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Development and Deployment of Deep Geothermal Single Wells in the UK

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ABSTRACT

Policies within the European Union are encouraging member States to reduce Carbon Dioxide emissions associated with the production of electricity and heat. Overall, in Europe, residential heat demand accounts for approximately 35% of the entire annual energy consumption. There is therefore a focus on promoting renewable heat technologies. Such technologies include Ground Source Heat Pumps, Biomass and Deep Geothermal heat.

Deep geothermal heat has not, to date, contributed meaningfully to the overall renewable heat supply in Europe. This is particularly true in the United Kingdom, where there is only one geothermal heat network in operation. This lack of deployment has been due to the geographical distribution of suitable geothermal aquifers, the high cost of drilling to suitable depths, the paucity of deep geological data and, more recently, permitting/ seismicity issues. To enhance the overall development of the deep geothermal resource, Geothermal Engineering Ltd (GEL) was funded by the Department of Energy and Climate Change in the United Kingdom to design and test new methods of extracting deep geothermal heat from "single" wells. This paper reports on the progress to date with the "single" well concept, the field trial in 2014, and future installations in the UK via Geon Energy Ltd, a joint venture between GEL and Ove Arup and Partners.

1. INTRODUCTION

Within Europe, there are a number of policy drivers aimed at reducing carbon dioxide emissions associated with electricity and heat production. As residential heat demand accounts for a significant proportion of the overall energy consumption in Europe (IEA, 2011) various initiatives have been developed to encourage the development and supply of renewable heat. In the United Kingdom, a subsidy system has been introduced, the Renewable Heat Incentive (DECC, 2011), to encourage developers to install and make use of renewable heat systems. The overall renewable heat strategy in the United Kingdom aims to make use of a variety of different sources of heat, including deep geothermal (DECC, 2012). According to recent studies (SKM, 2012), the deep geothermal heat resource in the United Kingdom is much greater than the total current annual heat demand. However, the development of deep geothermal energy as a source of renewable heat has, to date, been slow. The primary reason for the slow development has been the risk/ reward ratio for deep geothermal development, which, due to the cost of deep directional drilling and the uncertainty associated with drilling into unproven resources, is unacceptable to private investors. In an attempt to speed up the development of the deep geothermal resource, Geothermal Engineering Ltd was been funded by the Department of Energy and Climate Change in 2013 to design, test and develop so called 'single deep geothermal well' systems. The ultimate aim being to have an 'off the shelf' technology that can be installed in almost any geological environment, irrespective of permeability. This aspect of the technology significantly reduces the investment risk currently associated with deep geothermal development, whilst at the same time gaining greater knowledge of the deeper geology in the UK. This paper reports on the reasons for the design and development of the single well system, the basic elements of the system, the installation and field trial in an existing deep well and some of the follow on projects that the new joint venture company, Geon Energy Ltd, is working on.

2. BARRIERS TO DEEP GEOTHERMAL IN THE UK AND REASONS FOR THE SINGLE WELL CONCEPT

There are a number of well-documented reasons why development of deep geothermal projects in the United Kingdom has remained 'largely untapped'. The principal problem is the high risk/ low financial reward associated with deep geothermal heat supply. These barriers are not necessarily unique to the United Kingdom but are compounded by the lack of knowledge of deep on shore geology, an established geothermal industry and the absence of a legal framework. These barriers have meant that, despite a number of deep geothermal heat and power projects being planned over the past 5 years (Curtis et al, 2013), none have drilled wells and delivered heat or power to an end user or the grid.

Further, the cost of gas for heating in the UK has been relatively low due to the abundant supplies from the North Sea oil and gas fields. For the deep geothermal industry (heat and power) to develop in the UK we believe that the following hurdles will need to be overcome:

2.1 Exploration risk

It has been common practice to develop deep geothermal heat systems as 'doublet' systems that consist of two wells (one for abstraction and one for re-injection) drilled into a rock that has sufficient permeability to deliver high fluid flow rates. However, the permeability of the rock (the ability of rock to let water pass through it) and thus the heat or power delivery of the project is not confirmed in a new location until at least one or often both of the wells has been drilled. This means that every project has a high degree of 'exploration risk' whilst at the same time requiring significant capital investment. This is particularly true for most of the UK, where very few wells have been drilled on-shore to any depth. As the economic returns of a deep geothermal heat project are low, this early stage exploration risk is a major hurdle to investment.

The only deep geothermal well drilled in the United Kingdom over the last decade is a good example of how the permeability of the rock is not confirmed until the well has been drilled. The Newcastle Science Central Borehole was drilled in 2011 (Younger, 2013) with the aim of providing deep geothermal heat to the new buildings in the Science Central development. The drilling was mostly grant funded from the Department of Energy and Climate Change. The aim of the project was to target a highly permeable faulted zone in the rock at the target depth of close to 2km. Although the eventual well showed that a good geothermal gradient existed (39C km-1), the measured permeability was magnitudes smaller than predicted. This meant that the well could not produce anywhere near the required flow rate for an economic return and the project stopped. This situation exemplifies the risks associated with relying upon the presence of a high permeability aquifer at depth. It also shows that unless the reservoir is well proven by multiple wells, even if the first well of a doublet system has high permeability, the second well may display very different properties.

2.2 High capital cost per project and delivery times

Without subsidies or other government incentives such as risk insurance, the economics of deep geothermal heat delivery in the UK are marginal. This is mainly due to the high cost of drilling a minimum of two directional wells per project (one for abstraction, one for re-injection). This is particularly true in the UK, where relatively deep wells need to be drilled to reach suitable temperatures for district heating. Up to 80% of the capital cost of a project is associated with the drilling phase and the funding must be allocated to the project a number of years before the heat plant is constructed and the heat delivered. We believe that the delivery time and the capital cost needs to be significantly reduced before private investment will be forthcoming.

2.3 Geographical reach

Two well or doublet systems always have to be located above a geothermal reservoir (geological environments where sufficient water and permeability is located underground). Either that, or the reservoir needs to be 'manufactured' by hydraulic stimulation or sheering. Locations where these conditions occur are geographically limited in the United Kingdom and do not often coincide with the location of a heat load. The geographical reach of doublet systems is therefore limited and unlikely to be able to meet a meaningful proportion of the heat demands without significant hydraulic stimulation.

2.4 Induced seismicity

The drilling of a deep doublet system (deep enough to supply heat at circa 80C) within low permeability bedrock would require hydraulic stimulation or 'fracking' in order to create a permeability pathway for geothermal fluid flow. Normally the deeper the rock, the more difficult it is for water to move through it. A deep geothermal two well system needs to re-inject cooled water back into the rock at relatively high flow rates and under high pressure. Injecting fluids into the ground at depth under pressure has been historically associated with induced seismicity as was recently seen at the Preese Hall shale gas site near Blackpool (Green et al). It is our belief that the potential for induced seismicity will limit the geographical locations where doublet systems can be installed (i.e. not in urban areas) and may cause significant concern within the local community wherever they are proposed. This aspect of deep geothermal development has not yet been tested in the UK due to the lack of delivery of deep geothermal doublet projects. However, a community backlash to induced seismicity (however small) could severely limit the integration of such systems with urban heat demands.

2.5 Heat demand

Two well systems require multiple megawatts of heat demand to be in place above a location that is suitable for drilling. In the United Kingdom, there are very few large-scale heat networks (although this is gradually changing) and very few of them are above suitable geothermal aquifers. In the short term, it may prove easier to start with smaller scale heat demands (often single owner) so that the network can be planned and managed to suit the geothermal heat supply.

3. HOW THE SINGLE WELL ADDRESSES THESE PROBLEMS

Over the past three years, Geothermal Engineering Ltd and Ove Arup and Partners Ltd have been working on the design of a deep geothermal system to address some of the problems that are unique to the UK in order to kick-start the delivery of commercially viable geothermal heat. The resulting Deep Geothermal Single Well (DGSW) system has now been extensively modelled and field trialled in an existing deep well as part of a previous project in 2014 funded by the Department of Energy and Climate Change (DECC). The system addresses each of the hurdles listed above in the following ways:

3.1 Exploration risk

The DGSW technology is not dependent on abstracting large quantities of water from the sub-surface (such as the Newcastle Well). Instead, like a standing column well, the majority of the water is re-circulated within the well. This means that a successful project does not rely on identifying, targeting and hitting a highly permeable rock at a specific depth. The only requirement is that the temperature at depth is within the operational range for the building or plant. Although this reduces the heat delivery that is achievable from the well, it significantly reduces the exploration risk associated with a project. This is because the temperature at depth is much better understood than the permeability, which can vary by orders of magnitude between different wells.

3.2 High capital cost per project and delivery times

Drilling single vertical wells substantially reduces the upfront capital expenditure of a deep geothermal heat project. The total capital cost of a commercial DGSW system will be between £1.5m and £2.5m, compared to greater than £10 m for a deep geothermal doublet system that requires directionally drilled wells. Further, as the DGSW only consists of one vertical well and no plant at the surface, the project delivery time is reduced to between 12 and 24 months. The combination of low risk, short delivery times and reduced capital expenditure means that different funding routes can be pursued for these sorts of projects, such as community Crowdfunding. The simple vertical well design also enables turnkey drilling contracts to be developed that reduce the risk of cost over-runs to the developer.

3.3 Geographical reach

Because the DGSW system is not dependent on a geothermal reservoir (whether existing or artificially created), it has a much greater geographic reach than traditional systems and can be deployed in almost any geological environment where there is a heat demand at the surface. This is important as, in the UK, heat demands are often not located above ideal geothermal conditions. The small footprint also means that it is well suited to urban areas and therefore has a more realistic chance of supplying heat to existing end users than larger scale systems.

3.3 Induced seismicity

The DGSW system does not need to inject fluid into the ground at high pressure and does not need to create a reservoir at depth, which is always required in projects utilising doublet systems. In a hard rock such as a granite, some degree of stimulation or 'fracking' will always be required to engineer a reservoir between two wells. There is therefore no risk of induced seismicity when a DGSW is installed and no risk of community backlash. This is very important when trying to develop a new commercial industry in the UK. The recent induced seismicity at a shale gas site in England caused a two year delay to the entire industry whilst the Government investigated the incident and has associated "fracking" with "earthquakes" in the minds of the general public and the media.

3.4 Heat demand

The heat output of the DGSW is suited to sites where small heat networks can be developed quickly or are already in place (such as Universities, schools, sports centres, multiple apartment blocks etc). Larger scale networks with multiple end users are not required. This enables projects to be developed much faster as the number of parties involved in the Heat Purchase Agreement and network operation/ management/ liability is normally one. Given the relatively small number of large-scale heat networks in place in the UK, the DGSW can be rolled out to many areas that do not have such networks and will, realistically, never have them developed.

4. SYSTEM DESIGN/ OPERATIONAL MODES

The DGSW is a simple co-axial design that is similar to that deployed in a standing column well Ground Source Heat Pump system that would typically be found on the East Coast of the United States. The only difference between the two is the materials used for the pipework and the depth of the installation. A schematic of the system is shown in Figure 1.

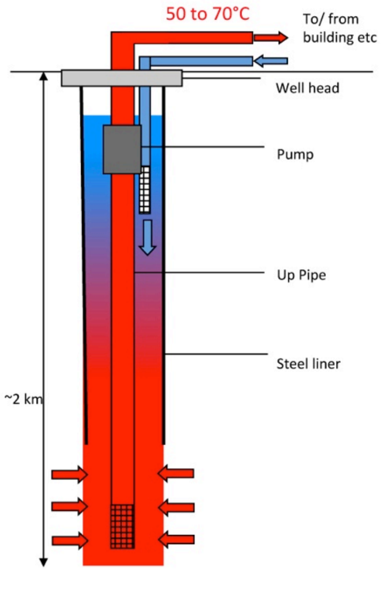

Figure 1 Schematic of the Deep Geothermal Single Well

The system has been designed to operate in two principal modes (Figure 2):

- Monovalent System – DGSW sole source of heat
- Bivalent System – DGSW using gas fired boilers for Supplementary Heat

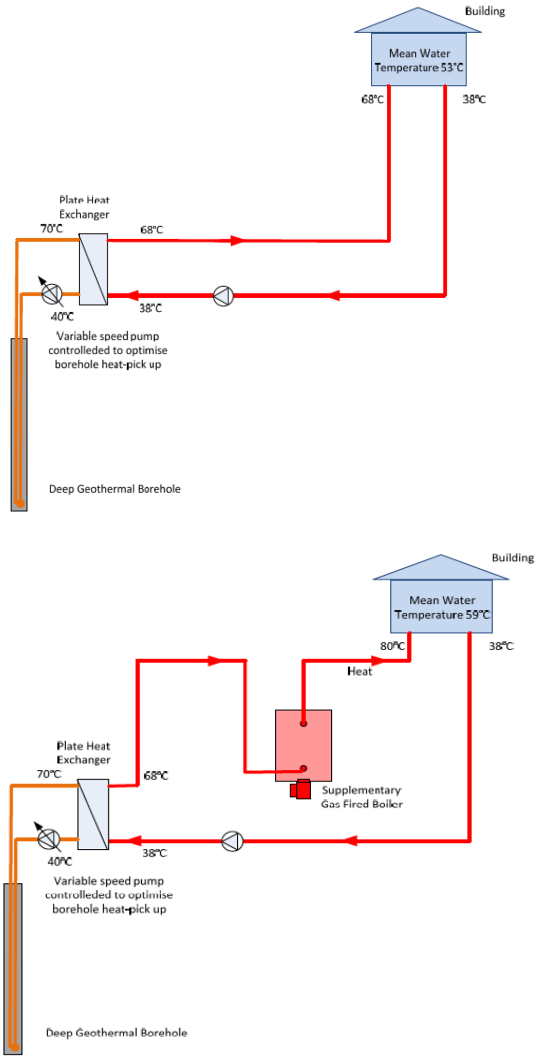

Figure 2 Monovalent and Bivalent modes of operation

In a standard project, to maximise the thermal output of the DGSW, the operation of existing heating systems will be adapted to run on a lower mean water temperature (MWT) than the norm. The MWT is very well suited to modern buildings that deploy underfloor heating or warm air systems. For retrofits, the secondary circuits will be configured to deliver space heating for longer time periods to accommodate the lower MWT. Thermal storage will also be added to the system (if not already in place) to provide better regulation of the delivery temperature.

In monovalent form, the system provides a simple robust solution to the delivery of heat with very low carbon content to buildings with underfloor heating or lower temperature distribution systems. We would expect to deploy the monovalent system in all new builds. The bivalent system is likely to be the form most commonly implemented in early stage retrofit projects.

5. INSTALLATION AND FIELD TRIAL

For the field trial, the DGSW equipment was installed in an existing 2.6km well that was drilled in the granitic rock in Cornwall during the 1980s as part of the Hot Dry Rock project (Batchelor, 1987). The pipework was installed and fitted with a fibre optic temperature cable along its length to enable an accurate temperature profile of the well to be recorded every 5 seconds during a range of energy abstraction tests that were carried out on the well (Figure 3).

Figure 3 DGSW Pipework being installed at the trial site

The energy abstraction tests were conducted using a 400kW 'Thermal Response Test' rig that was designed and built for this project. (Figure 4).

Figure 4 400kW Thermal Response Test rig with "air blaster" – external and internal viewpoints

The full results of the field trial will be discussed in a separate paper. In brief, a wide-range of tests were conducted on the well, which included flow rate variations, energy abstraction rate variations and durations and 'bleed flow' tests. High quality data was recorded from the entire length of the pipework installed in the well to enable calculations to be made on the thermal performance of the well under different conditions. The results were also used to validate the numerical models that had been created using the USGS SUTRA code during the design process. The results were also used to help enhance an analytical model developed for the project.

In brief, the field trial proved that the DGSW system could deliver heat with a very high co-efficient of performance. The pump input power was approximately 7kW to deliver a total flow rate of 3 litres/ second. The total heat energy output from the well was dependent on the total flow rate, the delivery temperature and the return temperature. With the current configuration, it was shown that a 2km system would achieve a delivery temperature of 69°C. Using the assumed return temperature of 40°C, the well would deliver 363kW with a 7kW input: an equivalent COP of 52. The supply and return temperatures are therefore key in maximizing the energy that can be abstracted from the well. The return temperature will depend on the building requirement and how that is managed. The supply temperature depends on a number of factors discussed below.

The data from the trial suggests that the principal factor that governs the performance (delivery temperature and duration) of the single well is the ratio between the velocity and volume of water inside the pipe to that outside the pipe. The faster the velocity of the water inside the central pipe, the greater the delivery temperature and the shorter the delivery time. However, the faster the velocity of water outside the pipe, the quicker the delivery temperature drops off with time. The extreme example of this is when the well is run at 100% bleed. The velocity inside the central pipe is at a maximum but there is no water flowing down the outside of the pipe. The highest delivery temperature is therefore maintained when the system is in full bleed mode.

The amount of bleed flow is very important when managing delivery temperatures and duration. The higher the bleed flow, the better the system performance and delivery temperature. Bleed flow will consistently need to be used in periods of peak demand.

The total thermal output can be improved by increasing the flow rate in the well. This could be achievable, depending on the rest water level in the well and the subsequent drop in water level during higher pumping rates. Although this would increase initial delivery temperatures, the faster velocity of the fluid moving down the outside of the pipe could cause a more rapid decrease in delivery temperature and therefore bleed flow would need to be deployed more often.

The data shows that during periods when the well is not bled, the delivery temperature is highly dependent on the depth at which the water enters the central pipe. There is clearly a trade off though between cost of drilling, installation depth and, for now, limitations on the pump inlet temperature.

The results also show that temperature degradation in the well is relatively insensitive to the amount of energy that is removed at the surface. This implies that a system with a lower return temperature e.g. 25°C (achieved through using a high temperature heat pump on the return flow), could provide more than 400kW of energy without impacting the well temperature at depth. This system will be trialled on a future project.

5. FUTURE MARKET SCALE AND ROLL OUT

There are around 30 million buildings in the UK today, with 170,000 new dwellings constructed each year. Heating for buildings makes up around a third of total energy demand in the UK, of which over 80% is met using gas-fired boilers, with electricity and heating oil making up most of the rest.

District heating networks make up around 2% of the UK's total heat supply, with nearly all of these also supplied by gas boilers and CHP engines. (DECC)

Although the DGSW system could serve a very broad segment of the market for heat, the most suitable applications are likely to be small to medium campus or estate-type developments including blocks of flats, universities, health care facilities and residential institutions.

Within these types, new buildings are more attractive than existing buildings. New buildings will have few planning and permitting issues, they can be designed to fit with the DGSW system and they are more likely to be driven towards low carbon solutions. Furthermore, although the system could work all across the country, the strongest commercial prospects are likely to be where temperature gradients in the ground are highest. UK deep ground temperature (at 2kms) variations (extrapolated from British

Geological Survey data) is shown in Figure 5. This highlights the parts of the country where deep geothermal wells are likely to be most cost effective.

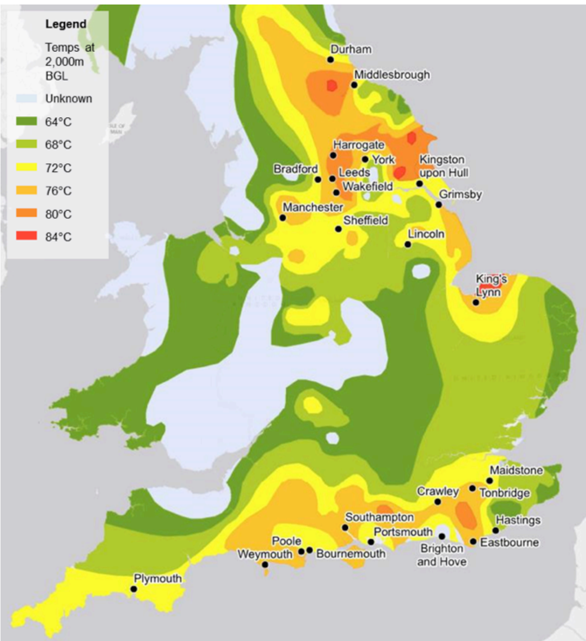

Figure 5 Inferred temperature at 2km depth in the UK

A total of 45 local authorities (LAs) lie within hotspots (i.e. have an average temperature at 2km below surface level above 70°C). The table below lists those local authorities and average underground temperatures.

From this data we extrapolated an estimate for the total planned development for the 45 hotspot authorities (based on population ratios), then estimated the amount of heat required to serve these developments, and in turn the number of DGSW wells that would be needed to meet that demand entirely through deep geothermal heat systems. The result is a total potential of 732 wells over the next five years and therefore the market is considered to be substantive.

The scale of the potential roll out of this technology is such that a joint venture company has been formed between Geothermal Engineering Ltd and Ove Arup and Partners Ltd. The new company, Geon Energy Ltd (www.geonenergy.com), was formed in 2016 with the specific purpose of developing single well heat systems. The involvement of Arup, who have more than 3,000 staff in the UK alone is important to deliver deep geothermal at scale.

5. FUTURE PROJECTS

One of the first projects will be to develop a deep geothermal single well project to supply heat to a portion of the Jubilee Pool, Penzance (Figure 6). The pool is an iconic lido that has recently (May 2016) been re-opened after substantial restructuring. To attract more visitors to the pool and to assist the wider redevelopment of the area, adding geothermal heat to a section of the pool is viewed as a substantial benefit.

The deep geothermal work will be part funded by the European Regional Development Fund and the project aims to drill the well in early 2017. The project represents a very exciting opportunity to showcase deep geothermal energy in Cornwall/ the UK and the single well technology in general.

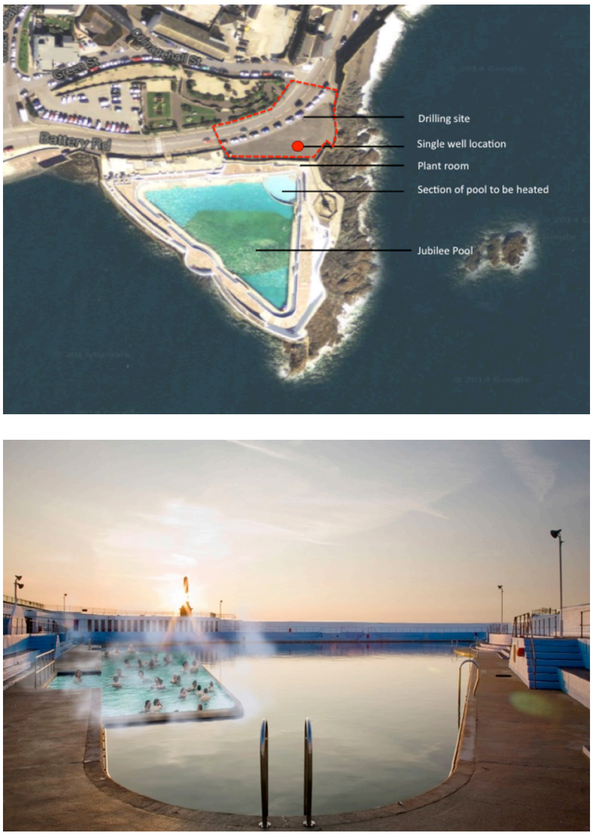

Figure 6 Jubilee pool location and future vision

At the other end of the UK, in Scotland, the Scottish Government released the 'Heat Policy Statement Towards Decarbonising Heat: Maximising the Opportunities for Scotland' (Scottish Government). This statement identifies that the supply of heat accounts for 55% of energy use in Scotland and is responsible for the largest source of carbon dioxide emissions (47%).

The Scottish Government is taking an aggressive stance on decarbonising heat with the aims to:

- decarbonise the heat system by 2050 to reduce greenhouse gas emissions;
- diversify sources of heat generation and supply to reduce reliance on fossil fuels and therefore support a resilient heat supply;
- reduce energy bills through reducing heat demand and providing affordable heat;
- seize the opportunities that this transformation offers through the development of new heat generation, distribution and demand reduction programmes.

Geothermal Engineering Ltd, Arup and St Andrews University recently completed a feasibility study for the Scottish Government (Low Carbon Infrastructure

Transition Programme) to install a high profile demonstrator deep geothermal single well at the new Aberdeen Exhibition and Conference Centre (Figure 7) to provide heat to both the Anaerobic Digestor unit and using the return flow to heat residential buildings nearby via ground source heat pumps (GSHP) as part of a low temperature heat network. The project is exciting for Scotland in that it could:

- Demonstrate that deep geothermal heat can be provided at low risk in Scotland;
- Provide a high profile showcase site for deep geothermal heat supply to commercial and domestic users;
- Benefit the immediate local community via return flow heating to dwellings;
- Provide much needed temperature and geological data from deep on-shore drilling

The location can also help to establish skills and commercial cross over and supply chain links between the deep geothermal industry and the oil and gas industry in Aberdeen.

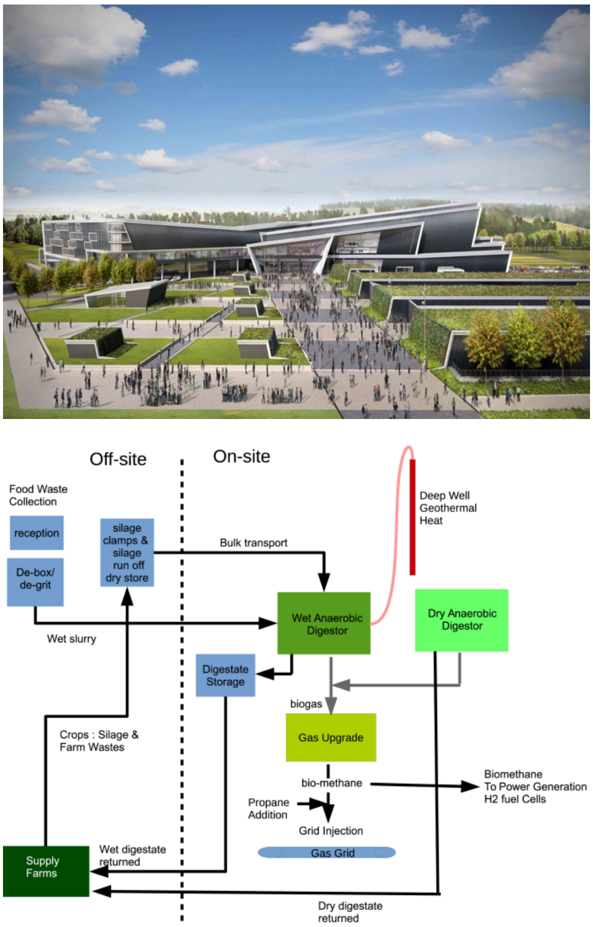

Figure 7 The new Aberdeen Exhibition and Conference Centre and the proposed integration with the AD unit

6. CONCLUSIONS

The Deep Geothermal Single Well system (DGSW) has been developed to kick-start the geothermal heat sector in the UK. It addresses a number of challenges that are unique to the United Kingdom.

The system was extensively field trialled in 2014 in an existing deep well in Cornwall. The results showed that, if managed correctly, the system can deliver circa 400kW with a 7kW electrical pumping input.

Further variations and development of the initial design are planned to improve the thermal output at subsequent sites.

Following on from the trial, a joint venture company has been formed between Geothermal Engineering Ltd and Ove Arup and Partners to roll out the technology in the United Kingdom – Geon Energy Ltd. Two high profile demonstrator projects are planned for 2017 in Cornwall and Scotland with further commercial opportunities to follow.

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