

## “On The Rocks” – Exploring Business Models for Geothermal Heat in the Land of Scotch

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### ABSTRACT

Despite valiant efforts, there are still no significant geothermal energy projects installed in Scotland, and only a few significant open-loop ground-source heat pump projects. This paper tells the stories, in brief, of these efforts, primarily made by a small company TownRock Energy (TRE). They gathered insight and best practice from projects around the world, from New Zealand to Iceland, California to the Netherlands, Kenya to Hungary. Outlined in this paper are the most important factors to consider when designing an economically viable geothermal heat network in a country with old cold rocks.

In 2015 the Scottish Government launched the Geothermal Energy Challenge Fund, which awarded a total of £234k to five consortia of businesses, local authorities and universities to complete site-specific geothermal heat network feasibility studies. TRE was heavily involved, and whilst none of the original projects were taken forward for test drilling, various consortium members went on to spend the following years hunting for the perfect demonstration sites. TRE has advised clients from all sectors, including airports, universities, and distillers, via over a dozen feasibility studies and business cases, evaluating fractured granites, hot sedimentary aquifers and most commonly flooded coal mines. The findings have been distilled in this paper.

Economic, environmental, social and political parameters all impact the business case. Risk analysis and mitigation is critical. The heat market requires substantial expansion through local and national government spear-heading the development of heat networks. The public sector holds most of the cards to reduce risks and increase incentives to investors in heat networks, or implement direct public sector investment in projects with initial low-returns but long lifetimes.

With the decarbonisation of heat appearing ever higher on the political and social responsibility agenda, the legislative, financial, and social barriers are closer than ever to being broken down. This is a new dawn of low-carbon heat for a country which most importantly needs a sustainable fuel source for the creation of the ‘fire water’ the world adores. Slainte mhath!

### 1. INTRODUCTION

In 2013 David Townsend graduated from the University of St Andrews, having specialized for his undergraduate thesis on the geological aspects of extracting geothermal energy from hot sedimentary aquifers in the central belt of Scotland. Shortly after graduating he won a business start-up funding competition and incorporated TRE as Scotland’s geothermal energy specialist consultancy. With intellectual help from Phil Townsend, who was a geologist and oil field manager for BP for 30 years, and Claire Macleod, an oil and gas lawyer and entrepreneur, the company gained a reputation as the go-to place for advice regarding Scotland’s geothermal resources. More recently John Naismith has joined the Board of Directors and contributes his broad reservoir engineer experience gained from over 30 years working in the oil industry. TRE has a wide range of highly experienced subsurface, engineering, drilling and commercial associates and partnering consultancies to draw on for each project

The company has now worked with over a dozen different clients from a variety of industries, and both public and private sectors. Completing feasibility studies which use historical geological data and modern engineering and drilling insight, the company has evaluated near every kind of geothermal resource and system design which could be considered for warm water production in Scotland. This report outlines the most relevant case studies, discusses why the projects have not yet proceeded from feasibility / business case stage, and recommends the value levers which should be focused on with further policy and commercial innovation to unlock the geothermal industry in Scotland and the wider UK. The only geothermal energy specific support mechanism available at the time of these case study evaluations was the Renewable Heat Incentive (RHI). This paid an operational subsidy for renewable heat generated at a rate specific to either Deep Geothermal (>500 m wells) or Ground-source Heat Pumps (<500 m wells), and was critical to the expected economic viability of these projects within the UK energy market.

Synergie Environ Ltd (SEL) is a low carbon energy engineering company established in 2009 and is at the forefront of delivering specialist energy engineering solutions in response to client’s technical needs.

SEL's portfolio currently includes the development of detailed energy and water masterplans, detailed appraisals of and investment grade business cases for district heat and energy networks, multi-million-pound anaerobic digestion projects that incorporate gas to grid, detailed feasibility studies for combinations of low carbon energy generation technologies, and energy management assessments. SEL's previous experience covers a unique and large range of commercial and industrial companies and multi-national corporations including a number of developments at airports. Where appropriate SEL have included appraisals of deep and shallow geothermal energy as a source of heating and / or cooling in district energy networks.

In the energy efficiency, district energy, and biofuel sectors SEL have rapidly established themselves as one of the leading players in the UK, regularly winning contracts in competition with global consultancies. SEL have delivered over 20 district heating feasibility studies with a geothermal resource in the past 3 years.

## 2. SCOTLAND'S GEOTHERMAL RESOURCES

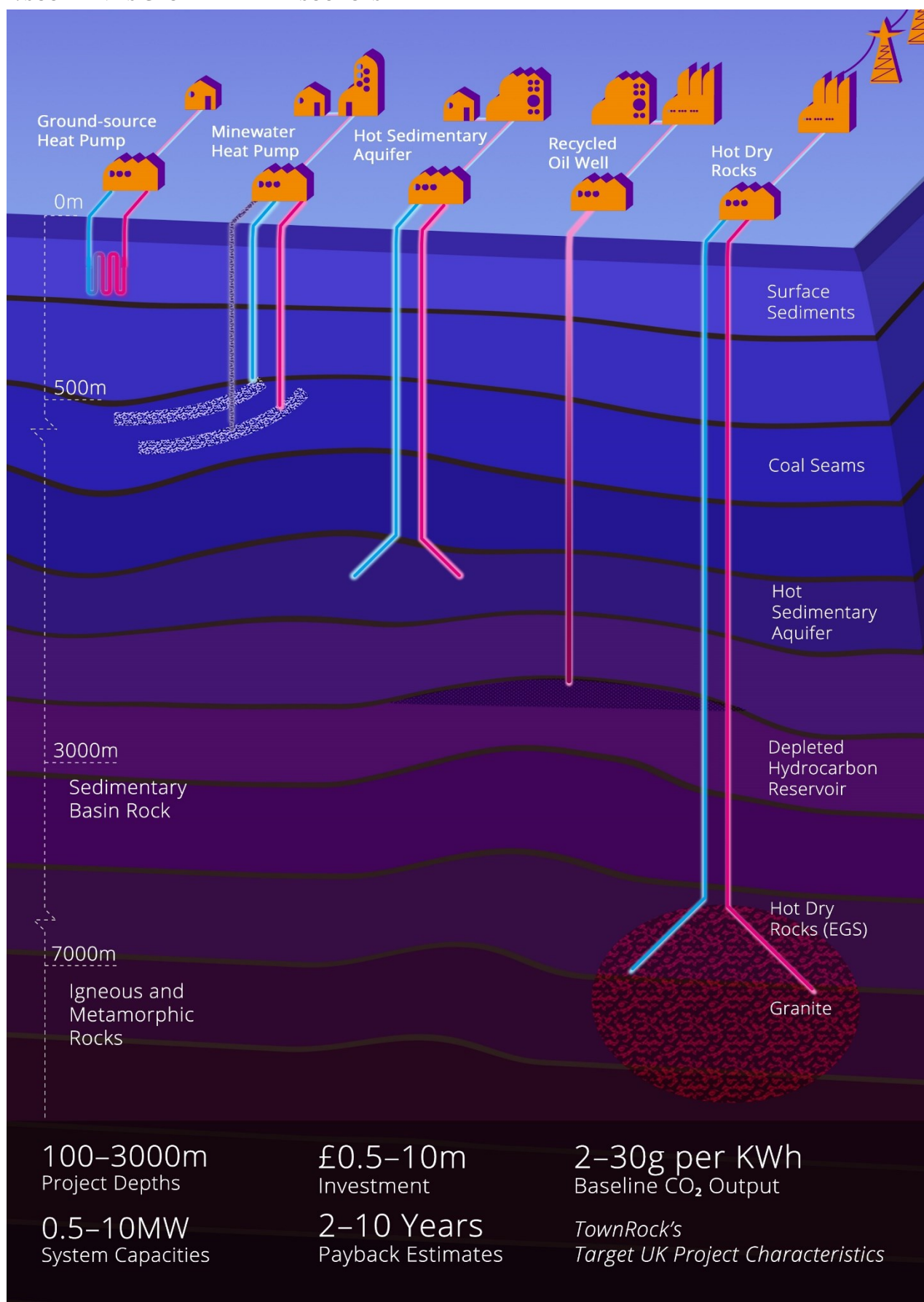


Figure 1: A graphic illustration of Scotland's geothermal resources with TownRock Energy's target UK project characteristics listed across the bottom.

### 3. PROJECT CASE STUDIES

The following case studies have been captured and summarised from detailed feasibility studies carried out between 2015 and 2019. Many of the feasibility studies explored multiple system design options with different cost, value and risk scenarios. To summarise these in a manageable way, for each project only a reference case has been presented outlining the characteristics of the most likely system design option.

Whilst care has been taken to make these case studies comparable, the assumptions used in each feasibility study for financial factors such as discounting rate, heat unit sales price, electricity unit costs and other factors have varied from project to project. This is due to improvements in our models over time, or due to differing requirements of the clients / funders involved. Other factors such as CAPEX vary due to market conditions at the time of acquiring quotes. In addition, each report generally models between 3 and 15 different scenarios, often termed Downside, Base / Reference, and Upside Cases. The authors have used their best judgement, drawing on the experience of project managing the original studies, to select a reference case for each project which is contextually similar and therefore comparable between case studies. Specific clients project sites have been anonymised at the clients' request.

A final note worth considering is the fact that whilst TRE has been heavily involved in all these projects, information including detailed financial assumptions, especially with regards the alternative heating options available to the client are not always shared. Therefore, the business case is often discussed in comparison to a clear alternative (gas, biomass, etc) which locally may skew the economic appraisal. It may be that only one option has been modelled, for example where the client is planning to finance, own and operate the system themselves. Alternatively, a third-party financier may invest in the project and the operation be sub-contracted to another third party. This further complicates direct comparisons between sites and echoes the importance of a financial model being developed with a specific audience in mind for any given project.

#### 3.1 Fortissat Community Minewater Geothermal Heat Network

TRE acted as Project Manager to assess the technical feasibility, the economic viability, and to define the initial strategy, to develop Scotland's first minewater geothermal scheme in over 15 years, in a semi-rural area with social deprivation. The study also addressed the complex technical and stakeholder management issues associated with development of a community district heating system within a varied portfolio of existing accommodation held under mixed tenure rather than a new-build housing scenario. The work was funded by the Scottish Government's Geothermal Energy Challenge Fund.

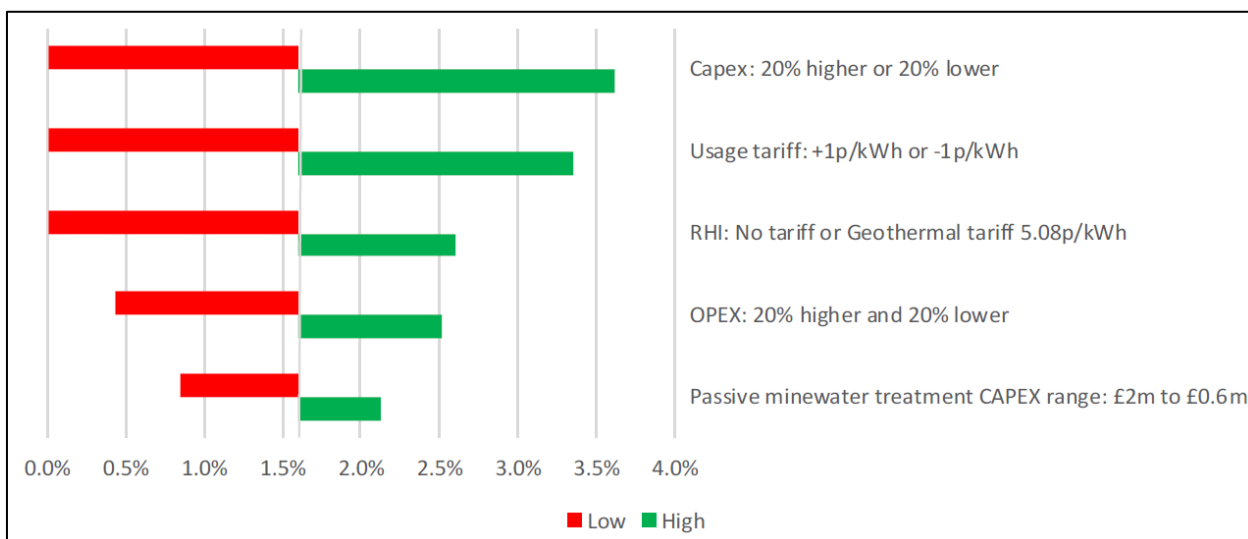
The project was conceived as a fully operational minewater geothermal district heating system demonstrator project: it would act as a proof of concept for UK-wide replication. It was proposed to be taken forward by the Council as a not-for-profit ESCO to address fuel poverty and carbon emissions. The project Capex included the minewater heat extraction, disposal (either via reinjection or passive treatment) and the full district heating network.

The commercial model proposed here is a Council or Third party financed geothermal heat network, competing with existing gas network and domestic gas boilers on price alone to attract domestic heat customers to connect.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>February 2016</b>	Source: <a href="http://www.gov.scot/Publications/2016/03/8520">http://www.gov.scot/Publications/2016/03/8520</a>
Resource	<b>Flooded coal mine</b>	Minewater was breaking out at surface at 10 - 20 L/s and being treated passively by reed beds
Depth	<b>380 m</b>	Below ground level
Source Temperature	<b>18°C</b>	Estimated
Flow Rate	<b>50 L/s</b>	Peak flow
Capacity	<b>2.3 MWth</b>	Reference case (a variety of capacities were modelled to match different heat network scales)
CO <sub>2</sub> Savings	<b>782 tCO<sub>2</sub> / year</b>	63% saving versus gas boilers
CAPEX	<b>£10.8 million</b>	
NPV	<b>£3.4 million</b>	Net cash flow over 20-year project life
IRR	<b>1.7%</b>	20-year project life
Payback		Not estimated

**Figure 2: Summary table of Fortissat project Reference Case.**

Sensitivity analysis was illustrated via a tornado diagram, which shows that the greatest IRR sensitivity was to CAPEX and the unit price for sale price of heat, and least sensitivity was to OPEX, a common trend for most of the projects in this paper.



**Figure 3: Tornado diagram showing IRR sensitivities for Fortissat project.**

The project was unable to proceed primarily due to the low estimated return on investment (ROI). The key reason for this was the low heat density of the heat network: all heat customers were semi-detached houses, and the majority of these were already connected to the national gas network. Going forward, TRE decided it should focus more on large heat customers to minimize the heat network infrastructure required to supply a significant heat load from a local geothermal resource.

### 3.2 Guardbridge Integrated HSA and Biomass Heat Network

The University of St Andrews were developing the derelict Guardbridge paper mill site into a low-carbon and sustainability innovation centre. This included a £25 million investment in a 6.5 MWth biomass heat centre and district heating network to provide heat to the North Haugh campus of the University. TRE and partners carried out a detailed feasibility study examining the integration of a hot sedimentary aquifer (HSA) resource into the existing biomass heat network. The work was funded by the Scottish Government's Geothermal Energy Challenge Fund.

The commercial model proposed was a University financed geothermal heat network, competing with an existing biomass network owned by the University on the cost for heat and / or ROI.

Item	Figure	Notes
Study Completed	<b>Phase 1: February 2016</b> <b>Phase 2: March 2017</b>	Source: <a href="http://www.gov.scot/Publications/2016/03/3520">http://www.gov.scot/Publications/2016/03/3520</a> Phase 2 included seismic acquisition to 800 m
Resource	<b>Aquifer</b>	Devono-Carboniferous
Depth	<b>1200 m</b>	Below ground level
Source Temperature	<b>24°C</b>	Estimated
Flow Rate	<b>15 L/s</b>	Peak flow
Capacity	<b>0.42 MWth</b>	Providing 50% of the heat demand, with the remainder being sourced from a 6.5 MWth biomass boiler which was designed to supply heat to the University campus 6 km away.
CO <sub>2</sub> Savings	<b>491 tCO<sub>2</sub> / year</b>	65% saving versus gas boilers
CAPEX	<b>£2.05 million</b>	
NPV	<b>-£0.6 million</b>	21-year project life
IRR	<b>-2%</b>	
Payback		Not estimated

**Figure 4: Summary table of Guardbridge project Reference Case.**

Reasons for not proceeding: the deeper wells were relatively costly as the targets were offset from the site at which drilling was expected. The CAPEX and electricity cost of a heat pump to deliver the required demand temperatures, given the lower temperature of the geothermal resource, meant the viable heat price could not match the price of heat supplied from the biomass boiler. Furthermore, the biomass boiler was already under construction and capable of providing all the heat demand on the network. The project was paused but could be revisited as part of a low-temperature heat network specifically for the redeveloped papermill site or the wider Guardbridge community.

Integrating a lower temperature resource into an existing or planned higher temperature heat network is not ideal. There is a significant opportunity in the earliest project concept stage to optimize the design of heating and cooling networks to allow a greater range of heat sources and lower temperature distribution in general. This opportunity recurs in later cases.

### 3.3 Banchory Deep Geothermal Heat Network

In partnership with Cluff Geothermal, the Hill of Banchory ESCO (HOBESCO) and other partners, TRE evaluated the potential for producing 75 – 90°C water from 2 – 3 km depth in the Hill of Fare granite pluton in Aberdeenshire. The hot water would be providing supplementary heat into the Hill of Banchory district heating network which currently utilises a biomass heat centre operating at 85-60°C flow-return. The work was funded by the Scottish Government's Geothermal Energy Challenge Fund.

The commercial model proposed here is a HOBESCO financed geothermal heat network expansion, competing with existing biomass network owned by HOBESCO on cost per kWh (heat) and / or ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>February 2016</b>	Source: <a href="http://www.gov.scot/Publications/2016/03/6881">http://www.gov.scot/Publications/2016/03/6881</a>
Resource	<b>Granite</b>	Relying on natural fractures for flow
Depth	<b>2.5 km</b>	2.1 – 2.9 km depths were considered
Source Temperature	<b>80°C</b>	65 - 90°C temperatures were considered
Flow Rate	<b>15 L/s</b>	5 – 50 L/s rates were considered
Capacity	<b>1.6 MW</b>	0.42 – 4.18 MWth capacities were considered
CO <sub>2</sub> Savings	<b>1,367 tCO<sub>2</sub> / year</b>	Versus gas heating (average over 30 years)
CAPEX	<b>£6 million</b>	£5.5 – 10 million were considered, depending on scale of heat network as £4 million is required for drilling and wellhead-to-energy-centre pipework
NPV	<b>Positive</b>	
IRR	<b>10%</b>	20-year project life, assuming 10,000 MWh/yr delivery at 2 p/kWh plus 5.2 p / kWh RHI
Payback		Not estimated

**Figure 5: Summary table of Banchory project Reference Case.**

TRE contributed thermal conductivity field sampling and laboratory analysis, compiled the risk register and mitigation actions, and provided general strategic oversight.

The report demonstrated technological feasibility, although with a significant degree of uncertainty in the productivity of the pluton at depth due to lack of local deep borehole data. This is a rare case where the geothermal resource is at conventional heat network temperatures and so integration could be made without the capital and operating costs associated with heat pumps.

Unfortunately, the cost of heat supplied from the geothermal resource was estimated to be higher than the current cost of heat from the biomass heat centre, due to existing local arrangements with biomass fuel suppliers and, at the time of the project, very favourable payments from the Renewable Heat Incentive (RHI) for biomass installations. The existing biomass heat centre also had advantaged expansion costs relative to introducing a new heat input some kilometers from the existing network. The indicative IRR may be acceptable for a new stand-alone heat network, but if considering replacement of an operationally profitable biomass boiler the case is very challenging to make.

The project may be revisited in the future following an expansion of the heat network, or a rise in the cost of biomass fuel, or a requirement to replace the biomass boilers, or successful demonstration of deep granite geothermal wells elsewhere in the UK.

### 3.4 Grangemouth Energy Project

The Grangemouth area in Falkirk is the largest industrial site in Scotland, with abundant sources of heat demand as well as waste heat from a refinery, chemicals plant, and numerous other industrial and commercial buildings. There is extensive public and private housing stock heat demand predominantly heated by gas boilers. An extensive flooded coal mine underlies the east of the site and the Firth of Forth. The work was carried out in partnership with Synergie Environ Ltd and Mace Group Ltd, and was funded by the Low Carbon Infrastructure Programme (LCIP) managed by Scottish Enterprise.

The commercial model proposed here is a Council or Third party financed geothermal (and potentially waste heat) heat network, competing with existing gas network and domestic gas boilers on price to attract domestic heat customers to connect.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>December 2015</b>	Report not publicly available
Resource	<b>Flooded coal mine</b>	
Depth	<b>580 m</b>	Max depth of workings c. 800 m extending underneath the estuary (Firth of Forth) to Fife
Source Temperature	<b>22°C</b>	Range of 21 - 23°C; a maximum temperature of 30°C at 800 m is expected
Flow Rate	<b>100 L/s</b>	Max flow rate. Range of 25 – 100 L/s provided to client. 100 L/s used in financial model – this is justified due to the large volume of the mine and expected inflow from the sea. A phased scale-up of heat supply to 100 L/s was recommended.
Capacity	<b>5.72 MWth</b>	Assuming a 10°C drop across heat pump's evaporator with a COP of 3.8.
CO <sub>2</sub> Savings	<b>5,600 tCO<sub>2</sub> / year</b>	Averaged from 140,000 tCO <sub>2</sub> / year over 25 years
CAPEX	<b>£38.9 million</b>	Predominantly heat network pipework costs
NPV	<b>£5 million</b>	25-year project life
IRR	<b>7%</b>	25-year project life
Payback	<b>13 years</b>	

**Table 6: Summary table of Grangemouth project Reference Case.**

The project was unable to proceed for a number of reasons. Complexity of the system both in terms of connecting existing heat customers and developing a sufficient supply from waste heat suppliers (although the figures in the table above assumed only minewater geothermal supply, a preferred case included waste heat capture from the refinery and / or chemical plant). Lack of response to project enquiries from the major industrial stakeholders in the area. Lack of a project champion from within the local authority. Competition with / distractions by other energy project investment options in the area including a major biomass CHP plant.

To our knowledge no heat network options have been taken forward at the site, and given the positive economics, this opportunity remains one of the best locations for a large-scale minewater heat network demonstrator project in Scotland.

This project perhaps best demonstrates the need for early and very broad stakeholder engagement, plus long-term commitment from national and local government to reducing the carbon footprint of heat. This location represents an excellent opportunity to build a heat network from scratch with multiple inputs and outputs, however, due to the wide variety of business operations across the area there would be very complex commercial arrangements for the recovery and supply of heat. This is likely to have deterred the engagement of major industrial players in the area. Furthermore there is little incentive to move from low cost fossil fuels, no requirement to recover the abundant waste heat, and negative perceptions associated with heat network connections due to lack of precedents.

### **3.5 Airport and associated businesses**

This assessment was part of a wider project to assess the feasibility of a district energy scheme to supply a proportion of power, heating and cooling requirements to key stakeholders at a Scottish airport and other local stakeholders. This work was funded by the Low Carbon Infrastructure Programme (LCIP) managed by Scottish Enterprise and funds from the local authority.

TRE assessed the technical and financial viability of using the flooded mines beneath the site as a low-grade heat source and / or thermal store, and provided various scales of heat supply utilising combinations of production and injection boreholes, the simplest of which was a large office building with both heating and cooling demand.

The commercial model here is a heat customer owned thermal energy network competing with existing gas boilers and A/C units on price per kWh and / or ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>February 2017</b>	Report not publicly available
Resource	<b>Flooded coal mine</b>	Carboniferous
Depth	<b>120 m</b>	Approximate, various well depths into workings between 100 and 200 m below ground.
Source Temperature	<b>12°C</b>	
Flow Rate	<b>7.5 L/s</b>	Other options ranged from 15 – 60 L/s
Capacity	<b>0.22 MWth</b>	0.22 MWth heating, paired with 0.24 MWth of cooling
CO <sub>2</sub> Savings	<b>46 tCO<sub>2</sub> / year</b>	Average over 20 years
CAPEX	<b>£425,000</b>	
NPV		Not estimated
IRR		Not estimated
Payback	<b>14 years</b>	Simple estimate

**Figure 7: Summary table of large office building at airport project Reference Case.**

Several scales of minewater heat pump heating / cooling network were scoped for the whole airport, and an upside case estimated a payback of 5 years on a c. £1 million CAPEX. Interestingly, a minewater discharge drain was found to be located close to the airport. This was found to have a flow rate due to gravity of 15 L/s, providing the potential for a 0.7 MWth heat pump with very low CAPEX due to elimination of drilling costs, and thus favourable return on investment.

However, the challenge for the clients at this airport was the existing buildings ratio of power to heat demand and the compatibility of the existing heat networks with heat which could be supplied directly from a geothermal system. The customers demand an annual average of 4 times more power than heat. This favoured the adoption of a gas fired cogeneration (CHP) system, which benefitted from low prices for imported natural gas and, at the time of the project, government incentives. To date, no heat network has been installed at this location, CHP or otherwise.

### 3.6 Scottish University Campus

TRE was commissioned by a Scottish University to investigate the geothermal heat opportunity at its main campus. The study was carried out within the context of the University's low carbon heat strategy: this aimed to develop campus-wide district heating systems and was itself part of a broader 5 year Carbon Management Plan target of reducing greenhouse gas emissions across the campus by 15% whilst supporting the continued growth. The University is understood to now be investigating more radical targets to underpin its next climate action plan. The study looked at the benefits of installing a geothermal heat system utilising a hot sedimentary aquifer resource of up to 300 m thickness located approximately 1500 – 2000 m below the site. The work was client funded.

The commercial model proposed here is a University (heat customer) financed geothermal heat network, competing with existing gas boiler and CHP units owned by the University on cost per kWh and / or ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>April 2018</b>	Report not publicly available
Resource	<b>Aquifer</b>	Devono-Carboniferous
Depth	<b>2000 m</b>	Open-hole from 1500 – 2000 m to maximise flow
Source Temperature	<b>53°C</b>	Average across 500 m depth interval
Flow Rate	<b>15 L/s</b>	8.4 L/s also modelled
Capacity	<b>3.24 MWth</b>	Heat pump is used to maximise the heat provided and to optimise the economic value.
CO <sub>2</sub> Savings	<b>2,826 tCO<sub>2</sub> / year</b>	20-year average
CAPEX	<b>£6.5 million</b>	Including well CAPEX of £3.5 million, pipework and other energy system costs. Doesn't include building fabric of heating system upgrade costs.
NPV	<b>£7.6 million</b>	20-year project life; for a 40-year project life, the NPV was £15 million
IRR	<b>12.3%</b>	20-year project life; the 40-year IRR was 13.5%
Payback	<b>9</b>	Including a discounted factor of 3.5%

**Figure 8: Summary table of University campus project Reference Case.**

The project was also modelled as a direct use geothermal system with no heat pump. The economics for this case also looked positive, with 20-year IRR at about 10%, however this scenario relied heavily on major refurbishment to the University buildings' heating and hot water systems. The costs of these were not included in the CAPEX figure as it was assumed that, due to age and redundancy these would be upgraded in the near future.

A lower flow rate estimate of 8.4 L/s was also modelled, which returned a positive NPV and an IRR of about 6%.

In June 2018 the project was offered 50% match-funding (£93,225) from Scottish Government's LCITP fund to develop an investment grade business case. However, due to wider financial challenges and potential thermal yield risks surrounding the project implementation, the funding was turned down and the project is paused. A new climate action plan is being drawn up by the University which may include a long-term view of geothermal development, but there are currently other options capturing the University's energy focus such as demand reduction via building fabric upgrades and improvements to building services.

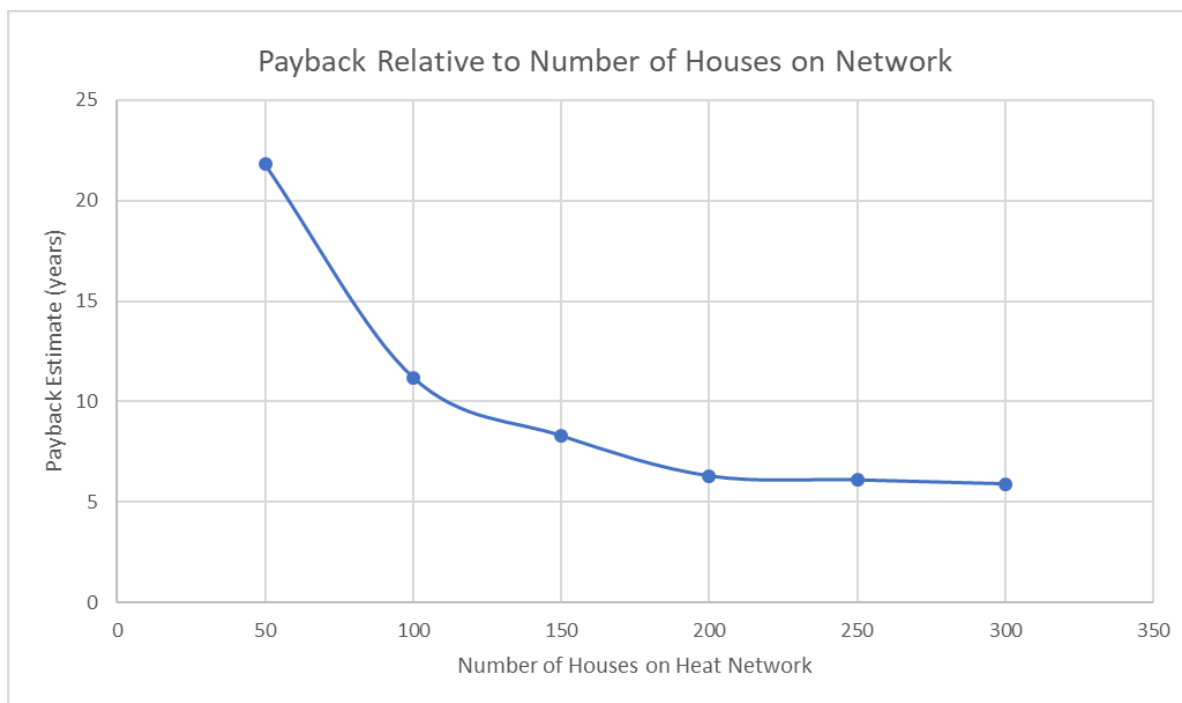
### 3.7 Lady Victoria Mine New-build Housing

This study provided a high-level assessment of the potential minewater heating and cooling resource within the flooded mine workings of the Lady Victoria colliery which is now the site of the National Mining Museum of Scotland. This involved an evaluation of the potential for a low carbon geothermal heat network to supply heat to a new housing development of c. 300 houses adjacent to the mine. The work was funded by a private client.

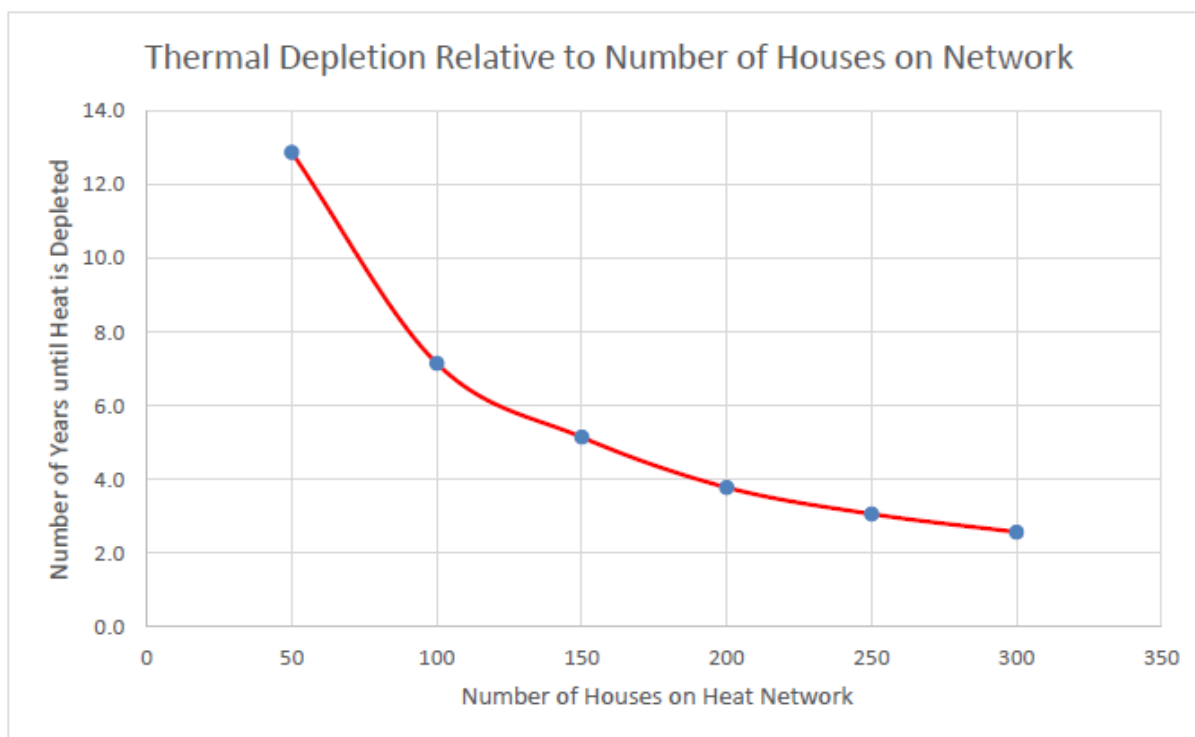
The commercial model proposed here is a developer financed geothermal heat network, competing with other new-build options such as gas grid connection on ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>February 2018</b>	Report not publicly available
Resource	<b>Flooded coal mine</b>	Carboniferous
Depth	<b>192 m</b>	Production well depth; injection well to 330 m
Source Temperature	<b>18°C</b>	
Flow Rate	<b>50 L/s</b>	Maximum peak flow, variable with heat demand.
Capacity	<b>1.4 MWth</b>	
CO <sub>2</sub> Savings		Not estimated
CAPEX	<b>£950,000</b>	Wells, heat pump and network pipes installed at time of housing construction instead of gas, so pipework costs partially offset by savings
NPV	<b>£1.3 million</b>	40-year project life
IRR	<b>15%</b>	40-year project life
Payback	<b>6 years</b>	4.5% discounting factor

Figure 9: Summary table of 300-unit housing development project Reference Case.



**Figure 10: Graph showing payback estimate relative to the number of houses connected to the network.**



**Figure 11: Graph showing estimate of thermal depletion of the flooded coal mine relative to the number of houses connected to the network.**

The estimate for thermal depletion is challenging to do accurately due to uncertainties in the underground flow path between the production and injection wells. However, this modelling highlighted the risks of thermally depleting the hydrogeologically isolated minewater resource if heat is extracted too quickly. The fundamental solution, as has been implemented at Heerlen in the Netherlands by the Mijnwater BV team, is to integrate cooling at different scales into the network. For a purely residential development, this is challenging at higher northern latitudes due to the minimal seasonal cooling demands for residential buildings. Importantly with addition of one commercial cooling customer such as a data centre or food processing facility to the network this system would become sustainable for the long term.

Regardless of the technical and economic challenges with regard resource depletion, the main obstacle to the project proceeding was our client's inability to purchase the land identified above the mine, due to the landowners long term lease arrangements, a very high

demand for land in the area, a lack of appetite from the local authority to grant planning permission for houses on the site, and a lack of resource within the local authority to champion the project.

### 3.8 Midlothian Industrial Estates

In late 2017 / early 2018 TRE worked with Synergie Environ Ltd. to evaluate three minewater thermal energy network opportunities at areas of heat demand above substantial mines in Midlothian. This is the high-level summary of two of the opportunities only due to similarity. This project was funded by the Low Carbon Infrastructure Programme (LCIP) managed by Scottish Enterprise.

#### 3.8.1 Pentland industrial estate minewater heating and cooling network

TRE carried out a high-level assessment of the potential heating and cooling resource within the flooded Straiton No. 8 drift mine underlying an existing industrial estate. These studies were funded by the Low Carbon Infrastructure Programme (LCIP) managed by Scottish Enterprise as part of a wider project to assess the feasibility of a district energy scheme to supply a proportion of power, heating and cooling requirements to key stakeholders in the area.

The two alternative options considered were:

- 1) To create standalone heating and cooling systems for each customer, using the connected oil shale workings for underground thermal energy transfer between the two buildings;
- 2) To link the buildings via a small heating / cooling network (to absorb any imbalance in heating and cooling), and to then use the mine predominantly for additional seasonal thermal buffering of the network (see figure below).

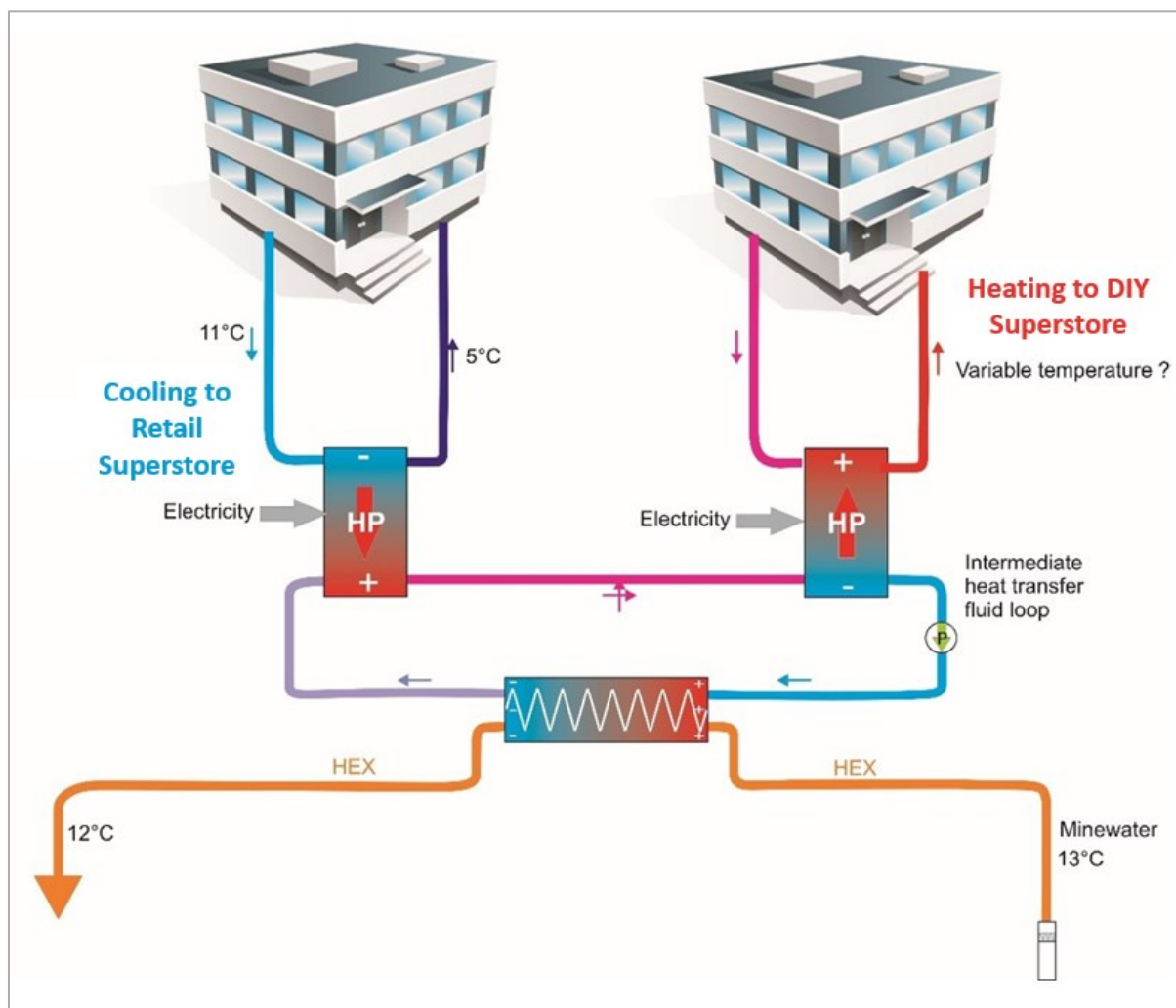


Figure 12: Schematic diagram illustrating how the components of option 2) may be arranged.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>November 2017</b>	Report not publicly available
Resource	<b>Flooded shale mine</b>	Carboniferous
Depth	<b>400 m</b>	Approximate, depth ranges from 304 m to 431 m
Source Temperature	<b>12°C</b>	
Flow Rate	<b>11 L/s</b>	Maximum peak flow, variable with heating and cooling demand.
Capacity	<b>0.3 MWth</b>	For both heating and cooling, with COP of 3.5
CO <sub>2</sub> Savings	<b>300 tCO<sub>2</sub> / year</b>	Average over 40 years
CAPEX	<b>£0.57 million</b>	For option 2: includes wells, pipework and heat pumps. Doesn't include building integration or upgrade costs.
NPV	<b>£0.17 million</b>	20-year project life
IRR	<b>12%</b>	20-year project life
Payback	<b>8 years</b>	8% discounting factor

**Figure 13: Summary table of Pentland project Reference Case.**

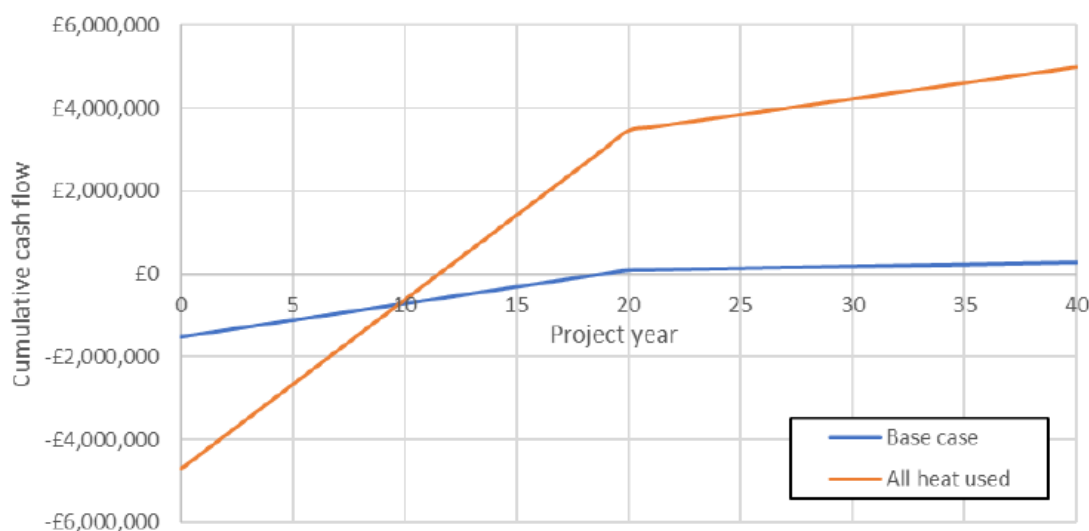
There was appetite from both multinational companies involved to explore the option, however the project was paused. This was for several reasons including: the estimated payback periods and financial rates of return not being attractive to the companies without external finance, the lack of available finance to develop the project further and the perceived commercial risks of sharing an energy system.

### 3.8.2 Newtongrange industrial estate minewater heat network

TRE carried out an assessment of the potential minewater heating resource within the flooded Lingerwood and neighbouring Lady Victoria colliery for the Newtongrange industrial estate.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>January 2018</b>	Report not publicly available
Resource	<b>Flooded coal mine</b>	Carboniferous
Depth	<b>350 m</b>	Approximate, exact well locations not selected
Source Temperature	<b>14°C</b>	
Flow Rate	<b>9 L/s</b>	Matched to existing peak heat demand.
Capacity	<b>0.24 MWth</b>	
CO <sub>2</sub> Savings	<b>350 tCO<sub>2</sub> / year</b>	
CAPEX	<b>£1.54 million</b>	Includes entire energy system including £600,000 for wells. Doesn't include building fabric or heating system upgrades.
NPV		Not estimated
IRR	<b>0%</b>	20-year project life
Payback	<b>19 years</b>	

**Figure 14: Summary table for the Newtongrange industrial estate project Reference Case.**



**Figure 15: Graph projecting cashflow for the project, with the Base / Reference case (current heating demand) in blue and the orange line showing the improved cashflow if all the available minewater heat could be utilised.**

The customers here are already connected to the gas grid so already benefit from cheap heat with no need for further capital investment. For a third-party financier, the relatively high CAPEX associated with drilling c. 350 m depth for both production and injection requires more heat customers to justify. Figure 15 shows a sensitivity case where the maximum well capacity (1,117 kWth) is utilised (it should be noted that consumers for this additional heat were not specifically identified).

By scaling the cost of the civil engineering required for the network based on the quantity of heat distributed, the initial capital cost for a network which used the maximum available heat from the minewater was estimated to increase from c. £1.5 million to c. £4.8 million. The first-year heat sales revenue increased from c. £81,000 to c. £409,000, resulting in an estimated payback period of 12 years, and a significantly positive NPV for a 20-year project life. This case was also estimated to be less sensitive to operating costs after the end of the RHI scheme (March 31st 2021): provided that the cost of electricity remains below £0.12 / kWh, cash flow remains positive without RHI payments. The IRR of this geothermal network in this full capacity scenario is predicted to be 7% after 25 years. The projects actual lifetime is expected to exceed 40 years, as is the case with most geothermal heat networks.

### 3.8.3 Conclusions on Midlothian industrial estates minewater heat networks

For each project two scenarios were modelled. The first considered a heat supply that would match the existing demand. The second showed the maximum heat supply available from the minewater resource. The general conclusion was that, due to the drilling CAPEX being closely correlated to minewater resource depth, the heat demand on the network must be sufficient to justify the investment. Due to the relatively low price for natural gas which exists at the present time, it is very challenging for alternative heat supply technologies to compete when compared on purely economic grounds. Factors which would encourage the development of geothermal heat networks at the current time include: financial incentives for new builds and retrofits to connect to district heat networks, opportunities to reduce business rates on geothermal developments and, effective, coherent and enforced policies which require new residential developments to connect to district heat networks.

Two very significant additional challenges are: forming an energy services company (ESCO) arrangement which suits all customers; and, for existing buildings, persuading all existing customers to simultaneously retrofit their individual heating and cooling systems in line with the installation of the heat network. A third challenge was finding sufficient customers willing to connect to a network. Together, these requirements proved too challenging and complicated at the time to be able to progress these projects.

This is a common issue faced by heat networks in Scotland and the wider UK, especially low-temperature networks: due to the lack of incentives or 'forced-connection' regulations, reliance on the 'free-market' and time limited operational subsidy (the RHI which is due to end in March 2021), it is very difficult to find investors willing to take on the up-front risk. Development costs and risks could be reduced if district heating developers / operators had the same rights as gas, electricity, water and phone companies to dig up the roads and pavements to install and maintain heat networks (The New Roads and Street Works Act (1991)).

Councils supported by national government need to play a greater role in spear-heading the development of ESCOs so as to reduce risks and increase incentives to investors in these smaller commercial heat networks, or the public sector needs to become the investor and accept initial low-returns on investment.

### 3.9 Major property development on outskirts of Edinburgh

A major development plan includes new commercial and residential properties on the western periphery of Edinburgh. A review of the site's current energy consumption was undertaken, including projected increases as a result of these developments. TRE carried out an assessment of the potential minewater heating and cooling resource and the Hot Sedimentary Aquifer (HSA) heating resource beneath the existing and proposed development area to investigate the potential of integrating geothermal heat and coolth into the future development. The work was funded by the Low Carbon Infrastructure Programme (LCIP) managed by Scottish Enterprise.

The minewater resource was deemed to have insufficient volume to progress a substantial heating and cooling system, due to risk of over-heating the mine from excessive cooling demand. The system could be balanced but there were insufficient drivers for a retrofit of the site's existing heating and cooling systems which were considered by the client to be a barrier.

The HSA resource was more attractive if it could be included as a standalone third-party investment option, selling heat into a new low-temperature (55-30°C) heat network that would have multiple heat sources feeding into it.

The commercial model proposed was a third party financed geothermal heat network for only projected new-build heat demand, competing with other options such as gas grid connection on ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>February 2018</b>	Report not publicly available
Resource	<b>Aquifer</b>	Devono-Carboniferous
Depth	<b>2000 m</b>	Open hole 1500 – 2000 m
Source Temperature	<b>53°C</b>	Average temperature from open-hole section
Flow Rate	<b>5.7 L/s</b>	Base case estimate; upside flow of 15 L/s
Capacity	<b>1.3 MWth</b>	By use of a heat pump with COP of 4
CO <sub>2</sub> Savings		Not estimated
CAPEX	<b>£3.8 million</b>	
NPV		Not estimated
IRR		Not estimated
Payback	<b>8 years</b>	Estimated to operate at 90% capacity all year round, with RHI income and heat sales of 2.6 p / kWh

**Figure 16: Summary table for new property development project Reference Case.**

This project has potential to proceed, and if so would have the opportunity to prove that geothermal operators can 'plug-in' to low-temperature heat networks in the UK as they are eventually rolled out across the country, creating an exciting new renewable energy industry for the UK. This commercial model is currently being explored by GT Energy for the retrofit Stoke-on-Trent City heat network.

### 3.10 North of Scotland Malting Plant

TRE assessed the geothermal energy potential of the Devonian sandstones extending c. 3,000 m deep below a whisky distiller's malting facility in the north of Scotland which supplies malted barley to many distilleries in Speyside. The malting process uses considerable amounts of low-grade heat which could be supplied by low carbon geothermal resources. Other opportunities to use geothermal heat were also investigated including pre-heating of water used in other parts of the distilling or ancillary processes. A single production well with sea disposal was decided the Reference Case design option which reduced CAPEX but added the risk of reservoir pressure depletion. The work was client funded.

The commercial model proposed was a heat customer or third party financed geothermal heat system, competing with other options such as gas boiler retrofit on ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>February 2018</b>	Report not publicly available
Resource	<b>Aquifer</b>	Devonian
Depth	<b>5000 m</b>	Open hole 2500 – 3000 m
Source Temperature	<b>68°C</b>	Average temperature from open-hole section, with potential to be up to 8°C higher
Flow Rate	<b>10 L/s</b>	Base case estimate; upside flow of 15 L/s in year 1 reducing to 10 L/s in year 6 to manage drawdown / ESP power consumption. Potential for upside of 20 L/s was also modelled.
Capacity	<b>2.22 MWth</b>	Years 1 – 5 capacity; reduces to 1.48 MWth from year 6
CO <sub>2</sub> Savings	<b>6,500 tCO<sub>2</sub> / year</b>	Year 1 savings estimate
CAPEX	<b>£2.75 million</b>	Rough estimate. Includes well, connection pipework, pump and heat exchanger costs. Doesn't include plant heating upgrade costs.
NPV		Not estimated
IRR		Not estimated
Payback	<b>4 years</b>	Simple estimate

**Figure 17: Summary table for maltings project Reference Case.**

The project was estimated to provide a range of between 15% and 50% of the total 800 - 1000 MWh per week heat demand, off-setting the current fuel oil heat source. The uncertainty in the flow rate achievable from such a depth, compounded by the high CAPEX, meant that despite potential upside of a 3-year payback (improvement from 4-year payback shown in Figure 17) with substantial CO<sub>2</sub> emissions savings, the client was unable to proceed. The client may invite TRE to revisit the project in a few years to reconsider if the economics have improved due to policy, energy prices, carbon prices or other factors. In the meantime, the client is installing gas boilers so that trucks can deliver gas instead of fuel oil, roughly halving the plant's operational carbon footprint.

### 3.11 Dollar Community Sustainable Housing

TRE was commissioned by a landowner in Clackmannanshire to evaluate the potential for a minewater geothermal system to supply heat and cooling to a prospective housing development of 34 houses with future scope for 200 houses. Other complementary renewable technologies were recommended for consideration as part of an integrated 'smart' balanced heat and power system including solar PV, battery storage and EV charging facilities. The overall aim is to create a carbon neutral sustainable housing development that helps to achieve the community's vision.

A detailed feasibility study for the 200 houses has not yet been completed. However, match-funding has been secured from the Scottish Government's Low Carbon Infrastructure Transition Programme (LCITP) fund for a techno-economic feasibility study. This will be released, and the study tendered if the project's exploratory drilling phase - funded by the Energy Technology Partnership (ETP) - proves that the minewater resource is available as estimated. Progress is paused to await confirmation from the local authority that the project may proceed following a planning permission in principle evaluation. Exploratory drilling is planned for April 2020.

The concept is to implement a shared-loop heat pump network as has been innovated by Kensa for several flagship projects in the UK. This concept has the potential to be scaled with the housing development as batches of houses are constructed. In addition, it passes over the heat pump CAPEX and OPEX to the individual houses, very similar to how individual houses in the UK currently operate their gas boilers.

A study was carried out for the 34-house initial phase (see Figure 18) which was client funded. An options appraisal for due diligence was funded by Zero Waste Scotland.

The commercial model proposed at this stage is for a joint venture ESCO that supports the community, that will be considered against other new-build options such as gas grid connection or other renewable heat options such as a biomass heat network.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>November 2018</b>	Report not publicly available
Resource	<b>Flooded coal mine</b>	Carboniferous
Depth	<b>55 m</b>	
Source Temperature	<b>11°C</b>	
Flow Rate	<b>5 L/s</b>	Peak flow, variable to match demand
Capacity	<b>0.23 MWth</b>	
CO <sub>2</sub> Savings	<b>23.2 tCO<sub>2</sub> / year</b>	Year 1 savings estimate
CAPEX	<b>£0.23 million</b>	33-house initial phase. Includes wells and shared loop pipe and pump costs. Houses require further £289,000 CAPEX for heat pumps which can be included in individual house cost
NPV		Not estimated
IRR		Not estimated
Payback	<b>7 years</b>	Simple estimate

**Figure 18: Summary table for Dollar sustainable community housing project Reference Case.**

Once complete, the project will provide an exciting opportunity to demonstrate to developers that new housing developments can be carbon neutral and that non-gas options can be straight forward and value generating, helping to meet government requirements for no new-build housing to be installed with gas boilers from 2025 (UK) / 2024 (Scotland).

### 3.12 Cheshire Basin

The only case study not from Scotland, this project is located on the north west side of the Cheshire basin in England.

Phase 1 evaluated the geology for geothermal energy potential across the whole area and recommended to target the Sherwood Sandstone aquifer due to its highly productive nature as a proven freshwater aquifer in many parts of England. Unfortunately, whilst it reaches several kilometres depth to the southeast with expected temperatures exceeding 100°C, the aquifer only extends to c. 800 m in the area of the study, limiting the maximum temperature available.

Phase 2 addressed recommendations from the client to focus the study on two leisure centres in Ellesmere Port; Ellesmere Port Sports Village (EPSV) owned by local authority; and David Lloyd Cheshire Oaks (DLCO) privately owned facility. Four swimming pools represented the bulk of the heat demand and required relatively low temperatures, compatible with the geothermal source.

This work was co-funded by the Heat Network Investment Project (HNIP) and the local authority's energy project delivery vehicle.

Comprehensive energy demand modelling was carried out as part of the study. The client is currently progressing applications for funding to initiate exploratory drilling,

The commercial model considered was for a Council and / or third party financed geothermal heat network, competing against existing gas CHP units and other retrofit options such as biomass boilers.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
Study Completed	<b>May 2019</b>	Report will be made public
Resource	<b>Aquifer</b>	Permo-Triassic
Depth	<b>800 m</b>	Max depth, shallower options were also evaluated as conventional open-loop GSHPs
Source Temperature	<b>25°C</b>	
Flow Rate	<b>15 L/s</b>	Peak, variable to match demand
Capacity	<b>0.68 MWth</b>	Limited by demand; geothermal wells could provide 1.13 MWth with additional heat pumps
CO <sub>2</sub> Savings	<b>600 tCO<sub>2</sub> / year</b>	91% emissions savings versus existing gas CHP and boiler heating systems
CAPEX	<b>£1.59 million</b>	Includes entire energy system and connection costs. Assumed that grant funding of £0.91 million of would supplement investment, to fund total CAPEX of £2.5 million.
NPV	<b>£0</b>	25-year project life
IRR	<b>3.5%</b>	25-year project life
Payback	<b>13 years</b>	

**Figure 19: Summary table for Ellesmere Port leisure centres project Reference Case.**

One of the most interesting take-aways from this study was that, in a full techno-economic comparison between a shallow (150 m six borehole GSHP) and a deeper (800 m well doublet) system, the deeper system came out with more favourable economics. This justifies further investigation of where the ‘sweet-spot’ may be for depth of wells when targeting a relatively homogenous HSA resource such as the Permo-Triassic sediments of the Cheshire Basin.

Sensitivities were explored to assess how project gas and electricity price changes would affect the system’s financial performance. Gas price increases over the project life of 5%, 29% and 50% were examined, as shown in the table below. (The UK government forecasts a 29% rise in gas prices for the period 2020 – 2025).

Gas price increase:	5% increase		29% increase		50% increase	
Value at year:	25 years	40 years	25 years	40 years	25 years	40 years
%IRR	4.2	3.4	6.8	6.7	8.6	8.7
NPV (£million)	£0.1	£0.0	£0.4	£0.4	£0.8	£0.8
Estimated payback period (years)	13	13	11	11	10	10

**Figure 20: Table showing changes in IRR, NPV and payback associated with future rises in gas price against the Reference Case shown in Figure 18. Reference case heat prices provided by the client were between 2.1 p/kWh and 2.8 p/kWh.**

The Department for Business Energy and Industrial Strategy (BEIS) forecast electricity prices to decrease relative to gas long term. It is also possible at this site (as at many) to build local renewable generation such as solar PV or integrate battery storage with variable electricity tariffs to bring electricity costs down for a private wire network.

<b>Fuel price change</b>	<b>Electricity @ £0.09/kWh</b>		<b>Electricity @ £0.09/kWh and gas with 29% increase</b>	
<b>Value at year:</b>	<b>25 years</b>	<b>40 years</b>	<b>25 years</b>	<b>40 years</b>
<b>%IRR</b>	4.50%	3.90%	7.50%	7.50%
<b>NPV (£million)</b>	£0.10	£0	£0.60	£0.60
<b>Estimated payback period (years)</b>	12	12	10	10

**Figure 21: Table showing change in IRR, NPV and payback associated with 1 p/kWh reduction in the electricity price against the Reference Case shown in Figure 18. Reference case electricity price provided by the client was 10 p/kWh.**

The economics improve substantially with these two minor and realistic adjustments, stressing the importance for commercial models to include realistic views of pricing and climate change impacts which will gradually eliminate gas from the energy mix. The project is currently under evaluation by the local authority.

### 3.13 Scottish Berry Farmer

Horticultural applications of geothermal heating and aquifer thermal energy storage are becoming increasingly popular, particularly in the innovative Dutch horticultural sector. Scotland cultivates enormous quantities of berries, but often does not take full advantage of extending the growing season through use of renewable heating.

The client has c. 400 acres of polytunnels, and by use of an 8 MWth biomass boiler and 240 kW biomass CHP currently heats 20 acres of polytunnels as well as c. 140 caravans which house the c. 600 berry pickers during the height of the growing season. The farm is situated a few km's southeast of the Highland Boundary Fault which has numerous regional fault zones associated with it, which could provide sustainable flows of warm water from fractures. The work was client funded.

The commercial model proposed is for a heat customer financed geothermal system, competing with biomass boilers and other new-build heat options on ROI.

<i>Item</i>	<i>Figure</i>	<i>Notes</i>
<b>Study Completed</b>	<b>July 2019</b>	<b>Report not publicly available</b>
<b>Resource</b>	<b>Fault zones</b>	Devonian sediments have been regionally faulted due to extensive movement along the HBF
<b>Depth</b>	<b>3500 m</b>	Open-hole from 3000 – 3500 m
<b>Source Temperature</b>	<b>75°C</b>	Average temperature estimate from open hole
<b>Flow Rate</b>	<b>20 L/s</b>	Base case assumption, little is known about the openness of faults at this depth
<b>Capacity</b>	<b>3.8 MWth</b>	Base case assumption with delta T of 30°C
<b>CO<sub>2</sub> Savings</b>	<b>1980 tCO<sub>2</sub> / year</b>	Versus gas boilers
<b>CAPEX</b>	<b>£6.75 million</b>	Includes all geothermal system capex including surface pipework, but no polytunnel capex
<b>NPV</b>	<b>£3.4 million</b>	20-year project life
<b>IRR</b>	<b>6%</b>	20-year project life
<b>Payback</b>	<b>7.5 years</b>	5% discounting factor

**Figure 22: Summary table for heated greenhouse project Reference Case.**

An upside case sensitivity was also explored: higher flowrate wells delivering 40 L/s at 90°C (so higher CAPEX figure of £12.75 million) and heat demand delta T of 60°C was assumed: this improved the payback to 5.4 years, and the 20-years NPV and IRR to £10.6m and 11% respectively.

This project requires substantial further work, including from academic specialists, to reduce uncertainty in the flow rate and temperature expected, and private sector innovation in reducing well CAPEX whilst maximising the number of open fractures intersected with the production well. However, this initial feasibility modelling shows that there can be a commercial case for deep geothermal heat for horticultural applications in Scotland.

## 4. CONCLUSIONS

No two projects are the same, but there are some clear conclusions that can be drawn from the case studies presented above:

1. The commercial case is relatively weak for most projects at present. This is not a surprise as there is always a significant price to deliver new technology to a new market, even more so where the technology is competing with an existing low-cost technology – in this case natural gas which is “on tap” in many areas and is at historically low price availability in the UK.
2. District heating networks are rare in Scotland, and the wider UK, relative to other European countries. A culture change is required that engages the housing developers, commercial property builders, local and national government. Creation of integrated heating and cooling demand in large networks, as in the Grangemouth study needs to become best practice, ideally through government mandate.
3. Geothermal projects have high front-end capex and low running costs. This is a disadvantage when completing economic appraisals of these projects compared to carbon fuelled technologies when project value is determined conventionally. This is particularly the case when competing with an existing heat network as opposed to supplying additional demand. Conventional economic appraisals will give a purely economic output; a more comprehensive assessment of the project's benefits will cover the wider sustainable development benefits of the project. Project economics and commercial structures should include the life cycle cost of carbon; innovative financing (i.e. national risk insurance schemes which may be privately run) once the market matures beyond grant funding necessity; and value added for price stability for long term consumers. These aspects acknowledge the climate change imperatives of shifting to low carbon heat as well as low carbon power in Scotland. Non-economic factors should have significant value weighting particularly related to climate change targets and commitments by local and central government.
4. Projects with fewer stakeholders have a greater chance of progressing.
5. On the short to medium term, primary finance needs government support up front – the RHI reduces OPEX which is already low but does not address the initial risks to value associated with drilling CAPEX and with flow rate uncertainty. Financial incentives as granted to the hydrocarbon exploration and production industries drilling costs should be considered by the government to help make such projects economically acceptable.
6. Integrated solutions with complementary renewable heat and power technologies should be considered where appropriate as part of integrated ‘smart’ balanced systems, including solar PV, battery storage and EV charging facilities as included in Dollar project (3.11).
7. The projects targeting deeper geothermal resources (Case studies 3.10 and 3.13 in particular) have greater geological uncertainty and require higher drilling investment to de-risk the resource. This is going to be a challenge which cannot be fully addressed by further academic studies and desk-based modelling. The relatively strong financial performance expected from these projects provides a case for specific government support for assistance with deep drilling projects to demonstrate opportunity (as has been completed recently in Cornwall at the United Downs Deep Geothermal Project). Assistance should also be considered for managing the potential decline of a production rate from a deep well due to unfavourable permeability and recharge.
8. The hurdles to be crossed for geothermal heat are comparable to any new technology introduction and development in the country, from North Sea oil in the 1970's to offshore wind in the last decade. Government support comes in many forms, both direct and contextual. There are opportunities to utilise taxation, direct grants, and revenue subsidies; and to encourage innovative finance, technology development; and ease planning for low-carbon projects. An integrated and long-term commitment is required to give the industry confidence to take on risk to access this great opportunity.
9. If legislation to support the Net Zero Carbon by 2050 target is enacted, several of the factors controlling project economics in the case studies outlined here would improve. Some projects that currently look unattractive relative to higher carbon alternatives may become attractive in coming years, so it will be worth re-evaluating projects as legislation, and the market's response to that, changes.

The value drivers for geothermal heat in Scotland are similar to those in other countries: capex, specifically for drilling; delta temperature, value generation from low temperature heat; flow rate; local market rates for alternative heat options; government subsidy and taxation.

In conclusion, the financial viability of the nascent geothermal energy industry in Scotland has been on the rocks, but with further work, government focus and research on the rocks, commercially viable heat will be produced from the rocks, to ensure that in the future everyone can enjoy sustainable Scotch whisky, on the rocks.

If we can make it work in Scotland, we can export our expertise globally as most of the planet does not have Icelandic levels of heat resource.

TRE is at the hub of a group of Scottish consultancies that can work together to evaluate projects across the geothermal heat spectrum and develop investor ready business cases including proposals to government and local authorities on planning and finance initiatives that can fairly promote the nascent geothermal heat industry in Scotland.

## 5. RECOMMENDATIONS

Favourable policy levers and government incentives have proven vital to kick-starting the geothermal energy industries of most geothermally active countries. The UK has only implemented one of the three levers: an operational subsidy, by use of the RHI. This will end in March 2021. To date, 0 deep geothermal projects have been developed which benefit from the RHI. Capital grant funding support especially for drilling is the most important and effective lever at present. As the industry matures the UK and Scottish governments should pay close attention to the success challenges of both licensing regimes and dry-hole / drilling risk insurance, as

these have been effective in several neighbouring countries including the Netherlands, France and Germany. Policies should be designed specifically for geothermal energy instead of continuing to lump the technology together with all other forms of renewable heat generation. The indirect economic benefits of the large carbon savings from geothermal projects should be fairly accounted for when comparing to other technologies.

Demand side systems and heat pumps need to be designed to maximise heat off-take, especially from lower (<50°C) temperatures, to maximise the delta T across the geothermal supply. For minewater resources, assurance is needed that the existing technology is sufficient to mitigate corrosive and reducing minewater chemistries as this is a common risk which is often thought to be a deal breaker for projects.

There are abundant project financiers looking for bankable renewable energy projects as the financial sector embraces the low-carbon transition. However, under current financial mechanisms the very high up-front CAPEX and minimal OPEX provided by the geothermal heating system is very rarely favoured over a lower CAPEX and higher OPEX due to the choice of discount factors. Further structured capital project support is required from government to enable the installation of a varied portfolio of geothermal demonstrator projects across the UK.

It is up to National Government to set the policy and legal requirements and for Local Government to implement and enforce them. National Government should enable through legislation and policy instruments alternative ESCO arrangements, financing models and / or creating a financial body to underwrite long term low interest loans for investments which reduce greenhouse gas emissions, or at least fund the gap between the conventional and alternative. There should be more encouragement / requirement on local authorities to create arms-length financial bodies to do this – be those ESCOs, development trusts or similar – which is common practice in the more mature geothermal heat network sectors of Germany / Denmark. This will help address the current lack of coherence and permanency in UK / Scottish energy policy caused by no single energy policy which cuts across all Government Departments, unlike the Federal Government of Germany that covers energy efficiency, buildings, renewables etc.

Finally, but most importantly, awareness of the geothermal heat opportunity needs to be increased among all stakeholders, predominantly within local and national government, but also within the energy consultancy and energy investment communities who often overlook geothermal energy in their energy master plans. Housing developers require assurance that installing a low-carbon heat network for new-builds is going to increase the value and attractiveness of houses to their customers. The general public and developers require education of the potential benefits of heat networks and their popularity in other countries.

Momentum is growing, and our understanding of what makes a geothermal energy business case strong is improving rapidly, so now is the time for public and private sector to increase collaboration to begin using the renewable heat underneath our feet to decarbonize heat and prevent a climate meltdown.

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