Geothermal Energy in Scotland

A synthesis report covering four feasibility studies

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1 Background

This report has been prepared at the request of ClimateXChange for the Scottish Government Heat and Energy Efficiency Unit.[1] It summarises the key findings of feasibility study reports from four projects carried out under the Geothermal Energy Challenge Fund, part of the Low Carbon Infrastructure Transition Programme (LCITP), which is supported by the 2014 – 2020 European Regional Development Fund (ERDF) programme. The projects were intended to explore the technical feasibility, economic viability and environmental sustainability of developing geothermal resources at sites in Fife, North Lanarkshire, Aberdeen City and Aberdeenshire.

The four projects and their reports are:

- Aberdeen Exhibition and Conference Centre Deep Geothermal Single Well Project; Feasibility Report for the Low Carbon Infrastructure Transition Programme.[2]
- Fortissat Community Minewater Geothermal Energy District Heating Network.[3]
- Geothermal Energy Challenge; Guardbridge Geothermal Technology Demonstrator Project.[4]
- Hill of Banchory Geothermal Energy Project; Feasibility Study.[5]

We have given a very brief overview for each project, followed by key learning points from each report under the headings Technical, Economic and Environmental.[6] Summaries of the reports' findings are then given under the same headings. It should be noted that these summaries are **highly condensed** from the full project reports and so cannot include all aspects covered. Best efforts have been taken to ensure the most important elements are explained.

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[1] Following initial submission, Scottish Government suggested a number of changes to the report text. Most of these have been accepted and incorporated. Some have been added as footnotes where this is considered appropriate.

[2] Geothermal Engineering Ltd, University of St Andrews, Ove Arup and Partners, *Deep Geothermal Single Well report.* (2016). http://www.gov.scot/Resource/0049/00497878.pdf

[3] James Hutton Institute, *Fortissat Community Minewater Geothermal Energy District Heating Network.* (2016). http://www.gov.scot/Resource/0049/00497924.pdf

[4] University of St Andrews, *Geothermal Energy Challenge Fund: the Guardbridge Geothermal Technology Project.* (2016). http://www.gov.scot/Resource/0049/00497934.pdf

[5] Hill of Banchory Geothermal Energy Consortium, *Hill of Banchory Geothermal Energy Project Feasibility Study.* (2016). http://www.gov.scot/Resource/0049/00497700.pdf

[6] Scottish Government note: the learning points in this report are not always evidence-based; in some cases, they are best-case scenarios from the relevant feasibility report.

2 AECC Deep Geothermal Single Well

2.1 Project outline

This project is proposed by a consortium comprising Geothermal Engineering Ltd, Ove Arup and Partners (ARUP) and the University of St Andrews. The project involves drilling a deep geothermal single well (DGSW) on the site of the new Aberdeen Exhibition and Conference Centre (AECC) near Aberdeen Airport, some 7 kilometres (km) north west of central Aberdeen. Planning for the new conference centre is advanced with construction expected to start this year. The AECC proposals include renewable energy provisions, including hydrogen fuel-cell and anaerobic digestion. The current project proposes that geothermal energy from a DGSW could be integrated into the energy mix by providing the heat input needed for the anaerobic digestion plant, replacing a gas boiler for heat supply. The proposal suggests that a DGSW could, in addition, provide heat to neighbouring residential properties.

One of the attractions of siting a DGSW demonstration project at the AECC site is that it would be ideally situated for encouraging public and industry awareness of geothermal energy. Synergies with the existing oil and gas industries in the Aberdeen area could help foster development of a geothermal supply chain. Existing skills and expertise can be applied directly to geothermal developments, giving the opportunity for supply-chain leadership based in the area.

2.2 Key learning

2.2.1 Technical

- DGSW technology is relatively simple needing only one borehole and a closed-loop water circulation with no reliance on permeability of the rock.
- The technology has been field trialled successfully by the consortium and a planned demonstration project has been fully permitted and funded.
- Peak geothermal heat output from a single well proposed at AECC of 2.0 to 2.25 km depth is expected to be around 0.5 megawatt (MW).
- Hot water supply to the heat demand will be at 50°C.
- The system is efficient; one unit of electrical energy used for pumping of fluids can deliver 40 units of thermal energy.
- Engineering requirements, costs and project plans are well defined; the project can be delivered in 27 months.

2.2.2 Economic

- Total project cost expected is £2.3 million (M); capital and financing costs make up 70% of costs, mostly from drilling the well.
- A typical DGSW project is modelled to have internal rate of return (IRR) of 18.8% over 40 years, assuming a tariff of c.5 p/kWh from the Renewable Heat Incentive (RHI),[7] making the technology attractive for investment.
- Unit heat costs are competitive with gas heating at current prices and expected to be more stable over time; 50-year life cycle costs are predicted at about half the cost of gas heating at 2.1 pence per kilowatt hour (p/kWh) compared to 4.3 p/kWh.

[7] Scottish Government note: some of the RHI tariffs are due for revision by the UK Government following a public consultation in 2016.

2.2.3 Environmental

- Environmental licensing, planning permission and compliance with health and safety regulation will be required; requirements and process are mostly well defined.
- There is a very low probability of fluid or gaseous pollution from the project.
- Life cycle carbon dioxide (CO_2) emissions (including construction, operation and maintenance) are calculated to be very low at 2,008 tonnes of CO_2 equivalent (t-CO_2e) over a 50-year expected lifetime, or 40 t-CO_2e per year (t-CO_2e/yr).
- Calculated emissions are some 12 times lower than gas heating on an equivalent basis, saving 22,170 t-CO_2e over 50 years (443 t-CO_2e/yr).

2.3 Technical summary

The DGSW technology is relatively straightforward. A single well will be drilled into the granite bedrock underlying the AECC site to a depth of 2.0 – 2.25 km. In this depth range it can be confidently predicted that the temperature at the bottom of the borehole will be 60 – 65°C. The well is lined over most of its depth with standard 7-inch diameter steel casing; the deepest 300 metres (m) are left unlined to maximise heat transfer from the hot rock; the upper 300 – 500 m are drilled to a larger diameter and lined with 10¾-inch casing. The well is fitted with a central polypropylene tube reaching nearly to the bottom. In the upper part of this tube (at 200 m depth) a submersible electric pump is fitted on the lower end of a flexible riser. This extracts water from the central tube causing a flow of hot water up through the central tube from the bottom of the well. The hot water is supplied to a heat exchanger on the surface with the returning, cooler flow fed to the top of the outer section of the well, where it returns down the well under gravity and pump-induced circulation.

The heat exchanger heats water in a secondary circulation loop, minimising the contact of geothermal waters (rich in dissolved salts) with surface plant. The secondary loop delivers water at 50°C to the heat demand, in this case maintaining the temperature in the anaerobic digestion plant. A control system is used to vary the speed of the DGSW circulation pump and the secondary loop pump, allowing temperatures in the two loops to be optimised. A supplementary gas-fired boiler can be included in the secondary circulation loop, either to boost the temperature or provide back-up during maintenance of the DGSW system. In the current project proposal, the temperature of the return flow in the secondary loop (30°C) is sufficient to provide heat to residential properties near the site. However, heat pumps are needed for each property to upgrade the heat sufficiently for domestic use.

The DGSW system is technology developed by Geothermal Engineering Ltd based on “closed loop” single geothermal wells. The system has been field trialled at a site in Cornwall with similar granite bedrock to that beneath the AECC. Results from the trial and modelling suggest the AECC well may produce a peak heat output of 400 to 600 kilowatts (kW) with an input/output ratio of one unit of electricity for the pump to 40 – 50 units of thermal energy delivered at the surface. The trial established the system at a technology readiness level (TRL 6) meaning it is ready to be used in a commercial project.

The use of a single vertical borehole with no requirement for fluid flow through the rock surrounding it is a significant advantage of the DGSW technology over other geothermal heat recovery methods, such as doublet well systems or systems relying on groundwater flows from aquifers. There is no dependence on rock permeability in the DGSW system. Standard drilling techniques can be deployed using a mobile rig, meaning drilling costs can be controlled through a fixed-price engineering procurement contract. The DGSW design uses off-the-shelf materials; it is quick to install (two weeks following drilling completion) and easy to maintain. A monthly maintenance schedule is defined and an annual service downtime of six hours is required to remove, clean and reinstall the submersible pump.

Project delivery has been planned in some detail with five work packages based on prior experience from the field trial. The first four of these have been costed in detail for staff costs, drilling contract costs and materials costs. The final package will extend over three years of monitoring and costs will be borne internally by the operator. The project will be run and managed by Geothermal Engineering Ltd with ARUP and the University of St Andrews closely involved. Project personnel have been identified and have suitable experience; working relationships between partners are already established from previous projects. A project plan is outlined for the first four work packages, extending over 27 months with the drilling programme defined in greater detail. A detailed risk register has been compiled, including risk-mitigation actions. The highest risks, in terms of successful project delivery, are judged to be delayed or restricted funding and delays to equipment delivery.

2.4 Economic summary

The total project cost is given as just under £2.3M. The second work package, drilling and installation, accounts for the largest portion at £1.7M. Across all work packages, capital expenditure (CAPEX) and the cost of financing this accounts for £1.6M with the bulk (£1.35M) from the drilling contract.

The AECC DGSW project costs will not be typical of future DGSW projects as it is the first-of-a-kind commercial demonstration project. It will need longer time for permitting and will be subject to greater testing than expected in future. A 40-year financial model has been developed for more typical DGSW projects. This suggests a project IRR of 18.8%, i.e. a payback (excluding finance costs) in less than six years, assuming that the RHI remains in place. The report suggests that there is a strong interest in investment for such projects once the technology has been fully demonstrated.

Calculated current (2015) and projected (2035) costs of heat from DGSW units are favourable in comparison to costs of heat from gas, biomass or ground source heat pump. DGSW costs are more stable over time than other heat sources due to low sensitivity to fuel costs (mainly electricity for pumping). The highest portion of DGSW costs is the CAPEX and the financing cost for this, making up around 70% of the total.

The report compares life-cycle costs of heat from DGSW with heat from gas boilers over a 50-year period, including initial capital and equipment replacement costs as well as all set-up, operating and fuel costs. On this basis, the gas system would cost around twice the DGSW system per unit – about 4.3 p/kWh compared to 2.1 p/kWh. However, it is noted that current normal heat supply contracts are only for 15 to 20 years.

2.5 Environmental summary

A study of the potential environmental risks from the DGSW project has focused on the potential for release of deep geothermal waters at the surface and the potential for leakage of radioactive radon gas from the borehole. While this study cannot be conclusive until the borehole has been drilled and samples are available, a provisional conclusion is that there is a very low probability of fluid or gaseous pollution at the DGSW site, or in its surroundings, resulting from project activities.

The project would require a licence from Scottish Environment Protection Agency (SEPA) and planning permission from Aberdeen City Council; discussions with these bodies have suggested the requirements and processes for these applications are mostly well defined, with only a few areas still to be agreed. Although there are no specific health and safety regulations covering geothermal wells, developers are obliged to comply with general and construction health and safety regulations. Discussions with the Health and Safety Executive suggest projects should also follow the processes and spirit of regulations covering onshore petroleum drilling. The project proposers have experience of submitting a planning application for a similar geothermal well at an urban site near Crewe, Cheshire, which was granted within three months with general support. This will be used as a model for the AECC project, if it progresses.

A life-cycle emissions comparison has been made between the DGSW system and a gas boiler system, both delivering 400 kW over a 50-year period, the expected lifetime of the DGSW system. This included emissions from construction, expected replacement of gas boilers during the period and the provision (but not use) of back-up boilers for the DGSW system. On this basis, the geothermal system has CO_2-equivalent emissions twelve times lower than the gas boiler system. However, the construction-related emissions of the DGSW system are high compared to the gas boilers. Much of this relates to embedded carbon emissions in the steel used for well casing; this could be reduced by using steel with a high recycle rate.

3 Fortissat Community Minewater Geothermal Energy District Heating Network Project

3.1 Project outline

Fortissat is a ward of North Lanarkshire Council, an area where there are a large number of abandoned, flooded coalmines. The James Hutton Institute owns a farm in the ward at Hartwood, which lies above two of the larger and deeper abandoned mines. This project, formed by North Lanarkshire Council and James Hutton Institute with Town Rock Energy as project managers and five other sub-contractors, proposes to harness the geothermal energy contained in the minewaters to provide heat to local villages. The geothermal energy will be concentrated using water source heat pumps at an energy centre and delivered through a proposed district heating network (DHN). Improvements to the thermal efficiency of properties connected to the heat network are also proposed as part of the project.

The initial project phase reported aimed to assess the feasibility of, and define an initial development strategy for a minewater geothermal scheme in a rural area with social deprivation. The project aims to provide a proof-of-concept demonstration for replication in other areas of Scotland.

3.2 Key learning

3.2.1 Technical

- Water in flooded mine workings is slightly warmer than most surface waters and can provide a supply of geothermal heat by using a water source heat pump system to concentrate the heat.
- Flooded mines in North Lanarkshire could provide geothermal heat to small district heat networks; a number of siting and network options are identified involving extracting minewater with a 340 m deep borehole.
- There is significant uncertainty over the scale of the geothermal resource available; a range spanning three orders of magnitude has been estimated. This is due to lack of information on minewater temperature and the volume of water that may be connected in abandoned mines and adjacent aquifers.
- The proposal would supply a heat network at a lower temperature (75°C) than normal domestic central heating systems; all existing properties would require upgrading to provide an equivalent level of comfort.
- A tentative project programme suggests delivery might be achieved in 44 months.

3.2.2 Economic

- Capital costs estimated range from approximately £5M to £10M, operating costs range from £0.12 M/yr to £0.23 M/yr, depending mostly on the size of the district heat network supplied; there are high levels of uncertainty in the estimates.
- Net cash flow over 20 years is estimated to be negative (loss making) for the smaller networks and positive, but low, for the larger network modelled, with an IRR of approximately 1.7%.
- Sensitivity analysis suggests the most important variable is the RHI; without this the project would have a large negative cash flow.

3.2.3 Environmental

- Compared to gas heating, CO_2 emissions savings from the project are estimated as 312 to 782 tonnes CO_2 per year (t-CO_2/yr), depending on network size and considering only operating emissions, not construction.
- The project would require a licence from SEPA under the Controlled Activities Regulations for water abstraction and reinjection or discharge.
- Depending on borehole site chosen, the project may help improve existing environmental issues caused by minewater overflow.
- The preferred borehole site is within a local nature reserve.

3.3 Technical summary

The project will use heat pumps to concentrate the energy present in the minewater, which is at a temperature of approximately 17°C, and deliver it to residential properties via a low-temperature DHN (75°C flow, 45°C return). In this way, it is similar to other water source heat pump systems that concentrate energy from rivers, canals or lochs, except for the water body used as the energy source.

For this project, the geothermal energy resource consists of the waters in two flooded, interconnected mine systems lying 300 – 400 m beneath Hartwood Home Farm (owned by James Hutton Institute) and the surrounding areas, including the villages of Hartwood and Allanton. A production well will be drilled approximately 340 m into the deepest level of the mine systems. A submersible pump in the well will bring water to the surface, where a primary heat exchanger will transfer heat energy into a clean water loop, used to protect the heat pumps from the potentially corrosive and fouling effects of chemical-rich minewater. Handling of the minewater discharge from the heat exchanger depends on the site chosen for the production well and is outlined below.

The clean water loop runs to an energy centre housing the heat pump (or array of heat pumps), a thermal store (hot water tank), back-up gas boilers and circulation pumps. The heat pump transfers and concentrates the energy from the clean loop giving a flow temperature of 75°C in the network, which distributes heat to individual properties; water returns from the network at 45°C.

This flow temperature was chosen to allow the system overall to qualify for subsidy under the RHI. A higher flow temperature would require greater electrical input through the heat pumps and so would not qualify for the RHI, falling outside of the performance threshold. However, 75°C is lower than normal central heating flow temperatures and will require each customer property to be fitted with upgraded insulation and other measures to maintain the level of comfort. Different geographic extents of DHN have been studied, with three covering parts of Hartwood and Allanton selected for financial analysis and further assessment. These have total heat demands estimated at 3,860 megawatt hour per year (MWh/yr), 5,713 MWh/yr and 9,670 MWh/yr.

Two options for siting the production well were compared in detail. The preferred site is at the original colliery for the mine workings at Kingshill, south of Allanton. This would handle minewater return through a passive water treatment system (aeration cascade, settling ponds, reed beds) before discharge to a local watercourse. The alternative site is on Hartwood Home Farm and would use two reinjection wells to return minewater into upper levels of the mine system. The comparison of siting options is reasonably evenly balanced; the preference for the Kingshill option arises from the possibility that it may help alleviate existing issues affecting Allanton. Currently, minewater resurgence from the abandoned colliery causes periodic flooding in the village and there are water quality issues from regular minewater discharge, despite an existing passive treatment system. Renewal of the treatment system by the project and lowering of the water table through pumping for geothermal heat extraction may help to alleviate these issues.

The report notes that there is a “significant degree of uncertainty” on the total geothermal energy potential of the minewater systems studied in the project. The total energy available depends on the volume and temperature of the minewater, both of which are subject to wide uncertainty, and the efficiency with which it can be recovered. Available water volume is estimated in the range of 3.62 – 6.12 million cubic metres (Mm^3). The water temperature is estimated to range between 13.2°C and 19.2°C. From these, with assumptions of recovery efficiency factors and other assumptions, a very wide range of total geothermal resource availability of 29 gigawatt hours (GWh) to 10,500 GWh is estimated. From this range, 1,420 GWh is used in the report to give example estimates of potential geothermal supply rate as 2.3 MW for 71 years or 0.63 MW for 258 years. Expressing this as a finite resource reflects uncertainties over the rate of reheating of minewater from geothermal input and the degree to which reinjecting cooled water (if this option is used) may cause cooling of the whole system over time.

An indicative project plan is given in the report, but only of the catalyst phase (in progress) and development phase (24 months from securing funding). Beyond that, construction is assumed to take 20 months. The programme is tentative due to the number of external influences on it, not least the need to engage with numerous stakeholders and get commitment to installing the DHN into both council and private properties as well as the upgrading of those properties.

3.4 Economic summary

Financial modelling for the whole system, including residential property upgrades, is presented for the two production well siting options. For the Kingshill well site, all three heat networks can be supplied and are modelled. For the Harthill Home Farm well location, only the larger network is relevant. The report details the assumptions used for model inputs for revenue, CAPEX and operating expenditure (OPEX) and discusses high degrees of uncertainty associated with some assumptions.

Revenue inputs assume heat sales at 6 p/kWh for the total demand of buildings connected to the DHN, and a non-domestic RHI tariff at the rates due to water source heat pumps over their first twenty years.[8] Whole project CAPEX estimates range from around £5M to £7M for the smaller networks to around £10M for the larger network with either well location. The report notes a high level of uncertainty in capital costs, particularly for the passive water treatment. Annual operating costs are estimated ranging £0.12M to £0.23M. Operating costs also have high uncertainties arising from a lack of definition of how the network would be costed and the structure of the operating company.

Using these data in the financial model suggests the smaller systems will have a negative 20-year net cash flow. The larger systems will have a small positive 20-year net cash flow, resulting in a small project IRR of around 1.7% at best. The report concludes that these returns are unlikely to be attractive to commercial investors but may be acceptable to a not-for-profit organisation, such as might be owned by North Lanarkshire Council.

[8] 8.84 p/kWh for first 15% of annual capacity, 2.64 p/kWh for remainder; a higher deep geothermal tariff for well depths greater than 500 m would not to be available to this project.

The sensitivity of IRR and net cash flow over 20 years to some of the main uncertainties has been analysed for the larger network. These financial indicators are sensitive to the variables studied, however, in most cases the overall effect makes little difference to commercial attractiveness and IRR and cash flow remain low. However, absence of the RHI tariff has a large effect, leading to a large negative cash flow. As the RHI will only last 20 years, project finances are likely to deteriorate after this time; some actions to mitigate this are discussed.

3.5 Environmental summary

An emissions audit has been carried out comparing CO_2 emissions from the four siting option/network combinations considered (with emissions from electricity for the heat pumps based on 2015 grid emissions intensity) and a business-as-usual case assuming current heat needs are supplied entirely by gas boilers. This estimates that the minewater geothermal systems lead to emission savings ranging from 312 to 782 t-CO_2/yr, depending on the extent of the DHN. The estimate only considers operating emissions, with no emissions resulting from construction activities being included.

The report provides a baseline environmental survey of the general area proposed for the minewater geothermal development. Land use in the area is mostly mixed farmland with some commercial forestry and settlements. There are some areas of previous opencast and deep-mining operations. The hydrology of the area has been assessed and the project would need a licence from SEPA under the Controlled Activities Regulations for operations involving minewater abstraction, reinjection and/or discharge.

The abandoned Kingshill Colliery site has been remediated and now forms a local nature reserve designated for its nature conservation interest, including meadows, woodlands and ponds. This is also the site of the existing passive water treatment system, which handles discharge from the abandoned mine. There are a number of other untreated minewater discharges in the area and ongoing issues with flooding from minewater resurgence affecting Allanton village. There are several other designated environmentally sensitive areas within a few kilometres of the proposals.

The report includes a section on risk management; however, this does not cover environmental risks. Risks from uncertainties over minewater chemistry are included, but only from the engineering point of view.

4 Guardbridge Geothermal Technology Demonstrator Project

4.1 Project outline

This project, led by the University of St Andrews with a consortium of six other partners, proposes to site a geothermal well at the Guardbridge Energy Centre. The centre involves redevelopment at the site of an old paper mill on the Eden Estuary, 6 km north west of St Andrews, for mixed commercial, research and community use. It includes a biomass heating system, currently under construction, with a district heating network to supply the main university campus as well as the Guardbridge site itself.

The geothermal technology project proposes using a single borehole to access warm groundwater in hot sedimentary aquifers below the site. Heat pumps would boost the temperature to provide about half the heat requirement of the developed Guardbridge site; this supply would be integrated with the biomass heating system. The feasibility study aimed to establish a financial model to evaluate different business cases for well design options and different heat supply networks, recommending one combination for a further phase of development. The project also aimed to provide information on different ways of accessing productive aquifers in the Midland Valley of Scotland to encourage other geothermal development in the region.

4.2 Key Learning

4.2.1 Technical

- A single well drilled at the Guardbridge Energy Centre site is proposed to extract groundwater from a depth of around 1,100 m; heat pumps will be used to concentrate geothermal energy from the water.
- Project viability requires availability of a groundwater flow of 5 to 20 litres per second (l/s) at 23 – 27°C. To achieve this the well will be drilled obliquely through a geological fault to benefit from permeability in the "damage zone" of fractured rock around the fault.
- The geology beneath the site is complex, significant uncertainty exists due to sparse data. The position of the fault is uncertain and the degree of fracturing is unknown.
- Reinjection of water is not planned; this limits lifetime of the geothermal resource to around thirty years. Instead, treated waters will be discharged to the Eden Estuary.
- Potential geothermal heat output of 0.14 – 0.42 MW is estimated. This will be integrated into the existing heating network of the Guardbridge site and, at the higher level, can provide half the heat requirement of the site as baseload. The output is too low for district heating of local residential areas.
- Initial definition of a second project phase is given, which may lead to full design of a well and drilling programme.

4.2.2 Economic

- Capital costs are estimated at £2.05M with 75% of this from drilling the well. Operating costs are estimated as £0.28 M/yr.
- Financial modelling over a 20-year period using central case data suggests negative IRR and negative net present value (NPV) for the proposed scheme.
- With best-case data, considered reasonable by the project, financial indicators are better but still not commercially attractive given the high risks, high capital and low thermal output.

4.2.3 Environmental

- Compared to gas heating for the Guardbridge site, the proposed scheme would have a CO_2 emission saving attributable to the geothermal heat supplied of 491 t-CO_2/yr, taken over 20 years and considering only operation, not construction activities or materials.
- The scheme will require a number of assessments, licences and permissions, which are detailed in the report. This is particularly due to the proposal to abstract groundwater and discharge it to the Eden Estuary, which is subject to a number of statutory environmental designations.

4.3 Technical summary

The study created a geological model for the region and identified four sandstone formations of interest. Significant uncertainty exists in the geological model due to sparse data. Two of the formations, present under much of Kinross-shire and eastern Fife, were identified as having potential for highly productive aquifers. Near Guardbridge, the depths of these strata are thought to be very different on either side of a major fault; different well options were investigated to target the aquifers at different depths.

The rock permeability (which controls groundwater flow) and the aquifer water temperature were estimated for the three main well options. Two were unlikely to produce the flow rates required and were ruled out. The third well modelled is predicted to supply 5 – 20 l/s of water at 23 – 27°C at the surface and was taken forward for evaluation. An electric submersible pump in the well would be used to raise the warm water to the surface.

To achieve these flows, the well would be drilled from the Guardbridge site with a deviated (curved) trajectory passing obliquely through the "damage zone" around the fault for about 460 m before entering the aquifers to the south of the fault at a depth of about 1,100 m. This long passage through the damage zone is considered key to achieving an adequate flow rate from the well, depending on the likely high degree of fracturing around the fault. However, the report discusses significant uncertainties in the location of the fault (even at the surface), the extent and nature of the damage zone and the permeability associated with it. The resulting uncertainty in potential flow rate is highlighted as the main challenge for the project. The temperature at depth is also uncertain, although better constrained by known geothermal gradients.

Hydrogeological modelling suggests that reinjection of water into the aquifer after heat extraction would be needed for output from the well to be sustainable in timescales beyond about 30 years, but the provision of a reinjection well was not included in the project design. Instead, options for discharging water to the Eden Estuary after treatment, or for recovery and re-use of water (which requires additional treatment), were evaluated. These options would have lower capital costs than a reinjection well.

Geothermal heat potential from the proposed well was estimated based on a temperature of 24°C and flow values of 5 l/s and 15 l/s, leading to potential heat outputs of 139 kW and 418 kW, respectively.

The project studied potential heat networks serving Guardbridge village and the larger nearby settlements of Leuchars and Bulmullo. However, the heat demands of these networks were greater than could be provided from the proposed well. Instead, the project focused on supplying heat to the developments planned within the Guardbridge Energy Centre, allowing a localised network close to the proposed well location on the site.

The project proposes using the geothermal supply with a heat pump to boost the temperature to that needed for supplying baseload heat to the Guardbridge site. This system would be linked through a heat exchanger to the Biomass Energy Centre (under construction), which would provide the additional capacity required. At the higher estimate of water flow from the well, the geothermal heat could supply half the heat demand of the proposed Guardbridge developments.

The drilling required for the deviated well design is outlined along with the type of equipment needed – a conventional drilling rig with directional drilling capability. There are a number of risks and uncertainties associated with the well design and the need to drill obliquely through the fault damage zone. Some mitigation measures are identified.

The report provides initial definition of a second project phase, including geophysical surveys, environmental permitting, test well drilling and, assuming positive outcomes, full well and drilling programme design. This programme is required to progress well engineering definition to a point where a clear case for rig procurement and drilling is complete.

4.4 Economic summary

The economic analysis given in the report is based on the high-flow case of 15 l/s water flow at 25°C[9] and a heat network to connect all proposed buildings on the Guardbridge site. CAPEX is estimated at £2.05M[10], made up of £0.53M for the heat pump and network and £1.52M for the well, flow testing and water treatment. OPEX is estimated at £0.28M a year, mainly from electricity costs for the heat pump and circulation pumps. A single major maintenance cost for the well after ten years is estimated at £0.25M; no other allowance for maintenance or staffing costs has been included.

[9] Marginally different from the temperature (24°C) used for the geothermal heat potential estimate.
[10] Alternately summed to £2.4M in Table 10.1 in the report.

Revenues are estimated based on the RHI at 5.08 p/kWh and heat sale values ranging from 36 to 47 p/kWh,[11,12] depending on customer size. Using these data, a 20-year cash flow model calculates economic performance in terms of IRR and NPV using a low discount rate of 3%.

The central case financial model suggests the project would be a poor prospect for investment, with negative IRR and NPV over a 20-year lifetime. Actual total values are unclear as the report presents the data from the perspective of a number of different stakeholders. The poor indications are exacerbated by the inherent risk that the geothermal well may not deliver the flow rate used in the economic analysis.

There are a number of sensitivities that affect economic performance, most importantly CAPEX variation and the RHI value, which is vital. The report points to a reasonable best-case scenario, where the economics are more favourable with small positive NPV and IRR of 10%. However, the economic performance was not seen as attractive largely due to low margins resulting from a low heat selling price and high capital cost of the well, which, in this project, can deliver only a modest geothermal heat output.

4.5 Environmental summary

Carbon emissions of the proposed geothermal-plus-biomass system have been compared to a business-as-usual case using gas boilers for each of the individual customers over a 20-year life cycle. The comparison has been made on the basis of fuel inputs and electricity only. No consideration of construction, drilling or embedded carbon in equipment has been included. On this basis, the proposed system leads to a level of emissions of about 16% of the comparison case. Avoided emissions of 491 t-CO_2/yr are attributable to the geothermal system, representing 42% of the reduction achieved by the integrated system.

Guardbridge is situated on the Eden Estuary, which is home to a number of important and sensitive species and subject to several statutory environmental designations. The project proposal to abstract groundwater and dispose of it after treatment to the sea is considered against this background. It will require licensing for both abstraction and disposal.

The report identifies the environmental regulation and legislative guidance that will need to be considered by the project and details the licences and permissions required. Potential environmental issues in construction or operation of the project are highlighted and their effects and implications considered in outline. Initial consultation with Scottish Natural Heritage suggests the proposed development will require a full Environmental Impact Assessment and Environmental Statement.

5 Hill of Banchory Geothermal Energy Project

5.1 Project Outline

Hill of Banchory is an area of ongoing mixed commercial, residential and community development on the northern edge of the town of Banchory in Aberdeenshire. This report describes a feasibility study into using geothermal energy from boreholes in the Hill of Fare granite, a few kilometres to the north, for district heating in Banchory. A doublet system would be used, with hot groundwater pumped from one well, used in a DHN in the Hill of Banchory area, and cooler water returned to the second well. An existing heating network is supplied by the Hill of Banchory Biomass Energy Centre, fuelled by woodchip sourced at very low cost from local forests with a sustainable supply chain.

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[11] These are the range and units given in report, possibly should be £/MWh.
[12] Scottish Government note: Units incorrect in feasibility study report, should be £/MWh.

The project consortium, an *ad hoc* group including the current energy supply company and network operator, other companies with an interest in geothermal energy, academics and Aberdeenshire Council, recognises the unusual potential in the area, where a likely geothermal heat source lies close to an existing DHN. The feasibility study finds that, while there are some specific circumstances where a geothermal project may be viable, the success of the existing network forms a constraint on use of geothermal heat through issues of integration and competitiveness with the low-cost biomass-fuelled system. However, the study suggests there is considerable potential for use of geothermal energy in the north east of Scotland in circumstances where it would displace the use of gas or oil for heat supply.

5.2 Key learning

5.2.1 Technical

- A doublet well system is proposed to extract geothermal energy from the Hill of Fare granite near Banchory for supply to a DHN in the town.
- Doublet systems rely on flow of water through the rock from an injection well to a production well. Permeability of the granite at suitable depths under Hill of Fare is unknown and hydraulic fracturing may be required to achieve sufficient water flows.
- Using assumed flow rates, heat output available at the wellhead from a doublet borehole system 2.2 – 2.9 km deep is estimated ranging 0.42 – 4.18 MW.
- Hot water will be transferred 3 – 4 km from the well site to Banchory, and cooler water returned, through insulated pipelines.
- Three options are identified to integrate geothermal heat supply with the biomass-fuelled heat network, depending on the temperature achieved. The temperature required for a direct heating option (>85°C) is unlikely to be achieved.
- Alternatively, new district heating networks in Banchory could be designed to operate at lower temperature such as 75°C; such networks have been identified.

5.2.2 Economic

- Capital costs for the two wells and pipelines for connection to the town were estimated at a total of £4M; costs for new district heating networks were estimated at £1.5M to £5.9M depending on size.
- Variable operating costs were assumed proportional to output at 0.5 p/kWh; fixed operating costs were estimated at £20,000 /yr.
- Eligibility for RHI payments was assumed, which would require public grants to be repaid using bank finance.
- Modelling concluded that the project could be financially viable with IRR of 10% if it could sell 10,000 MWh/yr at 2 p/kWh; this would be competitive with gas heating, but not with the current cost of biomass heating in Hill of Banchory.
- This level of sales is unlikely to be achieved through integration with the existing biomass-fuelled network, but could be achieved with the development of new networks.

5.2.3 Environmental

- Assuming mid-range geothermal heat production was achieved (13,140 MWh/year or 1.5 MW at 100% load factor), and including construction activities, materials and operations, the proposed system is estimated to save emissions of 2,367 t-CO_2/yr when compared to gas heating over a 30-year period.
- There would be no saving in emissions from displacing biomass heating.
- The proposal would require planning permission, a licence from SEPA under water regulations, and compliance with well design and construction and health and safety regulations.

5.3 Technical summary

The Hill of Fare granite is part of the Cairngorm Suite of granite intrusions in the north east of Scotland. Granite contains radioactive elements, which release heat as they decay, and is a relatively good conductor of heat from deep below ground, generally giving a more favourable opportunity for geothermal energy extraction than exists with sedimentary rocks. Based on new and existing data the thermal gradient at the Hill of Fare is estimated at between 21.1 and 29.0 °C/km, meaning that a temperature of 75°C is expected at a depth of between 2,200 m and 2,900 m.

The project considers a doublet borehole system that relies on water flow from one well to another; the rate of flow achievable depends on the rock permeability. Granite has inherently low permeability and flow is mainly through fracture networks, which are difficult to predict, making potential water flows uncertain. Data on fracturing and water flows from existing boreholes in granite is varied. Most cases have needed some degree of artificial stimulation, such as hydraulic fracturing ("fracking"), to achieve sufficient water flows for geothermal energy production. Low magnitude seismicity (not quantified in the report) is likely to be associated with the stimulation process.

Three flow-rate scenarios – 5, 15 and 50 l/s – were assumed on the basis of observations in similar granites and used for analysis of the potential of the scheme, although the report is careful not to present them as actual predictions of flow rates. Heat output from the system was estimated at 0.42 MW, 1.25 MW and 4.18 MW, respectively, assuming temperatures allowing direct integration to the existing heat network were achieved (see below).

Two boreholes into the Hill of Fare granite are proposed at a site to be determined 3 – 4 km from the Hill of Banchory Biomass Energy Centre. The boreholes would be typical of geothermal wells; each could act as the extraction or reinjection well allowing reversal of flow direction to avoid problems of clogging. Wells would take around six weeks to drill and complete. The wellheads would be linked to the heat network by a pair of insulated pipelines for the hot flow and cooler return.

The project proposes integrating extracted geothermal heat with the Hill of Banchory DHN. This is currently supplied by a 900 kW biomass boiler and two back-up gas boilers; a second 700 kW biomass boiler is planned. The system operates at a flow temperature of 85°C with return at 60 – 65°C. Two 50 m^3 water tanks allow heat storage. When the planned network is complete, with more housing and businesses connected, biomass will supply 70% of the heat with gas providing the remaining 30%.

Geothermal heat supply may be integrated with the existing network and its planned expansion in three ways depending on the water temperature achieved. For temperatures >85°C direct heating of the network flow would be possible, but this temperature is unlikely to be achieved. For intermediate temperatures pre-heating of the network return could be used; this is likely to be feasible with the temperatures expected but may not be economic (see section below). For temperatures close to or below the network return temperature, a heat pump could be used to extract heat from the geothermal water; this option would have higher costs and was not considered further. Alternatively, an intermediate temperature that might be achieved by the geothermal system, such as 75°C, could be used with a new heat network, beyond current plans, designed to operate at lower temperature.

The project considered the forecasted developments around the Hill of Banchory area and estimated the resulting increases in heat demand in the period to 2020. It also examined the wider Banchory town area to identify further potential development of heat networks to supply public buildings and council and private housing areas, which could be designed for lower supply temperatures. Estimates were made of the heat demand and profile of six potential sub-networks, with indicators of CAPEX for the networks and likely sales price and revenues. Two sub-networks were identified as most favourable for initial development, one including a school, swimming pool and sports centre, the other a council housing area.

The project identifies a programme of next steps to build a robust business case (spanning 17 to 38 months), with the ultimate objective of developing a geothermal well doublet to deliver heat to network customers in Banchory.

5.4 Economic summary

The study aimed to estimate the likely unit cost of heat produced from the proposed geothermal well doublet system. Due to the uncertainties in the temperature and flow achievable, and hence uncertainty in the heat supply quantity, a simple calculation is not possible. Instead, the project modelled the volume of heat sales at a series of heat unit prices that would be required to meet IRR thresholds for the project of 10% and 20%. This allowed a judgement of which network expansion options might be viable.

Capital costs of the main production elements were estimated at £1.5M for each well and £1M for the pair of connecting insulated pipelines, totalling £4M. Capital cost for the six potential sub-networks ranged from £1.5M to £2.3M for the smallest and £3.6M to £5.9M for the largest. Variable operation and maintenance costs were allocated nominally at 0.5 p/kWh, fixed annual costs were assumed at £20,000 per year. Project lifetime was taken as 20 years for the economic model, although the system potentially has a much longer lifetime. The initial rate of RHI was taken as 5.2 p/kWh;[13] heat price inflation was assumed as 2.5%.

The financial modelling used three scenarios with geothermal supply assumptions of 1.25 MW, 2.5 MW and 4.25 MW. The report simplifies the model output to conclude that the geothermal system described would be commercially viable if it could sell around 10,000 MWh/yr at 2 p/kWh. This price would be competitive with natural gas heating but not with the current low-cost biomass heating achieved at Hill of Banchory.

The study looked at the interactions between the geothermal system financial model and the planned expansion of the existing Hill of Banchory Biomass Energy Centre and heat network. The network demand is expected to grow beyond the supply capacity of the existing and planned biomass boilers, with the remainder made up by gas heating. However, this remainder is predicted at 4,000 MWh/yr, which is too small to be economically displaced by the geothermal supply, even at a heat unit price of 3 p/kWh, similar to gas heating.

The report concludes that, for a geothermal heat system to be commercially viable, development of additional network demand of about of 10,000 MWh/yr would be required, such as through connecting the two promising sub-networks. This would enable supply from a geothermal scheme to be viable with an affordable heat cost of 1.2 – 1.4 p/kWh.

Technical and financial issues that may lead to loss in value of the project have been identified. The largest risk is that of insufficient water flow from the well due to poor permeability or connectivity between the two wells. This can only be reliably determined when at least one of the wells has been drilled, with the cost of drilling already spent. One method of improving water flows from a well-doublet system is through a "stimulation" technique, such as hydraulic fracturing. This leads to a secondary risk, identified in the report, that the Scottish Government might extend its current moratorium on fracking for hydrocarbon recovery to cover geothermal wells where stimulation is required. The other high risk with limited possibility of management is that of the removal or reduction of the RHI, which would have a serious affect on the financial viability of the project. Several areas of

[13] In order to be eligible for this it was assumed that public grants received by the project had been repaid using bank finance.

risk result from current lack of detailed knowledge of the subsurface. An opportunity to mitigate this would involve drilling a test borehole, which may also have value for the development of other geothermal wells.

5.5 Environmental summary

The report identifies that the development would need planning permission, which may require an Environmental Impact Assessment. In principle, a closed-loop geothermal system would not require a licence under SEPA water regulations, as it would have no net abstraction or discharge. However, as the proposal involves a borehole deeper than 200 m a "complex licence application" to SEPA is required. No discussion of potential environmental risks from the project is included in the report. The borehole would be subject to specific well design and construction regulations and to broader health and safety regulations.

The CO_2 emissions of the proposed system, including construction activities and embedded carbon in materials as well as operating emissions, were estimated over a 30-year lifetime as 3.5 – 5.4 kilograms CO_2 per MWh, a very low level even compared to the current biomass-fuelled heating network. Compared to the use of gas heating, this emission level would save around 71,000 t-CO_2 over thirty years, or 2,367 t-CO_2/yr. However, this figure is based on an assumption of geothermal heat supply of 13,140 MWh/yr, which would require several of the new district networks beyond current expansion plans to be developed.

The report outlines an indicative estimate of the theoretical potential of multiple deep geothermal doublet systems based on the Cairngorm Suite of granite intrusions. Including a number of subjective assumptions, it estimates a total annual heat output of approximately 6 terawatt hours (TWh), from 250 systems averaging 3 MW each and running at 90% load factor. Assuming heat transport distances of tens of kilometres, it estimates that some 4.5 TWh of demand could be supplied by geothermal heat over a broad area, with its main axis along Deeside to Aberdeen. This represents nearly 5% of Scotland's total heat demand. With further assumptions about the fossil fuel heating displaced, this might lead to emissions avoidance of 0.9 Mt-CO_2/yr.

6 Concluding comments

The feasibility studies summarised in this report propose four different technologies for extracting geothermal energy in Scotland: a single well recirculation system (AECC); a minewater extraction system (Fortissat); a single well extraction system (Guardbridge); and a doublet well extraction/reinjection circulation system (Hill of Banchory). Each of these has inherent challenges and opportunities, and the studies demonstrate feasibility to different degrees. All the projects would lead to savings in CO_2 emissions of similar scales and roughly proportionate to their displacement of fossil fuel usage.

Taken as a whole, the four studies indicate that geothermal heat can have a useful role in the energy mix in Scotland and there is a range of potentially viable options. The deployment of geothermal heat in Scotland will require site-specific assessment; feasibility studies such as these are a necessary first step. Demonstration projects would help to reduce uncertainty and encourage wider use of geothermal resource in Scotland.