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The Geothermal Potential Held within Carboniferous Sediments of the East Midlands: A New Estimation Based on Oilfield Data

Catherine M. Hirst, Jon G. Gluyas

Department of Earth Sciences, Durham University, Science Labs, Durham, DH1 3LE

c.m.hirst@durham.ac.uk j.g.gluyas@durham.ac.uk

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ABSTRACT

Carboniferous sediments have, to date, been largely ignored when UK geothermal resource assessments have been made. Resources located within deep sedimentary Mesozoic basins, and those associated with radiothermal granites have formed the main focus of resource quantification in recent years. There has been no attempt to formally quantify the resource located within Carboniferous sediments due to their complex structural and diagenetic history.

The East Midlands Petroleum Province is the onshore extension of the Southern North Sea Basin. Oil reserves are typically found in Upper Carboniferous sandstone units, and rarely in Lower Carboniferous (Dinantian) Limestones. Exploration within the East Midlands has led to the discovery of over 30 separate fields. In 2011, IGas Energy PLC (IGas) purchased and now operates 16 of these fields. The well records and production data that were obtained as a result of this procurement has been used to produce a first quantification of the geothermal resource held within Carboniferous strata. Using known production data, Horner-corrected formation temperatures and oil/water specific gravity from 23 fields, a value of stored heat has been obtained for each field. In total, the geothermal resource has been approximated as being between 1.74 MW_t and 4.36 MW_t. Given these fields cover only 0.78% of the East Midlands total area, the potential for a larger geothermal resource base is likely to exist.

Removal and sale of heat from the co-produced water will improve the economics of tail end production by lowering the effective total operating expenditure. Reinjection of the cooled water could also help increase the recovery factor of the reservoir; the cooled water having a higher viscosity and hence lower mobility ratio contrast with the oil than would hot water.

1. INTRODUCTION

With a growing energy gap developing, renewable technologies are becoming increasingly important in the UK energy mix. By 2020, 15% of the UK's final energy consumption must come from renewable energy resources (as per the Renewable Energy Directive, 2009). This must be undertaken in accordance with the European Council's Directive set in 2007 that states 20% of final energy consumption in the EU must come from renewable resources. As of 2012, 4.1% of the UK's final energy consumption was from renewable sources (DECC, 2013). In addition to this, greenhouse gas emissions are required to be "reduced by 12.5% below 1990 emissions by 2008-2012, and by 80% below 1990 emissions by 2050" under the Kyoto Protocol (United Nations, 1997). Geothermal energy is a clean, non-intermittent, low carbon emission technology that fits this remit (Younger et al., 2012).

UK geothermal resources are currently coming back into focus after funding by DECC's Deep Geothermal Challenge fund allowed the sinking of the UK's first geothermal borehole in approximately 20 years (Manning et al. 2007). Further funding for a borehole at Science Central, Newcastle-Upon-Tyne was also made available to explore the low enthalpy resource associated with Carboniferous sandstones at 1.8-2km depth. These investments built upon the only working deep low enthalpy geothermal scheme in the UK; the Southampton Geothermal Scheme. Here water is extracted at 76°C from the Sherwood Sandstone at a depth of approximately 1.8km, and although it is currently under refurbishment, it is used to supply a district heating scheme within the city. More recently, a report by Atkins (2013), commissioned by DECC, has focused attention on resources associated with radiothermal granites at depths of 4-5km. Whilst it has provided a comprehensive review and quantification of these resources, it did not address the low enthalpy resource associated with deep sedimentary basins; this fell outwith the remit of the project.

Prior to the Atkins report, UK low enthalpy geothermal resources had been initially quantified by Downing and Gray (1986), with a later update published by Rollin et al. (1995). A major assessment of UK geothermal resources was undertaken between 1976 and 1986 which resulted in quantification of the low enthalpy geothermal resource held in Mesozoic basins and radiothermal granites, as well as an estimation of subsurface temperatures. It used existing borehole data made available from various industries / sources in order to make this assessment which was subsequently compiled into a catalogue; the Geothermal Catalogue. Whilst this has been actively updated, it uses 3057 subsurface temperatures from 1216 sites, 567 of which are from wells >1km depth from which to interpolate from (Busby, 2010). Based on borehole data collected during this study, the combined geothermal resource for Mesozoic basins (excluding the Larne basin) was estimated to be 300 EJ ($x10^{18}$ J). UK heat consumption currently totals approximately 3 EJ per annum, suggesting there is enough heat stored in these basins to decarbonise the UK heat requirement for the next 100 years (Younger et al., 2012).

The geothermal resource associated with Carboniferous sediments were discussed but not quantified due to their lateral variability, post deposition cementation and complex structural features (Holliday, 1986; Smith, 1986). Tracing productive strata across large areas is difficult in Carboniferous sediments, and attempts to place a value on the geothermal resource contained within these strata has yet to be undertaken.

2. THE CARBONIFEROUS GEOLOGY OF THE EAST MIDLANDS

Covering an area of approximately 15,700 km^2, the East Midlands has over 30 hydrocarbon fields contained within it. These fields produce predominantly from Upper Carboniferous strata with some fields occasionally producing from overlying Permian sands. An understanding of the geological history across the East Midlands is required in order to understand the distribution of productive strata. It also provides an appreciation of the diagenetic history which has a bearing on the porosity and permeability of these rocks. The geology of the East Midlands is displayed in Figure 1, along with a more general geological overview of the UK (Crampon et al., 1996). Carboniferous rocks outcrop along the western margin of the East Midlands dipping 1-3° eastwards, where they are progressively buried by a thickening sequence of Mesozoic sediments. The surface location of all but one oil / gas field lies upon Permo-Triassic sediments or younger, also indicated on Figure 1.

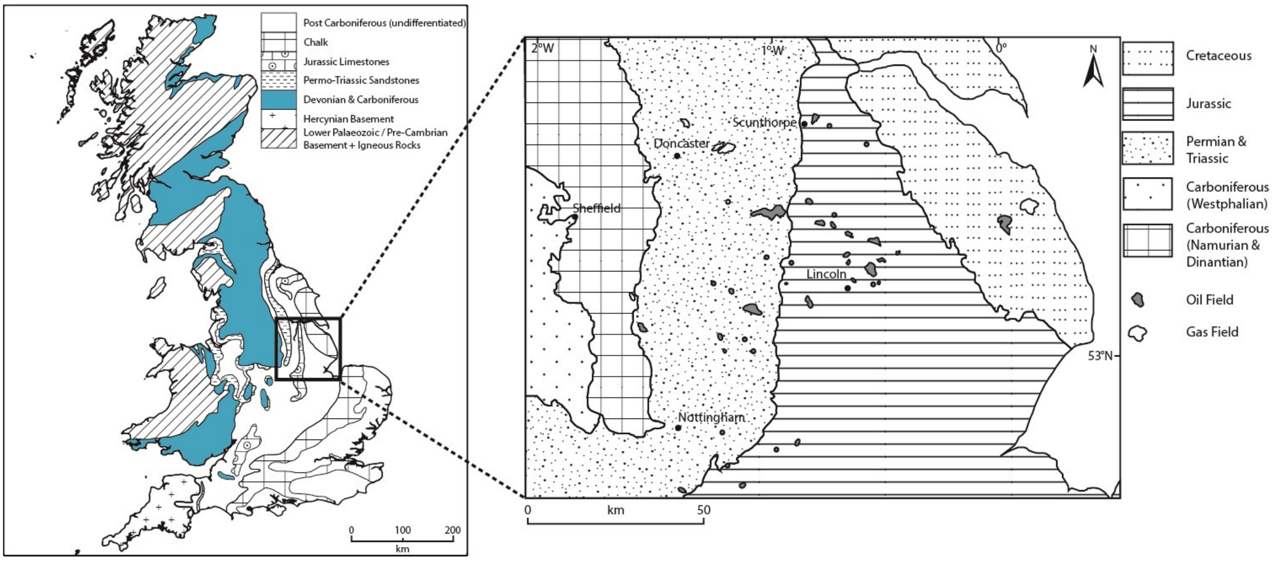

Figure 1: Summarised geology of the UK and East Midlands

The East Midlands has undergone several phases of structural deformation, all of which have a bearing on the distribution of productive target strata. Figure 2 shows the current structure of the East Midlands, whilst Table 1 provides a breakdown of the major structural history of the East Midlands.

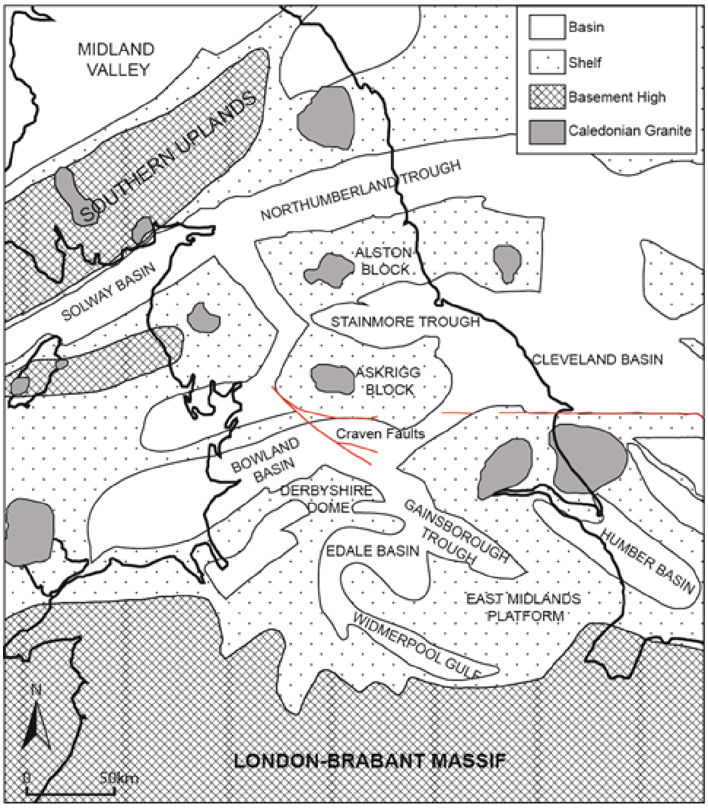

Figure 2: Present day structure of England, Wales and Southern Scotland

Table 1: Structural history summary of the East Midlands

Tectonic Event	Timing	Consequence	Stratigraphy
T1 N-S Extension due to subduction south of the London-Brabant Massif. Pulsed rifting.	Late Devonian / Early Carboniferous (Dinantian).	Graben and half graben formation on NW-SE orientation. Controlled by pre-existing structures within Caledonian basement.	Marine environment dominating to the south. Development of carbonate ramps / platforms / shelves on structural highs and calcareous mudstones and turbidites within basins. Incursion of prograding deltas originating from northern England. Notable formation of the Carboniferous Limestone.
T2 Thermal Sag – crustal cooling	Mid to late Carboniferous (Namurian & Westphalian)	Wider scale basin formation; the Pennine Basin. Stretching from the Craven Faults to the London-Brabant Massif. Rift topography buried.	Carbonate deposition ceased due to basin-wide subsidence. Deep marine mudstones dominate across the southern part of the basin. Northern England became dominated by southerly pro-grading deltas, introducing coarse siliciclastics (including the Namurian Millstone Grit). On burial of rift topography, deposits became cyclical; marine mudstones and fluvial channel sandstones dominate caused by high frequency sea level changes.
T3 E-W Compression – Basin Inversion	Late Carboniferous – Early Permian (Late Westphalian – Stephanian).	Uplift and erosion, alteration of major sediment depocentres. Erosion of Dinantian basins whilst pre-existing structural highs remained relatively un-deformed.	Small concentrations of alluvial fan deposits developed (Barren Red Beds: fluvial sandstones, siltstones and mudstones) separated by Permian unconformity.
T4 Tilting / thermal sag	Permian – Mesozoic	Rifting and thermal cooling, formation of Permian basin within the southern North Sea. Tertiary tilting of all rocks, 1-3° to the east.	Deposition includes (but is not limited to) the Sherwood Sandstone, Mercia Mudstone, Magnesian Limestone and chalk.

In summary, potential productive strata can form relatively thick intervals where, for instance, channel sandstones have become stacked to over 100 m thickness. These deposits can persist laterally, forming sheet like bodies that display facies variation, such as the Millstone Grit (DECC, 2010). Alternately sandstone bodies can form discrete relatively homogenous lenticular bodies that do not persist across large areas. These have been described as shoestring sands (DECC, 2010) and form local aquifers in places. Variable secondary silicification and breakdown of feldspars can be seen affecting these deposits, reducing porosity and permeability. The effects of these processes are difficult to predict across the East Midlands. In some areas, the Millstone Grit forms a potable water supply with abstraction rates of up to 50 l/s; other areas can support 0.5 l/s only (Downing & Gray, 1986). It is this inherent variability that has left the East Midlands geothermal resource unquantified.

3. THE PETROLEUM HISTORY OF THE EAST MIDLANDS

The geological and tectonic history has produced controls on the distribution of oil bearing strata across the East Midlands. Oil has been exploited within the East Midlands since 1919 when oil was discovered within an anticlinal structure comprised of Carboniferous (Dinantian) Limestone (Craig et al., 2013). The discovery was made at Hardstoft; a discovery that led to further exploration and the discovery of more than 30 fields (DECC, 2010). Many of these fields were identified during the 1950's and early-mid 1960's before exploration began to cease. Interest was reignited during the 1970's due to the growing Middle East oil crisis, and many wells were drilled throughout the 1980's. The location of the major oil and gas fields within the East Midlands has been shown on Figure 1. The presence of oilfields across the East Midlands show economic volumes of fluid are extractable from Carboniferous rocks. The petroleum system can be defined by the distribution of source rocks, reservoir rocks and seals. Knowledge of the distribution of these strata, along with knowledge of the geological evolution of the area can help when understanding how porosity and permeability across the field can be retained in some places and lost in others.

3.1 Source Rocks

Principle source rocks of the East Midlands are derived from early Namurian shales. These shales are distal pro-delta deposits that developed as a consequence of basin subsidence during T2. Mid to late Dinantian shales that developed during T1 are also classed as source rocks (DECC, 2010). The maturity of these shales has been controlled by the tectonic evolution of the area. Initial burial during T1 and T2, along with enhanced geothermal gradient allowed source rocks to become hydrocarbon producing. Subsequent basin inversion and exhumation of Upper Carboniferous sediments during T3 effectively caused cessation in source rock maturation, before tilting during T4 allowed oil generation to migrate in an easterly direction (DECC, 2010). This allowed oil to migrate both west and southeast.

3.2 Reservoir Rocks

The main reservoir rocks across the East Midlands have been summarized by DECC (2010). Namurian sandstones (Millstone Grit) and Westphalian Coal Measure sandstones form the dominant reservoirs across the field. These sandstones have generally formed in channel fills, crevasse splays and fluvial braided river channels. Where these deposits have become stacked, thicknesses of sandstones can reach over 100 m. Oil shows within the Basal Carboniferous, Dinantian Carboniferous Limestone and Basal Permian sands have also been recorded across the field, producing small quantities of oil. DECC (2010) indicate porosity and permeability has been preferentially preserved in these oil bearing reservoirs. Secondary silicification and breakdown of feldspars forming kaolinite and sericite has been avoided due to the presence of oil in these reservoirs.

3.3 Seals / Traps

Two types of oil trap within the East Midlands have been identified; structural and stratigraphical (Fraser and Gawthorpe, 1990). DECC (2010) also include sedimentological traps, which describe laterally discontinuous (shoestring) sands that form discrete oil reservoirs. Basin inversion during T3 created oil-trapping anticlinal fold structures, generating the most typical oil trap in the field (DECC, 2010; Glennie, 2005). Overlap of sandstone onto mudstone or tight limestone has also produced stratigraphic traps that have placed control over the migration of oil in the East Midlands.

4. CARBONIFEROUS RESOURCE ASSESSMENT

With the provision of temperature and production data for 23 fields within the East Midlands, a basic quantification of geothermal resource has been made. These fields have extracted economic quantities of oil, water and gas providing evidence that Carboniferous strata have the ability to support large volume fluid extraction. These data can be combined to produce a geothermal resource estimate based on this data only, and offers an opportunity to estimate the wider resource contained across the whole East Midlands area.

4.1 Temperature

Well logs provided by IGas for 16 fields have had temperature and production data extracted. In addition, data for an additional seven fields has been obtained from DECC and other literature (Bailey, 2003; Ward et al., 2003; Hodge, 2003; Gluyas & Hichens, 2003).

4.1.1 Temperature Correction

In order 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. During drilling, circulated drill fluids invade the formation causing temperatures to be suppressed below true formation temperature. For equilibration temperatures to be obtained for any given formation, the well must be left to stand undisturbed for anywhere between several months to several years (Majorowicz et al. 2004). Consequently, equilibration temperatures are rare. Several methods have been derived to correct suppressed temperatures, including the Horner method of correction. It is this method that has been applied to the dataset using the methodology laid out in Hirst et al., 2014 (after Deming, 1989).

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.

4.1.2 Temperature Gradient Calculation

Temperatures have been recorded by a range of down-hole logging tools including neutron density, microlog and gamma ray tools, as well as the more customary temperature logging tool.

Temperature gradients were calculated for each field in two ways, based on the level of data available:

- By calculating gradients for individual wells from corrected temperature data collected from all down-hole logging tools.
- By using temperature specific down-hole logs, applying the correction factor where necessary.

All gradients were created using a standard temperature of 10°C at ground level (Met Office, 2014), and where possible used a temperature measure in both Permo-Triassic and Carboniferous strata. Temperature measurements in the depth range 0-300m (i.e. within Permo-Triassic sediments) have to be treated with caution given the potential suppression of temperatures due to past glaciation and palaeo-topography (Banks, 2008; Westaway & Younger, 2012). Heat flow suppression within this zone can lead to under-estimation of temperatures. Temperatures recover to follow the regional gradient below these depths, 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. This data was only available for five fields, but is seen as a more robust way to estimate the gradient across the field as the tool used is temperature specific. Table 2 summarises the temperature gradient measures using both methods, including an average measure.

The difference in average between the two methods indicates with relatively good certainty that the margin of error associated with these measurements is reasonable.

4.2 Production Rates

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.

Table 2: Temperature gradient summary. "ND" denotes No Data. * denotes the average value was used due to lack of data in that particular field.

	Temperature Correction °C	Temperature Gradient °C/km	Temperature Gradient °C/km
Beckingham	2.30	32	35
Bothamsall	4.50	34	32.5
Cold Hanworth	5.30	ND	38
Corringham	6.90	ND	32.5
Crosby Warren	7.30	ND	30.5
East Glentworth	0.00	ND	34
Egmanton	0.51	23	33
Farley's Wood	3.85	ND	39
Fiskerton Airfield	0.00	ND	24
Gainsborough	2.10	25	28
Kirklington	8.40	ND	50
Long Clawson	1.57	ND	25
Nettleham	0.80	ND	28
Rempstone	3.00	ND	34
Scampton	3.10	ND	31
Scampton North	5.45	ND	31
South Leverton	*3.3	ND	36
Stainton	2.70	ND	32
Torksey	*3.3	ND	30
Welton	2.66	35	29
West Firsby	2.20	ND	33
AVERAGE	3.30	30	33

Table 3: Geothermal Resource Summary Table

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

4.3 Stored heat calculation

A simple stored heat calculation method has been employed to determine heat stored within target strata within each producing oilfield. It takes the following form:

$$Q = Mdot * cp * \Delta T \quad (1)$$

where Mdot represents mass flow rate (kg/s), Cp represents specific heat capacity (kJ/kg/K) and ΔT represents the change in temperature (°C). Oil and water density values were taken as 845 kg/m^3 and 1045 kg/m^3. These values are averaged from oil analysis reports for 21 wells located across 10 separate oilfields. Oil specific heat capacity was approximated to 1.8 kJ/kg/K (Burger et. al., 1985); water specific heat capacity was approximated to 3.93 kJ/kg/K (i.e. seawater). ΔT has been varied to determine the available heat for differing resource depletion.

4.4 Resource Summary

A summary of the geothermal resource available for each field has been summarized 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 ΔT has been take at 30°C giving an average reinjection temperature of 17°C.

5. DISCUSSION

5.1 Temperature Correction & Data Quality

Data across the field have been taken using electric line down-hole logging tools which date from 1955 (Egmanton) to 2007 (Cold Hanworth). These tools were first developed in the 1920's and have evolved dramatically since this time. The precision of these tools and their ability to measure temperature accurately have been discussed by several authors. Wisian et al., (2006) state electric line temperature measurements introduced in the 1960's had a precision of ±0.001°C. Prior to this, temperatures were measured using thermometers or clock driven recorders. The accuracy of such recorders is noted to be ±2°C (Steingrimsson, 2013). The accuracy of temperature sensors on logging tools that measure temperature as a secondary parameter is unstated, but it is assumed a similar level of accuracy is achieved with these sensors. All logging tools are calibrated prior to and immediately after running down-the-hole (Ball, pers.comm.), in addition to laboratory calibration undertaken prior to taking onsite. As such the results should be of a similar accuracy albeit currently un-quantified. By using two methods to determine temperature gradient in Section 4.1.2, the variation in using a temperature-specific log derived gradient versus using data from all logging tools is 3°C; less than the temperature correction factor of 3.3°C. This small variation between the methods gives confidence that the calculated geothermal gradient is relatively robust.

Temperature specific down-hole logs do indicate several wells are not static systems; there is some fluid movement within these wells that causing fluctuation in the temperature. An example log from one oilfield has been reproduced in Figure 3. Whilst the fluctuation in absolute temperature can be clearly seen, a geothermal gradient can still be derived. Fluid flow transports heat, increasing it in some areas and decreasing it in others. Elevated temperatures in some areas can be explained by the inflow of warmer water that has risen from greater depths than that penetrated. Conversely, outflow of water into the formation can actively suppress the temperature recorded within the formation. Within these well logs, fluid flow is likely to occur to a degree but it is difficult to quantify given the lack of flow data from down-hole logs. In addition, these logs have been produced within hours of drill circulation ceasing; a time when the well is still recovering from fluids being pumped into the well. Oil shows will actively flow into the well causing temperature perturbation also.

The level to which this perturbation affects the overall BHT is again difficult to quantify. Ultimately the temperature gradient can still be estimated relatively robustly, as the overall general increase in temperature with increasing depth can be taken as the geothermal gradient (as seen on Figure 3). Small scale fluctuation is something to be aware of, especially if anomalous data points arise within temperature records.

5.2 Geothermal Resource Extent

Oilfields across the East Midlands are reducing in capacity: Increasing water cut and a decline in reserves mean that current production rates are reduced. Therefore using peak production rates could be seen as unjustified. However, peak production rates show what the field is capable of producing with regards fluid volume, and is not limited to oil only. Pore spaces within these reservoirs are likely to be occupied by water as a result of oil removal and the fluid volume will therefore still exist. This can therefore justify the use of peak production rates within these calculations.

Many wells have been plugged across these fields, requiring drill-outs in order to bring the well back on-line. Whilst this is additional expense, the ground conditions are already well understood and the requirements for completing the borehole are also well understood. There will inevitably be some expense associated with the re-completion of many operational wells across all fields, as most will require new well screens with multiple completion zones. In a similar manner to production rate selection, using data from both operational and non-operational wells across the field can ultimately be justified.

The total calculated resource for the oilfields in question is 2.6 MW_t. This value is a conservative estimate due to the following reasons:

1. The calculated resource does not take into account the additional oilfields for which data was not available for. Over 30 oilfields have been discovered across the East Midlands, and the calculated resource in this study currently only relies on data from 23 of these fields. Regardless of whether the additional fields were major oil / gas producers, the poroperm characteristics within these fields have been favourable enough to allow the field to produce for a length of time and therefore a resource is likely to exist in these areas.

2. The oilfield data that has been utilized has focused on oil-bearing strata only; it does not account for any intervening strata that may be non-oil bearing yet water saturated. These units form a further resource that is yet to be accounted for. 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., 2014).
3. For the purposes of this paper, the areal extent of the East Midlands has been defined as the counties which incorporate the oilfields that have been analysed within this study, namely Lincolnshire and Nottinghamshire. The combined area of these counties is approximately 9119km^2. The area occupied by oilfields, as indicated in Table 3, covers a total area of 71km^2, and therefore represents 0.78% of the East Midlands. Whilst lateral variation in strata does exist in producing bodies, it is not unreasonable to extrapolate the resource identified within the oilfields to a larger area.
4. Reservoir rocks retain good porosity and permeability as a consequence of oil migration into these strata (DECC, 2010). Depending on the timing of this migration and the erosion history of the reservoir, it is possible some oil traps have been destroyed during basin inversion and erosion, allowing oil to escape to the surface. Retention of any residual porosity and permeability is dependent on the timing of subsequent tectonic phases, but there is the possibility that these units may still retain some enhanced poroperm characteristics.

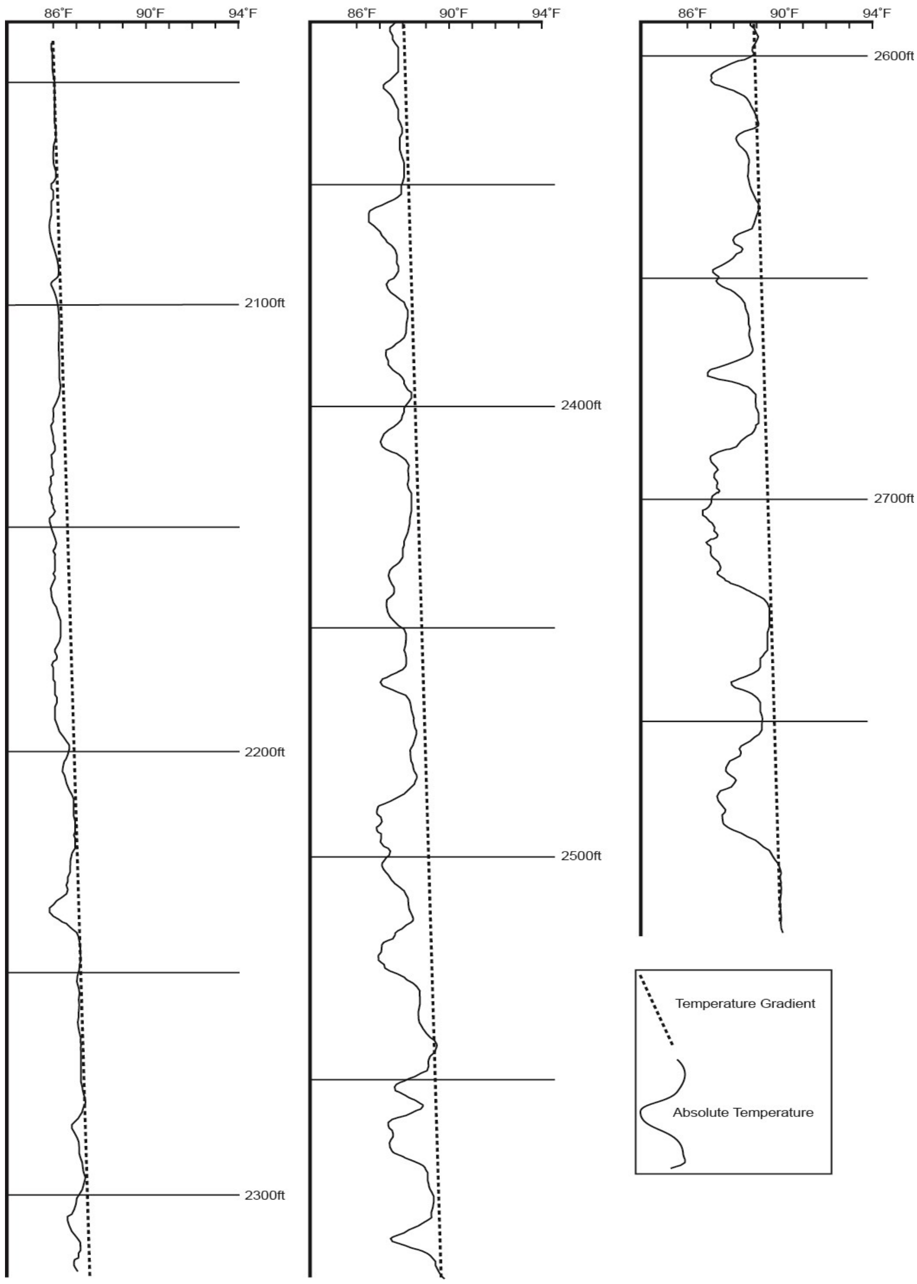

Figure 3: Downhole temperature log displaying fluctuations with depth.

5.3 Application of a geothermal scheme within a producing field

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.

6. CONCLUSIONS

The Carboniferous succession across the East Midlands is laterally heterogeneous making any geothermal resource quantification difficult. Oilfields in the area provide evidence that porosity and permeability can be retained in some areas, and therefore will permit abstraction of oil, water and gas in economic quantities. A first look calculation of this resource indicates 2.6 MW_t is stored within these fields (given a 30°C depletion in resource). Other non-oil bearing yet water saturated strata exist across the East Midlands that remain unquantified, but are likely to significantly contribute to the amount of available resource. Within the Welton field, taking account of these strata almost doubles the amount of water available for abstraction.

Currently extracted water across the fields is unused, being either disposed of or re-injected. The sale of heat contained within this warm water can provide additional income to extend the tail end lifespan of the oilfield in question. In addition, re-injection of cooled water can increase the recovery factor of the reservoir. Cooled water has a higher viscosity and hence lower mobility ratio contrast with oil than would hot water, and as such could “sweep” remaining oil reserves out of the reservoir further improving the economics of extraction.

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