaged, and each P10 value averaged.

For the 3km system, an average of Northumberland & Solway Basin (3000m), Glasgow & Clyde Basin Stratheden Group (3000m), Northern Ireland Sedimentary Basin Sherwood Sandstone (2650m) and Lower Permian Sandstone (3200m) was used for P90, P50, and P10 values.

As a result of this methodology, the levelised costs are reflective of a generalised UK reservoir rather than a specific reservoir. Specific reservoirs with greater thermal capacities would have lower levelised costs; however, while this site-specific assessment was not undertaken as part of this study, it could form part of subsequent work.

Coaxial well and O&G coaxial conversion systems were assessed at 1km, 2km, and 4km depth. In-house empirical models which consider system depth, thermal conductivity of well piping/casing, flow rates, and temperature difference across heat exchanger (dT) were used to calculate system capacities.

The thermal capacity of shallow closed loop systems were assessed using thermal capacity of the borehole (40W/m), borehole depth (150m), and heat pump performance (COP). The thermal capacities of shallow open loop and minewater systems, and deep O&G open loop conversion systems were calculated using the density and specific heat capacity of water, temperature difference across heat exchanger (dT), and flow rate. Flow rate was assumed at 10, 20, and 40 l/s for open loop systems, and 20, 60, and 120 l/s for minewater systems for low, medium, high respectively. Delta T was assumed at 8°C, based on stakeholder data which ranged from 6 to 10°C. Notably, this is greater than the commonly quoted 5°C; which will result in greater open loop and minewater system capacities.

3.2.5.3 Hurdle Rates

Deep geothermal systems are higher risk than shallow systems. Reservoir permeability remains uncertain until a deep well is drilled and tested. This requires upfront investment. This risk translates to higher hurdle rates during the drilling phase of a geothermal project, however once a well is drilled and production is proven the hurdle rate of the system drastically reduces. A hurdle rate of 10.1% has been assumed for all deep geothermal systems. This value is consistent with 2025 DESNZ commissioned research [116].

Shallow systems and ground source heat pumps are more developed and less risky. Therefore, their hurdle rates are less than deep geothermal systems. A hurdle rate of 7.5% has been assumed for all shallow systems. Due to lack of available data on shallow geothermal hurdle rates a value which is consistent with DESNZ internal analysis (2024) has been used. The DESNZ internal analysis was not specific to geothermal and is currently being reviewed.

3.2.5.4 Learning Rates

Ground source heat pumps are widely implemented and utilised global technologies. Deep geothermal drilling is a growing area with continued advancements and learning. Deep geothermal drilling has greater learning rates than shallow systems and the use of GSHPs.

For shallow systems, learning rates of 0.8%, 0%, and -0.2% were assumed for low, medium and high levelised costs. This was based on literature and rate of heat pump uptake across Europe [105][106][107]. These learning rates are for heat pumps only, they exclude shallow drilling, plant development, and operational learning rates.

Deep system learning rate was governed by drilling. US DOE values present low, medium and high scenarios from 0.5%, 13%, 30%; from 2035 – 2050. Fervo presented a learning rate of c. 3.3% over the last 6 years. Arup assessment used high, med, low of 3.3%, 0.5%, and 0.1% to 2035; high learning rate reduced to 0.5% after 2035. These learning rates are for drilling only. They exclude plant development and operational learning rates.

Learning rates were implemented within the models as percentage reductions in capital costs for each successive year after 2024. For example, a 0.5% learning rate assumes costs in 2034 are 95.11% of those in 2024; based on 10 years of compounding 0.5% reductions per year; $(100(1 - 0.5\%)^{10})$. Learning rates contribute to reducing levelised costs over time (e.g., 2050 costs are generally less than 2024 costs).

3.2.5.5 Drilling Costs

Deep drilling costs are discussed in detail within Section 4. The same drilling cost assumptions for the LCOE and deep LCOH have been used.

3.2.5.6 Decommissioning

Decommissioning requirements vary per technology. Under current UK regulations closed loop systems do not need to be decommissioned. Shallow open loop and mine water wells were assumed to be handed over to the EA or Coal Authority for monitoring at the end of their life; also, not requiring decommissioning.

Oil and gas wells have decommissioning requirements assumed at £450k, £725k, and £1M per well for low, medium, and high costs. This was based on stakeholder data.

Stakeholder data for coaxial wells ranged significantly from around £5k for a simple 1 to 2km well with no natural flow (i.e., closed systems); to more than £5 to £6M for complex 4 to 5km stimulated wells capable of flow and pressure change. For the purpose of this study, it was assumed that decommissioning costs were £5k, £10k, and £15k for low, medium, and high respectively for all coaxial wells regardless of depth.

Deep geothermal systems also have decommissioning requirements. £300k, £500k, and £1.2M for low medium, and high costs were assumed for each well (abstraction and reinjection). This was based on stakeholder data.

No cost for plant decommissioning of shallow heat pump systems was included. Deep geothermal system heat plant (and power plant) decommissioning was based on a single Danish published value. £467,500k, £586,500, and £705,500 were assumed for low, medium, and high respectively.

3.2.5.7 Model Boundaries

The LCOH models (and LCOE models) include all costs up to and including energy production at the heat/power plant. The models do not include costs associated with distribution. The reason the models were bound to production only is that distribution side arrangements can vary significantly. For example, installation of a new DHN is very costly, whereas integration into an existing DHN is far cheaper.

3.2.5.8 Seasonal Performance Factors (SPF)

Coefficient of Performance (COP) is the term used to describe the efficiency of thermal energy generation for a heat pump, in either heating or cooling mode. It is a ratio of heat or cooling delivered per unit of electricity used.

The COP value is 'instantaneous' and specific to certain conditions, such as input flow and delivery flow temperatures. Taking an example of a heating only system, operating in winter, which requires a 65°C delivery temperature. When this system is initially turned on, in day one of winter, the ground will be relatively warm (e.g. 15°C) so efficiency of the heat pump will be high (e.g. COP of 4). However, over the heating period (winter), and continuous thermal extraction of heat from the ground, it's temperature drops (e.g. to 5°C). A 5°C fluid will require more thermal boosting (electrical energy) to meet the 65°C delivery temperature, relative to 15°C fluid. This will result in a lower heat pump efficiency (e.g. COP of 3). The same principal applies in cooling mode. The variability of ground temperature means that COP values vary across an annual period. To capture this variability, seasonal performance factors (SPF) can be used. This is effectively an average efficiency of the heat pump over a given period.

Within the models, SPF values have been implemented; derived from stakeholder data, literature data, and calculations. For the shallow systems an SPF_H (heating) of 4 (for 55°C) and 2.5 (for 85°C), and SPF_C (cooling) of 5 have been assumed. This was based on stakeholder data. These are generalised values for the purpose of modelling.

For deep systems:

1. 1km systems feeding 55°C DHNs had an assumed heat pump SPFH of 6.
2. 1km systems feeding 85°C DHNs had an assumed heat pump SPFH of 4.
3. 2km systems feeding 85°C DHNs had an assumed heat pump SPFH of 6.
4. 2km systems feeding 55°C DHNs, and 3km and 4km systems feeding 85°C DHNs were assumed to be direct heating, without the need for a heat pump.

The difference in SPF (efficiency) is dependent on the difference in temperature provided from the geothermal system and the DHN; the smaller the difference the greater the SPF value. Direct heating can be undertaken where supply temperature exceeds DHN temperature.

3.2.5.9 Heat User

DESNZ required the models to assume a DHN heat user at 55°C and 85°C. These temperatures were selected to reflect high temperature 3rd generation DHN assumed at 85°C; and 4th generation low temperature at 55°C DHN.

To capture the heating and cooling uses of shallow systems; an additional use case was added. A hospital use case was assumed, which requires 80% annual utilisation of the ground source system; with annual operations of 60% in heating mode (e.g. to provide heating), and 20% in cooling mode (e.g. to provide district cold water, or cool data servers). This hospital scenario is likely an oversimplification and may represent an idealised use case. However, it serves the purpose of demonstrating the benefits of having balanced systems.

3.2.5.10 Heating and Cooling Revenue

The models assume that 100% of generated heating and cooling is sold to off-takers. For shallow systems, which are often purpose built for a given heat/cooling user, this assumption is reasonable as the system is unlikely to be operated unless the energy demand is present.

Deep geothermal systems are assumed to deliver heat to DHNs. This is dictated by the demands of the DHN. Should deep geothermal systems be geographically isolated, alternative heat users, such as distilleries or greenhouse agriculture may be suitable off-takers.

3.2.5.11 Costing Year

The reported costing year in this report reflects the project start year i.e. the year the model, and system development (pre-development), starts. For example, '2024 costs' refer to pre-development starting in 2024, not system operation. Different technologies have different development timescales; closed loop system are assumed to be operational after 1 to 2 years (i.e., start in 2024, operational in 2026), deep geothermal systems may only be operational after 4 to 8 years (i.e., start in 2024, operational in 2028 to 2032).

3.3 Summary of Findings

3.3.1 Findings

A selection of LCOH values is presented in Table 15. A lot of data was generated from these models. A full summary of output data, and further details is presented in Annex B.

Table 15: Selection of LCOH values, Medium scenarios (£/MWh)

Technology	Cooling revenue	2024	2035	2050
Closed loop – Hospital (NOAK)	Yes	23	23	22
Closed loop – Hospital (NOAK)	No	44	43	41
Open loop – Hospital (NOAK)	Yes	10	11	10
Open loop – Hospital (NOAK)	No	37	36	34
Open loop – DHN 55°C (FOAK)	No	92	90	87
O&G coaxial 2km – DHN 55°C (NOAK)	No	85	83	79
O&G open loop 2km – DHN 55°C (NOAK)	No	478	464	444
Coaxial 2km – DHN 55°C (FOAK)	No	523	498	462
Coaxial 2km – DHN 55°C (NOAK)	No	277	263	245
Deep geothermal 2km – DHN 55°C (FOAK)	No	172	167	156
Deep geothermal 2km – DHN 55°C (NOAK)	No	105	102	95

The outcomes of this modelling exercise are extensive, owing to the large number of variables. These include:

- System type: the selected system;
- FOAK/NOAK: FOAK values or NOAK cost values; these reflect costs (e.g. drilling rates), and system operational hours (e.g. 2000hrs FOAK, and 6000hrs NOAK for DHNs);
- Low, medium, or high cost: in which all variables are set to one of those three levels;
- Costing year (project start): 2024, 2030, 2035, 2040, or 2050 (the cost of developing that system in a given year); and,
- Cooling revenue: does the model include discounted cooling too, applicable to hospital scenarios only.

For simplicity, medium scenario cases will be referred to within this section. These refer to modelled cases using 'medium' values for all input parameters.

Capital costs comprised the biggest component for the majority of the technologies. O&G open loop systems were found to have high pre-feasibility costs; this is because the total construction costs are low; and these values are exaggerated because the system is inferred to have a low thermal capacity. A summary of levelised costs and their breakdown is presented in Figure 7 and Figure 8.

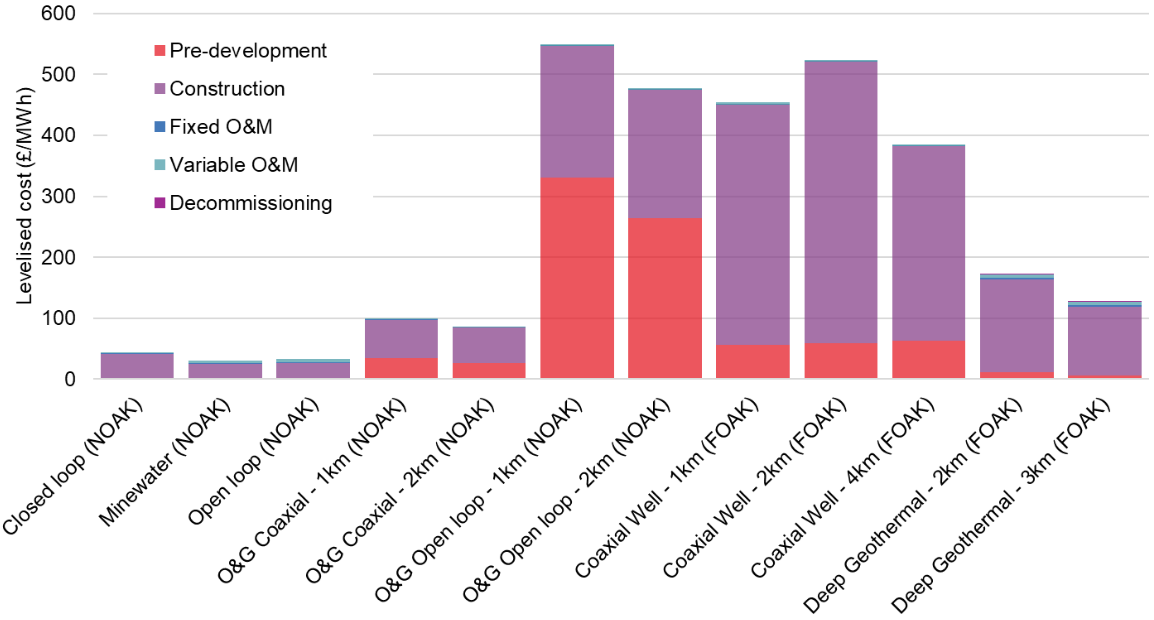


Figure 7: Levelised cost of heat for select technologies, broken down into cost components for a 2024 project start date for medium cost assumptions (£2023). Note that operational start date depends on individual project timings

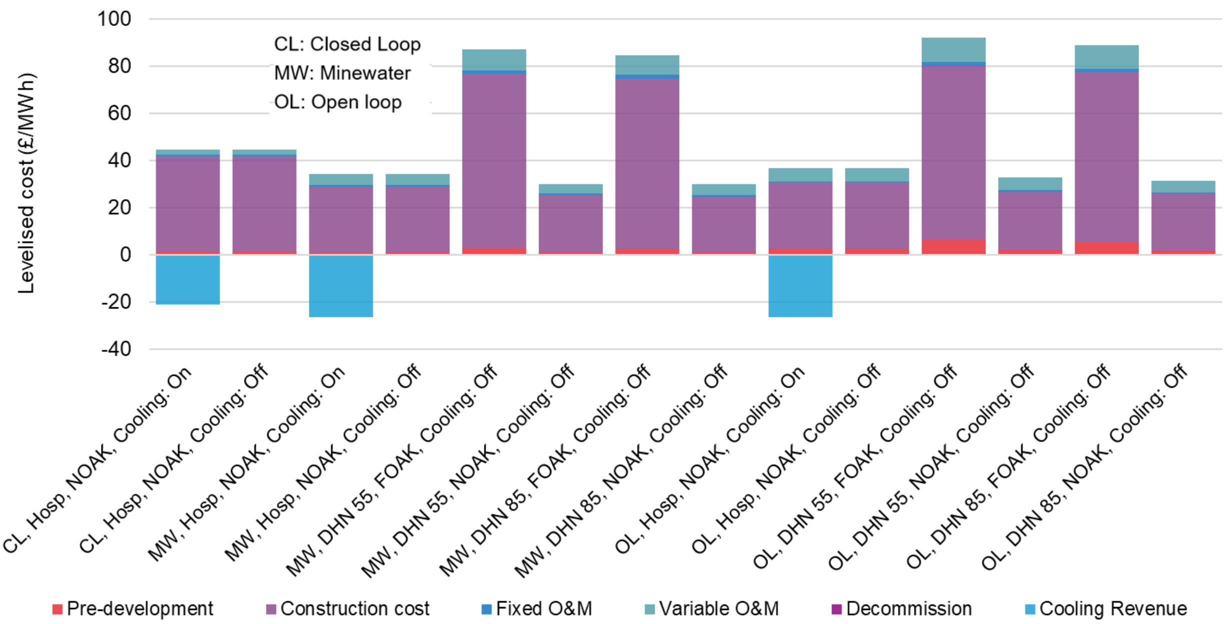


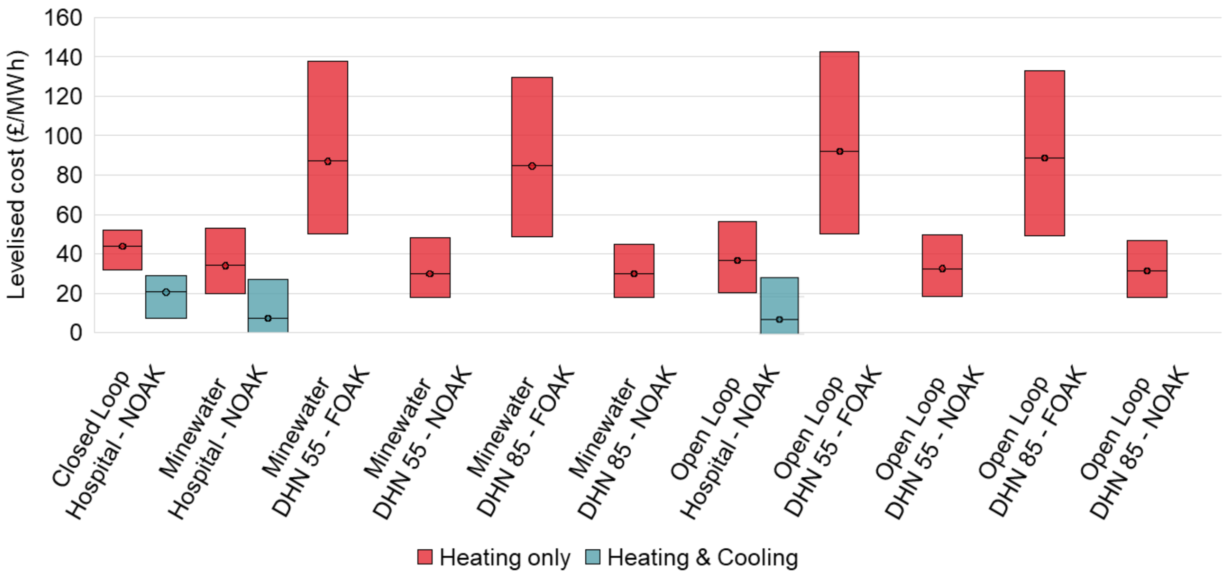
Figure 8: Levelised cost of heat for shallow technologies, broken down into cost components for a 2024 project start date for medium cost assumptions (£2023). Note that operational start date depends on individual project timings

3.3.2 Shallow Systems

In general, shallow systems (closed loop, open loop, and minewater) exhibit similar levelised costs (Figure 9). For 2024, the FOAK heating-only costs (low, medium and high scenarios) for shallow systems range from £49/MWh to £143/MWh and for 2024, NOAK range from around £18/MWh to £56/MWh. Cooling revenue was found to reduce levelised costs by approximately £19 to £29/MWh for 2024 project starting year (e.g., closed loop hospital costs drop from £44/MWh without cooling to £23/MWh with cooling). While it is reasonable to expect that cooling would reduce levelised costs due to increased thermal output, the cooling revenue is likely overestimated. This is evidenced by modelled LCOH values, which become negative when cooling is included.

In District Heating Network scenarios, NOAK costs are approximately 15% lower than FOAK costs. This significant difference is likely due to the operational assumptions: 2000 hours for FOAK DHNs versus 6000 hours for NOAK DHNs.

The LCOH is sensitive to hurdle rates, however hurdle rates have not been updated as part of this study and assumptions have been made. Assuming a higher hurdle rate than 7.5% for shallow systems would lead to costs estimates increasing. For example, if we assume a 10% hurdle rate, a heating only shallow mine water DHN 85°C this increase would be from the £30/MWh (NOAK, project start in 2024) to £36/MWh.



* Maximum value represents the 'High' cost, the inner point marks the 'Medium' costs and the minimum represents the 'Low' cost.

* Blue bars show the LCOH after deduction of cooling revenues, assumed to be equal to the cost of provision of cooling separately. Cooling revenues are likely overestimations. Lower bound LCOH for cooling have been truncated to zero.

* Levelised costs are related to their end user (hospital or district heating network (DHN) at 55°C or 85°C).

Figure 9: Levelised costs of heat for shallow geothermal systems (2024 costs)

3.3.3 Deep Systems

Overall, for deep systems, oil and gas coaxial conversion systems and deep geothermal doublet (NOAK) systems exhibit the lowest LCOH values (see Figure 10). In 2024, for medium scenarios, these costs range from £55 to £172/MWh. Oil and gas conversion systems provide relatively low energy output (around 200kW to 400kW) but have low capital costs since the wells are already constructed. Deep geothermal NOAK systems deliver high energy output, and although their costs are high, NOAK drilling costs are significantly lower than FOAK costs.

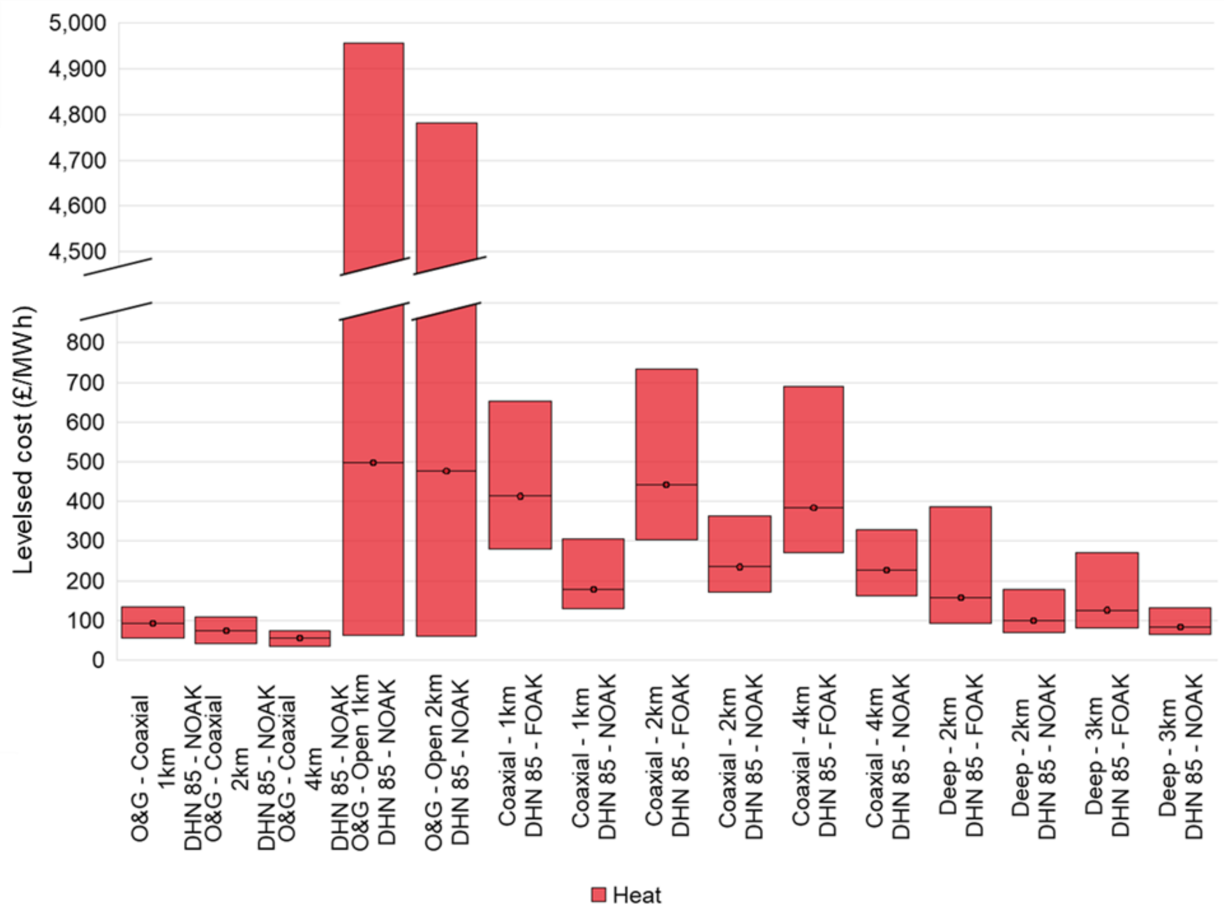
Oil and gas open loop conversions have very high costs, ranging from £56/MWh to £5503/MWh, due to assumed limited flow rates and low thermal capacity. Note the large range derives from the assumed flow rates, which varied by two orders of magnitude between Low and High-cost scenarios. Furthermore, it may be unlikely that two local O&G wells are suitable for conversion to a doublet system; instead, a single well may be suitable, and may require a second, purpose built well to connect to. In this instance, the capital costs associated with the second purpose build well would further drive up levelised costs. This scenario was not assessed within this assessment.

Deep geothermal FOAK systems have levelised costs between £73 and £446/MWh. The Low and Medium costs are (20% to 25%) higher than the NOAK equivalent, but the High costs for FOAK systems are substantially higher, owing to the low inferred capacities. Deep geothermal NOAK systems have levelised costs between £58/MWh to £197/MWh. The higher FOAK costs are attributed to higher drilling expenses compared to NOAK systems.

For 2024, FOAK coaxial wells have levelised costs ranging from £340 to £523/MWh, while NOAK costs range from £158 to £277/MWh for medium values. These high costs are due to relatively low thermal yields (around 200kW to 400kW) and high drilling expenses.

As with shallow systems, deep system LCOH is also sensitive to the choice of hurdle rate. Assuming a higher hurdle rate of 18.8%, for example would lead to costs estimates increasing for a deep doublet at 3km from £126/MWh to £264/MWh (FOAK medium scenario, 2024 project start, 2023 price base).

Levelised cost modelling assumed learning rates that predict costs could reduce over time (see Figure 11). No learning rate was applied to the operating costs, and therefore operating costs see no temporal difference. There was insufficient data to assume an operational learning rate with sufficient confidence. In reality we would anticipate some learning but this is likely to be of less significance than learning assumed for drilling.



* Maximum value represents the 'High' cost, the inner point marks the 'Medium' cost, and minimum value represent the 'Low' cost.
* O&G converted open loop systems have very high upper bound levelised cost estimates (owing to inferred very low flow rates / capacities)
* For visual clarity, only the 85°C DHN end user values have been presented. The 55°C DHN values and trends are broadly comparable

Figure 10: levelised cost of heat for deep geothermal systems (2024 project start date)

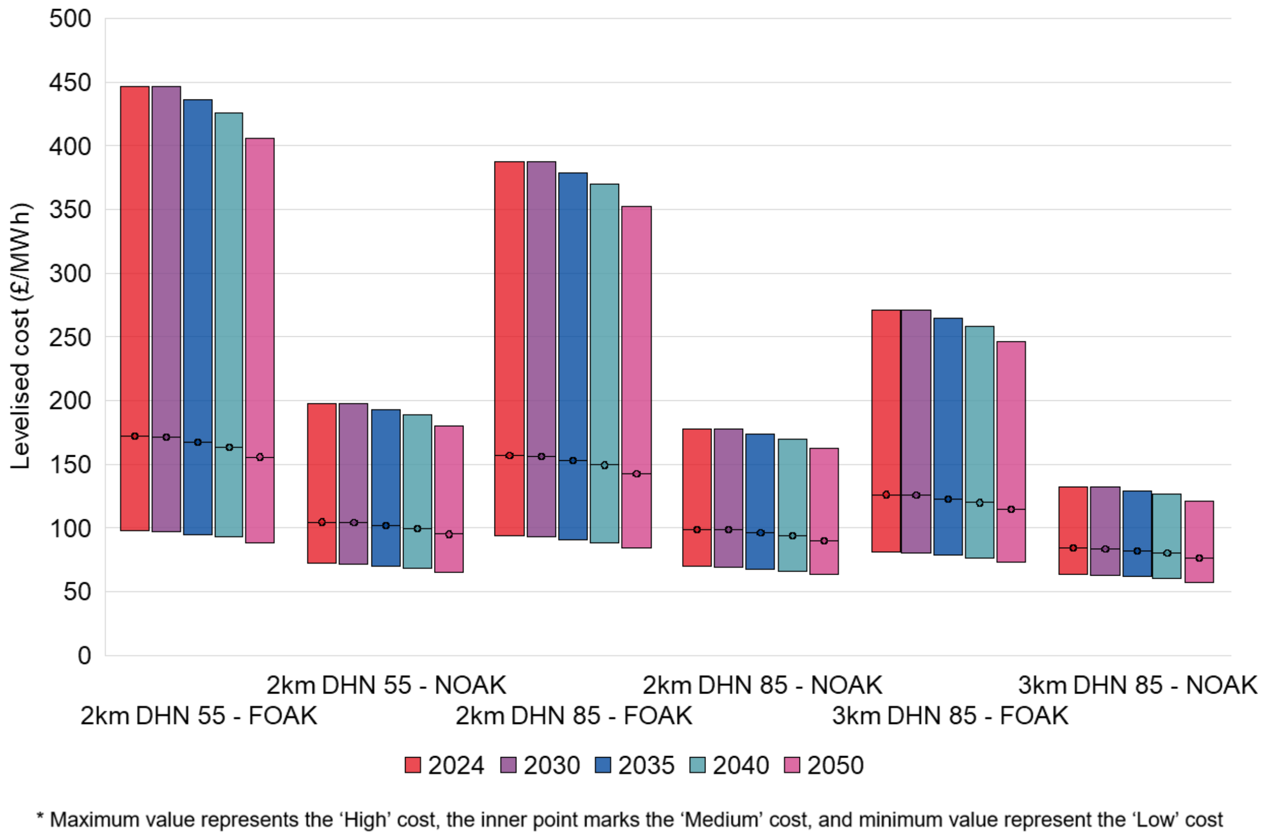


Figure 11: Levelised cost of heat for deep geothermal doublet systems across all modelled years

Within the levelised cost model thermal capacities were averaged from various UK reservoirs. This was done to provide 'general' cost values. However, the impact of this is that the total range in resulting levelised costs is reduced (as the lowest and highest thermal capacities are increased and reduced respectively). Deep geothermal systems have high regional variability, based on productivity of reservoirs. This variability may have been lost through the averaging methodology applied.

It is likely that the most favourable deep geothermal reservoir will be the first geothermal target for a new system. Therefore, an assessment of the most productive 2km, and 3km reservoir were assessed to provide most favourable levelised costs.

For example, for the 3km system but using the thermal capacities of 4.2MW (P90), 8.2MW (P50), 11.5MW (P10) for the Sherwood Sandstone in the Antrim basin. The levelised cost are £68/MWh to £183/MWh (FOAK), and £58/MWh to £104/MWh (NOAK).

For a 2km system but using the thermal capacities of 1.8MW (P90), 4MW (P50), 6.2MW(P10) for the Fell Sandstone in the Northumberland & Solway Basin. The levelised cost are £80/MWh to £247/MWh (FOAK), and £63/MWh to £129/MWh (NOAK).

These values are favourable compared to the 'generalised' results presented from the levelised cost model.

3.3.4 Back-up Systems

The levelised costs presented include costs for back-up gas boilers (assumed to be of a scale to match 100% capacity of the geothermal system, i.e., 100% system redundancy). The impact of including back-up system costs was assessed. It was found that when the back-up system costs were included, levelised costs, across all technologies, generally increased by between 0.5% to 4%. For instance, in 2024, the levelised costs for a closed loop system with a backup are £45.1/MWh, compared to £44/MWh without a backup, representing a 2.5% difference.

3.3.5 Benchmarking

Available LCOH models and outputs were reviewed to benchmark Arup's assessment. A summary is provided within Table 16.

Table 16: Published geothermal levelised cost values

Published value	Equivalent value (£/MWh)*	Source
UK Medium costs for <100kW water or ground source heat pumps ranged from $2,666/kW (2010) to $2,807 (2019) and spiked to $4,550/kW (2018). Systems >100kW (majority in this study) range from $2,408/kW to $1,276/kW (2019)	2019 prices range from £995/kW (>100 kW) to £1878/kW (<100kW). Assuming 2000 hours (i.e., DHN FOAK) this is c. £497/MWh (>100kW), and £939/MWh (<100kW). Assuming 6000 hours (i.e., DHN NOAK) this is c. £165/MWh (>100kW), and £313/MWh (<100kW). Assuming 8760 (100%) operation hours (heating and cooling), this is c. £113/MWh (>100kW), and £214/MWh (<100kW)	IRENA (2022) [50]
A 2018 study of levelised cost of heating across 21 geothermal district heating networks in the US reported a value of $35,750/GWh	£27.9/MWh (2018 prices)	Publication [51]
A German study (2023) found a that a modelled deep geothermal 15.7MW, 41,000 MWh system provided a levelised heat cost of 8 cent(Euro)/kWh; and near-surface geothermal systems with heat pumps, range from 15 to 25 cents(Euro) per kWh and more, depending on type, size, and location	Deep geothermal: £67.2/MWh Shallow geothermal: £126 to 210/MWh	Publication [52]
GeoVision study found competitive levelised cost of heat (LCOH) (deep geothermal) values in the range of $50 to $100/MWh for US deep geothermal.	£39/MWh to £78/MWh	Publication [53]
Deep (geothermal) enhanced geothermal systems (EGS) for direct-use applications were in the range of $12 to $49/MWh for US systems.	£9.4/MWh to £38.2/MWh	Publication [54]
US systems were found to have LCOH values of between $13 and $350/MWh for deep geothermal; however direct-use feasibility varies widely, depending on subsurface characteristics, system design, and financial conditions.	£10.1/MWh to £273/MWh	Publication [55]
* Conversion assumed an exchange rate of 0.78 USD:GBP, and 0.84 EURO:GBP		

As noted in Table 16, published levelised costs for deep geothermal heat vary, ranging from c. £9.4/MWh to £273/MWh. This is dependent on the reservoir conditions (system capacity), costs, etc. The published shallow datasets focused on heat pumps only with costs ranging from £126 to £210/MWh in Germany and inferred to be £113 to £214 (Hospital use), or £165 to £939/MWh (DHN use) for UK heat pumps. The values from the Arup NOAK models are generally consistent with these benchmarks.

3.3.6 Comparative Technologies

A review of published data for comparative technologies was undertaken to compare to geothermal technologies. Data from gas boilers and air source heat pumps (air-to-air, and air-to-water) was gathered from published sources [84][85]. These costs are for the residential sector. Scales of economy may apply with industrial (MW) scale systems and therefore the presented values are not directly comparable to the larger scale geothermal technologies.

ASHPs can also deliver cooling. The values below are for heating only, and therefore discounted cooling is assumed to not be factored. If factored, this would likely reduce levelised costs as the system delivers more thermal energy over a given operational year.

Country	USD($)/MWh			Equivalent cost in GBP(£)/MWh (2024)		
	Air-to-air	Air-to-water	Gas	Air-to-air	Air-to-water	Gas
Canada (2021)	66.3	72.4	66.3	53.8	58.7	53.8
Denmark (2021)	101	105	115	81.9	85.2	93.3
Denmark (2022)	140	139	164	113.6	112.8	133.1
France (2021)	156	148	122	126.6	120.1	99.0
France (2022)	155	148	122	125.8	120.1	99.0
Germany (2021)	155	146	127	125.8	118.5	103.0
Germany (2022)	172	170	116	139.5	137.9	94.1
Italy (2021)	165	163	139	133.9	132.2	112.8
Italy (2022)	143	132	116	116.0	107.1	94.1
Korea (2021)	71.6	81.4	97.3	58.1	66.0	78.9
United Kingdom (2021)	155	144	138	125.8	116.8	112.0
United Kingdom (2022)	179	158	93	145.2	128.2	75.5
United States (2021)	62	62	55	50.3	50.3	44.6
United States (2022)	65	64	60	52.7	51.9	48.7
Sweden (2021)	85	91	162	69.0	73.8	131.4
Sweden (2022)	93	98	242	75.5	79.5	196.3
* Conversion assumed an exchange rate of 0.78 USD:GBP, and GDP deflator used to convert between 2021/2022 to 2024 costs.						

Gas boiler and ASHP levelised costs are lowest in the U.S. at around £50/MWh (2024 equivalent costs). Across Europe, ASHP costs ranged from around £75/MWh to £160/MWh (2024 equivalent costs); and gas boilers from around £75/MWh to £130/MWh (excluding Sweden, at £196/MWh).

The geothermal technologies were evaluated at an industrial scale, whereas this data pertains to residential scales. It is advisable to review the comparative technology assessment and adjust the geothermal levelised cost models to include these comparative technologies. This will enable a more direct comparison.

3.4 Funding Mechanisms

3.4.1 Introduction

Arup modelled seven funding mechanisms to assess their impact on LCOH systems. The model is indicative only, it is not a detailed financial assessment. The purpose of this work was to outline how various funding mechanisms could be modelled and how they impact upon the LCOH value. Funding mechanism indicative models were assessed against selected deep geothermal case studies only for this study. The funding mechanisms assessed could also be beneficial to shallow geothermal case studies. The funding model formed part of the scope of works with the aim to explore how various funding mechanisms impact levelised costs for various geothermal technologies. The funding model implemented key assumptions on mechanism values, which are subject to change. The model also only assessed a single funding mechanism per model run, and therefore the overlapping interaction of combined mechanisms has not been explored. Further details are presented in Table 17.

Table 17: Summary of case studies included and excluded in model

Item	Mechanism	Description
Modelled		
1	Capital grants	This should be based on a match-funding model to finance a percentage of up-front costs in line with the Windsor Framework [88]. The Arup assessment has assumed a standard capital grant of 50%. This is applied to both pre-development and construction & infrastructure costs.
2	Standard loans	This is based on loans for unexpected costs in the German Renewable Energy Incentive Program. The loan amount is up to 100% of the upfront eligible costs, up to a maximum of £100M per project. The Arup assessment has assumed the loan constitutes 100% of predevelopment and construction & infrastructure costs (no system is assumed to exceed £100M total cost). A second negative revenue stream has been added for each year of operation to pay back the initial loan at 5% per year.
3	Insurance scheme (short term)	This is based on the French geothermal heat insurance scheme and uses the assumption of £20M as an initial government contribution.
4	Insurance scheme (long term)	This is based on the French geothermal heat insurance scheme and uses the assumption of £20M as an initial government contribution. The government covers the risk of damage or heat depletion over 15 years, for a flat rate of €15k/year. In the Arup assessment a negative revenue stream has been added for £12k for each year of operation, to cover the flat rate of insurance.
5	Risk sharing/ Alternative risk transfer	Risk sharing/ Alternative Risk Transfer schemes allow multiple players to share the risk associated with the project, e.g. investors, drilling companies and an insurance company. Daldrup & Söhne AG [89] have used an alternative risk transfer structure in the Netherlands and Germany based on a reinsurance framework which hedges the risk of discovery. It can be used to support the financing of qualified geothermal projects with a high proportion of debt capital from banks. The exploration risks are borne by third parties, rather than the developer. In Arup's research in Northern Ireland (2022) [49] industry stakeholders outlined that investors would be keen to take on some geological risk and identified a need for risk-sharing mechanisms to be available in the UK. The Arup assessment has assumed the hurdle rate is reduced by 10% due to sharing of the risk.
6	Heat tariff	Heat tariffs (per unit subsidies) can reduce revenue uncertainty linked to market price fluctuations for the sale of renewable heat. The Arup assessment has added a positive revenue stream for 15 years, with a value of £53/MWh (consistent with the now revoked Q1 2022/23 Renewable Heat Incentive tariff of 5.30p/kWh).
7	Convertible grants	Convertible grants are designed to ease the market development of innovative technologies. The funding is awarded as a grant but can be converted into another type of financing (e.g. equity or debt) once a project attains a certain degree of success (e.g. successful completion of drilling phase). Assume that an initial grants covers up to 80% of up-front costs but which are converted to loans on the successful completion of the drilling phase, to be repaid at a cost of X%. The Arup assessment has applied an 80% reduction to pre-development and construction costs, then from the year construction finishes, a negative revenue stream is applied at 5% of total grant per year for the full operational life.
Excluded – These were considered very similar to existing mechanisms, and/or challenging to model efficiently		
8	Concessional loan	A concessional loan has preferential e.g. lower interest rates, higher tolerance of risk, repayment terms (including Utilisation-Linked Finance - ULF - "Student Loan-style facility"). that are more favourable than the market would offer. These could come with stipulations / conditions to be met in terms of business model. Assume that an initial loan covers 100% of up-front costs but which begin to be repaid at the point the project has recouped its capital costs. Repayments to be made at X% of profits, accruing 3.5% interest p.a., with any remaining grant written off after 25 years.
9	Revolving funds	A revolving fund would use an initial investment from government to offer finance in the form of loans to cover the initial up-front costs for geothermal projects (e.g. drilling costs). Fees and repayments with interest are added to the fund to finance further projects.

Item	Mechanism	Description
		This could be based on the German national risk mitigation scheme, part of the Renewable Energy Incentive Program administered by the KfW and be based on the assumption of £20m as an initial government investment. The Fund was initially filled by the Bundesministerium für Umwelt (Federal Environment Ministry) with €60 M through the Renewable Energy Incentive Program MAP. The main advantage of the Fund is that it combines project financing via a credit and the mitigation of risk. Geothermal project developers in Germany can choose between two options of mitigation their resource risk: the federal risk mitigation scheme (Fündigkeitrisiko Tiefengeothermie) and private market-based insurance. The application fee amounts to €65,000 covering the assessment of the documentation by Munich Re and KfW. A further €45,000 is charged for auditing and expert monitoring of the project progress. A high interest rate is charged until termination of the drilling work, stimulation measures and hydraulic tests, plus a specific disagio (the negative value between the face value of a loan and its actual price) defined by the project risk. Projects can apply for a loan up to €16 M/ drilling (one doublet) covering a maximum of 80% of the eligible costs.
10	Feed in tariff	This is a power only tariff. The Arup assessment looked at heat only. Feed-in tariffs can reduce the uncertainty linked to market price fluctuation for the sale of renewable energy by guaranteeing the potential income from a project. In the electricity market, as the generator receives a fixed income per MWh produced, they are incentivised to produce as much energy as possible. In a market for geothermal heat, this could encourage projects to be as efficient as possible, supporting innovation, but the scheme would need to be carefully designed. Current examples include: The Netherlands, 15-year support for a price of 5.3Euro-cents/ kWh, with a higher tariff for specific types of projects. Portugal, 12-year support for plants up to 3MW, average value of 270 EUR/MWh Germany, 20-year support for plants who are able to respond to balancing needs at 25Euro-cents/ kWh Greece, 20-year support on a sliding premium, awarded through tenders. 139EUR/MWh for plants below 5MW capacity; 108 EUR/MWh for plants above 5MW capacity.
11	Auction scheme (CfD for heat)	This is a power only tariff. The Arup assessment looked at heat only. In an auction scheme, Government calls for tenders to procure a certain capacity of energy generation. Project developers who take part in the auction submit a bid with a price per unit of energy at which they can realise the project. The auctioneer evaluates the offers based on the price and other criteria and signs a 'power purchase agreement' with the successful bidder. Auctions can be developed for a specific technology. Auctions have been used in Europe where geothermal projects are able to generate both heat and electricity. In the UK, the Contracts for Difference is an example of an auction scheme which has been used successfully in the electricity market. CfD incentivises investment in renewable energy by providing developers of projects with high upfront costs and long lifetimes with direct protection from volatile wholesale prices, and they protect consumers from paying increased support costs when electricity prices are high. In a CfD for heat scheme, the assumption should be of an allocation round with a total budget pot of £105m and £20m protected for geothermal projects.

These funding mechanisms were applied to select case studies as presented in Table 18. These case studies were selected to provide comparisons between different DHN operating temperatures (55°C and 85°C); closed and open systems (coaxial wells and deep doublets); geological location (Wessex, Cheshire, Cornwall); and various depths (1.9km and 4km).

Table 18: Summary of case studies for funding mechanisms

Number	Location	Stage	Target	Depth	Heat User	System
1a	Wessex Basin	FOAK	Sherwood Sandstone	1.9km	55°C DHN	Doublet
1b	Wessex Basin	NOAK	Sherwood Sandstone	1.9km	55°C DHN	Doublet
2a	Wessex Basin	FOAK	Sherwood Sandstone	1.9km	85°C DHN	Doublet

Number	Location	Stage	Target	Depth	Heat User	System
2b	Wessex Basin	NOAK	Sherwood Sandstone	1.9km	85°C DHN	Doublet
3a	Wessex Basin	FOAK	Sherwood Sandstone	1.9km	55°C DHN	Coaxial
3b	Wessex Basin	NOAK	Sherwood Sandstone	1.9km	55°C DHN	Coaxial
4a	Wessex Basin	FOAK	Sherwood Sandstone	1.9km	85°C DHN	Coaxial
4b	Wessex Basin	NOAK	Sherwood Sandstone	1.9km	85°C DHN	Coaxial
5a	Cheshire Basin	FOAK	Early Carboniferous Limestone	4km	85°C DHN	Doublet
5b	Cheshire Basin	NOAK	Early Carboniferous Limestone	4km	85°C DHN	Doublet
6a	Cheshire Basin	FOAK	Early Carboniferous Limestone	4km	85°C DHN	Coaxial
6b	Cheshire Basin	NOAK	Early Carboniferous Limestone	4km	85°C DHN	Coaxial
7a	Cornwall	FOAK	Granite	4km	85°C DHN	Doublet
7b	Cornwall	NOAK	Granite	4km	85°C DHN	Doublet

3.4.2 Findings

The reduction in LCOH values presented by the funding mechanisms reflects the costs borne by the developer, rather than those covered by the government providing the funding; and excludes financing costs. Financing costs comprise the costs to repay loans, which apply to conditional standard loans, insurance schemes, and convertible grants. Each of these funding mechanisms provide an initial capital grant, with subsequent repayments following system operation (i.e., 5% repayment). When financing costs are included levelised costs are higher.

Logically, it could be assumed that if a developer has incurred greater costs developing a system, they are more likely to set commodity (heat or power) tariffs at higher values. This is to facilitate a return on investment for the developer. With the same logic, funding mechanisms which reduce developer costs, could also incentivise reduced commodity tariffs, benefitting the consumer (heat/power user).

For deep geothermal, capital costs were found to comprise around 80% of levelised costs; as a result, reductions of capital cost were found to be closely reflected in the levelised costs.

Risk-sharing mechanisms can act to reduce hurdle rates, which would benefit levelised costs significantly.

A heat tariff can provide long-term revenue guarantee, by providing subsidies on a generation (MWh) basis. Different tariffs would likely be required for different technologies and capacities. For example, a fixed tariff may be proportionally more beneficial to shallow geothermal systems with inferred low levelised costs, and less impactful for deep geothermal systems.

With respect to the funding providers (i.e., governments), capital grants present no equitable return. For example, a 50% capital grant covering pre-development and capital costs for a 2km doublet pair may cost around £10M to £20M with no direct return payment to the funding provider. Heat-tariffs similarly provide no equitable return for heat (or power, in the case of FITs) generation. However, these mechanisms do provide long-term stability, both for heat/power provision, reducing project risk. These benefits may also have the effect of reducing commodity tariffs for the consumer.

Comparatively, standard loans, short-term insurance schemes, and convertible grants recover all or part of the loan via repayments. Following system operation, once a developer's geothermal project has an income stream, the repayments commence and continue for all or part of the operational life of the project. In these instances, the funding provider receives a return on their loan. These funding mechanisms may be more favourable for governments relative to grants or tariffs, as the loan is repaid; whilst still providing a reduction in up-front capital costs for developers.

Risk sharing mechanisms help reduce geothermal exploration risk. Successful geothermal projects can be used to fund further exploration. This provides a buffer for failed wells (i.e., underperforming production well). Mechanism details are subject to the funding provider.

With long-term insurance schemes, cost to insurance provider is only realised if drilling for a geothermal project fails, or the long-term performance reduces. The level of insurance provided may vary and is to be determined by the insurance provider. For example, they may fully fund redrilling of a failed well; or fund the deficit in heat revenue for an underperforming system. Alternatively, they may only provide partial remuneration.

This assessment of funding mechanisms is indicative only, it is not a detailed financial review. The purpose of this work was to outline how various funding mechanisms could be modelled, their indicative impacts upon the LCOH value, and prompt further investigation. The assumptions, which are clearly stated, are subject to change and could be explored further by financial modellers. A review of shallow geothermal funding mechanisms is also recommended.

4. Levelised Cost of Electricity (LCOE)

This section summarises the Levelised Cost of Electricity Assessment for deep geothermal projects across the UK. It addresses Task 3: *Draft levelised cost chapter (Power) including Raw cost data, assumptions and calcs for power.* The full set of input and outputs data tables and assumptions are presented in Annex C.

4.1 Introduction

Deep geothermal energy has gained traction in the UK in recent years. Cornwall, a region rich in granite formations, stands out as a focal point for geothermal exploration. The United Downs Project in Cornwall serves as a successful example of deploying deep geothermal technology, providing both heat and power (c. 3MWe) to the local community (expected by end-2024).

As discussed in Annex A, there are potential deployment opportunities for geothermal across the UK particularly in the Sedimentary Basins and Granites.

4.1.1 Context

Geothermal power plants can be categorised into two types: dry/flash steam plants and binary plants. Dry/flash steam plants are suitable for high enthalpy systems, typically those with temperatures above 180°C. On the other hand, binary plants are designed for low enthalpy systems, with temperatures ranging from 100°C to 180°C. Notably, steam plants generally achieve greater efficiencies compared to binary plants. The UK is considered to be a low enthalpy geothermal system, and therefore binary plants would be utilised [91].

Geothermal plants function as combined heat and power systems. Initially, the heat extracted from the abstracted fluid is used to operate the power system. If there is sufficient residual heat, it can then be utilised for heat production, supplying a heat user. The overall change in fluid temperature (ΔT) across the geothermal plant must be carefully managed. Excessive extraction (large ΔT) could quickly deplete the thermal resource or induce seismic activity. The system's ΔT, flow rates, and the ratio of heat to power are heavily influenced by the geology of the geothermal reservoir, leading to variations in the operation of geothermal plants. The ratio of heat to power and its implications is discussed in Section 4.2.4.

Within the levelised cost model power and heat outputs are considered, with heat revenue being discounted from overall costs. It is assumed that 25% of heat is sold to off-takers (see Section 4.2.4). Identification of a heat user to sell the heat to is often limited; and therefore, this assumption may be simplified. This is further discussed Section 4.2.4.

4.2 Methodology

Levelised cost can be defined as the discounted lifecycle cost of building and operating an energy generation asset, expressed as a cost per unit of electricity or heat (£/MWh). LCOE represents the break-even tariff, i.e., the price per MWh that producers need to charge to recover their costs. The calculation averages the cost of production over the life of a plant and allows both cost and generation to be converted into a single value. For the analysis there are two important aspects of the definition which need to be considered:

- What assets are included within the cost; and,
- The operational time period over which the levelised costing will take place.

For consistency with previous studies, the definition of levelised cost applied in this study only takes into account the costs borne by developers in relation to construction and operation of a renewable geothermal generation project. It does not take account of the impact on the wider electricity network and support mechanisms.

Project duration is a critical factor in the development, delivery, and operation of geothermal projects. The following were factored into the calculation:

- The estimated time it takes for a project to go through design, construction, and delivery.
- The expected operational life of the technology in question.

The hurdle rate is applied as the discount rate which allows future values to be brought back to present values i.e., the value today of a future stream of costs.

LCOE is highly sensitive to the underlying assumptions made such as load factors, discount rates, plus, capital and operating costs. Consequently, the standard practice involves considering a range of costs rather than a single point. As per Arup's 2016 study [92], high, median/mean, and low estimates were produced for input into the LCOE model. This approach allows the modelling process to account for uncertainty and variability.

4.2.1 Components of Levelised Cost

Table 19 provides a summary of the components of levelised cost models.

Table 19: Cost Definitions for geothermal

Cost Items	Description
Development Costs ('DEVEX')	
Pre-licensing cost	Development costs including planning, submission fees, survey costs etc.
Technical development cost	Technical design associated with the development of a deep geothermal project, 2D and 3D seismic modelling (where required).
Planning cost	Covers regulatory costs, licensing, public enquiry, 'local community engagement' costs.
Capital Costs ('CAPEX')	
Capital (overnight) cost	Capital cost covers the projected design, procurement, and construction costs e.g. Engineering, procurement, and construction (EPC) costs if applicable (e.g. well drilling, equipment, plant). It also covers the full capital cost excluding interest costs during construction and land costs.
Owner's cost	Includes procurement cost, project management owner's engineer etc.
'Infrastructure costs' Grid connection costs Substation and Transformer cost	Excludes pre-connection securities but includes any upfront connection payments required. Electrical infrastructure cost was assumed to comprise grid connection costs (e.g. underground cable costs), local substation and transformer stations, connection to the nearest point on the grid and site works (fencing, access tracks).
Decommissioning costs	The cost to decommission the well assets to meet regulatory requirements and the cost to decommission surface plant. Well decommissioning requirements vary with technology (e.g. deep geothermal doublet systems are more onerous than closed loop).
Operational Costs ('OPEX')	
Fixed O&M cost	Costs such as labour, planned and unplanned maintenance, spares and consumables.
Variable O&M cost	Calculated on a per MWh of generation basis. These are output related expenditures, such as electrical submersible pump (ESP), heat pump, or surface plant pumping costs.
Insurance Cost	The cost of insuring generation plant.
Financial	
Hurdle rate	The minimum rate of return required on a project of investment. The greater the risk involved in an investment, the higher the hurdle rate. The hurdle rate for deep geothermal is greater than shallow.
Timescales	

Cost Items	Description
Pre-development	Time period for completing desk-based assessments, surveys, designs, planning, and permitting.
Development	Time period for drilling the well assets and constructing the surface plant.
Operation	Time period of system operation.
Decommissioning	Time period for decommissioning the well assets and surface plant.

Arup collected generation cost and technical data for deep geothermal energy, with the aim to provide DESNZ with an updated view on the commercial and technical aspects crucial for project development. Additionally, Arup conducted a review of learning rate forecasts for construction and operating costs.

Learning rates were implemented within the models as percentage reductions in capital costs for each successive year after 2024. For example, a 0.5% learning rate assumes costs in 2034 are 95.11% those in 2024; based on 10 years of compounding 0.5% reductions per year; ($100(1 – 0.5\%)^{10}$). Learning rates contribute to reducing levelised costs over time (e.g., 2050 costs are generally less than 2024 costs). Deep geothermal learning rates at 3.3%, 0.5%, and 0.1% for high, medium/mean, and low are based on drilling rates at Fervo [13] and were applied to all pre-development and development costs. Learning rates were not applied to operational and decommissioning costs. Learning rates are further discussed in Section 3.2.5.4.

Project timescales were assumed at 1 to 2 years for pre-development; 3.5 to 6 years for construction; and 25 to 40 years for operation. Pre-development costs were generally between 1 to 3% of total capital costs; construction costs at 50% to 80%; infrastructure (grid connection) at 10% to 30%; and decommissioning at 2% to 7%.

Heat revenue and potential lithium revenue are more complex and are described within Sections 4.2.4 and 4.2.6.

4.2.2 Data Collection

This section provides a more detailed breakdown of the type and volume of data collected for each of the key LCOE model inputs. A summary of the data collection is presented in Table 20 and

Table 21. ‘Stakeholder’ data refers to questionnaire responses, and one-on-one discussions.

Table 20: Deep Geothermal, Cost Data Collection

Data Item	Overview of Data Collected		Confidence[1]
	Stakeholders	Literature / Reports	
Deep Geothermal	Collected data from 10 companies through questionnaires and conducted one-on-one interviews with an additional 6 companies, resulting in a total of 16 data points. The questionnaire provided structured responses, while interviews allow for open-ended discussions, revealing nuances and details. There is data on factors such as resource availability, technology choices, operational costs, and regulatory challenges. These are crucial for LCOE modelling. Insights from the interviews highlighted unforeseen complexities and unique considerations specific to each company. This qualitative information complements quantitative data. The dataset also includes geographical diversity (from different countries), which enhances its usefulness. Geothermal resources vary by location, and this diversity ensures a more informed model. The dataset represents a cross-section of the geothermal industry. They cover a spectrum of project sizes, technologies, and operational contexts. Emerging trends and perspectives were captured. These additional data points enhance the dataset’s representativeness. While no dataset can fully encapsulate every scenario, this approach is considered to strike a balance between breadth and depth, making it a credible and relevant sample for LCOE modelling.		
Development costs (‘DEVEX’)			

Data Item	Overview of Data Collected		Confidence[1]
	Stakeholders	Literature / Reports	
Pre-licensing costs	6 stakeholders, 7 data points.	2 reports, 5 data points; includes U.S. DOE [5], EGEC [6].	High
Construction Costs ('CAPEX')			
Capital (overnight) costs – drilling	9 stakeholders, 13 data points (general values rather than project costs).	8 reports, 53 data points; includes EGEC [6], AFPG [7], NREL [8], Turkish data [9], FORGE [10], US Projections [11], Indonesia [12], and Fervo [13], and Arup experience	High
Capital (overnight) costs – plant	3 stakeholders, 3 data point (general values rather than project costs).	2 reports, 9 data points; includes EGEC [6], NREL [18].	Medium
Grid connection costs	1 stakeholder, 1 data point (general values rather than project costs).	Reviewed against Arup experience from other energy projects.	Low-Medium
Operational Costs ('OPEX')			
Fixed O&M costs	1 stakeholder, 1 data point (general values rather than project costs).	2 reports, 6 data points; includes IRENA [13], NREL [18].	Medium
Variable O&M costs	None	2 reports, 6 data points; includes IRENA [13], NREL [18].	Medium
Decommissioning (Abandonment) Costs ('ABEX')			
Well decommissioning	7 stakeholders, 7 data points (6 general values, 1 project value)	None	Medium
Plant decommissioning	1 stakeholder, 1 data point (project value)	None	Low
* No data point for insurance or for the Use of System. These items were excluded from the cost model. [1] Relative confidence is determined by the availability and reliability of data sources, whether from stakeholders or publications. Low confidence indicates parameters derived from only a few number of sources. Medium confidence reflects a combination of limited stakeholder data and some published information. High confidence reflects parameters supported by numerous stakeholder inputs and literature sources that are broadly consistent with each other.			

Table 21: Deep Geothermal, Technical Data Collection

Data Item	Overview of Data Collected		Confidence[1]
	Stakeholders	Literature	
Timing			
Pre-development period	1 stakeholder, 1 data points (general values rather than project costs)	2 reports, 3 data points; includes U.S. DOE [5], EGEC [6] (general values rather than project costs)	High
Construction period			High
Plant operating period			High
Power Output			
Net power output	Informed from Arup assessment (see Annex A)		See Table 6

Data Item	Overview of Data Collected		Confidence[1]
	Stakeholders	Literature	
Net thermal output	Heat to Power ratio; 4 reports, 20 data points; including German plants [2] and EGEC [19]		Medium-High
Lower heating value (LHV)	Consistent with previous DESNZ 2016 report [92]		Medium
Operational Assumptions			
Efficiency profile	1 report, 1 data point; CREST [8]		Medium
Availability profile (inclusive of load profile)	6 stakeholders, 6 data points	3 reports, 3 data points; including U.S. OEERE [20], IRENA [21], NREL [8]	High
Auxiliary power deduction	None	Experience, 4 reports, 5 data points; including Soultz [22], and other papers [23][24][25]	Medium
Other			
Hurdle rates	2 stakeholders, 2 data points (general values rather than actual data)	4 reports, 4 data points; including NREL [18] NERA [26], European data [27], EIA [28] DESNZ Hurdle rate estimates for electricity sector technologies [116].	Low
Learning rates	2 stakeholders, 2 data points (1 general value, 1 project value) [93]	1 report, 1 data point; including NREL [18]	Low-Medium
[1] Relative confidence is determined by the availability and reliability of data sources, whether from stakeholders or publications. Low confidence indicates parameters derived from only a few number of sources. Medium confidence reflects a combination of limited stakeholder data and some published information. High confidence reflects parameters supported by numerous stakeholder inputs and literature sources that are broadly consistent with each other.			

As presented in Table 20 and Table 21; a large volume of published data and stakeholder data has been used to inform the assessment. The data between stakeholders and published literature shows good agreement, and therefore is considered to be a reasonable basis for the values utilised in the LCOE model. However, it is important to note that certain parameters have more data points than others. Where previous year data has been used, data was converted to 2024 costs (using the deflator calculator from Office for National Statistics (ONS) - last updated 15 February 2024 GDP) and currencies converted, based on the available exchange rate at the time of report writing.

4.2.3 Stakeholder Feedback

Arup carefully examined stakeholder responses and one-on-one feedback to gain insights into their perspectives on the potential evolution of future costs, technical performance, and the geothermal systems market. A concise summary of these findings is provided in Table 22.

Table 22: Summary of Key Stakeholder Feedback

Key Highlights
Geological and system variability: stakeholders highlighted that use of generalised parameters is challenging, as each geothermal system will vary on a site-by-site basis. For example, the life of an electrical submersible pump (ESP) can range from 1 year to 10 years based on brine chemistry. Despite this variability, for the purposes of the study, stakeholders found the implemented technical assumptions generally reasonable. **Capital costs and Government support**: Currently the UK Geothermal market faces challenges and is less developed than Europe and global counterparts. High drilling costs and a lack of government incentives contribute significantly to this situation. Deep onshore drilling relies on European rigs, incurring substantial mobilisation fees (around £1 million each way). As geothermal projects increase, a UK-based deep drilling rig may become available. Currently, use of European drilling rigs incurs an estimated £1M to £2M mobilisation/demobilisation fee. A UK-based rig would significantly reduce this. Government incentives can mitigate the initial risk of the first well drilled, shifting investment from 100% equity financing to a balanced mix of grants and equity.

Key Highlights
Risk and contingency: Stakeholders highlight that cost contingencies for deep geothermal projects can vary widely (e.g., 20% to 100% contingencies). Government support and grants could help reduce capital risk. No contingency is included within the levelised cost models. **Permitting hurdles and project timescales**: Currently, local councils handle geothermal drilling and installation permits. Engaging with local councils, rather than a streamlined central government approach, can significantly extend project timescales. **Grid connection availability**: The UK grid infrastructure faces strain in multiple regions. Upgrading, installing, and connecting electrical infrastructure to geothermal systems can be time-consuming. **Community engagement and public perception**: Engaging with local communities is crucial for successful geothermal projects. Public perception affects permitting processes and project acceptance. Stakeholders recommend transparent communication and education. **Scaling and replicability**: While individual projects provide valuable data, scaling up is essential. Stakeholders discuss the potential for replicating successful models across multiple sites. Standardised approaches and knowledge sharing can drive industry growth.

4.2.4 Heat Revenue

The LCOE calculation typically excludes revenue income from plant operation, except in the case of Combined Heat and Power (CHP) generation, where both electricity and heat are produced. When estimating the LCOE for deep geothermal CHP, it is assumed that the heat produced is sold to a heat off-taker (the heat buyer). Consequently, the CHP operator receives revenue for each unit of heat sold (£/MWh). For LCOE modelling purposes, this revenue is subtracted from the final LCOE in present value terms.

To estimate a value of the heat an avoided cost methodology is applied. The aim is to approximate the cost that a heat off-taker would have incurred if it had produced the same amount of heat using an equivalent heating system. Traditionally, the 'equivalent' heating system was assumed to be a natural gas boiler.

The components that contribute to the heat revenue estimate are:

- The heat mix assumed: previously gas boiler, updated here to better reflect future mixes (which are more expensive than gas under current market arrangements)
  - The efficiency of each heat technology
  - Whether operational and capex costs are included in the avoided cost estimation
- The assumption for the proportion of heat sold/purchased (heat off-take)
- Any adjustment factor for the proportion of revenue from the avoided cost estimation
- The heat to power ratio

The methodology assumes that 25% of heat is purchased and reflects: 1) fuel costs (retail prices for gas and electricity); 2) heating system O&M (capex is a considered optional); and 3) heat production efficiency.

In 2019, the Committee on Climate Change (CCC) indicated that there are approximately 29 million homes in the UK. In 2017, the majority of residential buildings (85%) were connected to the gas grid, relying on a boiler and wet-based central heating system. While using a natural gas boiler as the equivalent heating system has been a reasonable approach, the UK's future heat supply is likely to shift towards low-carbon sources. This transition may involve various technologies, including gas boilers, heat pumps, hydrogen, and hybrid heating systems (combining heat pumps and hydrogen). The following provides a summary of the steps Arup has taken to estimate future avoided cost:

1. Arup has collated National Energy System Operator (NESO) Future Energy Scenarios ('FES') (please see FES spreadsheet 'EC.H' [56]) to prepare a view of the future heat technology mix. Table 23 provides a summary of the current mix and forecast mix presented. The values presented are an average of the four FES scenarios. The number of properties with gas boilers falls over time, replaced with low carbon heating systems.

2. For the avoided cost calculation, it was assumed that the technologies with the largest share should be used. These are: gas boiler; GSHP; ASHP; hybrid heat pump (ASHP + hydrogen boiler); and hydrogen boiler. The bottom rows of Table 23 present the totals including and excluding district heating.

Table 23: Future Heat Mix, 000s of properties and % share (average of 4 FES scenarios)

Heating Technology	2021		2035		2050	
Gas boiler	23,993	83%	17,408	54%	3,233	8%
Direct electric	2,358	8%	1,955	6%	1,499	4%
GSHP	62	0%	2,061	6%	5,238	14%
ASHP	193	1%	4,846	15%	10,108	26%
Hybrid (ASHP + Hydrogen boiler)	0	0%	360	1%	4,796	12%
Hydrogen boiler	0	0%	3,291	10%	7,302	19%
Biofuel boiler or hybrid	4	0%	588	2%	1,136	3%
District heating	746	3%	1,524	5%	5,145	13%
Other	1,520	5%	412	1%	56	0%
Total	**28,875**	**100%**	**32,444**	**100%**	**38,513**	**100%**
Adjusted total*	**24,428**	**84%**	**27,965**	**86%**	**30,676**	**80%**
*Total includes gas boiler; GSHP, ASHP, 'hybrid' (ASHP + hydrogen boiler), and hydrogen boiler.						

The LCOE model includes an input range for heat revenue per MWh. Arup estimated a new heat revenue range, weighted by the future heat mix presented in Table 23 above. For each heat system technology, Arup collated cost and technical performance information. The primary sources of information were: 1) DESNZ forecast of retail gas and electricity (fuel costs); 2) a report prepared by Eunomia around heating technology cost [4]; and internal benchmarks on technical performance. Please note that all cost inputs were inflated using the latest GDP deflator (from ONS - last updated 15 February 2024). Table 24 below provides a summary of the inputs. This updated methodology also considers capex and operational costs of the technology mix whereas the previous methodology did not. Table 25 and Table 26 outlined the retail fuel assumption used for natural gas and electricity.

Table 24: Heat revenue assumptions, Arup and DESNZ [94]

Heat Technology	Efficiency	Maintenance £/p.a
Gas boiler	85%	248
GSHP	271%	338
ASHP	244%	338
Hybrid (ASHP + Hydrogen boiler)	212%	231
Hydrogen boiler	84%	248

Table 25: Retail fuel input assumptions, natural gas, p/kWh (2023 prices)

	2024	2030	2035	2040	2050
Low	5.2	4.9	4.4	4.1	4.1

	2024	2030	2035	2040	2050
Medium	8.2	6.4	6.0	5.9	5.9
High	15.0	10.2	9.4	9.2	9.2

Table 26: Retail fuel input assumptions, electricity, p/kWh (2023 prices)

	2024	2030	2035	2040	2050
Low	26.3	24.3	22.2	21.3	20.5
Medium	35.3	25.8	23.6	22.7	21.8
High	58.9	28.4	25.0	24.1	23.1

With respect to updating the heat mix, avoided cost will increase due to electricity prices currently forecast to remain higher than gas. The avoided cost will change as these forecasts are updated.

The heat to power ratio is discussed in further detail in the next section, the values below reflect the £/MWh for the heat produced by the system rather than power production.

Table 27 below provide the weighted avoided costs Arup has developed for levelised cost modelling. It presents £/MWh for snapshot years to 2050 and a comparison with DESNZ' current assumptions.

With respect to updating the heat mix, avoided cost will increase due to electricity prices currently forecast to remain higher than gas. The avoided cost will change as these forecasts are updated.

The heat to power ratio is discussed in further detail in the next section, the values below reflect the £/MWh for the heat produced by the system rather than power production.

Table 27: Arup approach: weighted heat revenue £/MWh (2023 prices)

	2024	2030	2035	2040	2050
Low	99.5	98.4	102.7	109.6	115.4
Medium	134.4	115.8	117.4	123.3	126.6
High	214.9	158.2	148.6	146.6	144.1

Arup calculated a heating revenue based on the avoided cost methodology adopted in previous studies. The approach applied is therefore consistent with previous work. The aim of the avoided cost method was to produce an approximate 'revenue' value per unit of heat produced (£/MWh), which was then net off the levelised cost of electricity generation. The following provides a summary of the previously stated approach,

*"A simplified method based on the avoided boiler cost approach has been used to estimate the **heat revenue per MWh of electricity generated**. This approach estimates the cost that would have been incurred by the heat off-taker (the buyer of heat produced by the CHP plant) if they were to produce the same amount of heat using a boiler. This assumes that 100% of the heat is purchased. This would incur fuel costs at the retail gas price, which are avoided by buying heat from the CHP plant."*

Arup has assumed the same time-period for the sale of heat as per previous exercises; 20 years. No new evidence has been collated on the sale of heat for this levelised cost review.

Arup produced two long-term heat price scenarios: scenario one reflected heating revenue without capital cost recovery and scenario two includes capital cost recovery. Please note that DESNZ's approach was historically based on an estimate of equivalent gas boiler cost. It was an historically appropriate approach to estimating avoided cost. However, as UK heating decarbonises, future avoided cost analysis should reflect the changing mix of supply technologies. Arup's new approach reflected on the following:

1. There are a wide range of heating technologies presented in FES. Therefore, Arup used data collated on technical performance and cost from a study by Eunomia to inform its analysis;
2. A forecast of retail gas and electricity prices was provided by DESNZ. The range of input prices (high, medium, and low) were factored into the avoided cost calculation.
3. Based on an assumed future mix of heating supply technologies and estimated cost, a weighted average avoided cost was estimated (£/MWh).

4.2.5 Heat to Power ratio

Depending on the geological conditions and power plant operational parameters the heat to power ratio of combined heat and power plants, such as those assumed in Arup's geothermal power models, varies significantly. Arup assessed 20 data points across 4 reports; including German plants [2] and other European plants [19]. The heat to power ratio ranged from 0.8 (5MWe power output to 4 MWth thermal output) to 9.3 (4.3MWe power output to 40MWth thermal output). The power plants ranged from 0.5MWe to 10MWe in scale, and heat output from 1.2 MWth to 40MWth.

For the purposes of the LCOE model a reasonable heat to power ratio was required. Heat to power ratio percentiles were calculated from the available 20 data points. Values of 2, 4, and 7.9 were calculated for P10, P50, and P90, respectively. The average heat to power ratio of 4 was selected and incorporated in all LCOE models.

The heat revenue requires both the heat to power ratio and an assumption of the heat off-take is used in the estimation of heat revenue, as well as any adjustment factor applied to the proportion of revenue received. The LCOE values presented in this study for heat revenue do factor in the heat to power ratio, however, assume that only 25% of generated heat is sold to off-takers; this is equivalent to a heat to power ratio of 1:1. The sale of heat to off-takers is highly variable on geographical location (i.e., where it is isolated or not) and surrounding heat demand (e.g., in a city, heat demand is high). As a result, the percentage of heat sales is challenging to generalise, and a conservative value of 25% was selected and considered reasonable, but could be higher if heat off-takers are easier to find or the system can feed into a DHN. This is due to balancing the various uncertainties in the heat revenue estimation to indicate a lower estimate for heat revenue (1) the proportion of heat able to be sold (the off-take) is unknown for these nascent systems and is unlikely to be 100% and (2) the developer is unlikely to sell heat for the same price as alternative systems.

We note that if 100% of heat was assumed to be sold (4 x that of our 25% assumption) at the same price as the avoided alternative system the levelised costs for granites and NOAK sedimentary systems would become negative. The model is highly sensitive to assumptions over heat revenue and this would benefit from further review as the industry matures.

4.2.6 Lithium Revenue

Lithium revenue has been explored and full details are presented in Appendix C. This section provides an overview of lithium and its potential within geothermal systems.

In 2024, the global annual demand for lithium carbonate equivalent was around 1.1 million metric tonnes. In 2030 this is expected to double, to around 2.4 million metric tons of lithium carbonate equivalent; a strong driver of which is from battery demand for electric vehicles [59].

Direct lithium extraction (DLE) techniques from geothermal brines is a rapidly growing technological area and one which has the potential to bring another source of revenue from geothermal systems.

As part of the stakeholder exercise, Arup engaged with lithium companies across the UK. Only a single lithium stakeholder engaged with Arup. Whilst the stakeholder could not confirm their own anticipated costs for commercial reasons, they confirmed the value estimations from literature were reasonable. As a result, the Arup assessment relied heavily on limited available published literature. Data from ongoing projects, Vulcan Energy (Germany) [15] and Standard Lithium (US) [16][17], provided greatest insight. This reliance on limited datasets from lithium developers, mean that the values presented are indicative and potentially biased to more favourable lithium conditions. However, this is challenging to assess given that geological conditions are variable and there is limited available literature.

4.2.7 Lithium Revenue in the LCOE model

Lithium from geothermal systems within the UK is unlikely to be realised at scale for a number of years. Given the limited and indicative nature of the data assessed, lithium revenue within the LCOE model was not reported; however, its functionality in the model is available and should be informed from commercial lithium companies working with DESNZ.

More data and further consideration is required with regards to implementing lithium revenue within a LCOE model. Building on the work presented, reporting upon lithium revenue within the LCOE model could be considered within subsequent revisions of the LCOE model.

4.2.8 Discussion

Capacity estimates

For the power assessment, Arup assessed 3 to 4km sedimentary systems; and 4 to 5km granite systems. For the sedimentary system, the power values used in the cost model was an average of Cheshire Basin Early Carboniferous Limestone (3850 to 4350m) and Northern Ireland Lower Permian Sandstone (2900 to 3200m). For these each P90 value was averaged, each P50 value averaged, and each P10 value averaged.

For the Granites, it was an average of the 4km and 5km Scottish values, and the 4km and 5km Cornish values.

As a result of this methodology, the levelised costs are reflective of a generalised UK reservoir rather than a specific reservoir. Specific reservoirs with greater power capacities would have lower levelised costs; however, this site-specific assessment was not undertaken as part of this study. It could form part of subsequent work.

Costing year

The reported costing year in this report reflects the project start year i.e., the year the model, and system development (pre-development), starts. For example, '2024 costs' refer to pre-development starting in 2024, not system operation. Different technologies have different development timescales; closed loop system are assumed to be operational after 1 to 2 years (i.e., start in 2024, operational in 2026), deep geothermal systems may only be operational after 4 to 8 years (i.e., start in 2024, operational in 2028 to 2032).

Development Costs

The development costs for deep geothermal projects exhibit significant variability, ranging from approximately £400,000 to £1.3 million. These costs encompass several components, including feasibility studies, exploration, planning, permitting, well design, and procurement.

The range in costs represents the level of exploration required. Lower costs involve reinterpreting existing data, while higher costs account for acquiring, interpreting, and modelling new 2D seismic data. The c. £4 million cost for acquiring and interpreting 3D seismic data has been excluded from pre-development costs. 3D seismics are typically implemented in large-scale geothermal systems involving multiple production wells across a substantial region. In the UK, use of 3D seismics for geothermal systems is unlikely to occur anytime soon. Exploration drilling is also excluded, this is discussed in Section 4.4.3.

Construction Costs

Drilling cost and plant costs represent the largest proportion of the total construction costs.

Drilling costs vary with depth, and across various global regions. A summary of the drilling cost data is presented in Figure 12, and summary points outlined below and summarised in Table 28.

- U.S. Department of Energy baseline to ideal curves [10]. The baseline costs step up between 2.5 to 3km, and 4.5 to 5km with linear trend in between. The ideal curves are the lowest of all the literature, with linear, depth independent, drilling costs up to 7km depth. These forecast plots have been directly used to inform the NOAK drilling costs within the LCOE model. These drilling costs are very low, and would require significant investment, supply chain development and drilling to occur in the UK.

- FORGE data presents a reduction in costs between their A to C wells from around £2.2M per km to £1.2M per km.
- The Fervo data [93] is from two sites. The first two wells were drilled at Project Red and the other six at Cape Station. The drilling costs reduced from around £2.9m per km to £850k per km.
- Global cost data from Netherlands, Indonesia, Philippines, Kenya, Iceland, New Zealand, Australia, France, and U.S.. These data sets generally range from 1km to 4km depth.
- UK stakeholder data. High, medium, and low data has been presented for selected depths. Stakeholder data was not project specific and represents generalised numbers. The UK stakeholder data was used to inform the FOAK drilling costs within the LCOE model. These are depth dependent and highly variable, however the medium data is generally consistent with the global data sets.
- UK drilling cost are high owing to a limited supply chain and typical requirement to use European deep drilling rigs, of which mobilisation alone may cost £1M.

The global benchmarking assessment was undertaken to see where UK costs sit. However, within the LCOE model UK stakeholder data was used to inform the FOAK values, and US ideal curves used for the NOAK values.

Within the LCOE model the granite target was assumed to be between 4km to 5km depth. Low, medium, and high drilling costs for a 4km, and a 5km well were obtained from the FOAK curves in Figure 12. An average of the 4km and 5km costs was then taken to assume the drilling cost of the well.

The Sedimentary target was assumed to be 3km to 4km. This is because based on the UK geothermal assessment, these depths were required to achieve >100°C fluid, considered to be the minimum bottom hole temperature for economical binary plant operation. Again, high, medium, and low values were taken from 3km, and 4km depths on the FOAK curves in Figure 12. An average cost between the 3km and 4km costs was used in the LCOE model.

Deep geothermal systems also have decommissioning requirements. £300k, £500k, and £1.2M, low, medium, and high respectively, was assumed for each well (abstraction and reinjection). This was based on stakeholder data.

Table 28: Summary of inferred FOAK and NOAK drilling rates for various depths applied to the LCOE model

Depth (km)	Type	Low		Medium		High	
		Cost (£M)	Cost per km (£M)	Cost (£M)	Cost per km (£M)	Cost (£M)	Cost per km (£M)
1	FOAK	2.5	2.5	3.3	3.3	4	4
	NOAK	0.85	0.85	1.2	1.2	1.75	1.75
2	FOAK	3.8	1.9	5.1	2.6	6.9	3.5
	NOAK	1.5	0.75	2	1	2.7	1.35
3	FOAK	4.6	1.5	6.7	2.2	9.9	3.3
	NOAK	2.05	0.7	2.6	0.85	3.45	1.15
4	FOAK	5.5	1.4	7.8	2	14.2	3.5
	NOAK	2.65	0.65	3.8	0.95	5.45	1.35
5	FOAK	9.5	1.9	12.2	2.4	21.5	4.3
	NOAK	3.2	0.65	3.85	0.75	5	1

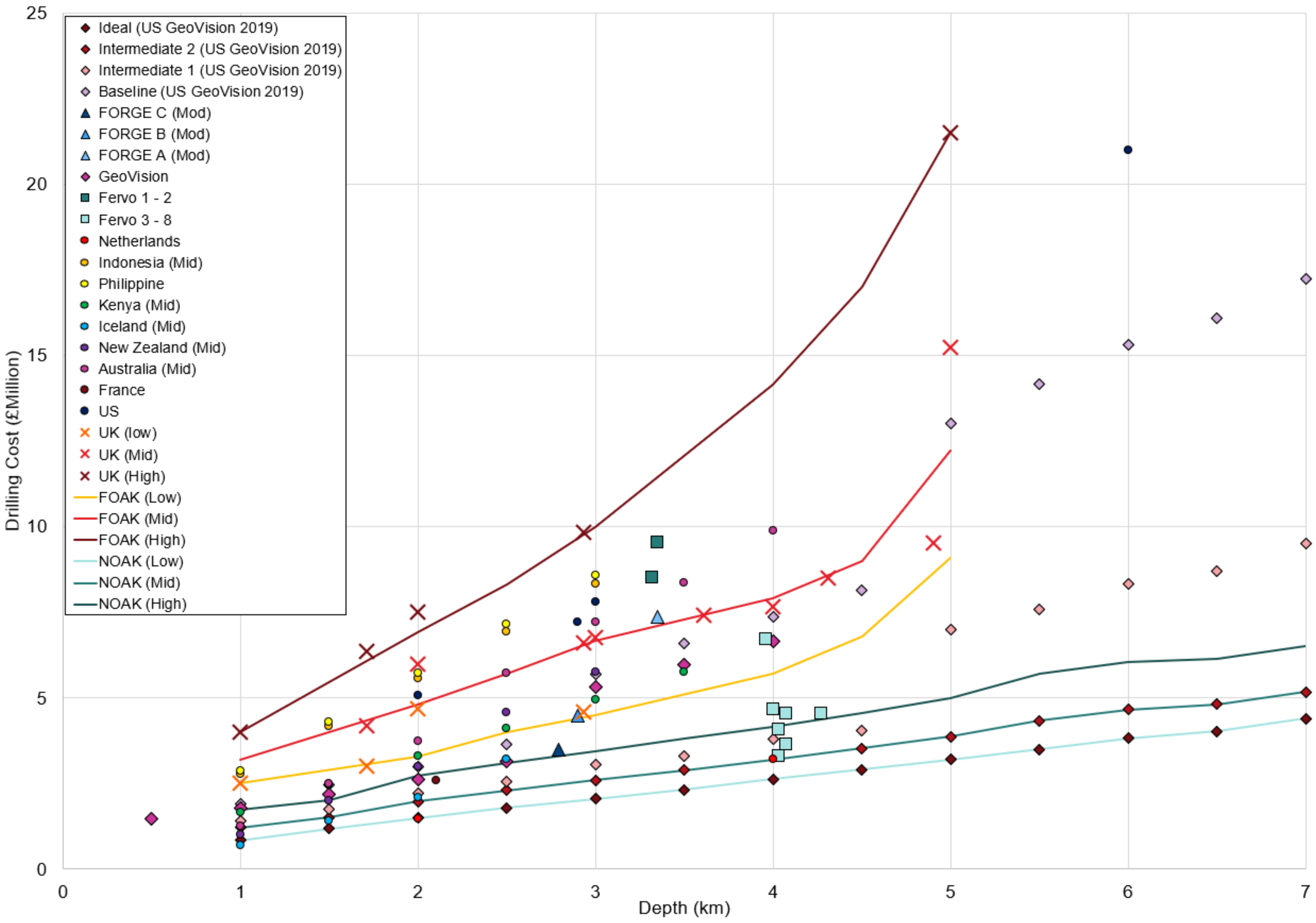


Figure 12: Drilling costs for a single deep well

4.3 Summary of Findings

4.3.1 Findings

Arup's assessment found that levelised costs (medium scenario, 2024 project start year) ranged from £852 to £136/MWh; with FOAK sedimentary systems delivering the highest LCOE values; and NOAK granites delivering the lowest LCOE values. These costs do not include heat and lithium revenue assumptions. Assuming a heat to power ratio of 4 (see Section 4.2.5) results in £143/MWh of heat revenues for projects starting in 2024. The revenues from heat may be an oversimplification (using the avoided cost methodology) and may be an overestimation (note that levelised costs become negative). These assumptions demonstrate the potential positive impact revenues such as heat could have on overall levelised costs. A summary of findings is presented in Table 29 and full data tables in Annex C.

The UK granite targets present lower overall levelised costs relative to UK sedimentary targets for power. This is principally a result of greater power and heat capacities, which overshadow the greater CAPEX (predominantly from increased drilling costs in deeper and harder granite formations) associated with the deeper granite targets. The UK granite assessment also averaged the heat and power capacity estimates from the Cornish and Scottish granites. An LCOE focusing solely on the Cornish granites would come out more favourably than a Scottish granite assessment; owing to the higher inferred geothermal capacities.

Levelised capital costs can range by an order of magnitude. This is driven by the range in power values, varying by around 2MWe between high and low estimates.

The LCOE is highly sensitive to hurdle rates. For example, assuming a higher hurdle rate of 18.8%, for example would lead to costs estimates increasing from £170/MWh to £453/MWh for central assumptions (Granite FOAK, heat revenues, 2024 project start, medium scenario).

Capital costs are assumed to reduce due to learning rates associated with drilling (assumed to be 3.3%, 0.5%, and 0.1% for high, medium, low respectively). No learning rate was applied to the operating costs, and therefore operating costs see no temporal difference. There was insufficient data to assume an operational learning rate with sufficient confidence. In reality we would anticipate some learning but this is likely to be of less significance than learning assumed for drilling.

The levelised costs for all systems follow a reducing trend over time. This trend is initially slow, between 2024 and 2030, and then increases to 2050. When heating revenue is included, between 2024 and 2050, levelised costs generally fall by 40% to 60%. When heating revenue is excluded, costs fell by 5% to 30% over this same period.

Levelised costs varied by 10% to 30% between models incorporating heating revenue and those without. This evidences that heat revenue carries significance with the levelised cost model. Each model assumed an effective 1:1 heat to power ratio; based on a heat to power ratio of 4 multiplied by an assumed 25% heat sales assumption. This assumption is subject to review, is likely variable, and site specific.

Arup's model findings were benchmarked against available published data. Published values for LCOE generally range from £50 to £190/MWh (Table 30). Arup's NOAK values are broadly consistent with these published values. This is driven by the significantly reduced NOAK drilling costs. However, FOAK values are far greater, especially for the FOAK Sedimentary systems (a result of high drilling costs).

4.3.2 Regional variability

Within the levelised cost model power capacities were averaged from the Scottish and Cornish granites. This was done to provide 'general' cost values. However, the impact of this is that the total range in resulting levelised costs is reduced (as the lowest and highest thermal capacities are increased and reduced respectively). Deep geothermal systems have high regional variability, based on productivity and geothermal gradients of reservoirs. This variability may have been lost through the averaging methodology applied.

It is likely that the most favourable deep geothermal reservoir will be the first geothermal target for a new systems. Therefore, an assessment of the Cornish granites (highest power capacity estimates) was undertaken.

Using the power capacities of 1.75MWe (P90), 2.6MWe (P50), 3.35MWe (P10) (average of the 4km and 5km power estimates, to reflect a 4 to 5km system). The levelised cost are £63/MWh to £463/MWh (FOAK), and £32/MWh to £40/MWh (NOAK).

These values are favourable compared to the 'generalised' results presented from the levelised cost model.

Table 29: LCOE summary table (£/MWh), medium scenario values

Scenario	Heating revenue	2024	2035	2050
Deep geothermal, granite (FOAK)	Yes	169	136	101
	No	311	304	290
Deep geothermal, granite (NOAK)	Yes	-6	-36	-62
	No	136	133	127
Deep geothermal, sedimentary (FOAK)	Yes	710	668	610
	No	852	837	798
Deep geothermal, sedimentary (NOAK)	Yes	41	11	-18
	No	183	180	171

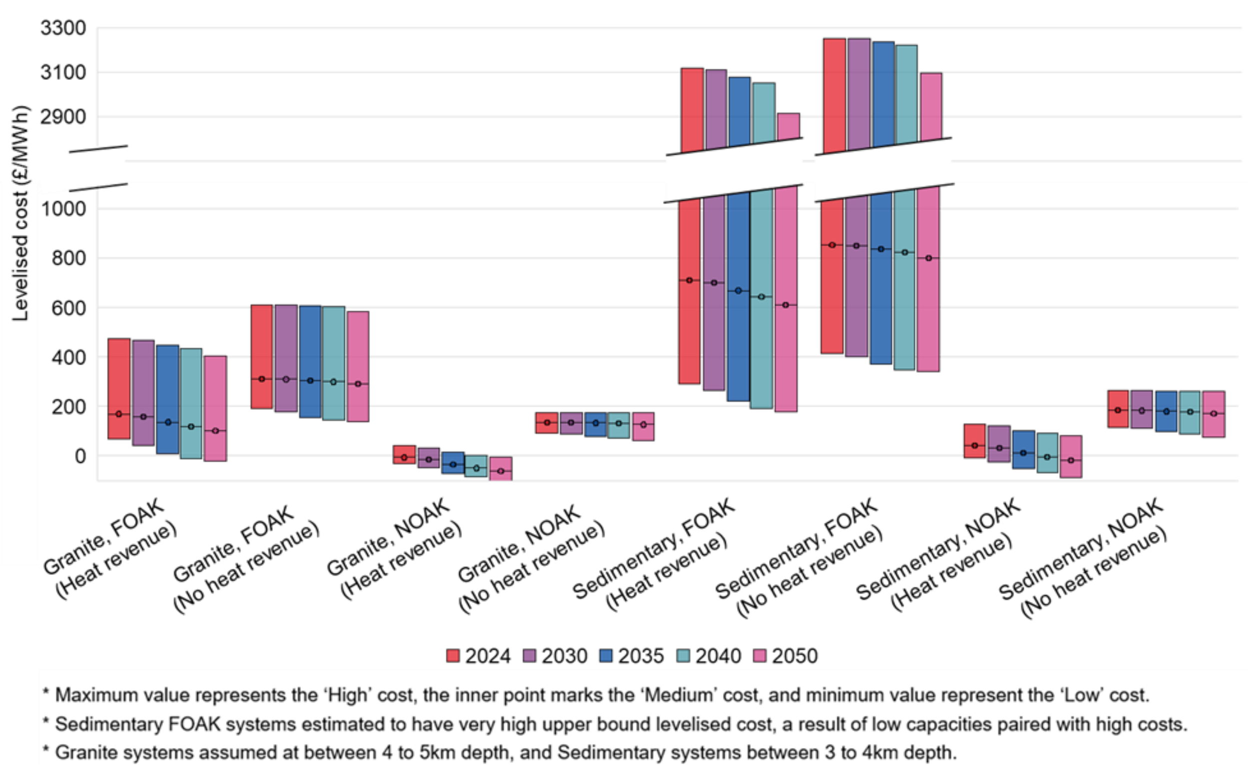


Figure 13: LCOE values for granite and sedimentary targets for each of the assessed years

4.3.3 Benchmarking

A review of available LCOE models and outputs was reviewed to benchmark Arup's assessment. A summary is provided within Table 30.

Table 30: Published geothermal levelised cost values

Published value	Equivalent value (£/MWh)*	Source
Between 2010 to 2022, the yearly global weighted average of installed geothermal plants ranged from \$0.053/kWh to \$0.091/kWh; However, the full extent of yearly costs ranged from >\$0.15/kWh to c. \$0.046/kWh	Yearly weighted average £68/MWh to £117/MWh. Full range from £192/MWh to £59/MWh	IRENA (2022) [73]
US unweighted levelised cost including tax credits of \$39.6/MWh	£50.8/MWh	EIA (2022) [74]
US immature (FOAK) range from \$34/MWh to \$460/MWh, Mature (NOAK) range from \$40/MWh to 105/MWh.	Immature (FOAK) range from £527/MWh to £359/MWh. Mature (NOAK) range from £34/MWh to £82/MWh	NREL (2023) [75]
* Conversion assumed an exchange rate of 0.78 USD:GBP		

4.4 Further considerations

4.4.1 Drilling success rate

Deep geothermal systems are often perceived as relatively high-risk energy systems. This is principally a result of high drilling costs paired with deep geological uncertainty, as the conditions of the geothermal target reservoir often remain unproven until a deep well is drilled and tested.

The LCOE model excludes consideration to drilling success rate as it is a cost basis for successful projects. However, drilling success and its impact of project contingency would be a consideration on a project basis. Exploration well success rates are reported at around between 50% to 90% [8][18]; and production well drilling success rate of 75% to 90% [18]. As a result, large contingencies are typically applied to drilling campaigns; typically, around 20 to 30%, and can be as high as 100%.

4.4.2 Geothermal system scale

In the LCOE model, FOAK systems have been assumed to comprise a single doublet, with one production well. This was considered appropriate because the FOAK systems need to work successfully before being expanded upon and scaled up.

For the NOAK systems, multiple production wells have been assumed. This is consistent with global large scale geothermal power systems. For large scale geothermal operations; an initial exploration exercise is undertaken to outline the most productive regions within a licenced exploration area. Following this, production well(s) are drilled and tested, prior to reinjection wells and further production well drilling. Multiple well systems benefit from scales of economy.

4.4.3 Exploration drilling

Exploration drilling is common practice across global geothermal regions. Exploratory drilling typically comprises ‘slim-well’ drilling. These wells are of narrower diameter, and as a result around 50 – 60% the cost of larger production wells. Whilst they are suitable for geothermal gradient measurements and downhole geophysical surveys among others; they are typically too narrow for use as a production well. Therefore, they are an additional cost to a production system.

In more developed geothermal markets, governments conduct geothermal licencing auctions, similar to on- and off-shore oil & gas and renewable licencing rounds. These comprise areas to be licenced to a single developer. In these instances, large areas of land (e.g. 20 km^2 to 100 km^2) are allocated. Licenced regions also protect geothermal systems from interference and potential reduced yield from any neighbouring system. In these instances, and with a focus on large scale investment, comprising multiple production wells over an extended drilling campaign; exploration drilling is a vital tool. Exploration drilling helps identify the regions within the licence area which are more productive and therefore priority for siting production wells. Currently, in the UK, geothermal systems are being explored on a site-by-site basis. As a result, exploration drilling underutilised, as the geothermal system is limited to a selected site; and therefore, the first well drilled is typically the production well.

4.4.4 Learning rates within a single reservoir

The LCOE model considers general learning rates across the geothermal sector with reduction in drilling costs and plant cost constituting to a reduction in LCOE. However, within a given reservoir or drilling campaign learning rates can also be observed as the drilling engineers become more familiar with the drilling conditions and considerations. For example, at the FORGE engineered geothermal system research site, and the adjacent Fervo site, in Utah, U.S; drilling costs reduced by around 3.3% per year over 6 years [10] [11]. Comparatively, within oil and gas reservoirs, reservoir learning rates are generally 10 – 15% between each well [8].

4.4.5 Comparative Technologies

Geothermal power costs are currently higher than other power generating systems, such as wind and large scale solar, due to high capital costs and modest power outputs, of around 2MWe to 3MWe (16GWh to 24GWh) per production well[11], relative to estimates of 8 to 12MW (c. 30GWh to 45GWh) per off-shore wind turbine[12], or 0.5MW (0.48MWh) per hectare of solar photovoltaics[13].

Currently, for power generation only, wind and large scale solar may have lower levelised costs. However, current wind and solar LCOE values are a result of substantial global investment over the last decade. For example, global weighted average LCOEs for solar have fallen by 89% between 2010 and 2022, from 0.445 USD/kWh (c. £347/MWh) to 0.049 USD/kWh (c. £38/MWh); and global weighted average LCOEs for wind have fallen by 69% between 2010 and 2022, from 0.107USD/kWh (c. 83/MWh) to 0.033 USD/kWh (c. £26/MWh) [73]. Comparatively, geothermal has seen less global investment and fewer projects, which likely contributes to a lack of stable year-on-year LCOE reductions, as observed with solar and wind energy.

Relative to solar and wind, geothermal can provide baseload energy (contributing to a more stable national grid) together with providing large heat capacities (unlike power only renewable technologies). Furthermore, as presented in Figure 13 and with investment, geothermal costs are likely to reduce.

[11] Based on Arup's assessment and based on a 90% load factor.

[12] Based on IRENA capacity data, and a 42% load factor (Energy Numbers). International Renewable Energy Agency (IRENA), Wind Energy, link: https://t.ly/Au2uX. Energy Numbers, UK offshore wind capacity factors, 2022, link: https://energynumbers.info/uk-offshore-wind-capacity-factors

[13] Based on capacity data from Carbon Commentary an 11% load factor. Carbon Commentary, Which is better: a hectare of solar or wheat?, 2022, link: https://t.ly/v6N1V

5. Carbon Assessment

5.1 Context

A whole life carbon (WLC) assessment has been undertaken to quantify the greenhouse gas (GHG) emissions associated with each geothermal technology within this study.

Carbon refers to carbon dioxide equivalent (CO_2e), the universal unit of measure to indicate the global warming potential (GWP) of all GHGs, expressed in terms of the GWP of one unit of carbon dioxide.

The whole life carbon of each geothermal technology has been calculated by multiplying activity data with an appropriate emissions factor, associated with the activity being measured.

Carbon emission factors have been applied at significant lifecycle stages to capture the assumed emissions associated with the construction and operation of the geothermal technologies.

Further detail of the scope and boundaries of the assessment is included in Annex D.

5.2 Introduction

This section summarises the Whole Life Carbon (WLC) assessment which has been conducted on the following geothermal technologies:

- Closed loop ground source heat pumps (GSHP): 1 well, 20 wells and 100 wells;
- Open loop GSHP: 20 litres per second (l/s);
- Deep geothermal doublet systems: 1km, 2km, 3km, 4km, 5km, 5km through hard rock.

The assessment findings are likely to be applicable to similar geothermal technologies as well. A full description of the carbon assessment methodology and results is provided in Annex D.

5.3 Methodology

The assessment methodology involved calculating the sum of greenhouse gas emissions (GHG) and removals over a 30-year period (2024-2054), encompassing all lifecycle stages, from preliminary studies and consultation through to decommissioned material disposal. The justification and data sources for each lifecycle stage in the assessment are listed in Annex D.

The carbon assessment included the following calculations:

- Calculating thermal capacities for each system to compare WLC emissions per thermal capacity of the system, which includes total heating capacity only. Geothermal systems have the capability to provide cooling and could increase the carbon saving. Thermal capacities were calculated based on the following assumed operations:
  - Closed loop system: heating only (5256hrs, 60% annual capacity)
  - Open loop system: heating only (5256hrs, 60%)
  - Deep geothermal (1km- 3km doublet): heating only (6000hrs, 68% annual capacity)
  - Deep geothermal (4km & 5km doublet): combined heat and power (7884hrs, 90% annual capacity)
- Calculating heat pump annual electrical demand by estimating the heating capacity then inversely applying the Seasonal Performance Factor (SPF).
- Calculating carbon emissions for each lifecycle activity (based on business-as-usual scenarios) using published emissions conversion factors [39][40][41].

The methodology is discussed further in Annex D.

5.4 Summary of findings

WLC results for each geothermal system are summarised in Table 31 below. A benchmarking exercise was also completed, these results are included in Annex D.

Table 31: WLC assessment results (tCO_2e) for closed loop, open loop and deep geothermal systems[14]

Lifecycle ref	Energy capacity (MWh)	Product Stage (A1-3)	Transport (A4)	Construc-tion (A5)	In-use (B)	End of Life (C)	WLC Total (tCO_2e)	Total per MWh energy delivered* ($kgCO_2e$/ MWh)
Closed loop								
Closed loop, single borehole	42	24	4	0.4	32	4	**64**	**51.0**
Closed loop, 20 boreholes	840	56	32	1	397	37	**529**	**21.0**
Closed loop, 100 boreholes	4,205	850	154	49	1,983	187	**2,470**	**25.6**
Open loop								
Open loop, 2 well	4,675	263	14	6	2,170	17	**2,470**	**17.6**
Deep geothermal								
Deep 1km	12,750 (heating)	1,942	239	112	9,326	339	**11,957**	**31.3**
Deep 2km	20,160 (heating)	2,046	335	196	11,175	503	**14,255**	**23.6**
Deep 3km	40,800 (heating)	2,098	339	245	6,090	572	**9,344**	**7.6**
Deep 4km	96,185 (heating) 9460 (power)	2,279	370	329	11,241	686	**14,906**	**4.7**
Deep 5km	129,300 (heating) 21,280 (power)	2,354	376	462	14,516	799	**18,506**	**4.1**
Deep 5km - hard rock	129,300 (heating) 21,280 (power)	2,266	369	560	14,516	841	**18,551**	**4.1**
*WLC value divided by whole life thermal generation (heating), and power generation, calculated as 30-year production. Note. A1-5, B and C are defined in Annex D.								

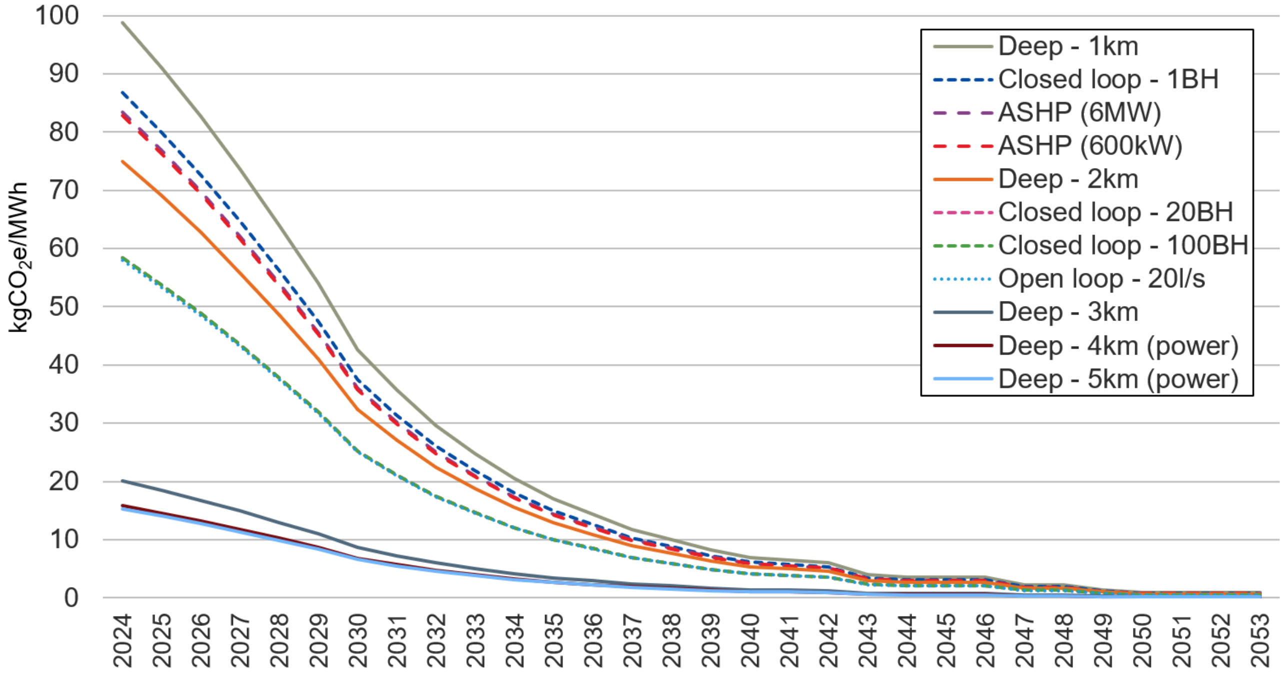
Across all systems, the primary contributor to carbon emissions is the electricity consumption within the In-Use (B) phase, specifically the operational energy emissions, which contributes an average of 77% of the whole life carbon emissions. These emissions stem from electricity consumption. Operational emissions from energy use were modelled using National Energy System Operator (NESO) trajectories ($kgCO_2e$/kWh) for the next 30 years. Operational emissions were highest for deep geothermal systems because of the potentially large hydraulic heads and high pumping requirements.

[14] Lifecycle references defined within Annex D.

Deep geothermal systems and open loop systems presented the lowest levelised carbon emissions; however, all systems were broadly comparable, generally within an order of magnitude of each other.

5.5 Technology comparators

The geothermal systems were compared with alternative technologies, namely air source heat pumps (ASHPs) and gas boilers. There was an operational carbon saving for all the renewable technologies compared with a scaled gas boiler system. Figure 14 shows that ASHPs and geothermal systems are projected to progressively decarbonise over the next 30 years as the National Energy System Operator (NESO) moves toward net-zero emissions.

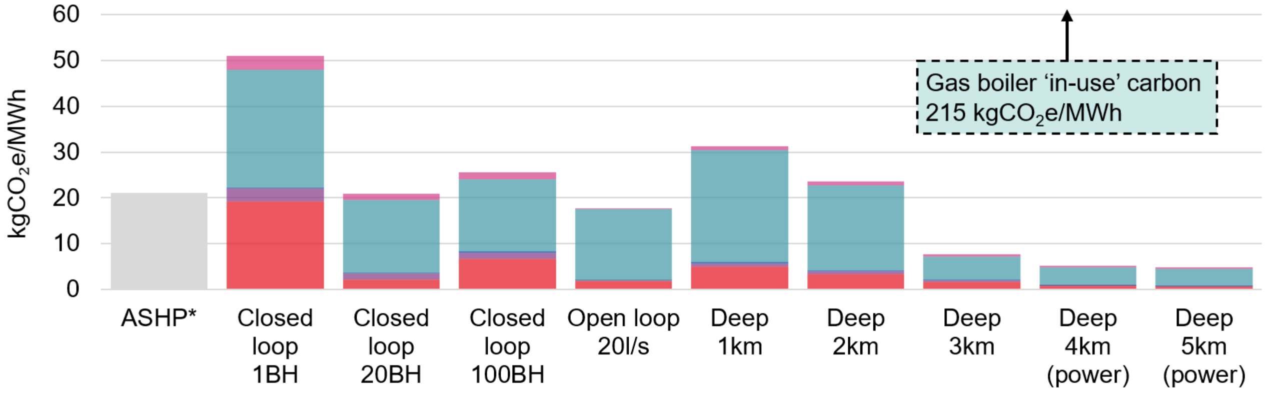


* Gas boilers have a consistent (flat line) carbon value of 215 $kgCO_2e/MWh$ which does not decrease over time.

Figure 14: Comparison of operational energy carbon emissions across all technologies, 30 year ($kgCO_2e/MWh$)

5.6 Discussion

The carbon intensity for each shallow geothermal scenario ranges from 17.6 $kgCO_2e/MWh$ for the open loop 20 l/s scenario to 51 $kgCO_2e/MWh$ for the 1-borehole closed loop scenario. Although the deepest geothermal technologies have the highest embodied carbon of the geothermal scenarios considered, they have the lowest levelised carbon due to high capacity as shown in Figure 15. Closed loop systems have the highest levelised carbon, but all systems were broadly comparable, generally within an order of magnitude of each other.



* ASHP embodied carbon from CIBSE TM65.1 Embodied carbon in building services: residential heating (2021) [115]. Arup converted the reported 55.2 $kgCO_2e/kW$ to 21 $kgCO_2e/MWh$, assuming the system is used for heating for 60% of the year (5256hrs), to be comparable with the shallow geothermal systems. The full reported range is from 34.5 to 71.3 $kgCO_2e/kW$ (c. 13.1 to 27.1 $kgCO_2e/MWh$). This is a residential value and therefore may not be suitable for direct comparison.

* Gas boilers excluded from graph. Gas boilers have an 'in-use' carbon value of 215 $kgCO_2e/MWh$, exceeding the axis of this graph.

* Carbon costs: A1-3, Products (piping, pumps, cement); A4, Transport (haulage); A5, Construction (enabling works, water disposal); B, In-Use (maintenance, equipment replacement, operational energy consumption); C, End of Life (demolition, transport, recycling).

Figure 15: Geothermal technologies whole life carbon emissions per power output ($kgCO_2e/MWh$)

6. Conclusions

This document presents the methodology adopted for the study, assesses geothermal potential in selected areas across the UK, and describes how generation costs and carbon emissions have been calculated. The report consolidates data from the outlined tasks, highlighting key insights in detailed appendices and annexes, such as emissions data for comparing different geothermal systems.

Levelised Cost of Heat (LCOH)

- Shallow geothermal systems have relatively low levelised costs compared to deep geothermal systems. They typically range from £49/MWh to £143/MWh for heating only (assuming the technology is a FOAK, 2024 costs) and from around £18/MWh to £56/MWh (assuming the technology is a NOAK, 2024 costs), with lower costs when cooling is included. The modelling shows that operating shallow systems in a balanced heating and cooling configuration is likely to make them more economically favourable, where there is demand for cooling, such as in hospitals.
- Purpose-built deep coaxial wells and O&G open loop systems have the highest LCOH and largest range, ranging from £56 to over £5503/MWh. These high costs ranges are primarily due to expensive drilling processes and relatively low heat capacities. Of deep systems, deep doublet (NOAK) and oil and gas coaxial conversion systems presented the lowest LCOH at £55 to £172/MWh (2024 costs, medium scenarios). These lower costs are due to higher heat capacities within a doublet system, with the additional benefit of experience gained over time (NOAK). For O&G wells the lower drilling costs result in a lower overall LCOH, however they are geographically restricted due to already being drilled.
- One of the key reasons for lower costs in shallow systems compared to deep systems is the assumed lower hurdle rate for shallow systems, as shallow geothermal systems are more developed and therefore include less risk. The hurdle rates are an uncertain parameter, and the rates used in this study may not be representative of all geothermal systems. For shallow and deep systems hurdle rates may be higher if there is higher associated risk than modelled here and vice versa if risks can be reduced then hurdle rates may reduce leading to improved cost-effectiveness.
- More favourable geothermal targets within the UK, which have greater energy capacities, are likely to present lower levelised costs compared to average values used in this modelling. Identifying and utilising these targets could improve overall project economics.
- Deep and shallow geothermal projects carry inherent risks due to the uncertainty of geothermal resources. The risk is higher within deep systems than shallow systems, as reflected by higher hurdle rates. Policy support mechanisms can mitigate these risks, for example reducing financial risks (e.g. through grants, convertible grants or loans) or enabling insurance or risk sharing. These mechanisms are likely to make heat and power prices more competitive for consumers.
- Overall, shallow geothermal systems appear to be more cost-effective in the current market and using the assumptions within this modelling. However, with strategic investments, leveraging learning rates and improved modelling, deep geothermal systems have the potential to become more cost-effective.

Levelised Cost of Electricity (LCOE)

- There is a large range in levelised costs, from £136 to £852/MWh when excluding heating revenues. UK granite targets generally present lower levelised costs compared to sedimentary targets. This is primarily due to greater power and heat capacities in granite systems, despite higher capital expenditures for drilling deeper and harder formations.
- LCOE can be reduced through utilising other revenues streams such a selling heat. The models incorporating heating revenue show significantly lower levelised costs, with reductions of 40% to 60% dependent on project start date.

- The effective power to heat ratio of 1:4 used in the models underscores the significance of heat revenue assumptions, though these assumptions are subject to variability and site-specific factors.
- Currently, for power generation only, wind and large scale solar may have lower levelised costs, however geothermal can provide baseload energy together with providing large heat capacities (unlike power only renewable technologies).
- Overall, granite systems, particularly Cornish granites, appear more economically viable due to lower levelised costs driven by higher geothermal capacities and heat revenue. Reducing drilling costs through learning could further enhance the cost-effectiveness of these systems over time.

Levelised Costs

- Development Costs exhibit significant variability for both LCOH and LCOE. Costs represent the level of exploration required. These costs are dependent on the extent of surveying required. However, if good data is already available, less money is required for the development stages.
- Construction Costs associated with drilling cost and plant costs represent the largest proportion of the total levelised cost of electricity. Drilling costs vary with depth, and across various global regions.
- FOAK systems exhibit higher costs, but as the technology matures to NOAK systems costs reduce, particularly in drilling and construction of large-scale facilities. However, achieving NOAK levelised costs in the current UK market requires further investment, research, and supply chain development.
- Possible benefits of experience gained over time (learning rates) have been reviewed between 2024 and 2050 for both LCOH and LCOE. Cost reductions are forecast for both heat and electricity generation from geothermal. Increased project delivery efficiencies are gained as a function of local practitioners delivering projects within the UK, which in part is supported from existing international experience.
- There are several technologies in development that could favourably impact geothermal costs and adoption that were not evaluated as part of this research, since these technologies are not considered to be currently commercially available (such as advanced geothermal systems or AGS).

Emissions intensity (Whole Life Carbon)

- Carbon intensity of energy from geothermal ranges from 4.1 to 51kgCO2e/MWh. All geothermal systems demonstrated a significant carbon saving in comparison to gas boilers (215 kgCO2e/MWh). Carbon intensity of geothermal was broadly comparable to ASHP.
- Operational carbon of geothermal systems makes up over 75% of the whole life carbon intensity. Electricity consumption during the in use (B) phase was the primary contributor. Future changes in grid electricity carbon intensities will result in a reduction in these carbon emissions for geothermal and other electric technologies.
- Deep geothermal technologies have the highest embodied carbon, especially at 5km depth, but lowest levelised carbon due to high capacity.
- Overall, geothermal systems can provide significant carbon savings compared to gas boilers and some savings compared to air-source heat pumps due to greater operational efficiency.

Geothermal going forwards and other considerations

- Wider benefits of geothermal were out of scope to evaluate quantitatively during this study. There are many benefits, including a small land footprint, the combined use of a system as heating and cooling or for both power and for heat, and the transfer of skills from industries such as oil and gas.
- There are a number of uncertainties in the costs and technical assumptions, in particular for deep geothermal given its nascency for the UK. Some cost assumptions are transferred from international literature sources and some are based on a small number of data points. As discussed in more detail

within the report, these are supported by a high number of detailed 1:1s during the course of this study combined with expert opinion from within Arup. Going forwards, these uncertainties should be reviewed as the UK industry matures.

- To achieve a reduction in levelised costs, the UK must promote awareness and draw lessons from the UKs existing deep geothermal projects: United Downs, Southampton, Eden; and benefit from more geothermally advanced nations. Key strategies include: adopting a data-sharing approach for geothermal datasets, implementing policy support to mitigate capital risks, providing long-term revenue guarantees, and streamlining the permitting process for geothermal systems. Crucially, the UK geothermal sector needs to develop a pipeline of new projects, such as those for NHS hospitals, university campuses, and public and private district heat networks. Large-scale opportunities in the UK can boost private sector confidence, leading to increased investment (e.g., in UK drilling rigs) and the development of supply chains.

The report, models, and assessments are based on reasonable assumptions and stakeholder and literature data. However, the LCOH model and funding mechanism indicative model are the first of their kind in the UK, and there is scope for critical review, revision, and re-modelling. Site-specific assessments could also be undertaken for more precise evaluations.

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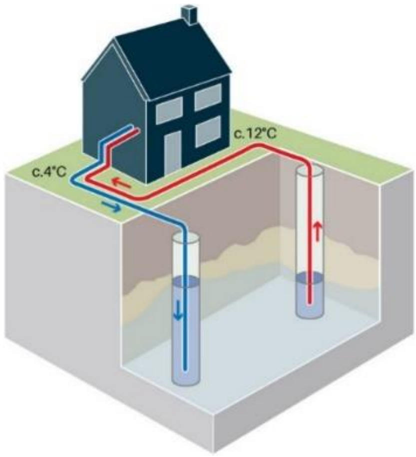
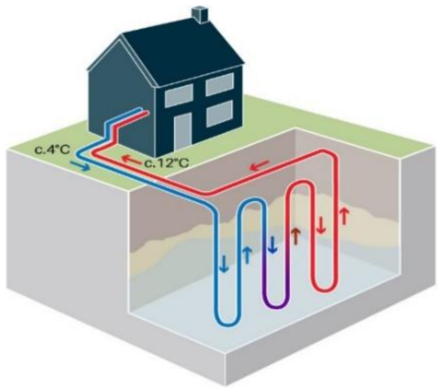
Appendix A: Overview of Geothermal Technologies

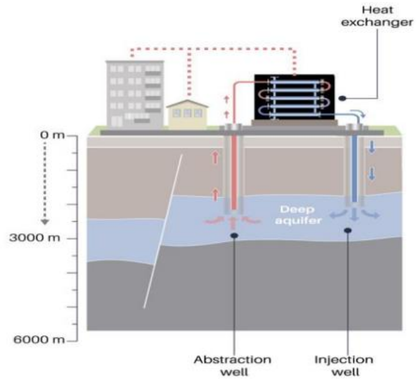
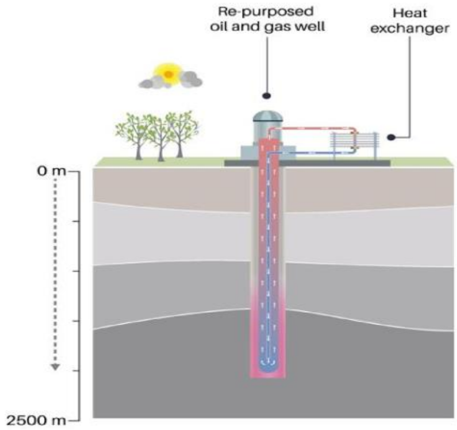
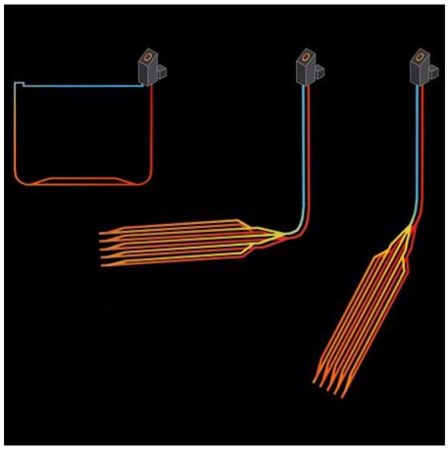
There are several technologies available to access ground energy at different depths and in different settings. Some technologies are widely used and well understood, for example, ground source heat pumps with open or closed loops.

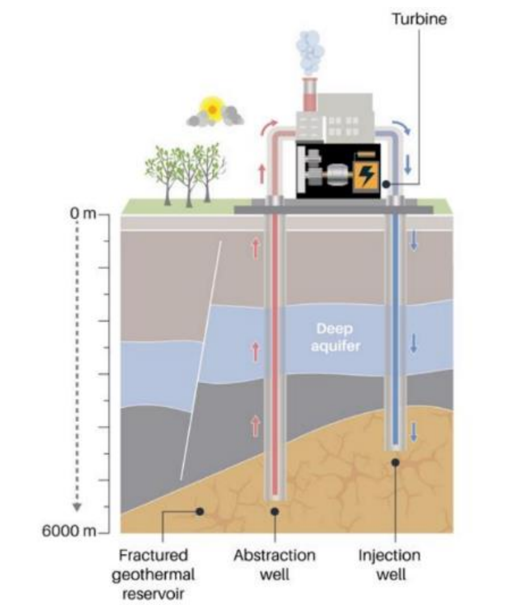
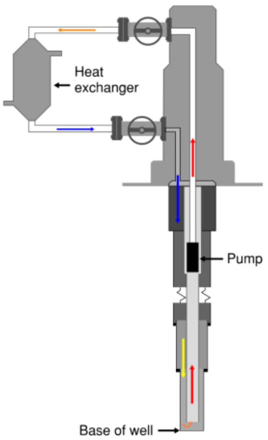
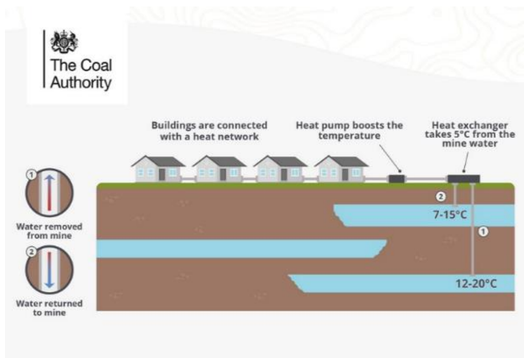
A comprehensive review for each of the technologies is presented in the 2022 Arup & BGS report titled 'Research into the Geothermal Energy Sector in Northern Ireland: Geothermal Technology and Policy Review' [49].

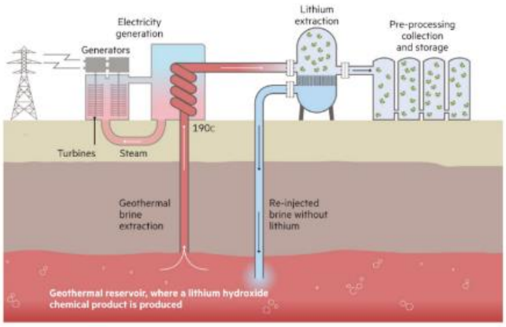
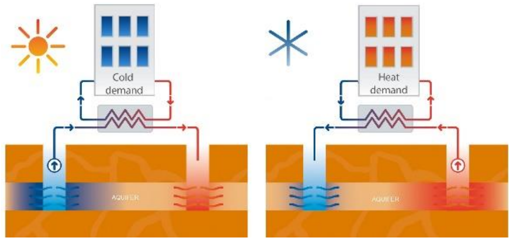
This appendix provides operational detail of the technologies which have been reviewed for this project, see Table 32.

Table 32: Summary of Geothermal Technologies

Technology	Summary	
Open loop	Open-loop geothermal wells require at least two water wells (boreholes): one for abstraction and at least one for discharge of groundwater to and from the same aquifer. The water is pumped from the abstraction borehole, usually using an electrical submersible pump (other pumps may be possible) and piped to the heat exchanger where heat is transferred to the heat pump prior to discharge.	 Source: BGS [32]
Closed loop (vertical boreholes)	Vertical loops/pipes are installed in boreholes between 50 and 200 meters deep below ground level. They are arranged in arrays/lattice patterns and are more common than horizontal systems due to their space efficiency, especially in cities with limited space and high energy demands. The system comprises an underground heat exchanger and piping network, heat pump/heat exchanger, and building distribution system. Manifolds are used to connect the borehole arrays.	 Source: BGS [32]

Technology	Summary	
Hot sedimentary aquifer	Hot sedimentary aquifer systems target deep reservoirs (>500m depth) and can provide water at higher temperatures relative to shallower systems but require favourable geological conditions. They work in a similar way to an open-loop system, utilising a well doublet (i.e., abstraction and discharge borehole). Abstraction requires a pump (typically an electrical submersible pump), and a second pump may be required to discharge water back into the aquifer. With sufficiently high temperatures, these systems can be used for direct heating (not requiring a heat pump) but do require a heat exchanger to transfer heat to buildings or district heating networks.	 Source: Abesser [2]
Deep single coaxial well/standing column well	A single borehole is fitted with an inner insulated liner, forming an annulus between the liner and the borehole wall/casing. The base of the well can either be ‘open’/perforated, referred to as a standing column well, or ‘closed’ referred to as a coaxial well. Warm water is brought up from the base of the well within the inner insulated liner, and the heat is transferred at the surface via a heat exchanger before being returned down the borehole via the outer annulus. Deep coaxial wells operate as closed-loop system, while standing column wells operate as an open-loop system; with low volumes of formation fluid being incorporated in the system, and often discharged at the surface, a process known as bleeding.	 Source: Abesser [2]
Advanced geothermal systems (AGS)	A deep closed-loop system works by conducting heat from the ground to a working fluid. The loops are formed using advanced drilling techniques to create continuous loops within which the working fluid is circulated. The boreholes are sealed from the adjacent rock using proprietary techniques, and lateral offshoot wells can be drilled to increase the contact area with the ground. The working fluid is circulated using a thermosiphon effect, whereby colder, denser fluid flows downwards and warmer, lighter fluid flows upwards, reducing pumping costs. A heat exchanger at the surface is used to transfer heat for direct use.	 Source: Eavor[33]

Technology	Summary	
Enhanced geothermal system (EGS)	Enhanced geothermal systems (EGS) are implemented in hot rocks where there is potential for natural permeable pathways that can be enhanced for circulating geothermal fluids. EGS involves drilling an abstraction borehole and a discharge borehole into a fracture/fault system. The natural fracture networks are then modified through stimulation to enhance their natural permeability and allow geothermal fluid to move from the discharge well to the abstraction well. The fluid is heated during transit. A binary plant is required for power production, and a heat exchanger is used to transfer heat to a heat network. Other equipment required includes cooling towers.	 Source: Abesser [2]
Repurposing oil and gas wells - onshore	Oil and gas wells are often drilled deep into permeable geologic strata. Repurposing these wells can be a cost-effective way to harness geothermal energy. One approach is to install an insulated liner to create a deep coaxial single well/standing column well, which is an adaptation of established shallow geothermal technologies. Another approach is to connect two existing wells and set up a hot sedimentary aquifer system. This system requires at least two wells: one for abstraction and at least one for discharge of groundwater to and from the same aquifer Repurposing wells benefits from reduced CAPEX costs (as the well(s) are already built). However, consideration must be given to the handling of co-produced gas and/or oil.	 Source: Arup
Minewater	Mine water energy systems utilise heat in abandoned mine systems. Both open and closed loop systems are possible. Open loop systems utilise boreholes installed into the mine workings to abstract mine water, which is then passed through a heat exchanger/heat pump before being returned to the mine workings via another borehole. Existing mine water abstraction schemes can provide an opportunity for an open loop system. Closed loop systems work by installing the closed loop into the mine workings via boreholes. Heat is transferred to/from the mine workings to the geothermal fluid within the closed loop.	 Source: The Coal Authority [34]

Technology	Summary	
Lithium	Geothermal brines in certain geological environments contain lithium at economic levels. The lithium production process typically involves three principal steps: hot brine extraction from the geothermal source, separation of lithium compounds from the brine, and conversion of extracted lithium chloride to battery quality Lithium Hydroxide (LiOH) at a refining plant. Alternative lithium end products area also possible, e.g. Lithium carbonate $LiCO_3$. The refining process is environmentally friendly, with recycled water, no toxic waste, and no emissions. Before deciding on the potential for lithium production, deep geothermal fluid needs to be tested, and small-scale technology trials conducted.	 Source: Financial Times [35]
Aquifer thermal storage (ATES)	Aquifer Thermal Energy Storage (ATES) is a renewable energy source that utilises the heat naturally present in the soil and groundwater. ATES systems store and recover thermal energy in subsurface aquifers by extracting and injecting groundwater using wells (open loop system). The systems commonly operate seasonally, with groundwater extracted in summer to cool buildings and reinjected into the aquifer to store the heated water. In winter, the flow is reversed, with heated groundwater extracted and used to heat buildings.	 Source: IF Technology [36]

Appendix B: Geothermal technology prioritisation matrix

A prioritisation matrix has been created which provides visual ranking criteria for geothermal technology priorities against depth and geology. This matrix has been through numerous iterations and the final matrix which has been used for this research is shown in Table 33 (the following page).

It is important to note that this table is not exhaustive and there are other geothermal technologies available that are not listed here and have not been included in this study. Additionally, the suitability of a particular technology depends on a variety of factors, including the geological conditions at a given site, the availability of water, and the local regulatory environment.

Table 33: Geothermal technology prioritisation matrix

		Types of technology					
	Typical Depth (m)[1]	Open loop	Closed loop (vertical boreholes)[2]	Minewater	Deep geothermal[3,4,5,6]	Deep standing column well[7]	Repurposing oil and gas wells – onshore[8]
Heat	300	✓	✓	✓			
	1000			✓	✓	✓	✓
	2000				✓	✓	✓
	4000				✓	✓	✓
Power	4000				✓		
	5000				✓		
	6500				✓		
Geology	Radiogenic granite		✓		✓		
	Sedimentary basin	✓	✓	✓	✓	✓	✓

[1] The depths provided are typical, assessment of select systems will only be undertaken where the geology is suitable (e.g., where an aquifer is present for an open loop system).

[2] Closed loop vertical boreholes are a location independent technology. Their operational performance is comparable across geologies. These will be assessed to 150m as is industry standard.

[3] Within this assessment, deep geothermal refers to a doublet system to depths of greater than 1000m. Per geographic location, up to two deep geothermal targets will be assessed; and although, depths of 1000m, 2000m, 4000m, 5000m, 6500m have been highlighted; the assessment of each location will depend on the presence and depth of the target reservoirs.

[4] AGS systems have been excluded from the assessment given the juvenile nature of the technology.

[5] Enhanced geothermal systems (EGS) and Hot Sedimentary Aquifer (HSA) systems are broadly comparable during operational and will be considered as 'deep geothermal' within the models. EGS may have additional CAPEX (for hydraulic fracturing).

[6] Lithium is considered an auxiliary function to an existing deep geothermal scheme.

[7] Deep standing column wells will be assumed to have a component of surface bleed (as opposed to coaxial wells, which have no bleed). The standing column wells are location independent (like closed loop boreholes). They will be assessed against a UK representative geothermal gradient range. This technology is inappropriate for power generation.

[8] Repurposing oil and gas well (onshore) will comprise two end members; creation of a standing column well, or an open loop/deep geothermal doublet system. The repurposing oil and gas well assessment will broadly match the standing column well and open loop/ deep geothermal assessments; varying only where CAPEX items are reduced (as the well(s) is already in place).

Appendix C: Lithium Revenue

In 2024, the global annual demand for lithium carbonate equivalent was around 1.1 million metric tonnes. In 2030 this is expected to double, to around 2.4 million metric tons of lithium carbonate equivalent; a strong driver of which is from battery demand for electric vehicles [59].

Direct lithium extraction (DLE) techniques from geothermal brines is a rapidly growing technological area and one which has the potential to bring another source of revenue from geothermal systems. Solar evaporation brine extraction is a dominant method for lithium extraction in which lithium brine is pumped to the surface, evaporated in ponds, and processed. This method uses large areas of land and water. Comparatively, lithium brine mining uses far less water and land; and therefore, is considered to be more environmentally advantageous.

The process involves abstraction of brine, energy recovery, processing of the brine at surface, before reinjection of the lithium-depleted brine back to the source formation. Geothermal lithium plants often include a component of energy recovery, either power or heat extraction depending on the brine temperature. This process can generate energy (heat or power) and as well are reducing the fluid temperature of the brine (if sufficiently hot) to be suitable for DLE processes. Energy recovered as power could either be used to power the facility or, if in surplus, be sold as heat as an additional revenue stream.

In most instances where lithium brine is being explored; lithium brine is considered to be a by-product of existing geothermal systems, the depths of which were dictated by the geothermal requirements. However, should purpose built lithium brine mining systems be installed, the well depths would likely be dictated by the lithium resource rather than geothermal; targeting areas of long-term high flow, high concentration lithium brine reservoirs.

There are two end-products which DLE companies target, these are lithium carbonate (Li_2CO_3) and lithium hydroxide monohydrate ($LiOH \cdot H_2O$). Given the high-level nature of Arup assessment, for the purpose of this study, the sale price of each 'lithium product' has been considered the same.

As part of the stakeholder exercise, Arup engaged with lithium companies across the UK. Only a single lithium stakeholder engaged with Arup. Whilst the stakeholder could not confirm their own anticipated costs for commercial reasons, they confirmed the value estimations from literature were reasonable. As a result, the Arup assessment relied heavily on limited available published literature. Data from ongoing projects, Vulcan Energy (Germany) [15] and Standard Lithium (US) [16][17], provided greatest insight. This reliance on limited datasets from lithium developers, mean that the values presented are indicative and potentially biased to more favourable lithium conditions. However, this is challenging to assess given that geological conditions are variable and there is limited available literature.

Arup's assessment considered three scales of production:

- Pilot scale: 100's tonnes (250 tonnes was used in this study)
- Semi-commercial: 1000's tonnes (2,500 tonnes was used in this study)
- Commercial: 10,000's tonnes (25,000 tonnes was used in this study)

The assumptions used to inform this assessment are documented in Table 34.

Table 34: Summary of assumptions used to inform Arup's lithium assessment

Variable	Comment
Lithium sale price	Vulcan Energy provided a forecast from 2026 to 2044 with an average lithium price of €30,283/t (c. £25,510/t) [15]. A 2022 article by McKinsey & Company quoted a 5-year average (assumed to be from 2017 to 2022) of $14,500/t (c. £11,400/t) [61]. A 2021 publication stated that Vulcan Energy could sustain a market price of $13,000/t by 2025 [63]. In June 2024, the London Metal Exchange had a price of $13,500/t [62]. During Covid-19 (2019 – 2021) lithium price jumped to over $80,000/t [64].

Variable	Comment
	Lithium price is challenging to forecast and falls outside the scope of this study. Arup used available published data to inform the lithium price assumptions. Lithium price (per tonne) was assumed at \$30,000 (£23,100), \$15,000 (£11,550), and \$10,000 (£7,700) for high, medium, and low, respectively.
CAPEX	Limited stakeholder data, and the following projects have been used to inform capital cost assumptions: • The Vulcan Energy plant [15] (CAPEX c.\$1.3B) and Standard Lithium's SW Arkansas plant [16] (CAPEX c.\$1.3B) are of commercial scale (>10,000t/yr). • Standard Lithium's Phase 1A plant (5,400t) (CAPEX c.\$365M) is considered semi-commercial scale. • Netherland's hypothetical 'Well C' is of pilot scale [95]. The Vulcan Energy and Standard Lithium project documentation is far more detailed than the hypothetical Netherlands project. Therefore, this lithium assessment has more data for the commercial scale systems rather than pilot scale.
Production cost (Opex)	Production costs were sourced from the same literature sources as listed above. Vulcan Energy and Standard Lithium had comparable lithium production costs (of c. \$4,710/t and \$4,073/t respectively), providing greater cost certainty. The Standard Lithium semi-commercial plant had a cost of \$6,810/t and Netherlands pilot plant of €22,700 (c. \$24,500/t).

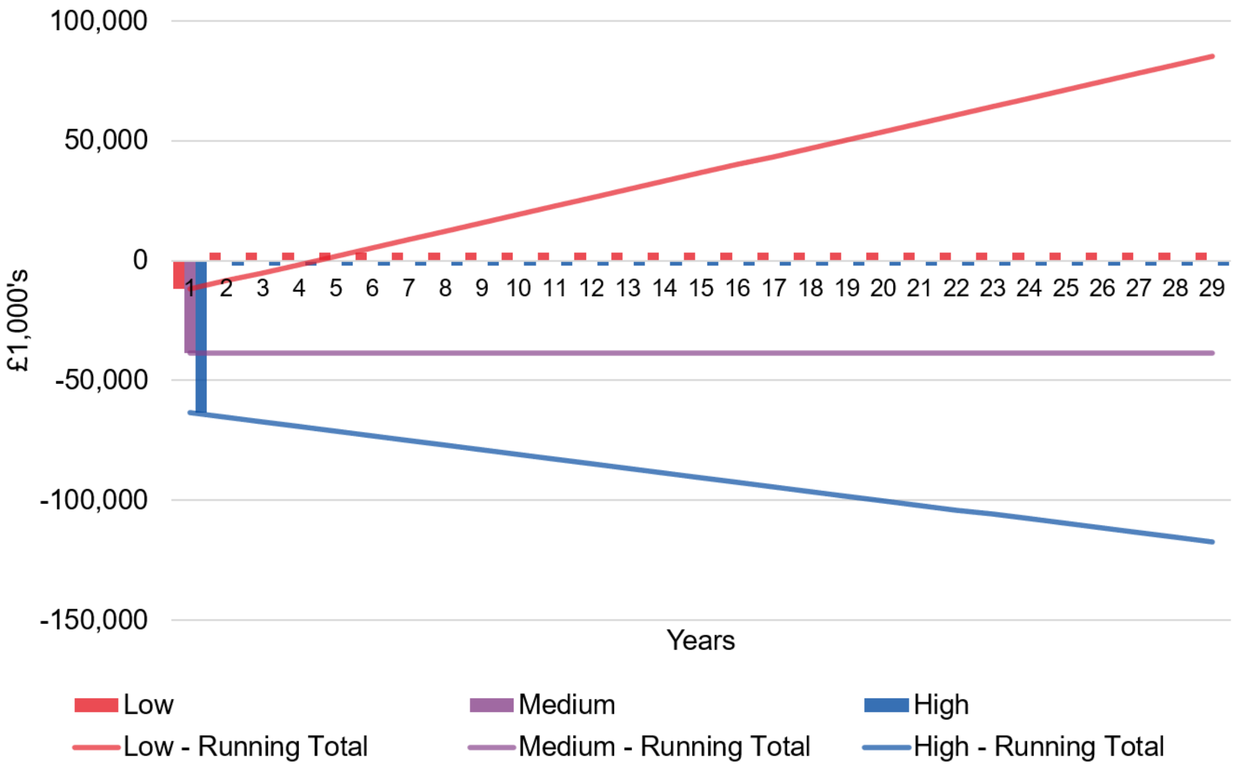
Table 35 presents three case study scenarios, considering pilot plant (250 tonnes/yr), semi-commercial plant (2,500 tonnes/yr), and commercial scale plant (25,000 tonnes/yr). Plots of costs and lithium sale returns are presented in Figure 16, Figure 17, and Figure 18. Pilot plant scale is effectively a FOAK system and commercial scale a NOAK system; with semi-commercial somewhere in between. 'Low' refers to a low levelised cost (i.e., low CAPEX and OPEX, with high lithium sale revenue). 'High' refers to a high levelised cost (i.e., high CAPEX and OPEX, with low lithium sale revenue).

Table 35: Low-Medium-High assumptions used within Arup's model

Parameter	Unit	Low		Medium		High	
		USD (\$)	GBP (£)	USD (\$)	GBP (£)	USD (\$)	GBP (£)
Sale price	price per tonne	30,000	23,100	15,000	11,550	10,000	7,700
Pilot Plant (250 tonnes/yr)							
CAPEX total	1,000's	20,000	15,400	50,000	38,500	80,000	61,600
Production cost (OPEX)	1,000's per tonne	12	9.24	15	11.55	20	15.40
OPEX total	1,000's per year	3,000	2,310	3,750	2,888	5,000	3,850
Lithium sales	1,000's per year	7,500	5,775	3,750	2,888	2,500	1,925
Semi-Commercial (2,500 tonnes/yr)							
CAPEX total	1,000's	200,000	154,000	300,000	231,000	400,000	308,000
Production cost (OPEX)	1,000's per tonne	5	3.85	7	5.39	10	7.70
OPEX total	1,000's per year	12,500	9,625	17,500	13,475	25,000	19,250
Lithium sales	1,000's per year	75,000	57,750	37,500	28,875	25,000	19,250
Commercial (25,000 tonnes/yr)							
CAPEX total	1,000's	1,000,000	770,000	1,300,000	1,001,000	1,600,000	1,232,000

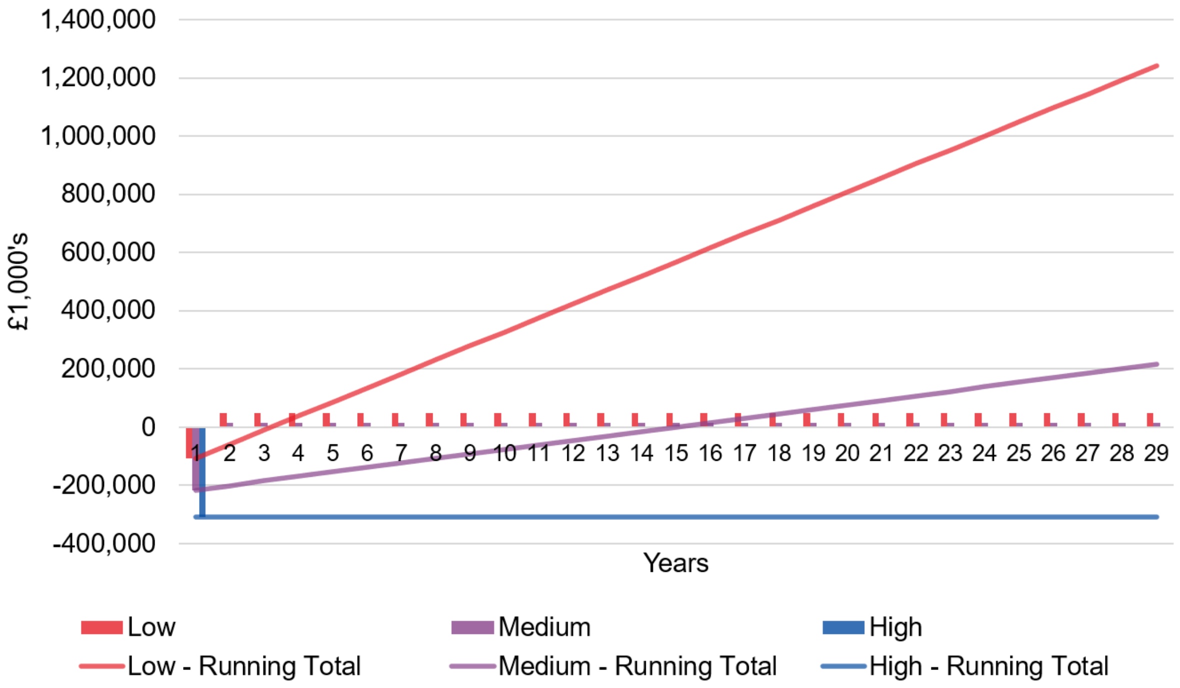
Parameter	Unit	Low		Medium		High	
		USD ($)	GBP (£)	USD ($)	GBP (£)	USD ($)	GBP (£)
Production cost (OPEX)	1,000's per tonne	3	2.31	4	3.08	5	3.85
OPEX total	1,000's per year	75,000	57,750	100,000	77,000	125,000	96,250
Lithium sales	1,000's per year	750,000	577,500	375,000	288,750	250,000	192,500
* Conversion assumed an exchange rate of 0.77 USD:GBP							

Figure 16, Figure 17, and Figure 18 below present financial models for each of the assessed system scales, applying the low, medium, and high ranges (in Table 35). The models are very basic and for information only. The entire CAPEX is assumed in year one, then lithium revenue and operational costs are used to infer net revenue each year. This is cumulatively applied each year to derive the linear trend. These models exclude re-investment, variability in lithium prices, etc; and should only be used to gain an understanding in how different system scales compare to each other.



* Low refers to a low levelised cost, i.e., low capex, high annual net revenue. The inverse applies to High.
* Annual net revenue/loss is presented with a cumulative 'running total'.

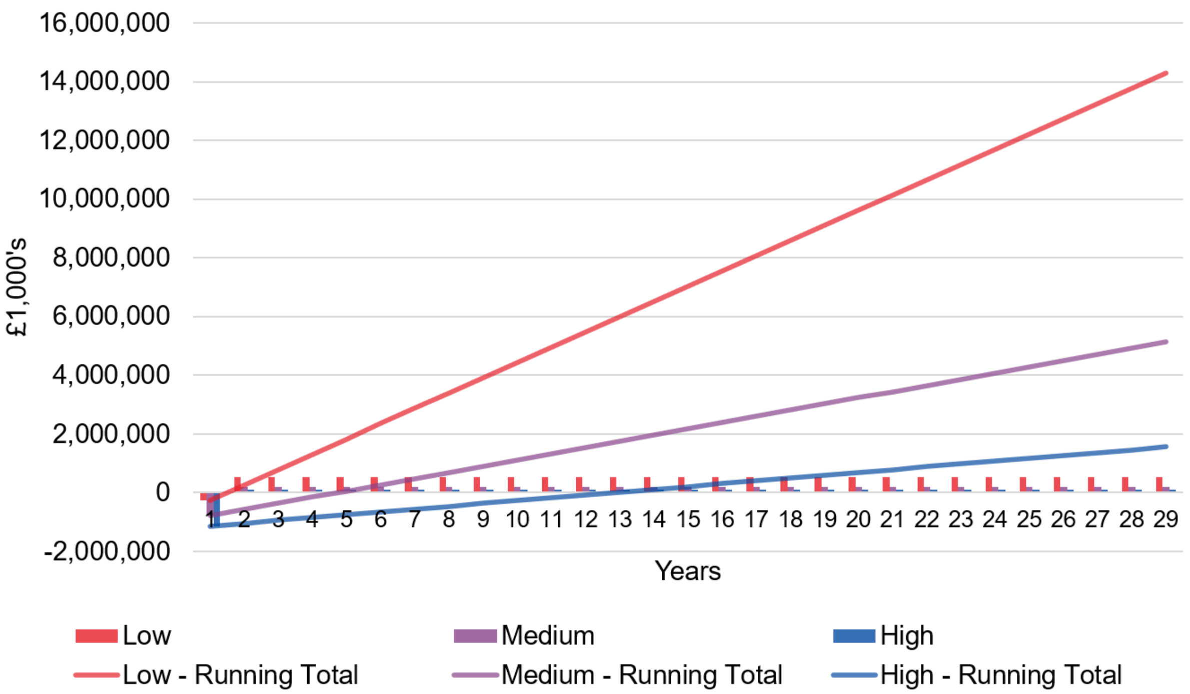
Figure 16: Pilot plant (250 tonnes/yr) high-level financial model



* Low refers to a low levelised cost, i.e., low capex, high annual net revenue. The inverse applies to High.

* Annual net revenue/loss is presented with a cumulative 'running total'

Figure 17: Semi-commercial (2,500 tonnes/yr) plant high-level financial model



* Low refers to a low levelised cost, i.e., low capex, high annual net revenue. The inverse applies to High.

* Annual net revenue/loss is presented with a cumulative 'running total'

Figure 18: Commercial plant (25,000 tonnes/yr) high-level financial model

These indicative financial models of various lithium plant scales evidence how lithium production is likely to only become economically viable at scale. This is principally driven by high operational costs, as a comparable number of staff are required to operate a pilot plant and commercial plant. Note that these figures exclude revenue from electricity or heat. This is further explored in the LCOE model, with lithium revenue discounted.

Due to the lack of robust data these models are only indicative, and not to be relied upon for detailed analysis. The following caveats apply:

- Future lithium price is unknown and variable. The models assume a stable lithium sale price for 30 years.
- Lithium reserves and long-term production is unproven. The models assume consistent lithium production from day 1, for 30 years. In reality, plant production may take a few months/years to scale up to full production rates; and whether a lithium resource is sustainable for 30 years is highly uncertain.
- In the UK, there are projects considering lithium production at scale, but none are currently active. Laboratory testing of water samples is being undertaken to refine DLE processes however production at scale is still in development in the UK. Various DLE technologies have progressed beyond Technology Readiness Level (TRL) of 4 (lab validation), but the majority are still in refinement stages [96][97].

Overview of Lithium extraction plants

A summary of global lithium extraction plants is presented in Table 36. Lithium extraction plant costs are significant, with commercial scale (10,000's tonnes annual production) inferred to cost more than £1 billion CAPEX, and £75M to £125M annual operating costs. System scale is vitally important to economic viability. For example, in this very simplified demonstration:

1. At a commercial scale: Vulcan energy has a capital cost of c. $1.3B, and annual operating cost of c. $130M. Assuming annual production of 40,000 tonnes LiOH, and $15,000 sale price ($600M income/year), the system has a return on investment of around 5 years.
2. At a semi-commercial scale: Standard Lithium's Pilot plant has a capital cost of c. $365M, and annual operating cost of c. $36M. Assuming annual production of 5,400 tonnes Li2CO3, and $15,000 sale price (c. $81M income/year), the system has a return on investment of around 10 years.
3. At a pilot scale: Netherlands 'concept Well C' has an annual operating cost of c. €5M to €7.5M. Assuming annual production of 211 tonnes LiOH, and $15,000 sale price ($3M income/year), this system does not return investment. Owing to the low, 22mg/l, concentration of lithium in the brines, the annual production is low and relative operational costs are high.

Table 36 demonstrates how system scale impacts upon project finance. While small, pilot-scale plants are often uneconomical for long-term operation, they serve as a crucial initial step to demonstrate system viability before attracting additional capital financing. Commercial viability is typically at 1000's of tonnes/annum scales. Figure 20 provides a further breakdown of costs from published sources.

When deep geothermal plants co-produce lithium alongside combined heat and power (CHP) or heat-only systems, they can become the most cost-effective configuration for harnessing geothermal energy.

Currently, the UK is at a pilot plant scale (FOAK).

Table 36: Summary of DLE projects (adapted from [101])

Company	SRI International	Vulcan Energy Resources [100]	Standard Lithium [98][17]	Standard Lithium [98][16][17]	E3 Metals Corp	Anson Resources	Pure Energy Minerals	Lake Resources	(Conceptual)	Geothermal Engineering Limited**
Project	Salton Sea	Upper Rhine Valley	Lanxess Smackover (pilot)	Lanxess Smackover (full scale)	Clearwater	Paradox Stage 3 (Li)	Clayton Valley	Kachi	'Well C'	United Downs (*ambitions*)
Location	California, USA	SW Germany	Arkansas, USA	Arkansas, USA	Alberta, Canada	Utah, USA	Nevada, USA	Argentina	Netherlands	Cornwall, UK
Brine type	Geothermal	Geothermal	Evaporite (Br tail brine)	Evaporite (Br tail brine)	Oilfield	Evaporite	Evaporite	Salar	Geothermal	Geothermal
Lithium concentration (mg/L)	400	188	217	168	74.6	100–500	65–221	289	22	340
Production (t/yr)	20,000*	40,000	5,400	20,900	20,000	15,000	11,500	25,500	211	100 initially, 1,000 in 2026, 12,000 by 2030
CAPEX ($1,000)	52,300	1,287,600	365,000	437,162	602,000	120,000	358,601	544,000	-	-
Production cost (OPEX) ($/t)	3,845	3,217	6,810	4,319	3,656	4,545	3,217	4,178	24,430 to 36,270	-
OPEX Total ($1,000/yr)	76,900	128,688	36,774	90,259	73,200	68,180	36,516	106,539	5,150,000 to 7,650,000	-
Modelled product price ($/t)	12,000	14,925	-	13,550	15,160	13,000	12,267	11,000	-	-
Modelled annual gross sales revenue ($1,000)*	300,000	600,000	81,000	313,500	300,000	225,000	172,500	382,500	3,165	-
Lithium recovery	Li_2CO_3	$LiOH \cdot H_2O$	Li_2CO_3	Li_2CO_3	$LiOH \cdot H_2O$	Li_2CO_3	$LiOH \cdot H_2O$	Li_2CO_3	$LiOH \cdot H_2O$	Li_2CO_3

* Annual production multiplied by sale price, assumes a sale price of $15,000/t

** United Downs values represent aims rather than reported measurements.

Scale

The size of lithium plant equipment is likely to be proportional to the flow rate. This is demonstrated below in Table 37.

Table 37: Example lithium extraction system costs [102]

System component	Low flow (50 GPM, c. 3l/s)	High flow (500 – 1000 GPM, c. 31.5 – 63 l/s)
Clarification and filtration	\$750k to \$2.5M	
Ion exchange and brine softening	\$300k - \$400k	\$1.5M - \$3M
Evaporation and high-pressure membranes	\$200k - \$400k	\$2M - \$4M
Full Pilot plant (1/10th scale)	\$50M to \$150M	
Large integrated system	\$500M to \$1B	

Key considerations for lithium extraction plants include:

- Brine contaminants; brines with higher levels of contaminants (unwanted metals/ element) require a greater level of filtration, which costs more.
- Lithium concentrations; brines with higher lithium concentrations require lower volumes of brine processing and low levels of secondary wastes, saving costs.
- Flow rate; high flow rates of lithium extraction systems require larger equipment and greater capital and operational costs (as outlined in Table 37).

Comparative Technologies (Reverse Osmosis, desalination)

Desalination plants, which utilise ion-exchange membranes (reverse osmosis), operate similarly to lithium exchange systems. Both processes exhibit comparable relationships between scale/flow rate and cost. According to literature, the capital expenditure (CAPEX) for a 1 million litre/day (MLD) system (approximately 11 litres per second) is estimated at \$5M per MLD. For a 10 MLD system (approximately 110 litres per second), costs range from \$1.2M to \$1.3M per MLD [103][104]. Operational costs range from \$0.2M to \$0.6M/MLD [104].

Semi-Commercial and Commercial Scale Examples (Standard Lithium, U.S.)

Standard Lithium [98][16] have cost data for their pilot plant (semi-commercial), 5,400 tonnes Li_2CO_3 and commercial plant, 30,000 tonnes $LiOH{\cdot}H_2O$. A breakdown of the surface plant costs are provided below in Figure 19 and Figure 20

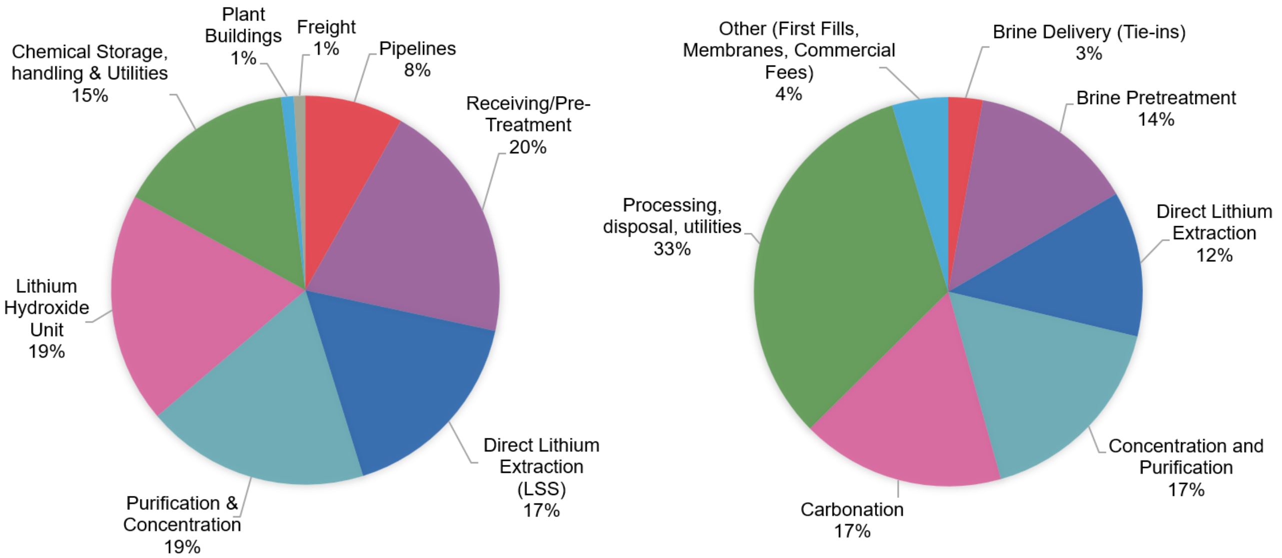


Figure 19: Breakdown of capital cost for commercial scale ($1.3B, left) and pilot scale ($365M, right) plants

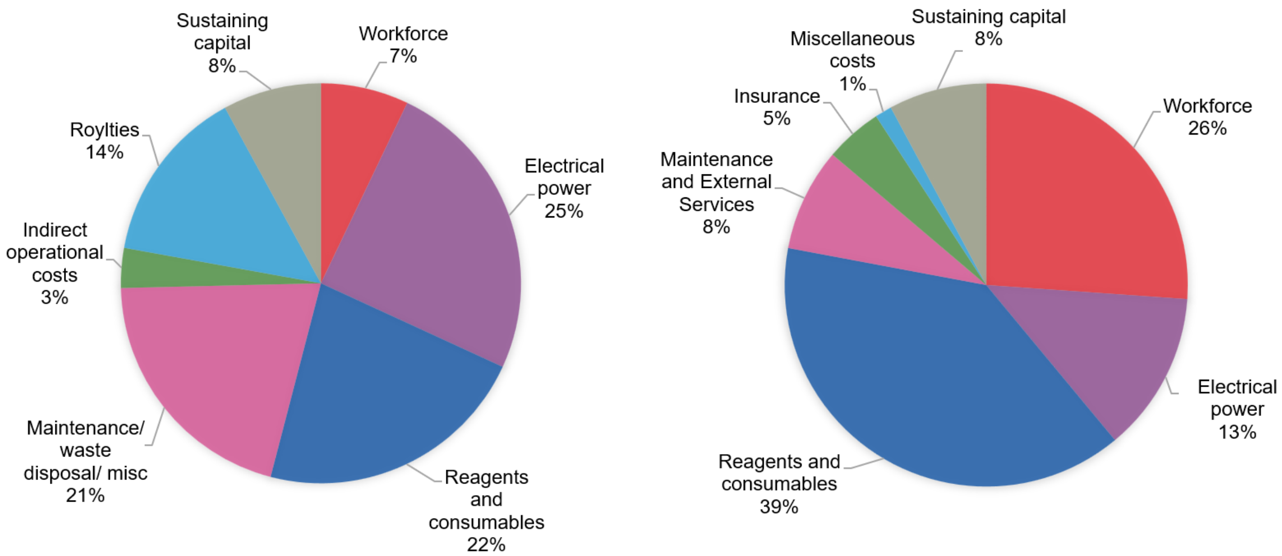


Figure 20: Breakdown of operational costs for commercial scale ($1.3B, left) and pilot scale ($365M, right) plants

Capital cost breakdowns between pilot and commercial scale costs are broadly comparable; with the plant scaled up relatively uniformly between each element for the larger scale. For the operational costs; workforce and reagents and consumables are the largest differentiators. For both the pilot and commercial scale plants, around 90 full-time staff were assumed. These examples of how operational components scale non-linearly with system size outline why small-scale plants have relatively greater operational costs.

Lithium Revenue in LCOE model

Lithium from geothermal systems within the UK is unlikely to be realised at scale for a number of years. Given the limited and indicative nature of the data assessed, lithium revenue within the LCOE model was not reported; however, its functionality in the model is available and should be informed from commercial lithium companies working with DESNZ.

More data and further consideration is required with regards to implementing lithium revenue within a LCOE model. Building on the work presented, reporting upon lithium revenue within the LCOE model could be considered within subsequent revisions of the LCOE model.