Proceedings World Geothermal Congress 2020+1
Reykjavik, Iceland, April - October 2021

Repurposing Hydrocarbon Wells for Geothermal Use in the UK: a Preliminary Resource Assessment

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Keywords: UK, Deep Geothermal, Oil and Gas, Well Repurposing, Country Wide Assessment of Geothermal Potential Resources

ABSTRACT

One future opportunity in the development of geothermal energy in the UK is that of repurposing onshore hydrocarbon wells for the production of geothermal energy and storage. This paper presents an overview of an EPSRC National Centre for Energy Systems Integration (CESI) research project to investigate the most favourable candidate sites for geothermal repurposing of onshore hydrocarbon wells in the UK, taking into consideration the range of technological options available and the range of thermal energy output from a repurposed hydrocarbon well. To facilitate this study, a GIS mapping model integrating the onshore hydrocarbon well data with the UK's potential geothermal resource was generated. This model has integrated data such as: location, depth and operational status of all onshore hydrocarbon wells, measured and estimated bottom hole temperature data for hydrocarbon wells and the extent, depth and thickness of aquifers across the UK. Of the 2242 onshore hydrocarbon wells in the UK, 621 wells have the potential to be repurposed as they are categorised as completed (operational), completed (shut in), plugged, under abandonment phase one or abandonment phase two. Of these, optimal candidate wells include those in fields such as: Wareham and Wytch Farm in the Wessex Basin, and Caythorpe and West Newton in the East Yorkshire and Lincolnshire Basin, amongst others.

1. INTRODUCTION

Geothermal energy exploration is driven by the need to produce low carbon renewable energy, which is becoming increasingly important in the energy mix of the United Kingdom (UK), particularly given the need to address the energy "trilemma"; being able to provide a sustainable, equitable and secure energy supply. Geothermal energy has the capability to address each of these issues and its associated technologies are low carbon, clean, green, sustainable and do not suffer from the intermittency problems experienced by other renewable energy sources such as wind and solar (Younger, 2015; Gluyas et al., 2018a).

The UK Climate Change Act (2008) delivered a binding commitment to reduce emissions of greenhouse gases by 80% by 2050. In June 2019, the UK Government amended this legislation and set a revised target of achieving net zero greenhouse gas emissions by 2050. Offshore wind and photovoltaic electricity production continue to deliver success stories. However, the UK Committee on Climate Change (Bell et al., 2016) stated that only decarbonization of heating in the UK could deliver the major reduction in emissions needed to meet the 2050 target.

In the UK, heat represents around 45% of total energy demand. Around 28% of energy is used on an annual basis for space heating. This heating demand is dominated by the use of gas in the UK, where 62% of the total gas consumption is for domestic heating and cooking and a further 18% is used by industry (BEIS, 2019). With summer 2018 being the joint hottest on record in the UK, low carbon energy cooling systems may also soon be in high demand. Agriculture is another large energy consumer and greenhouse gas emitter and is exposed to fluctuating energy prices. Geothermal heating and cooling can thus play a key role the decarbonization of energy supply in the UK.

One potential opportunity is that of repurposing onshore hydrocarbon wells for the production of geothermal energy and storage. As presented by Hirst and Gluyas (2015) and Hirst et al. (2015) for the East Midlands Petroleum Province in the UK, repurposing hydrocarbon wells for geothermal energy could make a significant contribution to meeting the heat demand of local housing stock, or commercial agricultural uses. The current UK regulatory framework does not contemplate geothermal co-production from existing hydrocarbon wells, or their retrospective repurposing for geothermal use; once hydrocarbon production ceases, wells must be plugged and abandoned by the operator. If ad hoc regulations are developed in the future, there is the potential for reusing existing energy infrastructure to provide sustainable, low-cost heat from these hydrocarbon wells. In this study, it is assumed that regulations will be changed in future, recognising the added value of reusing existing energy infrastructure to provide sustainable, low-cost heat. The substantial volumes of co-produced water present many opportunities, such as electricity generation, direct use of heat by nearby users, district heating and cooling, industrial heating and cooling and combined heat and power generation. Use of the co-produced water in this way has the potential for reducing operational expenditure (OPEX), extending the life of the hydrocarbon field, improving ultimate hydrocarbon recovery and delaying decommissioning liabilities. In some cases, it may be possible to re-complete abandoned oil & gas wells as single-well, closed-loop geothermal wells (Westaway, 2016; Falcone et al., 2018). The wealth of infrastructure, expertise and subsurface data that exists within the onshore hydrocarbon sector in the UK stands as a formidable tool and asset to be used in the development of low-carbon energy resources such as geothermal energy.

This paper presents an overview of key findings of an EPSRC National Centre for Energy Systems Integration (CESI) research project to investigate the most favourable candidate sites for geothermal repurposing of onshore hydrocarbon wells in the UK based upon established practices in the petroleum sector.

2. GEOTHERMAL ENERGY IN THE UK

There are a number of deep onshore sedimentary basins in the UK in which the thickness of sedimentary (and thus, likely, porous and permeable) water bearing, rock exceeds 2km (Gluyas et al, 2018a). The age of these basins is typically older (upper Palaeozoic) in northern England and Scotland and younger (Mesozoic) in the south of England. In addition to the sedimentary basins, the UK also hosts suites of radiothermal granite batholiths, which are also a target for geothermal energy projects. The extent and location of the UK's potential geothermal resource is shown in Figure 1.

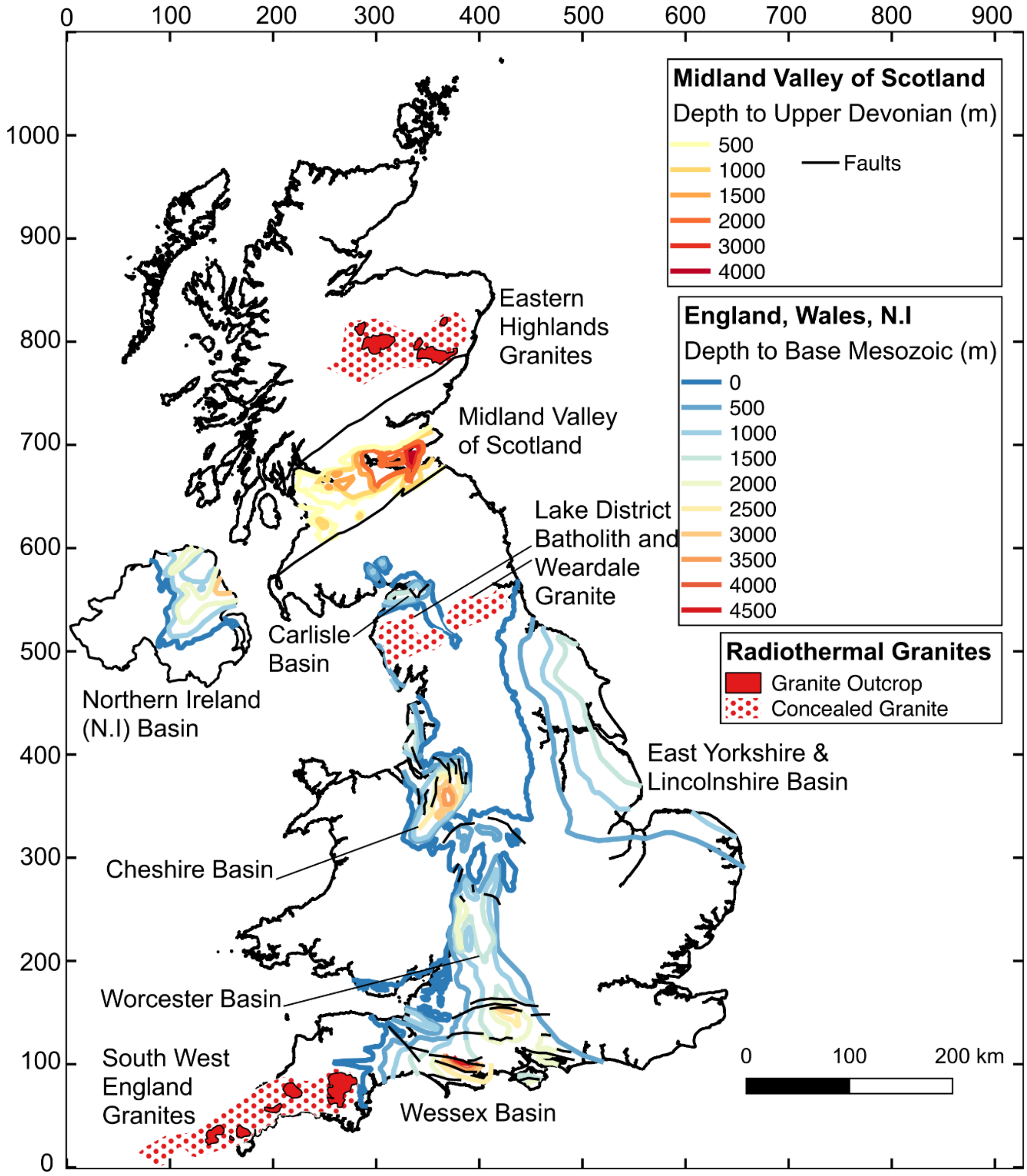

Figure 1: Geothermal resource map of the UK showing potential geothermal resource in radiothermal granites and sedimentary basins. Reproduced from Downing and Gray (1986). British National Grid coordinates (north and east) are in 100 km intervals.

The investigation of the geothermal energy potential of the UK began in the 1970's as a consequence of the global oil crisis and at a time when the petroleum resource offshore of the UK had largely been undiscovered. Based upon the preliminary studies conducted in the late 1970's, seven deep geothermal exploration boreholes were drilled, although these were not completed until 1980-1985 by which time the UK had become a petroleum exporter (Gluyas et al., 2018a). Three of the boreholes, located at Marchwood and Southampton in southern England, and Larne in Northern Ireland, were drilled and tested to investigate the geothermal potential of the Permo-Triassic sandstones of the respective sedimentary basins. This programme of research was continued in 1984 with the drilling of the Cleethorpes-1 borehole in North East Lincolnshire. This borehole was drilled to a depth of 2100 m, the primary target being the Basal Permian Sands with a secondary target of the Triassic Sherwood Sandstone Group (Downing and Gray, 1986). In addition to the boreholes drilled in the aforementioned sedimentary basins, three further boreholes were targeted at radiothermal Variscan granite in Cornwall, South West England. While these boreholes, drilled at Rosemanowes, received much attention as part of the Hot Dry Rock Programme, none made it to production (Richards et al., 1991).

The borehole that can be considered successful, in that it led to an operational geothermal heat project, was that drilled at Southampton (Downing and Gray, 1984; 1986; Barker et al., 2010). Since 1987 this borehole has supplied water at 75 °C with thermal power of 2.2 MW, as part of the Southampton District Energy scheme, delivering heat and power to a hospital, university and commercial businesses in central Southampton (Barker et al., 2010).

After a two-decade long hiatus of geothermal exploration in the UK, in 2004 an exploration well was drilled at Eastgate to a depth of 998 m. The background to this project is summarised by Gluyas et al (2018a) and explained in detail by Manning et al (2007). The well encountered naturally fractured Weardale Granite as planned. The bottom hole temperature was 46 °C, indicating a heat flow of 115 mWm^{-2}. This well produced saline water at a temperature of 27 °C from a fractured zone at 411 m depth. The Eastgate-1 borehole proved capable of producing water at a rate of 140 m^3h^{-1} (39 ls^{-1}) per metre of drawdown. An appraisal well, Eastgate-2, was drilled in 2010 around 700 m from Eastgate-1 to determine whether the fractures were pervasive throughout the granite or were limited to the vicinity of a major fracture in the granite, known as the Slitt Vein. The granite at Eastgate-2 had the same geothermal gradient as at Eastgate-1, but also proved to be impermeable, confirming that the fracture permeability at Eastgate-1 is associated with the Slitt Vein.

A further geothermal exploration well was subsequently drilled in the city centre of Newcastle upon Tyne, named the Newcastle Science Central well. This reached a depth of 1.8 km. This well confirmed the high regional geothermal gradient however demonstrated that the Fell Sandstone in this locality is extremely ‘tight’, no useful rate of water production being feasible (Younger et al., 2016) although it has provided useful information about the shallow mine water geothermics of the area (Westaway and Younger, 2016).

The potential geothermal resource in Cornwall had not been investigated since the 1980’s. However, at the United Downs project site in Cornwall, drilling was completed in April 2019 for the UD-1 well to a depth of 5275 m (MD; 5057 m TVD), with a bottom hole temperature of 193 °C, and in June 2019 for the UD-2 well to 2393 m (MD) (e.g., UDDGP, 2019). This project, located in the Carnmenellis Granite ~7 km from the Rosemanowes site, is for an unconventional well doublet: the aim being generation of geothermal electricity with an electrical power output of 1-3 MW (e.g., Cotton et al., 2018).

In Scotland, in the Clyde Gateway Regeneration area of the east end of Glasgow, drilling of observational and monitoring boreholes has commenced at the Glasgow Geothermal Energy Research Field Site (GGERFS). This site is part of the Natural Environment Research Council (NERC) funded UK Geo-energy Observatory (UKGEOS) project. The objective of the GGERFS is to investigate the geothermal potential of the flooded, abandoned mine workings beneath this area of the city (Monaghan et al., 2017). Flooded, abandoned mine workings indeed present the “low hanging fruit” of the potential geothermal resource in the UK (Banks et al., 2019), however these projects require detailed examination of the connectivity of the flooded mine workings and quantification of the resource prior to development (Watson et al., 2019). Projects of this type in the UK will benefit from expertise obtained from existing projects in other countries, such as Germany (e.g., Ramos and Falcone, 2013).

Downing and Gray (1986) provided the first comprehensive nationwide assessment of geothermal potential for production of hot water from Permian and younger strata. Their work has formed the basis for reviews by SKM (2012) and Atkins (2013). Busby (2014) provided a summary of the geothermal heat resource potential for the UK, indicating a minimum potential of 200 EJ.

Despite the reported potential of geothermal energy in the UK, the high technical and economic risk at the exploration stage, as evidenced by the past investigations, currently acts as a significant barrier to development of the sector. One “low hanging fruit” of geothermal energy exploration in the UK lies in the potential resource in the aforementioned abandoned, flooded mine workings. A further “low hanging fruit” is to target well-characterised hydrocarbon reservoirs. Whether by utilizing data previously obtained from the onshore petroleum sector to characterize the geothermal resource, or the infrastructure by repurposing onshore hydrocarbon wells for geothermal energy production and storage, a substantial reduction in drilling risk and cost could be achieved. This could provide a vital boost to the fledgling geothermal sector in the UK.

3. REPURPOSING HYDROCARBON WELLS AND TECHNOLOGICAL OPTIONS

The geothermal potential of hydrocarbon wells has been investigated by several authors, with pilot projects already implemented worldwide and pre-feasibility studies carried out (e.g., Alimonti et al, 2014; Auld et al, 2014; Al-Mahrouqi and Falcone, 2016; Westaway, 2016; Singh et al, 2017; Gluyas et al 2018b; Liu et al, 2018). Although offshore hydrocarbon fields offer geothermal energy potential (e.g., Auld et al, 2014; Lefort, 2016; Gluyas et al, 2018b), it is likely that only electricity generation would be appealing in such remote environments and exclusively for in-project utilisation, unless interconnecting export grids become available (e.g. from Iceland). However, as presented by Hirst and Gluyas (2015) and Hirst et al., (2015) for the East Midlands Petroleum Province in the UK, an opportunity may exist whereby onshore hydrocarbon wells could be repurposed to provide geothermal heating which may make a significant contribution to meeting the heat demand of local housing stock or indeed commercial agricultural uses.

The UK has more than 2000 onshore petroleum exploration wells (compared with about 9000 offshore wells) drilled since the beginning of the twentieth century (Davies et al., 2013). Most of these were drilled in the petroleum provinces of the East Midlands and the Wessex Basin, with fewer drilled in the Midland Valley of Scotland and the Cheshire Basin. Onshore commercial drilling activity since the 1980’s has resulted in additional data being added to the UK’s dataset of subsurface temperature and heat flow measurements (Burley et al., 1984; Rollin, 1987). From assessment of the Oil and Gas Authority (OGA) onshore hydrocarbon well database, 873 wells terminate at a true vertical depth (TVD) of less than 1 km, 1096 between 1-2 km, and 149 greater than 2 km depth (OGA, 2019). This contrasts with the situation offshore in which most wells have been drilled to depths of around 3km and many in excess of 5km. However, given the regional geothermal gradients and heat flows within sedimentary basins in the UK, coupled with the need to produce renewable heat for direct heating applications, onshore hydrocarbon wells may be ideally suited for repurposing for geothermal energy production. In some cases, it may be possible to re-complete abandoned oil & gas wells as single-well, closed-loop geothermal wells (Westaway, 2016). The wealth of infrastructure, expertise and subsurface data that exists within the onshore hydrocarbon sector in the UK is a valuable asset to be used in the development of low-carbon energy resources such as geothermal energy.

There are a number of ways in which hydrocarbon wells could be used to harness their geothermal potential. For producing mature fields, hydrocarbon operations could continue, but with the inclusion of geothermal equipment and infrastructure as studied at the Wytch Farm (Singh et al., 2017; Liu et al., 2018) and Trecate-Villafortuna (Alimonti et al., 2014) onshore fields. The substantial volumes of co-produced water present many opportunities, such as electricity generation, direct use of heat by nearby users, district heating and cooling, industrial heating and cooling and combined heat and power generation. Use of the co-produced water in this way has the potential for reducing operational expenditure (OPEX), extending the life of the hydrocarbon field, improving ultimate hydrocarbon recovery and delaying decommissioning liabilities. Depending on the long-term infrastructure of the field and the regulatory framework, the hydrocarbon operator may eventually transfer a field to a geothermal operator. For abandoned exploration wells, or wells that have ceased hydrocarbon production there are a variety of technological options to enable the repurposing of the wells. The well could be re-drilled into deeper aquifer zones to enable some wells to be converted to geothermal producers and others to water re-injector wells. This option could likewise be used for aquifer thermal storage, and the structural/stratigraphic traps in permeable lithologies such as Carboniferous limestone would be a suitable target for this (Narayan et al., 2018). Another option is to drill multilateral slim holes from the existing or deepened well-bottom well-bottom to increase water withdrawal, as the original mother bore completions could host more water following the depletion of hydrocarbons.

An alternative to re-drilling the well is to re-complete the well to implement a closed-loop wellbore heat exchanger system (Alimonti et al., 2018; Falcone et al., 2018). This would be dependent on favourable geological conditions and the heat output requirements of the locality (Westaway, 2018). Application of this technology to suitable candidate wells would remove the cost related to drilling a new deep geothermal well. If required, enlargement of the near-wellbore region could be conducted to artificially enhance the downhole thermal properties (Falcone et al., 2018).

4. METHODOLOGY

Taking into consideration the range of technological options available and the range of applications of the thermal energy output from a repurposed hydrocarbon well, this study assesses favourable candidate sites whereby onshore hydrocarbon wells in the UK could be repurposed for geothermal energy production or storage. This is achieved through the following methodology:

1) Conduct a screening survey of potential candidate sites based upon a GIS mapping exercise and database compilation of available public domain information on onshore hydrocarbon wells in the UK, the deep geothermal potential of the UK and regional heat demand.
2) Select case studies and conduct a resource assessment of the potential geothermal resource at the site.
3) Conduct a Decline Curve Analysis (DCA) of well/field production rates to extrapolate geo-fluid production over time to determine P10-P50-P90 probability range of recoverable heat resources over an assumed project lifetime.

5. SCREENING SURVEY

Starting from public domain datasets, the first objective of this study was to conduct a screening survey of candidate hydrocarbon wells which have the potential to be repurposed for geothermal energy production. However, as discussed in Westaway et al., (in review), the UK currently has no dedicated mapping tool or mechanism to assess the potential geothermal resource at any location in the country in a similar vein to ThermoGIS (www.thermogis.nl) in the Netherlands (Van Wees et al., 2012; Vrijlandt et al., 2019). Also, there has been no attempt so far to apply the United Nations Framework Classification for Resources (UNFC) to the UK; the UNFC is the only international standards for the classification and reporting of oil and gas, mineral resources, nuclear fuel resources, renewable energy, injection projects and anthropogenic resources. Furthermore, the UK's National Heat Map used to match energy supply points to areas of energy demand was decommissioned in April 2018. Thus, to facilitate this study and conduct the mapping exercise of potential candidate sites, a GIS mapping model integrating the onshore hydrocarbon well data with the UK's potential geothermal resource and regional heat demand needed to be generated in its entirety. It was necessary to first outline the criteria to be assessed and the datasets required to be collected to enable this survey, which would then enable an integrated mapping model of the datasets to be built. The objectives of the screening survey were:

1) Determine the location and depth of each onshore hydrocarbon well in the UK.
2) Determine the operational status of each onshore hydrocarbon well in the UK as per the Well Operational Notification System (WONS) definitions in the UK (OGA, 2018).
3) Determine the age of the well based upon the drilling completion date.
4) Determine the type of hydrocarbon well (i.e. conventional oil and gas, coal bed methane, shale gas, mine gas, gas storage).
5) Obtain measured temperature data from hydrocarbon well records, if available.
6) Determine the extent and depth of potential geothermal aquifers in the UK to assess proximity to onshore hydrocarbon wells.
7) Obtain measured temperature data from the aquifers, if available
8) Determine regional geothermal gradients and heat flow across the UK to inform estimation of well bottom hole temperature and aquifer temperature, if measured data unavailable.
9) Determine hydraulic properties of aquifers which were intersected by existing/abandoned hydrocarbon wells.
10) Determine hydraulic properties of aquifers that could be intersected by re-drilling or recompleting the wells.
11) Determine heat demand near the screened well locations.
12) Assess repurposing technological options and applications.

5.1 UK Onshore Hydrocarbon Well Data Mapping: Method and Results

The OGA is the regulator of the oil and gas sector in the UK and holds the repository for onshore and offshore oil and gas related information. From the OGA online Data Centre, spreadsheet and GIS shapefile data relating to each onshore hydrocarbon field and well in the UK were collected. Considering the well data to begin with, as of January 2019, this included data such as: location, well registration number, well name, operator, license, well type, deviation, county, spud date, completion date, and intent. This data is available for all 2242 onshore hydrocarbon wells.

While the previously mentioned data were included in the spreadsheet and GIS Shapefile, data such as the depth of the well and operational status were not. To compile this data, individual searches of all 2242 onshore wells were made on the OGA's online public wellbore search tool, which allows the user to view profiles of each of the wells where the required data was found. From this, a complete database was compiled with all required OGA onshore hydrocarbon well data.

Following the compilation of this database, criteria could then be applied to select potential candidate sites. This included applying criteria based upon the depth of the well and the operational status of the well. The definitions of the operational status of each well are from the OGA's Well Operations Notification System (WONS) classifications and are as follows: completed (operational), completed (shut in), plugged, drilling, abandonment phase 1, abandonment phase 2, and abandonment phase 3 (OGA, 2018).

A well which is neither operational or fully abandoned is assigned one of four temporary status classifications in WONS (OGA, 2018). Completed (shut in) describes a well that is shut in either at the tree valves, or subsurface safety valve and this status is normally applied if the wellbore is intended to be shut in for 90 days or more. Plugged wells have been plugged with a plug rather than an abandonment barrier. For abandonment phase 1 wells, the reservoir has been permanently isolated and the well below the barrier is no longer accessible. Likewise, for abandonment phase 2, all intermediate zones with flow potential have been permanently isolated and the well below the barrier is no longer accessible. Wells defined as abandonment phase 3 are considered fully abandoned, where the wellhead has been removed and the well will never be used again.

For the purpose of the screening survey, wells of abandonment phase 3 status were therefore removed from the database. All other wells were considered as candidates for further assessment.

In addition to this, hydrocarbon wells with a true vertical depth (TVD) of less than 500 m were also disregarded, as this value reflects the regulatory definition of "deep geothermal" in the UK. Of the 2242 hydrocarbon wells, 278 wells have a TVD of less than 500 m and 124 wells do not have any depth data. One of the wells with no current depth data is the Stockbridge 25 well (well registration LQ/29- 30) which, as of June 2019, is currently being drilled. This well is included for further assessment. A screening of candidate wells based upon their age was not applied. In order to make an informed judgement on the well integrity of candidate sites, closer inspection of well completion diagrams would be required. This is more appropriate for an individual site by site assessment and not at a country wide level.

Once these criteria are applied, the total number of wells is reduced from 2242 to 621, as shown in Figure 2 and Table 1. Of these, wells with mechanical status completed (shut in) can be considered the highest priority for further investigation. These wells are approaching cessation of production but have not yet been plugged and abandoned. A window of opportunity exists during this time period for the operator and the authorities to engage in discussions to prolong the life of the well.

Table 2: Status of UK onshore hydrocarbon wells

Status	All Wells	Candidate Wells
Completed (Operating)	338	293
Completed (Shut In)	109	83
Drilling	1	1
Abandonment Phase 1	185	163
Abandonment Phase 2	63	61
Abandonment Phase 3	1520	0
Plugged	22	20
No Data	4	0
Total	2242	621

This Table summarizes the operational status of all UK onshore hydrocarbon wells and those selected as potential candidates for repurposing for geothermal energy production.

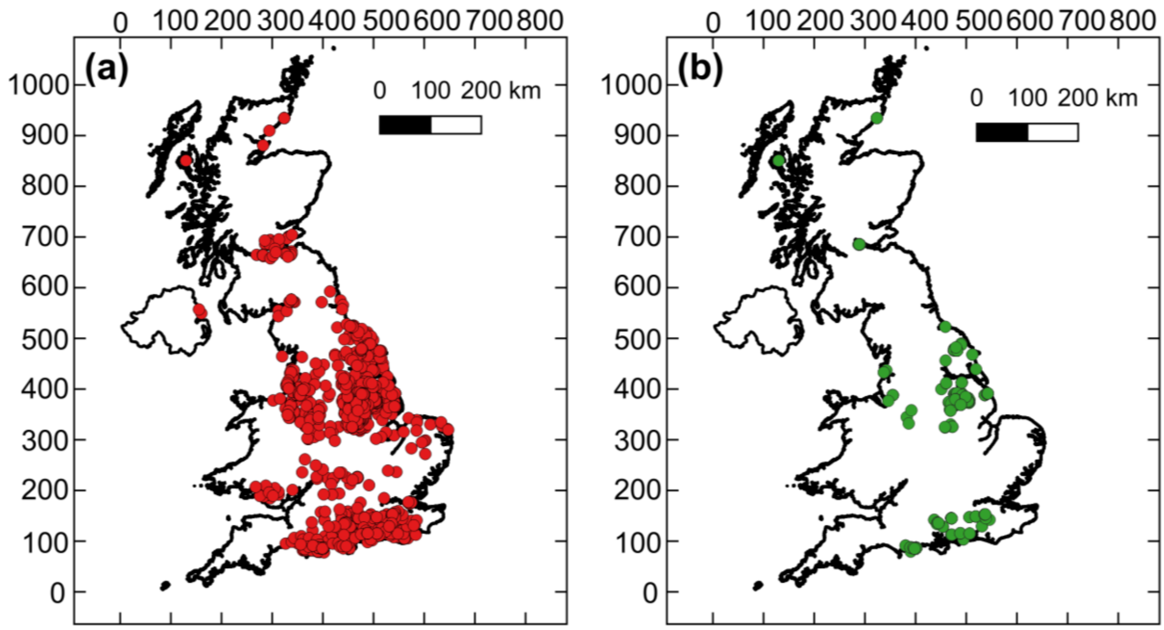

Figure 2: Location of all UK onshore hydrocarbon wells (a) and those selected as potential candidates for repurposing for geothermal energy production (b). British National Grid coordinates (north and east) are in 100 km intervals.

5.2 Aquifer Data and Mapping: Method and Results

As discussed in Section 2, a detailed investigation of the UK's potential geothermal resource was conducted in the 1970's and 1980's. This resulted in the publication of a series of reports and maps detailing the extent, depth and thickness of potential geothermal aquifers in sedimentary basins across the UK (Downing and Gray, 1986). In the absence of a UK equivalent to ThermoGIS, based upon the content of these reports and maps a GIS model of the extent, depth and thickness of these potential geothermal aquifers was generated across the UK. To achieve this, original paper copy and scans of maps from Downing and Gray (1986) were uploaded to the QGIS software (https://qgis.org/en/site/), georeferenced and then re-drawn in order to produce GIS Shapefiles of the extent, depth and thickness of each of the aquifers which may be targeted by hydrocarbon wells.

These aquifers include the Triassic Sherwood Sandstone, Basal Permian Sands (Yellow Sand Formation), Carboniferous Coal Measures, Carboniferous Limestone/Millstone Grit, and the Early Carboniferous-Late Devonian sandstones of the Midland Valley of Scotland. These aquifers were produced from maps at a basin scale (i.e. Cheshire, East Yorkshire and Lincolnshire, Midland Valley of Scotland, Northern Ireland, South Wales, Wessex Basin, and Worcester) as well as at a UK wide scale. Examples are shown in Figure 1, with the depth to the Upper Devonian sandstone aquifer shown at a basin scale for the Midland Valley of Scotland and the depth to the base of the Mesozoic at a UK wide scale.

At a UK wide scale, Downing and Gray (1986) mapped the extent and depth of the Mesozoic Basins across the UK where they are considered potential geothermal aquifers. Structure contours, as in Figure 1, indicate the depth to the base of either the Permian or Triassic aquifers where they are considered potential geothermal targets. In addition, these workers mapped the location and extent of "potential geothermal fields". These are defined as aquifers with mean temperatures in the range of 40-60 °C and 60-80 °C (Figure 3). As well as this, aquifers with a transmissivity of 5 and 10 Darcy Metres (Dm) were also mapped (Figure 4). It is important to note that while lower permeability aquifers may not be suitable for conventional hydrothermal production, they could be targets for single well closed loop systems.

By generating GIS Shapefiles of the extent, depth and thickness of each aquifer, in addition to GIS Shapefiles of the "potential geothermal fields" as defined by Downing and Gray (1986), the following can be achieved when overlain with the location of the candidate hydrocarbon wells:

1) Determine the depth and thickness of each aquifer at the location of each candidate hydrocarbon well site by using QGIS Triangulation Interpolation and Vector Geo-processing tools,
2) Determine which candidate wells have intercepted aquifers by comparison of the aquifer depth and the well TVD.
3) Determine which candidate wells can be re-drilled to intercept an aquifer by comparison of aquifer depth and the well TVD.
4) Determine which candidate wells are located in areas considered "potential geothermal fields".
5) Determine the temperature, transmissivity and depth of the aquifer in the "potential geothermal field" for comparison with the depth of the hydrocarbon well.
6) Determine which candidate wells either intercept lower permeability aquifers or do not have an aquifer present.
7) Based upon the outcome of (2), (3), (4), (5), and (6), determine potential repurposing options for the candidate hydrocarbon wells as detailed in Section 3.

As an example of the aquifer mapping output, Figure 3 shows the hydrocarbon wells which are drilled within the areal extent of Mesozoic and upper Palaeozoic basins where a potential geothermal aquifer is present.

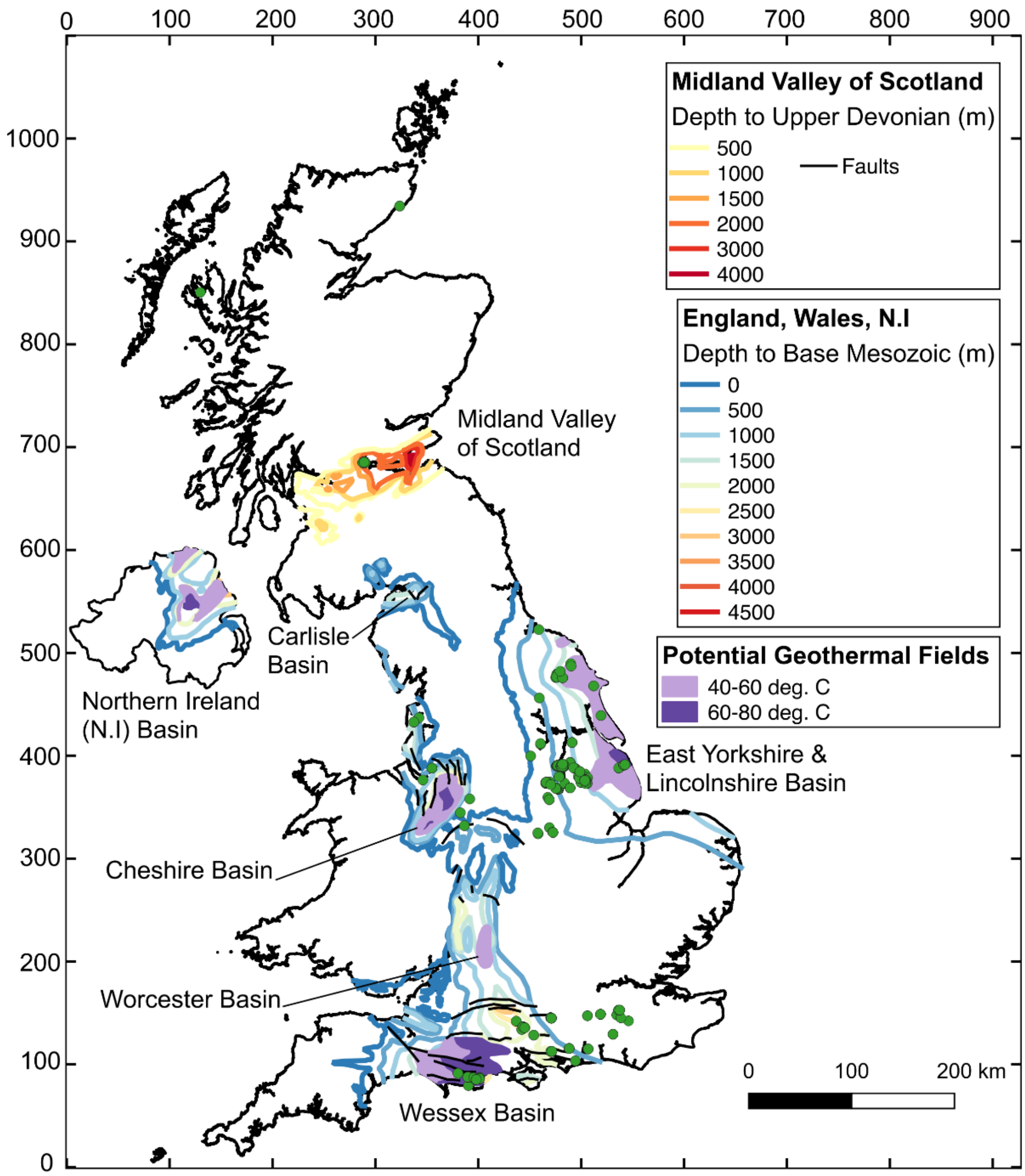

Figure 3: Aquifer map showing extent and depth of Triassic and Permian aquifers in England, Wales and Northern Ireland, and the extent and depth of the Upper Devonian aquifer in the Midland Valley of Scotland. Potential candidate wells overlain (green dots). Extent of "potential geothermal fields" also shown. Reproduced from Downing and Gray (1986). British National Grid coordinates (north and east) are in 100 km intervals.

Figures 3 and 4 show those candidate wells which coincide with the "potential geothermal fields" as defined by Downing and Gray (1986). There are 231 candidate wells located within "potential geothermal fields". Wells which are contained within these "hotspots" are wells from the Waddock Cross, Wareham and Wytch Farm fields in the Wessex Basin and Caythorpe, Ebberston, Keddington, Marishes, and West Newton fields in East Yorkshire and Lincolnshire. Figure 4 shows that in the Wessex Basin, all candidate hydrocarbon wells in the Waddock Cross, Wareham and Wytch Farm fields are contained within the zone where the Sherwood Sandstone aquifer is noted as having a transmissivity of 10 Dm and a temperature range of 60-80 °C. In the East Yorkshire and Lincolnshire basin, similar mapping output highlighted that wells at Keddington and Saltfleetby were in a zone where Basal Permian Sands has a transmissivity of 5 Dm and a temperature range of 40-60 °C and 60-80 °C respectively.

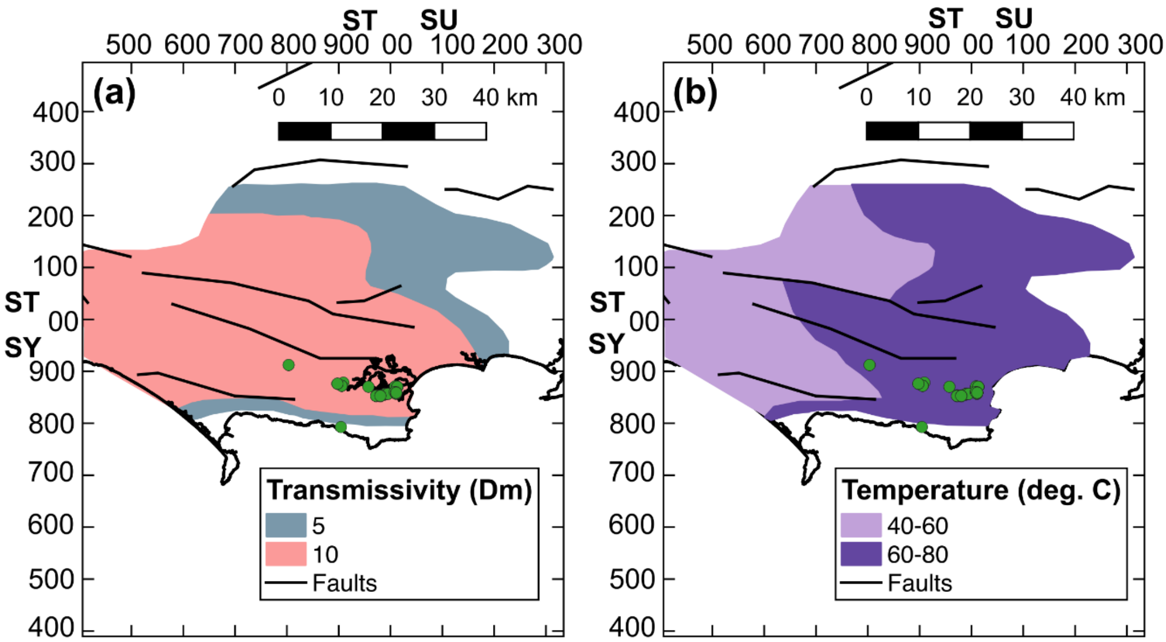

Figure 4: Transmissivity and temperature of the Wessex Basin, reproduced from Downing and Gray (1986). Overlain with candidate hydrocarbon well sites for the Wytch Farm field. Coordinates (north and east) are in kilometres relative to the origin of the British National Grid in British National Grid 100 km quadrangles ST, SU, SY.

To supplement this, the depth of potential geothermal aquifers and proximity to the candidate hydrocarbon wells are examined at a regional basin scale. By comparison of the TVD of the candidate hydrocarbon wells and the depth to the base of aquifers, there are a number of wells which either terminate within or intercept an aquifer at depths whereby temperatures may be sufficiently high to enable repurposing of the hydrocarbon well. In addition to the QGIS shapefile output from this mapping exercise, a database of the aquifer depth, aquifer thickness and vertical proximity to each hydrocarbon well has been compiled.

5.3 Temperature Data and Mapping: Method and Results

Having established the depth of each onshore hydrocarbon well and the extent and depth of aquifers across the UK, an estimation of the subsurface temperature at each respective geological horizon could be made. Three approaches were taken to determine the bottom hole temperature of candidate hydrocarbon wells in this study, depending on the data available.

In their assessment of the potential geothermal resource of the East Midlands Petroleum Province, Hirst and Gluyas (2015) present temperature data obtained from well records in 21 hydrocarbon fields. The Horner Correction was applied to these temperature datasets to correct for the suppression of bottom hole temperature measurements induced by drilling. From the corrected well temperature data, these authors calculated the temperature gradient for individual wells and determined values of temperature gradient for 21 fields in the East Midlands Petroleum Province. Hirst et al., (2015) present a detailed examination of temperature data from well records obtained for the Welton hydrocarbon field and an average temperature gradient of 29 °C km^{-1} was determined for the Welton field from individual well gradients by these authors. For candidate wells in fields in the East Midlands Petroleum Province assessed in this present study, the bottom hole temperature of each individual candidate well was calculated using the temperature gradient for the respective field as reported by Hirst and Gluyas (2015) and Hirst et al., (2015), a surface air temperature of 10 °C and the known TVD of the well.

To determine the bottom hole temperature of wells outside of the East Midlands Petroleum Province, borehole temperature data and temperature gradients from depths greater than 500 m were obtained from historic compilations of geothermal data for the UK (Burley et al., 1984; Rollin, 1987). This dataset was then supplemented with borehole temperature data from wells drilled between 1987 and the present day (e.g. Manning et al., 2007, Younger et al., 2016, Gluyas et al., 2018a). This database includes ~1200 onshore subsurface temperature measurements with ~500 temperature measurements observed in onshore hydrocarbon wells. However, despite the extent of the data available from these historic compilations, it was not necessarily the case that data was available relating to the specific candidate hydrocarbon well. Following the approach of Hirst and Gluyas (2015) and Hirst et al., (2015), the temperature measurements and temperature gradients observed in onshore hydrocarbon wells were grouped by hydrocarbon field. The average temperature gradient for each hydrocarbon field was then calculated based upon the data from individual wells contained in the field. The bottom hole temperature of each individual candidate well was calculated using the temperature gradient for the respective field, a surface air temperature of 10 °C and the known TVD of the well.

If no previous measurements of bottom hole temperature had been made in the well or in any neighbouring wells in the field, then the bottom hole temperature was estimated from the following procedure. A mapping exercise was conducted to determine the heat flow and geothermal gradient at the location of each onshore hydrocarbon well in the UK. The regional variation of heat flow across the UK has been published in various iterations, most recently by Busby and Terrington (2017) where an estimate of the palaeoclimatic correction to heat flow has been accounted for (Fig. 5a). As well as this, Busby et al (2011) present the regional variation of subsurface temperature across the UK at 1000 m depth (Fig. 5b). In the absence of the raw data and/or GIS models used to produce these previously published maps, the maps were reproduced using QGIS software. To do this, a similar methodology to the generation of GIS Shapefiles in Section 5.2 was followed, whereby a scan of the map was digitized, and contour lines redrawn to produce GIS shapefiles of the dataset. In doing so, by overlaying the location of the onshore hydrocarbon wells and by utilizing QGIS geo-processing tools, a value of heat flow and temperature (at 1000 m depth) was attached to each candidate hydrocarbon well data point.

Busby et al. (2011) assumed a surface temperature of 10°C across the UK to generate the maps of temperature at depth as in Figure 5 (b). As a result of the above mapping exercise, each candidate hydrocarbon well location has a value of heat flow and temperature at 1000 m depth. Using the assumed surface temperature of Busby et al. (2011) and the temperature at a depth of 1000 m, the temperature gradient across the depth range of 0-1000 m is calculated at each candidate hydrocarbon well site. Then, as a preliminary estimation, the temperature gradient was extrapolated to relevant depths to determine the bottom hole temperature of the hydrocarbon well. This should only be considered a preliminary estimate of the temperature at depths greater than 1000 m. For more detailed analysis, the harmonic mean thermal conductivity of the geological sequence at each candidate hydrocarbon well site should be established to account for variations in the temperature gradient due to changes in stratigraphy. Furthermore, a more thorough consideration of the effects of palaeoclimate and topography should be accounted for (as in Westaway and Younger, 2013) to enable accurate extrapolation of shallow geothermal gradients to deeper horizons.

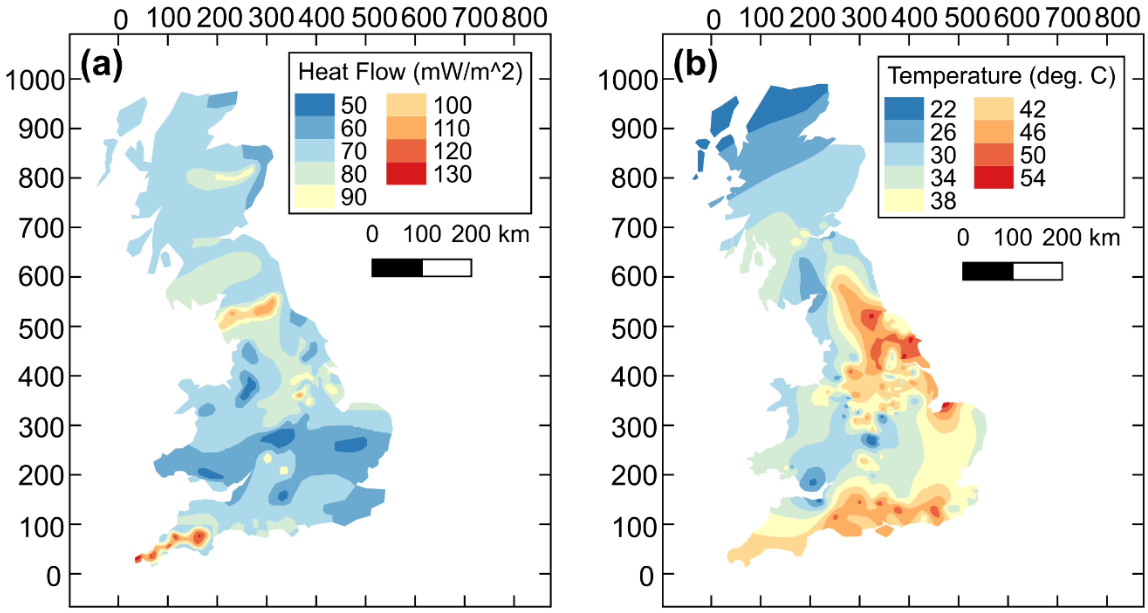

Figure 5: Heat flow map of the UK (a), reproduced from Busby and Terrington (2017). Regional variation of temperature at 1000 m depth across the UK (b), reproduced from Busby et al., (2011). British National Grid coordinates (north and east) are in 100 km intervals.

Of the 620 candidate wells (Stockbridge 25 currently in the process of drilling so no TVD and hence no bottom hole temperature), the bottom hole temperature of 310 of these was determined using the historical compilations of geothermal data from Burley et al (1984) and Rollin et al (1987). For 192 wells, the mean temperature gradient reported in Hirst and Gluyas (2015) was used to determine the bottom hole temperature. The bottom hole temperature of the remaining 118 wells was determined from the mapping exercise based upon the data from Busby et al (2011) and Busby and Terrington (2017) maps.

There are 493 wells with an estimated bottom hole temperature greater than 40 °C. There are 391 wells with an estimated bottom hole temperature between 40-60 °C. Gainsborough (34), Welton (43) and Wytch Farm (139) are the fields with the largest number of wells in this temperature range. There are 85 wells with an estimated bottom hole temperature between 60-80 °C, 6 of these are at Wytch Farm, 8 at West Firsby, 8 at Singleton, 24 at Saltfleetby, and 6 at Cold Hanworth. There are 17 wells with an estimated bottom hole temperature greater than 80 °C.

Table 2: Bottom hole temperature ranges for candidate onshore hydrocarbon wells for geothermal repurposing in the UK

Temperature Range (°C)	No. of Wells
20-30	14
30-40	113
40-50	133
50-60	258
60-70	45

70-80	40
80-90	10
90-100	4
>100	3

Table 3: Bottom hole temperature ranges for candidate onshore hydrocarbon wells for geothermal repurposing in the UK

X	Y	Well Name	Type	Status	TVD (m)	T (°C)
512222	467920	Caythorpe 1	Gas	AP 1	2061.97	92
512222	467920	Caythorpe 2	Gas	AP 1	1950.11	88
536658	388161	Keddington 1Z	Oil	AP 2	2262.71	91
536658	388161	Keddington 2	Oil	AP 2	2210.35	90
536658	388161	Keddington 2Y	Oil	AP 2	2193.94	89
536658	388161	Keddington 2Z	Oil	AP 2	2226.87	90
536658	388161	Keddington 3	Oil	AP 2	2212.24	90
536658	388161	Keddington 3Z	Oil	Operating	2193.04	89
536658	388161	Keddington 4	Oil	AP 2	2189.34	89
536652	388170	Keddington 5	Oil	Shut In	2223	90
477110	478930	Kirby Misperton 1	Gas	AP 2	3413.46	110
477136	479004	Kirby Misperton 8	Gas	Shut In	3097.07	101
519272	439150	West Newton 1	Gas	AP 1	3008.38	118
398937	85645	Wytch Farm A11Z	Oil	AP 1	2607.87	83
398937	85645	Wytch Farm A6X	Oil	Operating	2528.01	81
398937	85645	Wytch Farm A6Y	Oil	Operating	2518.87	81
398040	85260	Wytch Farm X2 (X14)	Oil	Operating	2691.69	85

In addition to determining the bottom hole temperature of the candidate hydrocarbon wells, the temperature at potential geothermal aquifers at each hydrocarbon well site is also calculated. There are 137 wells which intercept the Sherwood Sandstone at a depth whereby the estimated aquifer temperature is calculated as greater than 40 °C. High ranking candidate sites include Caythorpe, Wareham and Wytch Farm where wells intercept the Sherwood Sandstone with an aquifer of greater than 60 °C. There are 73 wells which intercept the Basal Permian Sands at a depth whereby the estimated aquifer temperature is calculated as greater than 40 °C. High ranking candidate sites include Caythorpe, Ebberston, Keddington, Marishes and West Newton where wells intercept the aquifer with an estimated temperature of greater than 60 °C. There are 43 wells which intercept the Carboniferous Limestone at a depth whereby the estimated aquifer temperature is calculated as greater than 40 °C. High ranking candidate sites include Cold Hanworth, Crosby Warren, East Glentworth, Saltfleetby, Scampton North and West Firsby where wells intercept the aquifer with an estimated temperature of greater than 60 °C.

Understanding the magnitude of the temperature either from within the hydrocarbon well, or in a target aquifer, enables an assessment of the optimum repurposing strategy, as detailed in Section 3. From this, wells could be categorized in terms of their potential use. As an example, Caythorpe, Kirby Misperton and West Newton (Table 3) are dry gas fields and therefore there is no possibility for utilization of co-produced fluids from either field. Given the high temperatures observed in wells in these fields, there may be the possibility that the wells could be repurposed as closed loop deep geothermal single wells. However, an alternative strategy could be applied to wells from the Wytch Farm field (Table 3). Three of the four wells are still in operation, and from the analysis described in Section 5.2, each have intercepted the Sherwood Sandstone aquifer at depths where the temperature is suitable for use in a conventional geothermal doublet well system. Alternatively, the opportunity exists to recover heat from the co-produced water in these Wytch Farm field. Given that the wells are still operational, this could prolong the life of the well and improve hydrocarbon recovery.

6. SUMMARY RESULTS OF SCREENING SURVEY

By conducting a thorough screening survey and mapping exercise, this study has assessed candidate locations in the UK whereby the potential exists to repurpose onshore hydrocarbon wells for geothermal energy production. Based upon public domain data, a GIS mapping model and associated database have been produced to integrate onshore hydrocarbon well data with the UK's potential geothermal resource. Key to the decision-making process, this model has integrated data such as:

1) Location, depth and operational status of all onshore hydrocarbon wells in the UK.
2) Measured and estimated bottom hole temperature data for hydrocarbon wells in the UK.
3) Extent, depth and thickness of aquifers across the UK.
4) Extent, temperature and transmissivity of aquifers considered "potential geothermal fields" across the UK.

Of the 2242 onshore hydrocarbon wells in the UK, 621 wells have the potential to be repurposed as they are categorised as completed (operational), completed (shut in), plugged, abandonment phase one or abandonment phase two. By integrating data such as that described above, the following assessments have been made on the 621 potential candidate sites:

1) Determined candidate hydrocarbon well sites based upon operational and abandonment status.
2) Determined candidate hydrocarbon well sites based upon TVD of the well.
3) Determined candidate well sites based upon observed or estimated bottom hole temperatures in the well.
4) Determined candidate well sites based upon their proximity and relation to aquifers.

The preliminary results of the screening survey are as follows:

1) Based upon bottom hole temperature, the optimal candidate well locations are Caythorpe, Keddington, Kirby Misperton, West Newton and Wytch Farm.
2) From assessing hydrocarbon wells which are located in "potential geothermal fields" with high temperature and high transmissivity aquifer conditions, optimal candidate sites are Waddock Cross, Wareham and Wytch Farm.
3) From assessing data on the depth and temperature of the Sherwood Sandstone aquifer at the location of each hydrocarbon well, optimal candidate sites are Caythorpe, Wareham and Wytch Farm.
4) From assessing data on the depth and temperature of the Basal Permian Sands aquifer at the location of each hydrocarbon well, optimal candidate sites are Caythorpe, Ebberston, Keddington, Marishes and West Newton.
5) From assessing data on the depth and temperature of the Carboniferous Limestone aquifer at the location of each hydrocarbon well, optimal candidate sites are Cold Hanworth, Crosby Warren, East Glentworth, Saltfleetby, Scampton North and West Firsby.
6) Of the 621 wells which passed the initial screening survey, 421 are oil wells where the possibility may exist for heat to be recovered from co-produced fluids. Based upon field production rates, optimal fields with the potential to recover heat from co-produced geofluids are Stockbridge, Welton and Wytch Farm.

This study has highlighted candidate hydrocarbon wells based upon the above criteria. Despite not being a priority target of this study, one significant outcome is that this study highlighted aquifers that could be reached by existing hydrocarbon wells, where either the well has already intercepted the aquifer or could reach the aquifer through well redrilling or recompletion, or the aquifer could be targeted through drilling new geothermal wells. In each case, the cost and risk for exploration will be reduced given the existing subsurface knowledge and/or infrastructure at the site. The UK has not yet adopted a tool or mechanism which would allow the user to determine the potential geothermal resource at any location or determine optimal locations for geothermal developments. This study can be considered a step towards achieving this positive outcome. Further assessment and integration with heat demand data will aid the selection of candidate sites.

7. CONCLUSION

One potential catalyst for the future development of geothermal energy in the UK is to repurpose onshore hydrocarbon wells for geothermal energy production and storage. In order to conduct a thorough screening survey of candidate sites, a GIS mapping model and associated database have been produced to integrate onshore hydrocarbon well data with the UK's potential geothermal resource. This GIS mapping model and associated database informs the choice of repurposing strategy and the selection of candidate sites by determining the latter based on: the operational and abandonment status, observed or estimated bottom hole temperatures in the well, and the proximity of hydrocarbon wells to aquifers. Of the 2242 onshore hydrocarbon wells in the UK, 621 wells have the potential to be repurposed as they are categorised as completed (operational), completed (shut in), plugged, abandonment phase one or abandonment phase two. Of these 621 wells; 102 have an estimated bottom hole temperature greater than 60 °C, 137 wells intercept the Sherwood Sandstone aquifer at a depth where it could be considered a target geothermal resource, 73 wells intercept the Basal Permian Sands at a depth where it could be considered a target geothermal resource and 43 wells intercept the Carboniferous Limestone at a depth where it could be considered a target geothermal resource. Of these, optimal candidate wells include those in fields such as: Wareham and Wytch Farm in the Wessex Basin, and Caythorpe and West Newton in the East Yorkshire and Lincolnshire Basin, amongst others. If the current UK regulatory framework is changed in the future to allow geothermal co-production from existing hydrocarbon wells, or their retrospective repurposing for geothermal use, the wealth of infrastructure, expertise and subsurface data that exists within the onshore hydrocarbon sector in the UK stands as a formidable tool and asset to be used in the development of low-carbon energy resources such as geothermal energy.

8. ACKNOWLEDGEMENTS

The authors would like to acknowledge funding from EPSRC-CESI grant number FFC1-024, which has enabled this project to be carried out. Also, the authors would like to thank the industrial partners to this project, Perenco and Schlumberger, for providing data, advice and guidance.

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