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Unlocking the UK Geothermal Resource Base

Charlotte A. Adams[1], Richard J. Williams, Nadia S. Narayan, Catherine Hirst and Jon G. Gluyas

[1]Durham University, Dept. of Engineering, South Road, Durham, UK, DH1 3LE

c.a.adams@durham.ac.uk

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ABSTRACT

The UK's geothermal resources were evaluated during the 1980s yet focused solely on Mesozoic sedimentary basins and radiothermal granites. Subsequent investigations have focused on the electricity generation potential of UK geothermal resources even though their relatively low temperatures means that they are best suited to supply heat. This aligns well with the UK's need to decarbonise heat and improve energy security by reducing reliance upon gas imports. Since these earlier evaluations, the UK geothermal resource base has been extended by looking beyond the granites and sedimentary basins to include lower temperature and more novel sources of geothermal fluid such as water contained within flooded abandoned mines, produced water from oil fields and water flowing though deeply buried karst. These enigmatic resources could help to de-risk geothermal energy developments thereby unlocking increased geothermal potential across many regions of the globe.

The Earth's geothermal gradient means that forecasting how temperatures will increase with depth is relatively straightforward. Predicting the permeability at depth is more complex, yet sufficient permeability is key to successful geothermal energy developments. In this paper we evaluate recently identified geothermal resources, present a rationale for their use and assess their contribution to the UK resource base. Although with very different provenances, these systems are all known to flow water. They include tepid water within flooded abandoned mines which underlie the many towns and cities that grew from the strength of their coal reserves, co-produced waters increasingly produced from ageing hydrocarbon wells both offshore and onshore and karst systems that are buried deep enough to provide a geothermal target. The examples we present allow us to increase both the spatial distribution of geothermal resources and the heat in place over and above that which has been previously identified.

1. INTRODUCTION

The Earth's subsurface presents regional-scale opportunities for energy storage and supply. In non-tectonic temperate regions, at depths of around 10m below the Earth's surface, temperatures remain a constant 10°C year round and increase by 25-35°C per kilometre of depth. The Earth is effectively a huge thermal store warmed constantly by heat emanating from radioactive decay at its mantle and crust and remnants of heat produced during its formation some 4.5 billion years ago. The geothermal heat potential stored within the upper 5 km of the earth has been estimated as 1.40 x 10^8 EJ (WEC 1998). Less than 1% of this resource has been developed yet 78 countries report using a combined total of 4.3 x 10^5 TJ direct geothermal heat (IGA 2015). The top 10 producers of direct geothermal heat globally are shown in Figure 1. Although huge potential remains, existing developments are not insignificant and offset around 46.2 million tons of oil equivalent annually (Bertani, 2016).

For temperate regions the generation of heat generally accounts for around half of the overall energy demand. The UK, remains heavily reliant upon burning gas to produce heat and it is essential to find alternatives in order to meet carbon reduction targets. Decarbonising heat is challenging due to the magnitude and amplitude of both daily and seasonal demands and these cannot be wholly met by transferring heat demands directly onto the electricity network.

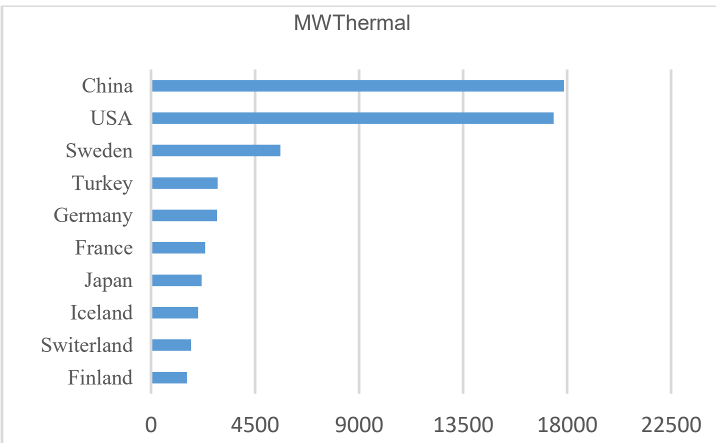

Figure 1: Ten leading global producers of geothermal direct heat

Fluid flow is key in developing geothermal systems because fluids have a key role as energy carriers that convey heat from source to surface. Temperature increase with depth is relatively easy to predict using the prevailing geothermal gradient; for the UK, this results in a temperature increase of around 35°C per km (Busby, 2010). Predicting porosity, transmissivity and hence flow at depth is not as straightforward and is difficult to constrain using currently available geophysical prospecting methods. These factors greatly contribute to the high upfront risk and capital cost associated with drilling deep (>1km) wells and is stifling deep geothermal development especially in countries that have no government supported risk insurance schemes for deep drilling. Risks are further compounded for lower temperature heat only wells rather than those that produce heat and electricity because the latter is more portable than heat and provides an additional revenue stream. The Earth's subsurface contains naturally occurring rock formations and manmade infrastructure that has the potential to store and transmit the water and by virtue, the heat it contains. These natural formations include deeply buried sediments and radiothermal granites. The challenge is to find sufficient permeability at depth to deliver sufficient flows at surface for energy extraction. Despite the huge potential, there is a lack of information about the UK subsurface at depth and this has also limited geothermal developments in the UK. Younger (2014a) advocates creative thinking when it comes to global geothermal prospecting, and we also take a more strategic approach to de-risk the low enthalpy geothermal potential of the UK by focusing upon developing systems known to flow water. This thinking has stimulated research into geothermal resources associated with manmade infrastructure such as water within flooded abandoned mines (Adams *et al.*, 2019, Gluyas *et al*., 2018), produced water from petroleum fields (Auld *et al.*, 2014) and water within buried ancient cave (karst) systems (Narayan *et al*., 2019). It is interesting to note all of these "lower risk" resources were originally excluded from previous UK geothermal resource assessments made in the 1980s yet they have the potential to increase the available resource over and above that originally identified and reduce the risk associated with its development.

2. ASSESSING THE UK RESOURCE

The 1973 oil crisis and concurrent miners' strikes left the UK dealing with an energy crisis manifested as energy shortages and enforced blackouts. The UK government's response was to commission research and development programmes into alternative energy sources including geothermal (Schimacher, 1985). The UK geothermal programme ran from 1977 to 1994 (Busby 2010) and resulted in seven deep wells being drilled. Authors such as Bott *et al.* (1972), Oxburgh (1976), Burley *et al.* (1984) Downing and Gray (1986) and Rollin (1987) produced seminal works on the UK's geothermal potential associated with radiothermal granites and deep sedimentary basis. Downing and Gray (1986) report the geothermal energy potential of seven Mesozoic basins as potential sources of direct geothermal heat and radiothermal granites as potential targets for hot dry rocks (HDR) to produce electricity. The total resource identified in these studies are shown in Table 1. 845 EJ of energy was potentially available from Mesozoic Basins and HDR (Busby, 2014). Subsequent to these reviews further assessment of UK geothermal potential were undertaken by SKM (2012) and Atkins report (2013). These did not add much to the original resource assessments and were focused on electricity production whereas the UK resource is best suited to heat production.

Table 1: Results of UK geothermal resource assessment (Downing and Gray, 1986)

Resource Type	Resource Available (EJ)
HDR	380
Mesozoic Basins	465
Total	**845**

Despite the potential identified in the 1980s, the adversity experienced by the nation during the energy crisis was quickly forgotten and the UK did not develop its geothermal resource except for the well drilled at Southampton. This was developed by a forward thinking accountant, Mike Smith. This well intercepts geothermal brines at 72°C at a depth of 1.8 km and supplies around 2 MW of heat to a range of customers. Despite the success of this scheme it has yet to be replicated elsewhere in the UK. However, nearly half a century after that initial work, the UK geothermal resource is again being considered however upfront capital cost and risk of drilling wells that do not flow and the fact that the value of hot water is far less than an equivalent volume of fossil fuel thwarts the development of geothermal projects.

3. LOW ENTHALPY AND ULTRA LOW ENTHALPY GEOTHERMAL SYSTEMS

Geothermal resources are classified by their reservoir temperature as high (above 150ºC) or low (below 150ºC) enthalpy (Nicholson, 1993). These divisions are somewhat arbitrary and not universally agreed upon but the key point is that away from tectonic settings most regions have access to low enthalpy geothermal resources which presents opportunities for decarbonising energy supply. It would seem logical to provide a further subdivision between low enthalpy resources where heat can be used directly and what we define here as ultra low enthalpy i.e. where ambient temperature is below the temperature of application and a heat pump (or similar) must be used to boost temperatures to meet demand. Table 2 also highlights the complexity of developing low enthalpy resources because the range of available energy conversion systems decreases as source temperature declines.

Table 2: Energy conversion opportunities for different grades of geothermal energy (low-high taken from Younger 2014b)

Ultra low temperature (<40°C)	Low temperature (<85°C)	Moderate temperature (85-150°C)	High temperature (>150°C)
Heat pump	Direct use (heat)	Direct use (heat)	Flash steam power plants
	Heat pump	Binary power cycles	Binary power cycles
			Dry steam plants

4. GEOTHERMAL POTENTIAL OF FLOODED ABANDONED MINES

Coal mining was an important industry within the UK, although dating back to the 1700s (Fretwell, 2011), the most recent and intense period of coal mining occurred between the early 1800s and 1920s. During the period 1913 to 2013, 15 billion tons of coal were extracted from the UK subsurface. Peak production occurred in 1913 when around 287 million tonnes of coal were produced (Coal Authority, 2018). Figure 2 shows the gradual decline in coal output and its coincidence with political events (mainly strikes), technological interventions (development of diesel and electric trains) and competition with cheaper imported coal from Russia and Poland. Around a century after peak coal, the end of deep coal mining in the UK was marked by the closure of Kellingley Colliery in 2015. In May this year the UK celebrated reaching a two-week period where coal was not used to produce electricity. This represented the longest period that the country had gone without burning coal since the 1880s.

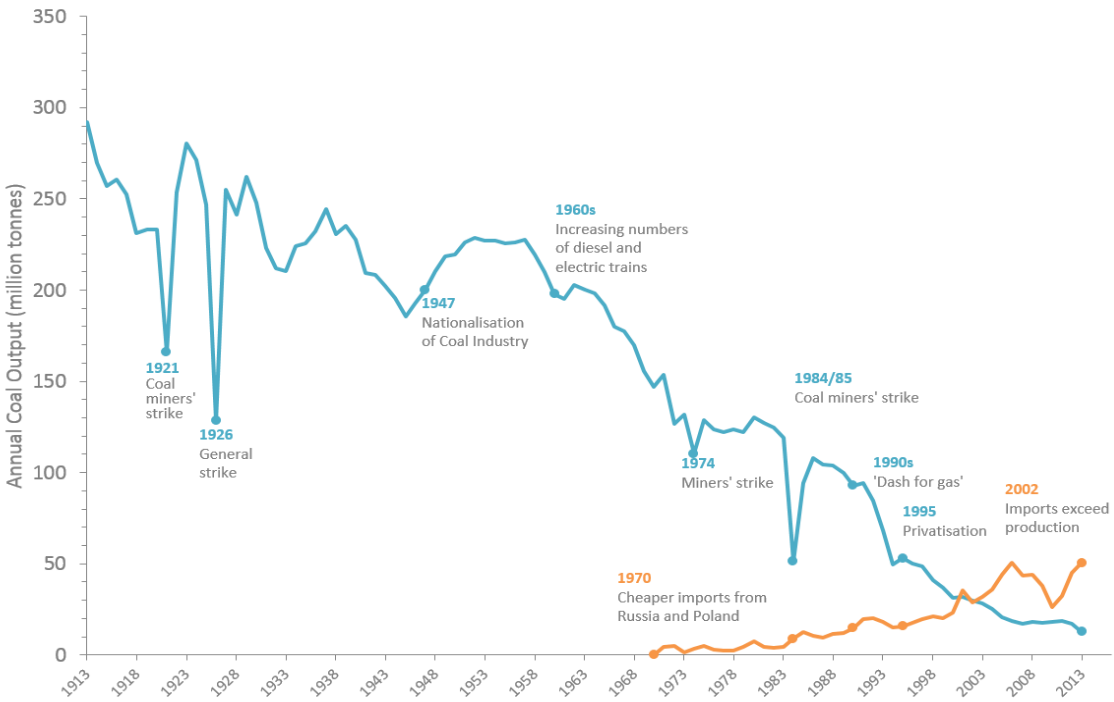

Figure 2: UK Coal output since 1913

Deep mines were usually dewatered to gain access to coal reserves, meaning that copious quantities of water were continuously pumped to keep pits dry. Following mine abandonment, pumping ceases and water levels begin to rise. Over a period of a few decades, mines flooded with groundwater and unchecked, minewater threatened to emerge at surface through shafts or adits and potentially pollute surface watercourses or water supply aquifers (Younger, 1993; Burnside, 2016 and Banks *et al*., 2003). To avoid this, the UK Coal Authority manages several sites across the UK, where water is continuously pumped from deep mines to control water levels. At these sites, depending on quality, minewater may or may not be treated before discharge at surface. Cumulatively, the water pumped from abandoned mines across the UK is estimated to contain around 80MW of heat that is currently unused and dissipates to the atmosphere. 25% of the UK built environment overlies worked coalfields and could relatively easily access this source of geothermal energy. Development of mine energy systems generally requires drilling boreholes to access and return minewater following heat extraction. Abstraction and re-injection wells generally access deeper and shallower seams respectively and prevent short-circuiting where re-injected water is removed at the abstraction well before it has had time to become reheated as illustrated in Figure 3. There are also other configurations possible for mine energy systems using single wells or existing shafts or pumped discharges employing closed or open loop models of operation (Athresh *et al*., 2015; Burnside *et al*., 2016).

The greater the flow rate through an abandoned mine, the more heat that can be theoretically extracted for a given decrease in temperature. Coal mines normally have high volumes of water flowing through them, often observable at gravity drainage points such as at Page Bank in County Durham which constantly flows water at 14°C at rates of around 220 l/s. Flow of heat and water will occur both through the workings and from the external unworked rock mass into the open voids. Mine waters are typically warmer than average surface temperatures due to their depth (Burnside *et al*., 2016). Even moderately shallow workings up to 100m depth may still deliver relatively warm waters, approximately 13-14 °C (Banks *et al*., 2004). Clearly these temperatures require boosting to be appropriate to meet space heating and hot water demands and this is achieved using a heat pump. It is important to note that, the deeper the target seam for abstraction, the greater the capital cost for drilling and the greater the running costs will be. The electricity consumption associated with lifting water should not be so great as to negate the carbon benefits associated with using a heat pump.

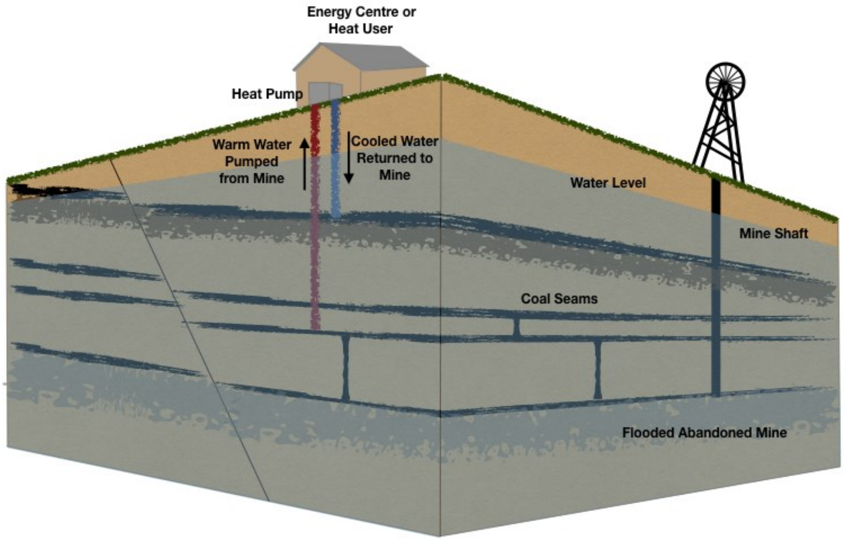

Figure 3: Block diagram of mine energy system

In addition to considering mine geometries, water temperature and flow rate it is also important to consider water quality for any open-loop mine energy system. Dissolved iron in groundwater may precipitate and foul components of the groundwater-exchange loop, reducing the flow of water and increasing the maintenance requirement on the heat pump system (Bailey *et al*., 2013; Banks, 2012). Coal mine waters typically contain dissolved iron and sulphate as a result of pyrite oxidation/breakdown in the exposed workings, along with carbonates from the surrounding geology (Banks *et al*., 1997). On exposure to oxygen in the atmosphere, the iron precipitates from solution forming ochre, which may be visible in watercourses that receive untreated mine water or spoil heap drainage. Raw mine water may still be used (and has been used successfully) in open-loop systems (Verhoeven *et al*., 2014), providing that atmospheric contact is minimised and pressure is maintained to prevent degassing.

4.1 Examples of Mine Energy Systems

A review of current literature suggests that minewater is used at around 21 sites globally for heating or heating and cooling. These systems are based upon a range of configurations and operated at a range of scales (considering thermal output) from a few kW e.g. Caphouse Colliery, UK (Burnside et al., 2016) to over 1MW such as the Robert Müser project in Germany (Bracke and Bussmann, 2015). The earliest mine energy systems have been in operation since 1992 and 1994 in USA and Canada respectively demonstrating that the concept of using minewater as a heat source is not new since. The Springhill system was commissioned in 1994 at the Ropak packaging plant in Springhill in Nova Scotia, where a minewater heat pump system uses minewater at 18°C to provide heating and cooling for the 13,500m^2 site. This lead to huge savings in avoided fuel-oil costs and the system paid for itself within 5 years (Jessop *et al*., 1995).

The Heerlen project in the Netherlands provides 700kW of geothermal heat from two hot water (30 - 35°C) wells sunk to a depth of 700 m, into the coal workings below the development (Hall et al., 2011). The abstracted mine water is circulated around the site, directly to heat pump plants which use heat exchangers to extract heat from the mine water and provide heating to office buildings and blocks of flats (Verhoeven et al., 2014). The abstracted mine water is not allowed to come into contact with the atmosphere prior to reinjection via a "cool-water" well, preventing the build-up of scale and ochre. The Heerlen project is a primary example of a successful mine water heating network, and highlights the need for sealed system when directly using mine water.

The range of operational projects also shows that mine energy systems are relatively bespoke that highlights the versatility of mine energy systems for varying applications and scales. However, this may also provide a barrier to development as it is difficult to take a "one size fits all" approach which adds complexity to making generalisations in relation to capital, and operational costs.

4.2 Calculating the Resource Potential

To assess the potential of this resource, it is necessary to obtain abandonment plans from the Coal Authority, for seams within the collieries worked and then use these to calculate the worked areas and seam thickness. The large scale extraction of coal from the subsurface leaves voids that remain long after mine abandonment. Yet these voids will not remain exactly as they were at abandonment. Shafts were often filled with rubble from the demolished topside colliery infrastructure before being capped rendering many of no value for future water pumping. The floor of galleries may "heave" and roof material may collapse leading to tunnels with partial blockages along their length. The amount of remnant void space depends upon the method of deep mining employed. Early 'room and pillar' mining involves working a grid leaving pillars of coal intact for roof support and mining the areas between. Room and pillar mining was later replaced by longwall mining (first developed in Shropshire in the 17th Century) as a more efficient means of removing coal.

Many areas formerly mined by room and pillar method were latterly reworked using longwall extraction. Longwall mining involves driving tunnels to the furthest extent of the mine then removing coal from the seam laterally whilst retreating from the workings. As longwall mining proceeds the overburden above the seam subsides producing "goaf" (collapsed waste). The consequences of this are; an area mined by room and pillar methods can be assumed to have around 50% of the original void space remaining and for longwall mining around 20% of the original void space remains (Younger and Adams, 1999). These voids in effect have created an 'anthropogenically-enhanced aquifer' from which heat can be extracted from or re-injected to the large water volumes existing within the mine workings. For the entire UK, the coal extraction figure of 15 billion tons was used to calculate an equivalent void space that was then reduced by 50% to allow for post closure subsidence. The abandoned mines that currently underlie around one quarter of UK homes are estimated by the Coal Authority to contain around 2.2 million GWh or 7.9 EJ of heat.

5. GEOTHERMAL POTENTIAL OF PETROLEUM WELLS

Total world oil production peaked in mid 2004 (Hook *et al*., 2009) and half of global crude oil production is produce from around 100 largely old petroleum fields (Sorrell et al., 2012). Oil industry produces hot water and the potential for "dual play production" where petroleum and hot water are both valued as energy sources is gaining interest (Davies and Michaelides, 2009; Cheng *et al*., 2013; Wight and Bennett, 2015 and Lui *et al.*, 2018). Water cut increase as oil production depletes and can dominate total fluid production, particularly where water is injected at the periphery of the field or beneath the oil bearing horizon (Gluyas and Swarbrick, 2013). Hot water can be used offshore to produce electricity (Auld *et al*., 2014) or onshore for direct heat (Hirst *et al*. 2015).

Most oilfields globally are now in their decline phase with production weighted decline rates of around 5% per year (Hook et al., 2009). Anything that adds value to oilfield operations can defer abandonment. This can include changing market forces (such as increased oil price) but more often some form of investment is required, especially for technical interventions. One example of such an intervention is enhanced oil recovery (EOR) where gases or fluids are re-injected through wells back into the oilfield to drive out previously unswept oil (Latil, 1980). This technique has the potential to substantially increase reserves (Sorrell et al., 2012). The exploitation of geothermal energy which is the focus of this paper, offers a further technical intervention that could be concomitant with oil production and other interventions (such as EOR) and has the potential to defer abandonment. Two UK Onshore petroleum fields have been considered for their geothermal potential and are reported below. More recently the authors have considered the Beatrice field which is offshore Scotland but within relative striking distance of land.

5.1 East Midlands Oil Province

The East Midlands oil province covers an area of approximately 15,700km^2 and comprises over 30 separate fields. Oil has been produced since 1919 when oil was discovered within Carboniferous (Dinantian) limestones within an anticlinal closure. Available well records and production data have been used to provide information on the flow rates potentially available from Upper Carboniferous strata and highlight the potential for extracting economic volumes of geothermal fluids from Carboniferous strata (Hirst *et al.*, 2015).

To estimate the resource size, temperatures taken directly from well logs must first be corrected to reflect true formation temperature. Bottom Hole Temperatures (BHT) are commonly recorded during the drilling process but are typically lower than expected due to circulation of drilling fluids leading to underestimation of resource. Gathering true formation equilibration temperatures requires that the well remain undisturbed for anywhere between several months to several years (Majorowicz et al. 2004). Clearly this is impractical and several methods exist to correct suppressed temperatures, including the Horner method of correction which was applied to the East Midlands dataset using the methodology laid out in Hirst et al., 2015 (after Deming, 1989).

Table 3 From Hirst *et al*, (2015)

Field ID	Field Area (km^2)	Production Rate m^3/yr		Geothermal Resource (MW$_t$)	Output at 80% Load Factor (GWh)
		Oil	Water		
Beckingham	12.3	44729	9259	0.1	0.71
Bothamsall	0.7	30299	5821	0.07	0.47
Cold Hanworth	2.6	8471	56536	0.23	1.6
Corringham	1.5	20493	1281	0.03	0.24
Crosby Warren	2.0	15483	0	0.02	0.17
East Glentworth	1.0	4733	1234	0.01	0.08
Egmanton	6.3	17637	59108	0.25	1.8
Farley's Wood	1.0	5787	62	0.01	0.06
Fiskerton Airfield	0.4	21720	16074	0.09	0.7
Gainsborough	12.3	44940	3845	0.08	0.56
Glentworth	1.8	6785	3204	0.02	0.16
Keddington	7.3	6024	2658	0.02	0.13
Kirklington	0.4	451	2150	0.009	0.06
Long Clawson	1.2	10373	19303	0.09	0.63
Nettleham	0.6	17027	34257	0.16	1.1
Rempstone	1.2	3160	6947	0.03	0.22
Saltfleetby	9.1	-	4246	0.02	0.12
Scampton	0.5	2466	127	0.004	0.03
Scampton North	1.0	34838	8423	0.08	0.6
South Leverton	0.7	9075	4351	0.03	0.21
Stainton	0.9	3128	43	0.005	0.03
Welton	5.1	176734	166850	0.91	6.36
West Beckingham	N/A	3122	337	0.01	0.04
West Firsby	1.2	6853	79846	0.32	2.26
TOTAL	71			2.6	18.3

Twenty One (21) fields had associated temperature data; nineteen (19) of these fields contained data that could be assessed and corrected using the Horner correction method. An average temperature correction factor was calculated to be 3.3°C, which was then applied to the remaining two fields that did not satisfy the criteria for temperature correction. All temperature gradients were created using a standard temperature of 10°C at ground level, and where possible used a temperature measure in both Permo-Triassic and Carboniferous strata. Temperature measurements in the depth range 0-300 m (i.e. within Permo-Triassic sediments) were treated with caution given the potential suppression of temperatures due to past glaciation and palaeo-topography (Westaway & Younger, 2012). Below 300m, temperatures recover to follow the regional gradient, and as such are not seen as having a major effect on the temperature gradients calculated in each field, considering BHT are within Carboniferous sediments; a linear relationship can be used to determine the gradient. The latter method of temperature gradient derivation uses data from down-hole temperature logging tools. These data were only available for five fields, but likely provide a more robust way to estimate the gradient across the field as the tool used is temperature specific.

The difference in average between the two methods indicates with relatively good certainty that the margin of error associated with these measurements is reasonable. Twenty three (23) fields have associated production data. These data were assessed for both oil and water production. Peak production rates have been identified in each field and are noted in Table 3. The data that has been presented here assumes temperatures at 1500m depth will be 47°C (assuming an average temperature gradient of 31.5°C/km), and a temperature drop (ΔT) of 30°C has been used giving an average reinjection temperature of 17°C.

Production from the East Midlands oilfields is declining associated with increasing water cut and a decline in reserves. Using peak production rates to estimate geothermal potential is justified because these figures show what the field is capable of producing with regards fluid volume, and is not limited to oil only. The total calculated thermal resource for the oilfields in question is 2.6 MW (Table 3). This value is a conservative estimate because data were only available for 23 of the 30 fields in the province. Also the resource estimate focused on oil-bearing strata only and therefore does not account for any intervening strata that may be non-oil bearing yet water saturated. In the case of the Welton oilfield, an additional estimate of produced water from such intervals almost doubles the amount of heat available for extraction (Hirst et al., 2015).

Hot water produced from oilfields only is an undervalued commodity within the oil industry. Currently co-produced water is disposed of or re-injected; the heat contained within extracted water is unused. The additional profit from selling heat from co-produced water could extend the tail-end field life of oilfields. In addition, the infrastructure provided by producing fields significantly reduces the investment required for geothermal scheme to be implemented. The risks usually associated with a new geothermal scheme can be significantly reduced when co-managed with an existing oilfield and temperatures and flow rates from these fields would be compatible with horticultural uses such as glasshouses (Hirst et al., 2015).

5.2 Wytch Farm, Dorset

Wytch Farm in Dorset was discovered in the 1970s and is currently the second largest onshore oilfield in Western Europe occupying an area approximately 18 km long by 3 km wide. Oil is produced from Jurassic and Triassic deposits comprising the Wessex Basin. It, was originally discovered in 1973 and was developed and produced by British Petroleum (BP) and the Gas Council. Wytch Farm is now operated by Perenco. The site operates discretely within an Area of Outstanding Natural Beauty (AONB). The overarching structure is an east-west trending gently dipping anticline divided into blocks that dip northwards following the development of extensional faults during the Early Cretaceous (Hogg et al., 1999). The field extends offshore to the east and comprises three separate reservoirs: Sherwood (Triassic), Bridport and Frome (Jurassic). Peak oil production plateaued between 1996 and 1998 at around 0.53 million m^3 per month, while total fluid production peaked in 2003 at around 1.45 million m^3 per month (1.2 million m^3 water 0.25 million m^3 oil). The majority of the oil produced has been extracted from the Sherwood Sandstone Group which is approximately 150m thick (McKie *et al*., 1998) and comprises medium to fine-grained sandstones with permeability controlled by cementation, detrital and authegenic clay content the amount of feldspar dissolution together with sorting and grain size distribution (Zheng *et al.,* 2009). Zheng attributed the high net to gross productivity of the reservoir to the well-connected sand bodies which form the reservoir.

Water is associated with various oilfield structures at Wytch Farm both as residual water within the oil leg and groundwater present within the aquifer beneath the oil-bearing horizon (Worden *et al*., 2006). As oil production has declined, water production has increased and the water cut now exceeds oil production ten-fold (Figure 4). The produced water is a combination of original connate water and that injected to maintain reservoir pressure and promote oil sweep. Although wells operating with higher water cuts may still be economic, operating costs increase due to increased power consumption associated with pumping increasing quantities of water.

Using public domain data from wells producing in 2000 (OGA, 2019), the 43 operational wells at Wytch farm had an average water cut of 54% with water cuts varying between minimum and maximum values of 1 and 96% respectively. Cumulative monthly production from the entire oilfield for 2013/2014 is shown in Figure 4 with current water cut at around 94% at over 120 million m^3 per month. This water is currently re-injected into the formation to maintain reservoir pressure. The average flow from the Wytch Farm oilfield is 0.9 million m^3 per month (353 l s^{-1}) with a temperature of 66°C.

The recoverable heat from the hot brine to cold water stream using heat exchangers has been estimated at 35 MW assuming a pinch point temperature of 5°C (this value determines the size of the heat exchanger). Using oilfield production water at 66°C and recovering 35 MW would raise the temperature of the sea water cooling stream to 61°C. The value of the recovered heat needs to be balanced against the power consumption and capital cost of the circulation pump required to flow 353 l s^{-1} through the system, a smaller pump may be less costly but flow rates and recoverable heat would be reduced.

To put the potential at Wytch Farm into context, it should be compared with the UK's only geothermal heat network at Southampton. The Southampton geothermal scheme is located some 70km from Wytch Farm and delivers heat (1.7 MW thermal) to a heat network that also includes a gas-fired combined heat and power plant. Geothermal fluid at Southampton is delivered from a borehole drilled 1800 m into the same Sherwood Sandstone Formation that Wytch Farm exploits. The flow of water at Wytch

Farm is around thirty times greater than that at Southampton albeit at a slightly lower temperature (66°C as opposed to 72°C). Wytch Farm lies between about 5 km and 10 km south west of the Poole and Bournemouth urban areas and the potential heat supplied from the co-produced water could support around 19,000 homes, far outweighing the geothermal component of the Southampton scheme.

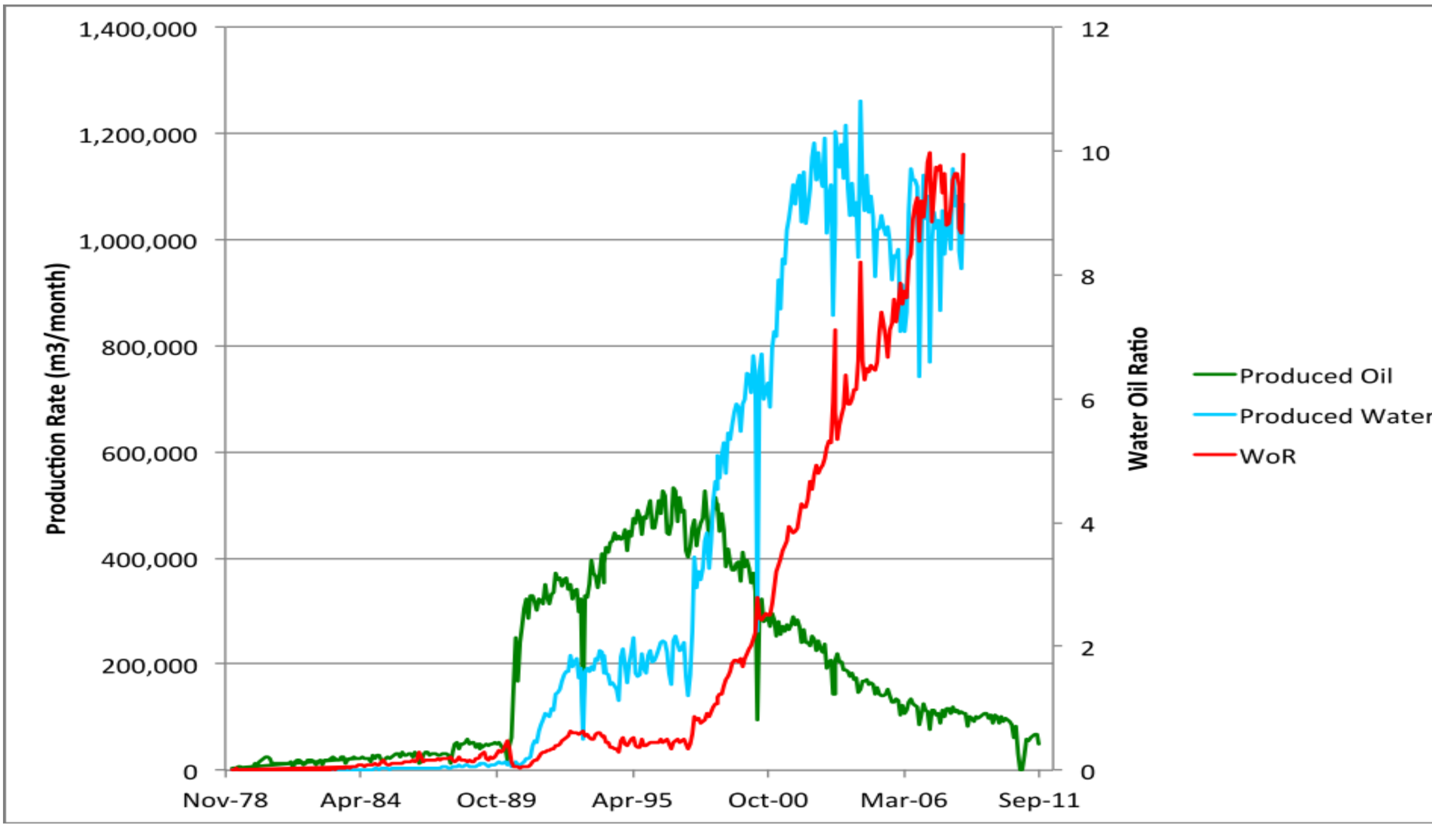

Figure 4 Production data for the Wytch Farm Oilfield (OGA, 2019)

5.3 Beatrice Field

The Beatrice field lies offshore in the Moray Firth of the North Eastern coast of Scotland (UKCS Block 11/38) around 22 km from the mainland at the East Caithness cliffs in a water depth of around 45m. The Beatrice field was discovered in the mid 1970s by MBSA petroleum, oil production peaked in 1985 at around 300,000m^3 oil per month. The life of the field was extended in 2009 with the development of the adjacent Jacky field. The Beatrice field was in production from 1981 until March 2015. The crude oil from the Beatrice Alpha production platform was exported to the mainland via a 67 km submarine pipeline that makes landfall at Shandwick. From here, the crude travelled a further 9 km via a buried onshore pipeline to the Nigg oil terminal.

Permission for cessation of production at the Beatrice Field was granted in 2014 as continued production was deemed economically unviable. The decommissioning report states that field life extension options were investigated and were all found to be sub-economic, however, it provides no detail as to what these options were (Repsol Sinopec, 2017). Any reuse option will likely be a constrained by the nature of and timescale for field decommissioning. The current schedule for decommissioning Beatrice lies within the window 2024 to 2027.

Field data were provided from the publicly available Oil and Gas Authority database (OGA, 2019). During its 34 years of production, the Beatrice field produced around 27 million m^3 of oil (170 million barrels of oil). Peak output was achieved in the mid 1980s when production reached over 300,000 m^3 of oil per month. From this point, oil production gradually declined reaching 768m^3 per month. The field ceased production in 2015 (Figure 5).

Production and injection data, indicate that a flow rate of 500,000m^3 of water per month is likely to be a sustainable abstraction rate. This equates to a flow rate of 0.186 m^3/s or 186 l/s. The temperature of the produced water was noted to have a temperature of 80°C (Gluyas and Hichens, 2003). These flow and temperature figures were used to calculate the heat potential of the resource.

The geothermal potential of the Beatrice field was assessed by assuming that the original pipe will be used to supply hot water rather than installing a purpose built insulated pipe. In this way we are considering a worst case scenario in terms of transmission losses whilst minimising capital cost. The main oil export line comprises a 0.4m diameter crude oil export line that conveys oil from the platform to the mainland at Shandwick. It then travels a further 9km to the Nigg oil terminal. The pipeline is buried to a depth of 1 m above the pipeline, increasing to 3 m as the pipeline approaches land. It is lined with an anti-corrosion coating of glass fibre reinforced enamel and asbestos felt with a concrete outer coat. 59 km of the subsea section was replaced in in 2001. This section was epoxy coated with no concrete coat and was installed adjacent to the existing section which remains in situ (Repsol Sinopec, 2017).

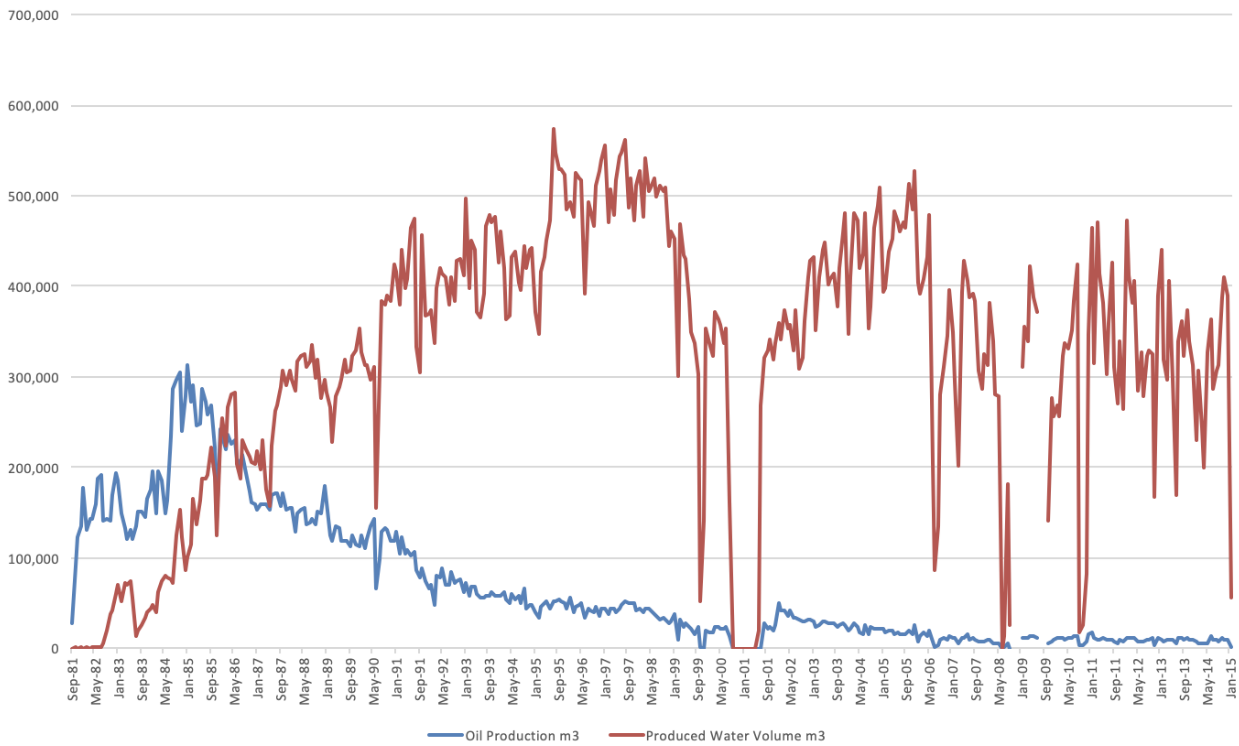

Figure 5 Production data for the Beatrice Field (OGA, 2019)

To model drop in temperature as fluid flows from well to land, the pipe was treated as discrete 1km sections calculating the loss in each section with the outlet temperature from each section providing the input for the next section. It was assumed that the pipe is steel coated with enamelled glass fibre and that it is a standard schedule 40 pipe insulated with the same thickness of glass fibre. It was also assumed that the concrete cover is 50mm thick along the entire pipe length and that the seabed is saturated sand. This method will be refined in future to improve accuracy and accommodate changes in pipe construction, burial depth or seawater temperatures along the length of the pipe. Using the assumptions listed above and an ambient seawater temperature of 5°C, this method revealed that the water temperature where the pipe makes landfall will be 64°C which means it could provide a valuable source of direct heat.

Table 4 Heat Potential of the Beatrice Resource

Flow (kg/s)	*Energy (kW)*	*ΔT (°C)*	*Annual (KWh)*	*Annual (MWh)*	*No of Homes*
186	2343.6	3	20529936	20530	1369
186	3906	5	34216560	34217	2281
186	7812	10	68433120	68433	4562
186	23436	30	205299360	205299	13687

These calculations show that there is enough heat for between 1300 and 13687 homes if 3°C or 30°C were removed from the ambient water from the Beatrice Field respectively (Table 4).

6. GEOTHERMAL POTENTIAL OF CARBONIFEROUS KARST

Karst is generally found in carbonate terrain that has been shaped due to the dissolution of carbonate rocks via the action of carbonic acid and water. It is characterised by limestone pavements, caves, sinkholes and subterranean water features. Key factors that influence karst development include the calcium carbonate content that needs to be at least 70% and a temperate tropical to sub-tropical climate. Other factors that promote karst formation include high soil CO_2 concentrations, high rainfall and percolation rate in conjunction with periods of exposure at surface, the presence of a fracture network, plus steep gradients and changes in relief which facilitate runoff and hence dissolution (Ford, 2007). During the Carboniferous period, the UK occupied equatorial latitudes whilst limestone deposits were forming. England and Wales have karstic limestones exposed at surface and at depth, this study identified additional potential areas of buried karst or fractured units south of Leeds and North of Shrewsbury (Figure 6).

Karst is of interest as a potential geothermal target because in the UK, most thermal springs are associated with the fractures and karst in Carboniferous limestones. Elevated temperatures of around 44-45°C have been found at Bath, combined with appreciable flow rates of 1296m^3 per day. This provides a tantalizing glimpse of a potentially deeper and hotter geothermal source. Further evidence that karst sequences can flow fluids was provided by the UK's first oil well: Hardstoft1, which struck oil at 953m within Carboniferous limestone and produced 28,000 barrels (around 4,500m^3) (Craig *et al*., 2014).

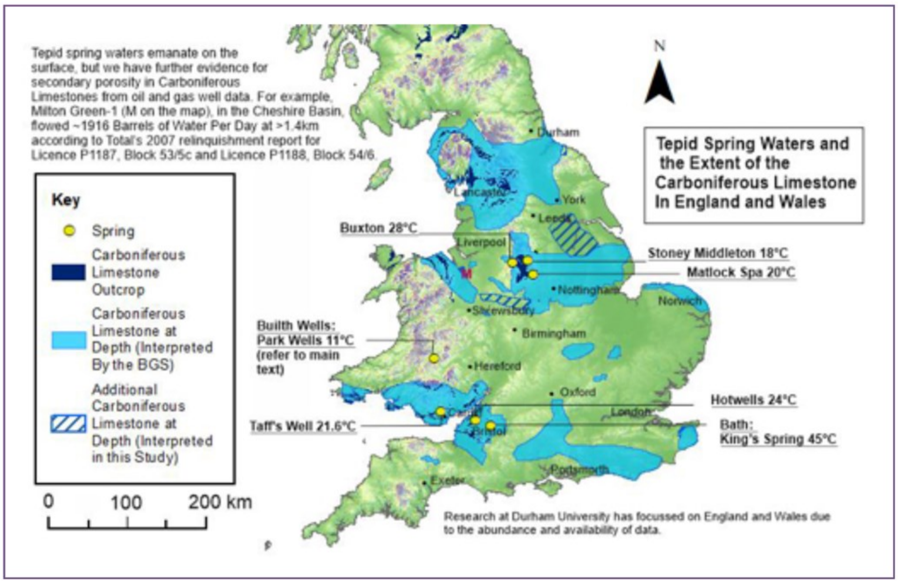

Figure 6 Map showing distribution of exposed and buried karst in England and Wales (Source: Narayan *et al*., 2019)

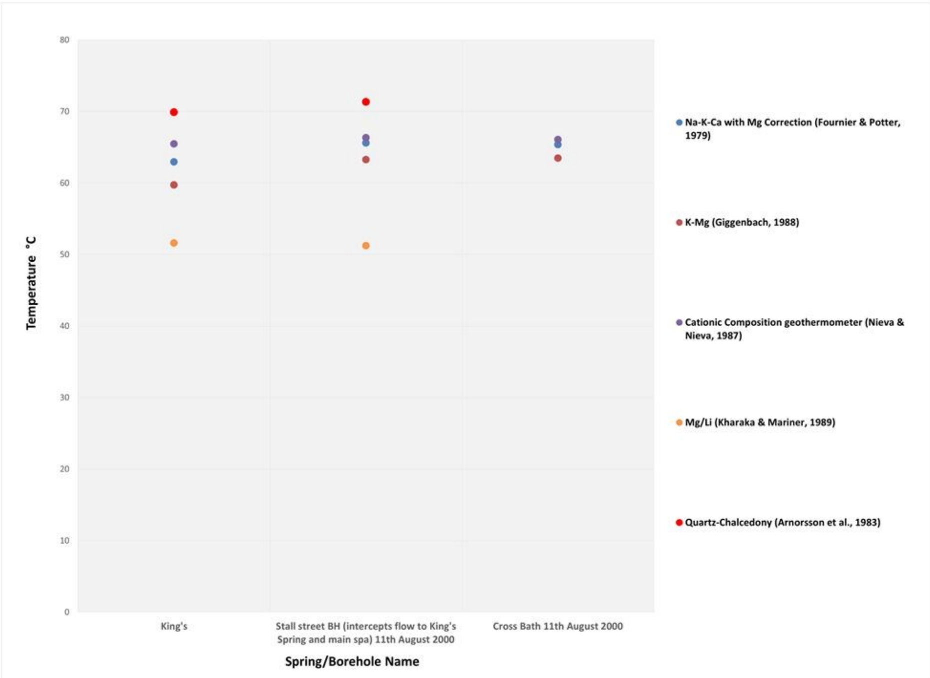

Figure 7 Plot showing geothermometry results for three Bath spring waters

Research into the UK's geothermal potential associated with karst is ongoing and has included inspecting seismic profiles and well logs to identify Carboniferous unconformities that might indicate buried karst (Figure 6). This has been combined with geothermal prospecting for a range of spring waters from across the UK. Various authors have created geothermometry indicators as a way to determine the equilibrium temperatures of spring waters at depth. This involves applying a set of empirical formula to a measured dataset. Here, these have been applied to the Bath Spa waters famously known as the hottest spring waters in Britain emanating at temperatures of 44-45°C (Gallois, 2007).

These waters are thought to cycle through spring pipe structures relating to a karstified surface formed during the Triassic (Gallois, 2006). For Bath Spa, five different geothermometers are applied: Na-K-Ca with Mg correction (Fournier & Potter, 1979), K-Mg (Giggenbach, 1988), a cationic composition geothermometer (Nieva & Nieva, 1987), Mg-Li (Kharaka & Mariner, 1969) and Quartz-Chalcedony (Arnorsson *et al*., 1983). Na-K and Na-Li indicators have been excluded from the plot as they skew the results and appear to provide inconsistent results depending on which author's empirical equation is used for example there is as much as a 60°C temperature difference between two different Na-Li indicator results. The two indicators are sourced from different authors.

On the other hand, the indicators listed previously are more reliable as they are within a more limited range despite being different indicators from different authors and for different cation-anion ratios. It should also be noted that a high calcium content has been observed to result in anomalous results in Na-K geothermometers (Fournier & Truesdell, 1973). This has been observed here and is the basis for excluding the results calculated from these. Figure 7 depicts the geothermometry for King's Spring, the borehole that intercepts this spring and Cross Bath Spring. Equilibration temperatures indicated are between 51°C and 71°C. Preliminary analysis using this method in PHREEQC (in conjunction with AquaChem) corroborates that which is calculated by the empirical formulae above; 53°C to 81°C. However, this excludes parameter estimate for CO_2 degassing and mixing, for example, all of which can alter results.

Excluding buried karst already identified by the British Geological Survey, the area of buried karst considered in the current study has been estimated at around 6250 km^2 in the Leeds area and 1250 km^2 in the Shrewsbury area. In their comparison of the main exposed karst regions of Britain (Yorkshire Dales, Northern Pennines, Peak District, the Mendip Hills and South Wales, Waltham et al. (1997) cite formation thicknesses of 200 m, 40 m, 400 m, 700 m and 150 m respectively, taking the average value gives a thickness of 298 m. Bulk porosity and transmissivity data for karst systems are likely to be highly variable and data are sparse however Xianzheng et al. (2015) calculate that the porosity of intraburied-hill karst reservoirs in the range of 1.0% to2.0% and 4.0% to 5.0%, with permeabilities of 0.01 to1 mD. Table 5 shows the estimated potential geothermal resource associated the with two areas of buried karst identified above for porosity values of 1 and 4% and temperature drops of 5°C and 10°C. For the higher porosity values and temperature drop, the resource is around half of that contained within UK abandoned coal mines.

Table 5 Estimated geothermal potential for areas of buried karst identified

Location	Area km^2	Rock Volume Km^{3*}	Heat from 1% porosity ΔT=5°C (EJ)	Heat from 4% porosity ΔT=5°C (EJ)	Heat from 1% porosity ΔT=10°C (EJ)	Heat from 4% porosity ΔT=10°C (EJ)
Leeds	6250		0.39	1.56	0.78	3.12
Shrewsbury	1250		0.08	0.31	0.16	0.62
		Totals	**0.47**	**1.87**	**0.94**	**3.74**
			Heat from 1% porosity ΔT=5°C (GWh)	Heat from 4% porosity ΔT=5°C (GWh)	Heat from 1% porosity ΔT=10°C (GWh)	Heat from 4% porosity ΔT=10°C (GWh)
Leeds	6250		1.08E+05	4.33E+05	2.17E+05	8.67E+05
Shrewsbury	1250		2.17E+04	8.67E+04	4.33E+04	1.73E+05
		Totals	**1.30E+05**	**5.20E+05**	**2.60E+05**	**1.04E+06**

*Assumes formation thickness of 298m

+Assumes a burial depth of at least 1km where fluid temperatures could be expected to be around 25-35°C.

7. RESULTS AND DISCUSSION

Table 6 shows the resources added to the UK inventory through some of our recent research. Around 8EJ of additional resource has been identified It is interesting that these additional geothermal resources more recently identified in coal mines, petroleum wells and buried karst are all hosted by Carboniferous strata which has historically been excluded from previous assessments but could again deliver rich resources in the form of low carbon heat. Geologists are trained to prospect for and quantify resources such as groundwaters, fuels, minerals and aggregates however we often become constrained by the complexities associated with their development. With particular reference to low enthalpy geothermal sources, temperatures may appear too low to be useful or distances for heat transmission too great. It is here we must work with engineers to turn resources to reserves, if we highlight the potential technology can be developed to harness it which promotes innovation and new business opportunities.

Table 6 Revised geothermal potential including additional UK resources

Resource Type	GWh	Resource Available (EJ)
HDR	1.1×10^8	380
Mesozoic Basins	1.3×10^8	465
Abandoned Mines	2.2×10^6	7.90
Onshore Petroleum	310	1.81×10^{-3}
Karst	1.3×10^5	0.47
Total	2.4×10^8	853

This has been demonstrated by developments in power cycle technology culminating in a reduction in the temperatures from which power can be generated from hot water to 72°C (Pikra *et al*., 2015 and Holdmann and List, 2007). Future efforts to lower this temperature further through research into improved working fluids serves only to increase potential reserves. Similarly for heat transmission, the development of vacuum insulated heat network pipes (Berge *et al*., 2015) and the development 4th generation (Lund *et* al., 2014) and 5th generation heat networks (Vivian *et al*., 2018) allow much lower temperatures to be used and a significant reduction in energy losses. In addition to the identification of resources and engineering solutions the heat transition will also require policy drivers and social acceptance.

8. CONCLUSIONS

Anthropogenic activity in extracting fossil fuels from the subsurface has ironically left a legacy of voids many of which now contain water that can be recovered to provide a future energy source long after closure of the original mine or petroleum field. For abandoned mines, two centuries of intensive coal extraction in the UK, has left a flooded underground asset that contains around 2.2 million GWh of heat. By re-using this infrastructure we not only honour the effort that was expended during its creation but also de-risk geothermal developments by developing systems known to flow water and hydrocarbons.

In the case of petroleum fields, the energy density of hydrocarbons far outweighs that of geothermal fluids, the benefits of combining the two systems in increasing the probability of success can be appreciated. Use of co-produced water from hydrocarbon extraction does provide an interesting route to de-risking geothermal exploration (by reducing both drilling costs and geological uncertainty) while simultaneously improving the economics of the oilfield itself. This is because the longevity of aging hydrocarbon fields is controlled by the economics of income from hydrocarbon sales versus the cost of running the operation that may increase as production declines. Falling or lost margins typically precipitate abandonment of fields. Revenue income from selling heat, or electricity most of which will come from the co-produced water, will reduce the effective operating costs and so lead to an extension of field life and hence better recovery of non-renewable oil resources. This could extend field life essentially indefinitely but with a switch of revenue from oil to water production.

Buried carboniferous karstified limestones also offer geothermal potential and by combining geophysical techniques, onshore well data and geothermometry of springs we combine this information in a new way to prospect for geothermal resources.

Though these more recently identified resources are dwarfed by the potential that exists in Mesozoic basins and HDR, the fact that they are potentially less risky to develop means that they serve to increase the UK's geothermal resource base, and by offering reduced development risk, could offer a important bridge to increase the uptake of low enthalpy geothermal for the UK.

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