Application of hydrogeological parameters for evaluating the thermal resource potential of deep groundwater systems

C.A. Adams, J.G. Gluyas. and S.A. Mathias

Durham University

Abstract

Geothermal energy has significant global potential as a clean non-intermittent energy resource. Exploiting geothermal energy uses water which either flows naturally or is stimulated to flow in the sub-surface within deep aquifers or fractured basement. Therefore, it is necessary to understand fluid flow in the upper crust of the Earth (0–5 km depth). Fluid flow could be through water-bearing porous and permeable media (e.g. sandstones and limestones), fractured dry rocks or fluid filled fault zones. The UK has low to medium temperature geothermal resources related to past intrusive igneous activity. A thorough understanding of these low to medium temperature systems is particularly important, because their usefulness will only be realised by optimising site conditions from a geological and engineering standpoint. It is necessary not only to examine the temperatures at depth but to ensure that fluid flow is sufficient so that the geothermal resource is not quickly depleted. Conversely, we also need to ensure that any fluids removed for heat extraction can be re-injected elsewhere in the system to prevent discharge of warm, chemically unsuitable fluids to surface water courses. The requirement to understand these systems is critical for the UK because economic exploitation of a marginally productive resource relies upon the interplay of several finely balanced factors. This paper presents a hydrogeological evaluation of two geothermal case studies, one from north-east England and one from the North Sea. The applicability of these two case studies to other marginally productive geothermal areas is then discussed.

Introduction

Ensuring energy security against a backdrop of rising energy costs, climate change and depletion of fossil fuel resources is a key global challenge. More efficient and less polluting use of fossil fuels and a mix of renewable energy technologies are key to continuity of future energy provision (Lior, 2009). Advances in drilling technology and the development of binary plant technology have expanded the availability and scale of geothermal resources (Bertani, 2009). In 2005, 0.3% of worldwide electricity demand was sourced from geothermal power plants (Lund, 2007). Longevity of geothermal plants on a scale of decades has been demonstrated at the Lardarello field in Italy since 1913 (Henley and Ellis, 1983) and the Wairakei field in New Zealand since the early 1960s (Henley and Stewart, 1983). Geothermal energy represents a low carbon, non-intermittent energy resource which can be used directly to provide heat and power. Geothermal plants also have minimal land and water use requirements. Capacity factors of up to 96% for geothermal plants have been demonstrated (Lund, 2007). Geothermal plants produce a small fraction of the emissions of conventional fossil fuel plants.

Types of Geothermal systems

There are three types of geothermal system: hydrothermal convective systems, enhanced geothermal systems (EGS) and hot aquifers (Downing *et al*., 1984). All these systems tap into energy resources derived from the decay of radioactive isotopes occurring within the Earth's interior. Ground source heat is often referred to as 'geothermal' energy, however ground source heat systems generally rely on the low temperatures (10 to 15°C) found at shallow depths (up to a few hundred metres) and this energy source is derived from the sun warming the Earth's surface.

Hydrothermal convective geothermal systems represent the classic type source of geothermal energy. They are found at plate margins where there is active volcanism. Most of these systems occurring globally are restricted to the Pacific 'ring of fire'. Meteoric water enters the subsurface through cracks and fissures and becomes heated at depths of up to 8km by the magmatic source. The less dense, heated water then convects upwards and issues at surface. Examples of this type of system include the geysers in California (Henley and Ellis, 1983). Advantages of this type of system include their high temperature and less need for drilling or circulating fluids by pumping. The main disadvantage of these systems is their volatility and geothermal plants of this type have been destroyed by eruption of adjacent volcanoes.

Enhanced or Engineered Geothermal Systems (EGS), also referred to as 'hot dry rock' systems, exploit granitic bodies at depths of 3 to 5 km. They are described as 'enhanced' or 'engineered' because the permeability of the host granite has been increased by hydrofracturing. High pressure, cold water is pumped down an injection well to increase fracture permeability and hydraulically stimulate geothermal resources. Heated water re-emerges from the abstraction well and is suitable for power generation as steam or with a binary cycle plant. Examples of EGS systems are in the Rhine Graben at Landau Pflatz (Germany) (Bächler *et al*., 2003) and Soultz Sous Forets (France) (Gerard *et al*., 2006). These sites produce 3 MW and 1.5 MW of electricity respectively and similar systems are planned for the south-west UK.

Hot aquifer geothermal systems are low enthalpy and comprise groundwater within an aquifer at depths

BHS Third International Symposium, Managing Consequences of a Changing Global Environment, Newcastle 2010

of 2 to 3 km, heated by convective heat flow. At these depths, temperatures are typically 60°C or above (Downing *et al*., 1984). An example of a hot aquifer system is the Southampton district heating scheme. This is the only operational geothermal plant in the UK. It was developed in 1987 and exploits a Triassic sandstone at a depth of 2 km (Barker *et al*., 2004). The source temperature is 76°C falling to 74°C at surface. Yields of 860 m^3 day^{-1} are abstracted to provide 1.4 MW of thermal energy. Spent, cooled brine is discharged to sea at 28°C. This has caused a decrease in resource temperature with time.

Exploitation of high and low enthalpy geothermal energy

Geothermal systems are further classified as high (above 150°C) or low (less than 150°C) enthalpy. Low to medium enthalpy sites by their nature are marginally economic and have individual problems/properties. Most systems that exploit these resources are heat only but improvements in drilling technology (as used in EGS systems) and plant design (optimisation of organic rankine and kalina cycle technology) are facilitating power generation. One such example is at Chena Hot Springs in Alaska (Brasz and Holdmann, 2004) where water at 72°C is used to generate 400 kW. The use of geothermal energy for direct heating is more efficient than power generation and ranges in scale from single systems to schemes serving an entire district. The conversion of thermal energy to electrical energy is more efficient at higher temperatures. In the case of the UK, the financial rewards are much greater if electricity can be generated in addition to heat because of the Renewable Obligation Certificates and feed-in tariffs paid to producers of renewable electricity. The uptake of the renewable heat incentive (planned for summer 2010) will provide further incentives for the development of geothermal heating schemes.

At resource temperatures in excess of 210°C, dry steam power plants are used for power generation. Typical plants have outputs of 20–100 MW, the most well-known being The Geysers in California. Flash power plants are used in most high temperature fields binary cycle plants are used for temperatures of less than 175°C. In a binary plant, the geothermal fluid is pumped through a heat exchanger which uses a low boiling point working fluid (e.g. butane) that is vapourised then fed through a turbine. Binary system efficiencies are around 10–13% (DiPippo, 2007). For very low enthalpy resources (up to 50 to 60°C), heat pumps are used. Heat pumps have become increasingly popular for domestic heating having a global annual growth rate of 30% in energy production (Lund, 2005). The focus of this paper will be on low enthalpy schemes.

Identification of low enthalpy geothermal resources

The production of geothermal power is protected from fuel cost fluctuations but prospecting for and evaluating geothermal resources is costly and can be risky. To illustrate this point, a typical well doublet in Nevada which can support 4.5 MW would have a 20% chance of failure, and would cost around $10M to drill (Calpine Corporation, 2009). Electrical plant construction and well drilling cost 2–5M Euro per MW of electrical capacity (Bertani, 2007). In an ideal world where economics were not a driving factor, a deep borehole (say 6 km) would guarantee that sufficient temperatures for generating geothermal power would be reached. However, there would be no guarantee that a continual and sufficient supply of fluid would be present from which to generate power.

As a rule of thumb, 1 km^3 of granite at 250°C could supply 10 MW per year (assuming a water to wire efficiency of 90% at 250°C) over a period of 20 years using four wells and circulating 560 m^3 d^{-1}. The geothermal reservoirs currently of interest in south-west England have been modelled upon a 20 year life span — this is comparable with other forms of power generation both fossil and renewable. However, unlike other forms of power production, at the end of its life, a geothermal plant can be rested prior to future use. Evaluating resource potential relies upon interpretation of heat flows as it enables source temperature predictions to be made at depth. Most of the heat transfer within the Earth is driven by conduction and this gives a baseline surface heat flow of up to 60 m W m^2 (Downing *et al*., 1984). Areas where surface heat flow values exceed the baseline values cannot be explained by conduction alone and the increase in heat flow values can be attributed to fluid convection.

A major risk for any geothermal project is that flow rates will not be sufficient to support the abstraction required to supply the desired amount of power and/or heat. That deep aquifers are capable of supporting fluid flows is demonstrated by the sandstones and chalk which are significant oil and gas producers in the East Midlands and the North Sea.
The best reservoirs have sustained flow from individual wells of tens of thousands of barrels of oil and water over periods exceeding 20 years. Poorer quality reservoirs such as the Carboniferous sandstones of the East Midlands oil province can still flow hundreds of barrels per day over similar multi-decade periods. Many of the North Sea reservoirs have temperatures close to or above 100°C while those of the East Midlands may be as low as 40°C (Green, 1989). At depth, porosity and permeability tend to decrease due to compaction and cementation. In the limestone formations, matrix porosity is usually low while joints, solution features and fractures transmit fluids and impart secondary permeability.

The distribution of fractures within fractured aquifers is unpredictable. These problems can be overcome by hydrofracturing rocks to improve fracture networks. However, these activities also carry some uncertainties related to accurately controlling the location of fracture generation. Microseismic activity will almost certainly be induced during hydrofracturing and care has to be taken to ensure surface disturbance is avoided as occurred at Basel (Deichmann and Ernst, 2009).

Demonstration plants using low to medium temperature geothermal resources are operational at Soultz-sous-Forêts in France (Gerard *et al.,* 2006) and Landau-Pfalz in Germany (Bächler *et al*., 2003). Other projects are planned for the USA, Australia and the UK, some examples are provided in Table 1.

Practical Considerations

Six factors influence well longevity: power output, well density, injection strategy, initial reservoir pressure, initial fluid temperature and permeability in and around the reservoir (Hanano *et al,* 1990). Longevity of geothermal plants on a scale of decades has been demonstrated at the Lardarello field in Italy since 1913 (Henley and Ellis, 1983) and the Wairakei field in New Zealand since 1958 (Henley and Stewart, 1983). It is generally accepted that if possible it is better to re-inject spent geothermal (which will still have residual thermal value) to prolong the life of the reservoir.

Using low enthalpy geothermal brines directly for heat and power generation (rather than using a heat exchanger) carries some risks. The geochemical composition of geothermal fluids can often create problems associated with scaling and corrosion and the disposal of spent brine

Table 1 Low to Medium Enthalpy Geothermal Energy Case Studies

Name	Location	Type	Source Depth (m)	Source Temp (°C)	Yield (m^3/day)	Output (MW)
Southampton (E)	UK	Heating	2000	76	860	1.4 [th]
Chena Hot Springs (E)	USA	Heat and Power	217	74	2850	0.4 [e]
SuperC Aachen (E)	Germany	Heating/Cooling	2544	70	Not known	Not known
Soultz-sous-Forêts (E)	France	Power	5000	200	3024	1.5 [e]
Landau-Pfaltz (E)	Germany	Power	3300	160	-	3 [e]
Redruth (P)	UK	Heat and Power	5000	170	Not known	55 [th], 10 [e]
Eastgate (P)	UK	Heating	995	46	>1600	0.75 [th]
Eden Project (P)	UK	Power	3000-4000	150 to 160	Not Known	3 [e]

(E) Denotes existing project
[th] Denotes thermal energy output
(P) Denotes planned project
[e] Denotes electrical energy output

may require careful consideration to avoid contamination of surface water bodies or in the case of re-injection, aquifer contamination. These issues can be dealt with by analysing waters for a suite of major anions and cations (Ca, Mg, Na, K, SO_4, HCO_3, F, Cl) and minor elements (Sr, Mn, Ba, Si). In situ measurements of temperature and conductivity are also invaluable (Jones *et al.,* 2000). The chemical composition of geothermal water may also change with time as different areas of a particular reserve are drawn down. Re-injection of spent geothermal fluid can negate these problems by avoiding the release of potentially contaminated fluids to surface watercourses but more importantly, re-injection prolongs the output of the reservoir although care must be taken to avoid short circuits.

Case Study 1: Geothermal potential of the North Pennines, UK

The UK has modest heat flows with average thermal gradients of around 26°C km^{-1} with peak values of 35°C km^{-1}. Areas of high heat flow are underlain by radiogenic granites with high thorium content. An example of this is the Weardale Granite batholith that was emplaced into a Palaeozoic basement during the Devonian. The Weardale Granite batholith was postulated to explain the mineralization of the North Pennine Orefield by Dunham (1934), investigated using a gravity survey by Bott and Masson-Smith (1957) and proved in the 1960s when the Rookhope Borehole was drilled [NGR3938, 5428]. The granite has been described in detail by Dunham (1990) who noted the presence of horizontal jointing and steeply inclined joints. The age of crystallisation is believed to be around 410±10Ma but hydrothermal activity is believed to have continued to 365±8Ma (i.e. for at least another 45Ma) suggesting that conduits remained open and flowed for millennia. This has implications for fluid flow in the area.

A borehole drilled at Woodland [NGR4091, 5277] in 1962, to further prove the geological sequence, penetrated 500 m of strata and terminated at the Whin Sill (Bott *et al.*, 1972). The Weardale Granite (Figure 1) was not recorded at this location but anomalously high heat flows (comparable to those recorded at Rookhope) were recorded. A temperature of just below 30˚C was recorded at 500 m (a surface heat flow of 90 mW m^2 was recorded). This value is unusual because Woodland is not underlain by the Weardale Granite and its high heat flows have been attributed to hydrothermal water ascending up the Butterknowle fault and associated fault splays (Figure 1). During recent investigations at Eastgate [NGR3938, 5382] (Manning *et al.*, 2007) a 998 m deep borehole was drilled to investigate the permeability and geothermal potential of the Weardale Granite at this location. A major water bearing fissure was intercepted in fractured granite at 410 m bgl with several other fractures also intercepted below this, the deepest recorded fracture located at 813 m bgl (Manning *et al.*, 2007). A temperature of 46˚C was recorded at the base of the borehole.

Further evidence supporting the geothermal potential of this area was provided in the 1980s. Manning and Strutt (1990) sampled tepid saline waters within Cambokeels Mine at Eastgate. Comparison of these waters with samples from the Carnmenellis Granite taken by Edmunds *et al.* (1984) suggested that these mine waters were derived from depths within the Weardale Granite and that the water had equilibrated with this host at temperatures of up to 150˚C. The Weardale Granite and its associated structural features display geothermal potential that extends beyond the surface trace of the granite body. Hydrothermal deposits of barite have been found at various localities along the trace of the 90 Fathom and Butterknowle faults (Hirst, 1974) that bound the Alston Block (which hosts the Weardale Granite) to the North and South respectively (Figure 1). At Tynemouth where the 90 fathom fault outcroups at the coast, the Permian

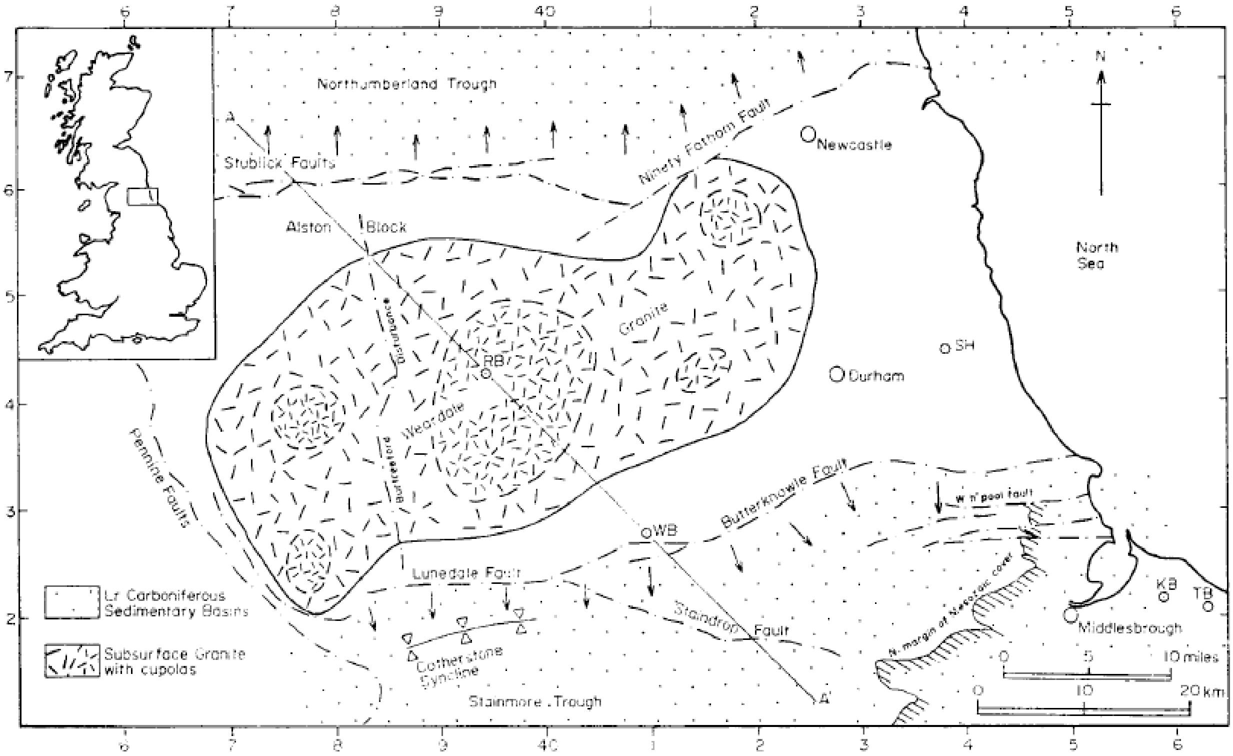

Figure 1 *Geological setting of the Weardale granite and associated structures (after Bott et al.1972)*

Figure 2 *Cemented Permian sandstone with granulation seams adjacent to the 90 Fathom Fault, Cullercoats, NE England (coin diameter 25mm)*

sandstones are cemented by barite (Figure 2) but further south (at Thrislington Quarry) these deposits are worked as unconsolidated sands.

A second borehole is currently being drilled at Eastgate which will serve as a re-injection well for fluids extracted from the original Eastgate borehole. The intention is to develop the system further so that geothermal heat can be used for a spa development as part of a wider eco-village development planned for the Eastgate site.

Case Study 2 Geothermal potential of North Sea Oilfields

Production of oil and gas from the North Sea commonly targets reservoirs between about 2.5 km and 5 km deep in a basin with a geothermal gradient of about 30ºC km^{-1}. Thus the temperature at the reservoir location is commonly in excess of 70ºC and may be up to 150ºC.

For the aging oil reservoirs in the province (Figure 3), production of oil is accompanied by production of water. In many instances fields may produce 10 to 20 times more water than oil as they reach end of life. The very largest North Sea fields produce up to 500 000 bwpd (20 million gallons) and many produce water in excess of 100 000 bwpd (4 million gallons) (Figure 4). Currently, this water is either cooled and after cleaning, dumped overboard or reinjected to maintain pressure in the reservoir. However, these same fields are commonly power-deficient because the falling oil production also means falling gas production. Eventually, there becomes insufficient gas to power the platform (commonly 2–10 MWh day^{-1}). Companies resort to importing gas if suitable pipelines exist or diesel with its transhipment risks.
In purely calorific terms, it is possible that the produced hot water could be used to power the platform. Moreover, production of cold water as a by-product of such a process

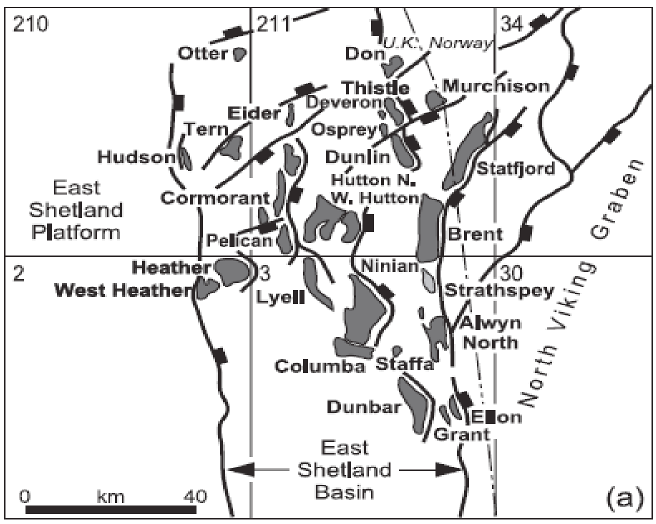

Figure 3 *Distribution of oilfields in the Brent Province (North Viking Graben, North Sea) east of the Shetland Isles.*

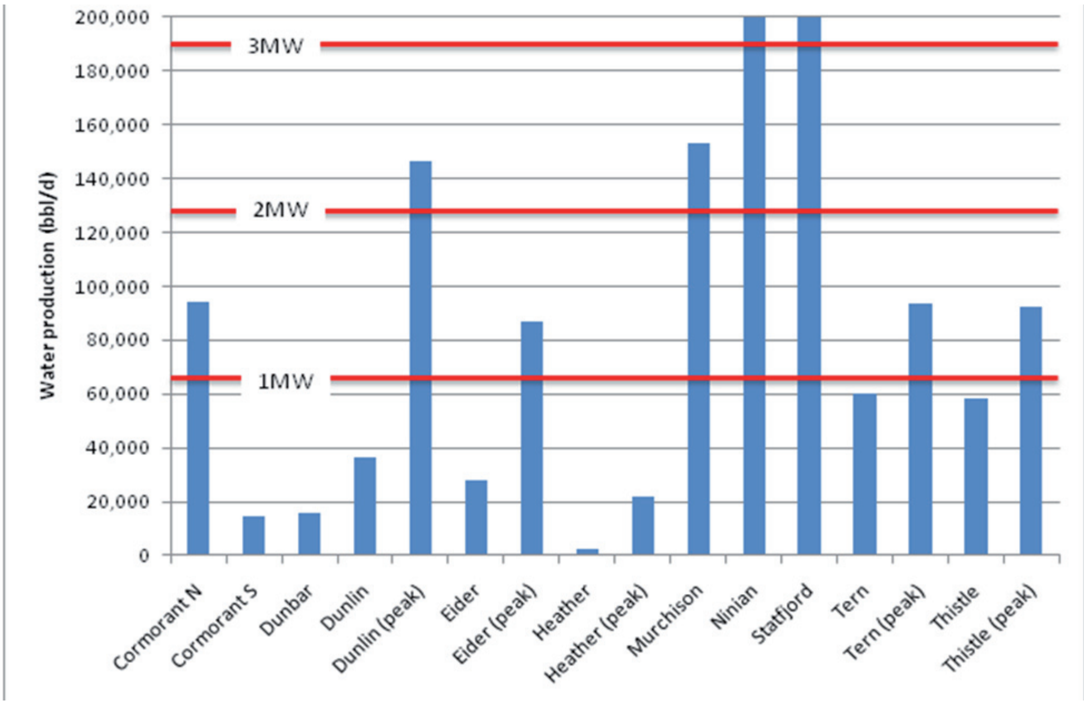

Figure 4 *Water production data (barrels of water per day) from Brent Province Fields (North Sea). Peak production for some of the fields is also shown.*

would have increased value as an injection fluid because of promoting thermal fracture in the injection wells and improving the mobility ratio with the oil and hence sweep efficiency.

Based upon current binary cycle power plant (heat engine) technology, we calculate that it should be possible to produce 1 MW of electricity from 64 000 bbl per day of water at 100°C (with the temperature in the condenser at ~20°C) and that the required equipment would occupy about the same volume as a sea-crate.

A survey of the fields within the Brent Province (Figure 4) shows high rates of water production for many fields. Largest amongst these is Statfjord which in 2008 produced on average over 680 000 bbl/d (Table 2), with a geothermal potential of >10MW^e. Similarly Ninian produced over half a million barrels of water per day in 2008 with a geothermal potential of 8–9 MW^e. Water production rates for Statfjord and Ninian are exceptional, nonetheless most of the power-depleted platforms in the Brent Province produce or produced at peak sufficient water to generate 1–3 MW^e. That water (and tail-end oil) production in many fields is declining is commonly due to the paucity of available gas for powering injection pumps. Recent experience with the Thistle Field has demonstrated that with increased injection of water to support production, oil rates can rise. Thus a restoration of power availability through application of power generated from the geothermal potential of the produced water may well help deliver increased oil reserves and field life extension.

Table 2 *Water production and temperature data for Brent Province fields (production data from DECC data release, temperature data from Abbots (1991) and Gluyas and Hichens (2003).*

Field	*Year*	*Water production (bbl/d)*	*Temperature (°C)*
Cormorant N	2008	93,945	91-99
Cormorant S	2008	14,482	91-99
Dunbar	2008	15,699	128
Dunlin	2008	36,154	100
Dunlin (peak)	1999	146,388	100
Eider	2008	27,971	107
Eider (peak)	2000	86,785	107
Heather	2008	2,628	108-117
Heather (peak)	2003	21,805	108-117
Murchison	2008	152,934	110
Ninian	2008	544,054	101
Statfjord	2008	680,977	89
Tern	2008	60,124	93
Tern (peak)	2005	93,705	93
Thistle	2008	58,558	104
Thistle (peak)	2007	92,444	104

Discussion and conclusions

Rising energy costs, combined with the need to guarantee secure, low-carbon energy resources, has widened interest in the possibility of exploiting geothermal energy in regions not classically associated with geothermal resources (as in Case Study one) or where the value of a potential resource was not recognised (as in Case Study two) because alternative and lower cost energy sources were readily available. The successful development of low enthalpy geothermal systems is not without financial and technical risks but improvements in resource assessment, technology development and plant design, linked with economic incentives provided for the production of low carbon heat and power, are improving the case for exploitation. Several examples where these resources have been successfully developed have added further support to the cause.

For both the northern England and North Sea case studies, it is clear that geothermal energy could provide a useful supplement to existing power generation and heating systems. Both of these case studies could be transferred to other similar geological situations globally. For the onshore example, geothermal heating and modest electricity generation could provide a sustainable and low-carbon-footprint alternative to using fossil fuels. The offshore example is rather different. Power generation from what is otherwise waste water could lead to longer field lives, increased reserves and a reduction in the requirement to import either gas or diesel to ageing North Sea platforms. Collectively this would reduce costs and environmental risks (from diesel transhipment) as well as helping to minimise platform emissions. A further co-incidental benefit from cooling the produced water would be to improve petroleum sweep in the reservoir once the cooled water is re-injected because of its increased viscosity.

References

Abbotts, I.L. 1991. (Ed), United Kingdom oil and gas fields: 25 Years Commemorative Volume. *Geol. Soc. London, Mem.,* **14**, 49–54.

Bächler, D., Kohl, T. and Rybach, L. 2003. Impact of graben-parallel faults on hydrothermal convection - Rhine Graben case study. *Phys. Chem. Earth, Parts A/B/C.* **28**, 431–441.

Barker, J.A., Downing, R.A., Gray, D.A., Findlay, J., Kellaway, G.A., Parker, R.H. and Rollin, K.E. 2000. Hydrogeothermal studies in the United Kingdom. *Quart.J. Eng. Geol. Hydrogeol.,* **33**, 41–58.

Bolton, R.S. 1970. The behaviour of the Wairakei geothermal field during exploitation. *Geothermics*. **2**, 1426–1439.

Bott, M.H.P., Johnson, G.A.L., Mansfield, J. and Wheilden, J. 1972. Terrestrial heat flow in north-east England. *Geophys. J. Roy. Astronom. Soc.*. **27**, 277–288.

Bott, M.H.P. and Masson-Smith, D. 1957. The geological interpretation of a gravity survey of the Alston Block and the Durham Coalfield. *Quart. J. Geol. Soc.,* **113**, 93–118.

Brasz, J.J. and Holdmann, G. 2004. Transforming a CentrifugalCompressor into a Radial Inflow Turbine. Paper C060 presented at the *17th International Compressor Engineering Conference* at Purdue, West Lafayette, Indiana, July 12-15, 2004.

Calpine Corporation (CPN) (NYSE Arca) Profile. 2009. Reuters Press Release.

Deichmann, N. and Ernst, J. 2009. Earthquake focal mechanisms of the induced seismicity in 2006 and 2007 below Basel (Switzerland). *Swiss J. Geosci.*, **102**, 457–466.

DiPippo, R. 2007. *Geothermal power plants; Second Edition: Principles, Applications, Case Studies and Environmental Impact*. Oxford: Butterworth-Heinemann.

Downing, R.A., Allen, D.J., Barker, J.A., Burgess, W.G., Gray, D.A., Price, M. and Smith, I.F. 1984. Geothermal exploration at Southampton in the UK – a case study of a low enthalpy resource. *Energy Explor. Exploit.,* **2**, 327–342.

Dunham, K.C. 1934. The genesis of the north Pennine ore deposits. *Quart. J. Geol. Soc., London*, **90**, 689–720.

Dunham, K.C., Dunham, A.C., Hodge, B.L. and Johnson, G.A.L. 1965. Granite beneath Visean sediments with mineralisation at Rookhop, northern Pennines. *Quart. J. Geol. Soc., London,* **121**, 383–417.

Dunham, K.C. 1990. *Geology of the North Pennine Orefield: Volume 1 Tyne to Stainmore;* 2nd Edition. HMSO, London.

Edmunds, W.M., Andrews, J.N., Burgess, J.N., Kay, R.L. F. and Lee, D.J. 1984. Evolution of saline and thermal groundwater in the carnmenellis granite. *Mineral. Mag*., **48**, 407–24.

Erkan, K., Holdmann, G., Benoit, W. and Blackwell, D. 2008. Understanding the Chena hot springs, Alaska, geothermal system using temperature and pressure data. *Geothermics*, **37**, 565–585.

Green, P.F. 1989. Thermal and tectonic history of the East Midlands shelf (onshore UK) and surrounding regions assessed by apatite fission track analysis. *J. Geol. Soc.*, **146**, 755–773.

Gerard, A., Genter, A., Kohl, T., Lutz, P., Rose, P. and Rummel, F. 2006. The deep EGS (Enhanced Geothermal System) project at Soultz-sous-Forets (Alsace, France). *Geothermics,* **35**, 473–483.

Hanano, M., Takahashi, M., Hirako, Y., Nakamura, H., Fuwa, S., Nose, J., and Itoi, R., 1990. Longevity evaluation for optimum development in a liquid dominated geothermal field – effects of integration of reservoir pressure and fluid temperature on steam production at operating conditions. *Geothermics*, **19**, 199–211.

Hirst, D.M. and Smith, F.W. 1974. Controls of barite mineralization in the lower magnesian limestone of the Ferryhill area, County Durham. *Trans. Inst. Min. Metall. (Sect. B),* **83**, B49–B55.

Henley, R.W. and Ellis, A.J. 1983. Geothermal systems ancient and modern: a geochemical review. *Earth-Sci. Rev.*, **19**, 1–50.

Henley, R.W. and Stewart, M.K. 1983. Chemical and isotopic changes in the hydrology of the tauhara geothermal field due to exploitation at wairakei. *J. Volcanol. Geotherm.Res.* **15**, 285–314.

Hirst, D.M. and Smith, F.W. 1974. Controls of barite mineralization in the Lower Magnesian Limestone of the Ferryhill area, County Durham. *Trans. Inst. Min. Metall. (Sect. B),* **83**, B49–B55.

Jones, H.K., Morris, B.L., Cheney, C.S., Brewerton, L. J., Merrin, P.D., Lewis, M.A. Mac Donald, A.M., Coleby, L.M., Talbot, J.C., McKenzie, A D., Bird, M.J., Cunningham, J. and Robinson, V.K. 2000. The physical properties of minor aquifers in England and Wales. *British Geological Survey Technical Report WD/00/04*, BGS Keyworth, Nottingham.

Kavouridis, K. and Koukouzas, N. 2007. Coal and sustainable energy supply challenges and barriers. *Energy Pol*., **36**, 693–703.

Lior, M. 2009. Energy resources and use: The present (2008) situation and possible sustainable paths to the future. *Energy*, In Press.

Lund, J.W., Freeston, D.H. and Boyd, T.L. 2005. Direct application of geothermal energy: 2005 Worldwide review. *Geothermics*, **34**, 691–727.

Manning, D.A.C., Younger, P.L., Smith, F.W., Jones, J.M., Dufton, D.J. and Diskin, S. 2007. A deep geothermal exploration well at Eastgate, Weardale, UK: a novel exploration concept for low enthalpy resources. *J. Geol. Soc., London,* **164**, 371–382.

Manning, D.A.C. and Strutt, D.W. 1990. Metallogenetic significance of a North Pennine springwater. *Mineral. Mag.*, **54**, 629–636.