Interim comments on UK's geothermal energy potential and how to progress it

Highland Geology Limited 10th October 2024

The child pages along with this one show the geology of around 20 locations in northern onshore UK basins where, in our opinion, groundwater in the temperature range 70-100 degrees Centigrade can be brought to surface at rates adequate to run through a heat exchanger for resulting vapour to spin a bi-turbine set, giving commercial electricity generation. High-efficiency turbine technology wasn't available in previous decades and it is an enabler for low-temperature geothermal developments.

There is now massive potential in UK, and overseas too, for low-temperature geothermal projects based on bi-turbine technology. HGL and its associates (particularly Jim O'Hare, a hugely experienced consultant drilling engineer) have been thinking about where, with today's matured technology, a new dedicated generation of companies recognising enhanced opportunity onshore UK could best acquire acreage positions to start drilling geothermal plays of the type we outline. We have run generalised AI model economics for small, stand-alone projects, which are very encouraging. Our emphasis presently is on East Midlands, the northwest, and Northumberland intra-Lower Carboniferous, at least for a definitive, first proving project. We shall expand this work, and target larger projects to see how detailed economics for grouped well pads look when a FEED is run.

Ongoing "traditional" focus on hot rocks, using water as the working fluid to provide steam for turbines, entailing deep drilling and therefore heavy front-end capital outlays, appears to have and continues to be disabling Government's confidence in development of onshore UK's enormous geothermal resource. Onshore and offshore wind is dominant in forward planning, despite its vulnerability to weather conditions, and its high reliance on subsidy. There have been advances in drilling method too, which likewise are not reflected in recent government-published assessments. Its time for outdated advisory material to be flagged as such, as long as it remains on the public websites.

The economics of low-temperature geothermal projects based on producer wells drilled to around 2000-3000 metres and return injectors to around half that depth order, are perfectly feasible, provided they are drilled into zones which deliver fluids at reasonably high rates. From a geological point of view, if you know the UK structure style it's straightforward to identify onshore locations and assemble a portfolio of quality targets for drilling geothermal wells. Modern pressure-pulse drilling connects and enhances natural fracture systems. There is plenty of onshore acreage which is not licensed for oil and gas exploration (and thus is much less likely to automatically attract objections and serious delays in getting permissions), and it is serviced very cheaply by available seismic data. How one can apply for rights to drill geothermal plays and assert ownerships in open acreage investments, when no regulatory legislation for this form of activity yet exists, is presently unclear. Misdirected historical advice led to this situation.

We think that capital limitations will not be a problem, as soon as one clear instance is shown to prove the concept we show in these notes. The present big minus is the lack of a dedicated regulatory system which is the rules and conduct book for projects. A regulation and licensing system is mandatory from the outset, easily constructed, hardly more than an afternoon's work. Simply adapt one, from Europe. Government can quickly fix this.

These following notes summarise our current views. Our overall message is, implementing impressive new technology calls for engineering innovation and skill. If we want to get to a net-zero electricity-based economy, it can be done by 2030 without the massive costs of building and running offshore wind farms. Government backing is welcome when necessary to accelerate permissions: that's where we will need input, to materially speed the work.

(i) Let's start with a short summary of **ORC technology**. ORC, meaning Organic Rankine Cycle, is a thermodynamic process which bi-turbines use to convert low-temperature heat sources into electricity. ORC systems employ organic fluids which have lower boiling points than water, and that lets them extract energy from geothermal heat sources like groundwater reservoirs below 100 degrees C. The key components of an ORC Bi-Turbine are these:

The **working fluids** include pentane, butane, R245fa. They have boiling points lower than water and vaporise at lower temperatures, which allows efficient extraction from geothermal fluids around 100 degrees Centigrade.

The geothermal fluid arriving at surface is going to be close to 100 degrees, it is pumped into a **heat exchanger** where it transfers heat to the organic working fluid, which vaporises. The exchanger is set up for optimal transfer efficiency whilst minimising pressure drop. The vaporised working fluid, now at high pressure, enters the first, **high-pressure turbine** which extracts the initial energy and converts it to drive an **electric generator**.

After it has gone through the first turbine the working fluid is part-expanded and still has some energy. It can be pre-heated before it goes into the second, **low-pressure turbine**, to improve process efficiency. This further converts the remaining thermal energy into mechanical work, the output from this second turbine also drives an electric generator. (A lot of modern turbines work like this, aero jet engines for example).

When the working fluid has passed the second turbine it is **condensed** to liquid state, ready to recirculate in the cycle. The condensed liquid is pressurised by a **feed pump** and goes back into the exchanger. The pump is important, it must operate across a range of temperatures and pressures for system stability.

So, the bi-turbine design allows energy extraction over a broader range of pressure and temperature than a single turbine can, resulting in more electricity generation than a single ORC system can deliver. If temperatures and flow rates of the produced geothermal fluids vary, the bi-turbine can be tuned to match varying conditions. ORCs are specifically designed to run efficiently at lower temperatures than traditional steam turbines, and are particularly well-suited for geothermal plays with fluids in range 70-100 degrees Centigrade.

ORC bi-turbines also have a small footprint, having minimal emissions (gasses such as hydrogen sulphide in the fluid go back downhole in the second, injector well), small land-use demand, they can run off-grid and provide stable, continuous power supplies to areas which have limited access to electricity. They continue to see design development: efficiency will get still better.

(ii) On the drilling side, for UK geothermal much of the advice tendered in publications by supposedly knowledgeable groups is completely out of date now. For instance, the radiogenic granites in Cornwall are still being heralded as the only systems in the UK that can support viable large scale geothermal power generation. The idea that you need "special" geological conditions to get commercial "deep" geothermal opportunities, and nothing else will work, arises from limited understanding of UK basin structure, coupled with reliance on the old technology and questionable appreciation of how geothermal producer and injector wells should be designed and drilled.

An example, in the Eakring Field area current published opinion states it's the granite basement which generated the warm water anomaly there. Much more likely, seismic supports the concept that the brine came from southwest, from the thick Lower Carboniferous sequence in eastern Widmerpool Trough. It migrated updip into the fractured Eakring Fault footwall and crossed the strike-slip fault zone into the equally-heavily fractured hangingwall, and thence to fold structures.

Yes it's expensive to drill wells to depths at and greater than 2000 metres, but it doesn't have to be high-risk. Small groups who know what they are doing can design and execute 2-well projects which will deliver profitable results in short order, provided the operating and ownership rules are clarified. Regarding capital required, a twin-well pair where the producer is completed at about 2 km and the injector to dispose of cooled brine goes to about 1 km, can be done back-to-back for around £3 million. That's not crippling: it's the price of a central London apartment! Two wells, a heat exchanger and small, modern ORC Bi-Turbine, along with the team overheads, might deliver a small-project at no more than £10 million. Groups of pads exploiting proven trends will show economy of scale.

(iii) Under current government pre-occupation with wind, it looks like we'll need to wait a year or so before re-juvenated geothermal's time will come. In the meantime, let's get private sector key people interested in the chance to build a transformative new generation of UK-based companies, taking the field of low-temperature geothermal forwards!

With this aim, it really is important to remove some of the more recent misleading summaries from government websites. A particular reason is that specialist City firm researchers looking for new investment opportunities in green energy, will see it. Here are two particular examples.

Westminster open report OR/23/032 of last year had an avowed purpose: "to help accelerate the development and deployment of deep geothermal energy projects". It assembled masses of information, but it's all old. Its introductory/summary text misrepresents UK geothermal potential:

"There is consensus that geothermal development should focus on exploiting the resources at moderate depths (1-3 km) for direct-use heating and thermal energy storage. This is because commercially achievable enthalpies in the UK's sedimentary basins (which make up most of the available geothermal potential) are not expected to be high enough for power generation within economically drillable depths (currently at 5-6 km). Furthermore, <u>geothermal heating technologies are seen to be more readily deployable than technology for power generation (i.e., they do not require construction of a power plant) and generally entail lower risks</u>. It is recognised, however, that in some areas of the UK, such as Cornwall, special geological conditions exist which could make power generation economically viable. <u>However, the focus of geothermal developments in the UK is seen to be weighted towards heating applications</u>".

Those two underlined (by us) statements are very much open to challenge. A kilometre of insulated pipeline costs a million pounds, and then you have to lay pipelines in the centre of a large town or city, to connect with hospitals, universities, large schools, barracks, prisons, local authorities wanting heat: all of which can get government grants in any case to double-glaze, install ground and air heat pumps, at far less cost than signing up for geothermal schemes run by people who don't operate on an independent commercial basis. Selling heat is far more expensive and complicated than electricity to the grid: presuming a grid connection is available.

In a second report, in April 2022 UK Parliament POSTbrief 46 addressed the status and potential of geothermal energy. “Geothermal projects have high capital expenditure (CAPEX), most of which is spent on drilling and materials. In addition, there is geological and financial uncertainty over the subsurface conditions and volume of revenue that will be delivered. High upfront costs and drilling risks are considered a main barrier to wider uptake of geothermal energy in the UK as they make it difficult to obtain project finance under current technology awareness and market conditions. Projects currently need financial support to improve their commercial viability and reduce risks to developers and investors”.

No they don’t. Not now. Compare this analysis with the US Energy Department projection for cost of geothermal energy on www.energy.gov/eere/geothermal/enhanced-geothermal-shot . They think that the cost of next-generation geothermal energy in the USA is going to reduce to $45 per megawatt hour by 2035 and that the geothermal industry could become a powerhouse of U.S. economic growth, with particular benefits for rural communities. The same could go for UK. Closing down key components of UK manufacturing could stop. The recent wholesale baseload contract price of UK electricity has been around £60 per MWh, which is $77 per megawatt hour. The difference with US expectation is partly accounted for by the carbon price applied to gas for CCGT power stations: but there’s plenty of return to anticipate on investment in geothermal in UK.

HGL greatly appreciates interest from energy specialists, and looks forward to comments.