Repurposing of disused shale gas wells for subsurface heat storage: preliminary analysis concerning UK issues

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Abstract: Development of many wells is envisaged in the UK in coming decades to exploit the abundant shale gas resource as fuel and petrochemical feedstock. Forward planning is therefore warranted regarding reuse of the resulting subsurface infrastructure after gas production has ceased. It is shown that this infrastructure might be repurposed for Borehole Thermal Energy Storage (BTES). Preliminary calculations, assuming an idealized cycle of summer heat storage and winter heat extraction, indeed demonstrate annual storage of ~6 TJ or ~2 GWh of energy per BTES well. Summed over the anticipated well inventory, a significant proportion of the UK's future heat demand might thus be supplied. This form of BTES technology has particular relevance to the UK, where the shale resource is located in relatively densely populated areas; it is especially significant for Scotland, where the resource coincides with a particularly high proportion of the population and heat demand.

Heat forms a high proportion of energy demand, estimated as 47% of the total worldwide and 37% of the total for the OECD countries (Beerepoot & Marmion 2012). It is 46%, or ~800 TWh yr^{-1}, of the UK energy demand (DECC 2012), the proportion being higher, 55% (or ~80 TWh yr^{-1}), for Scotland (Scottish Government 2014), due to the combination of relatively cold climate and limited energy efficiency of much of the building stock. Despite this, many predictions of future scenarios treat 'energy supply' as equivalent to 'electricity supply' and thus do not consider the supply of heat; this is true even for some assessments of future energy supply for the UK, which envisage that 'decarbonizing' heat supply means provision of electrical heating using low-carbon electricity, rather than making use of low-carbon sources of heat (e.g. King *et al*. 2015; Pfenninger & Keirstead 2015). The future energy scenario analysis by National Grid (2015) does consider heat, but this topic only occupies 6 of their 288 pages and concludes with generalities, such as noting that 'a mix of solutions will be required that suits the infrastructure that already exists, is cost effective, and returns significant carbon reductions'. Some generic works on future energy scenarios (e.g. IEA 2014) mention that thermal energy storage is being investigated but provide no details. Sustainable energy scenarios that do give serious consideration to heat supply envisage that in future much of this will indeed come from heat storage (e.g. Pinel *et al*. 2011; Persson & Westermark 2013; Hesaraki *et al*. 2015), rather than being provided largely via the burning of fossil fuels, as at present.

Various scenarios for seasonal thermal energy storage have been investigated, including energy storage by heating water in insulated pits or tanks, or in aquifers, or via thermal conduction into the rocks adjoining boreholes, this latter technology being known as Borehole Thermal Energy Storage (BTES) (e.g. Schmidt & Miedaner 2012). Technological variants include diurnal, rather than seasonal, storage and/or storage of 'cold' rather than heat in climates where the main thermal load is for cooling rather than heating (e.g. Ruddell *et al*. 2014). Other, more experimental, technologies have also been considered, including thermal energy storage utilizing compressed air and/or phase changes and/or

thermo-chemical effects (e.g. Marano *et al.* 2012; Anderson *et al.* 2014; Chai *et al.* 2014a, 2014b; Peng *et al.* 2014, 2015; Wu *et al.* 2014; Murphy *et al.* 2015; Zanganeh *et al.* 2015).

The current state of knowledge of BTES has recently been reviewed (Gao *et al.* 2015); hitherto, as regards seasonal energy storage, this topic has focused on consideration of shallow boreholes, usually in the uppermost ≤100 m of the subsurface (e.g. Schmidt & Miedaner 2012). Significant recent developments include refinements to theory for the heat transfer process in subsurface heat exchangers (e.g. Lamarche & Beauchamp, 2007; Li *et al.* 2014; Choi & Ooka 2015; Xiong *et al.* 2015) and considerations of optimum system design (e.g. Lanini *et al.* 2014). As regards the latter issue, Lanini *et al.* (2014) showed that, to minimize radial heat losses into the surroundings, the optimum BTES design involves the construction of 'fields' of borehole heat exchangers (rather than single vertical boreholes), arranged such that the diameter of the 'field' is double the vertical extent of the boreholes.

The Gao *et al.* (2015) review also identifies several general factors inhibiting the more widespread adoption of BTES: these include the need to understand the subsurface properties and details of heat transfer mechanisms, including effects of groundwater flow, at each site in great detail, the corresponding need to understand system operating characteristics, concerns regarding thermal disturbance of the subsurface, and the relatively small heat capacity of such systems, which require large volumes to achieve significant heat storage. The latter issue is reflected in the cost of these systems: one recent project, at Crailsheim in SW Germany, had a capital cost of €520,000 (Schmidt & Miedaner 2012), and is shown below to have created a seasonal heat storage capacity of ~0.56 GWh (Table 1), the cost being thus equivalent to ~€1.10 or ~£0.80 per kWh of seasonal heat storage. Since natural gas, the UK's principal heating fuel, can currently (February 2016) be bought at a retail cost as low as ~£0.03 per kWh (see, e.g., https://www.energylinx.co.uk/energycalc.html?db=gas), this does not appear to be a favourable comparison. This is even though the running costs of BTES systems are relatively low and they will maintain something like their planned seasonal storage capacity for many years, although the effectiveness of particular designs will decrease over time as increasing proportions of the stored heat progressively conduct (or are transported by groundwater flow) so far away that they cannot be recovered by the borehole heat exchanger (see e.g. Mielke *et al.* 2014).

The possibility of repurposing future disued shale gas wells in the UK for geothermal energy supply has been noted previously, for example by GEL (2015a) and Bridge *et al.* (2015), albeit with few technical details provided. Furthermore, a number of other demonstration or prototype projects are currently under way in the UK to implement deep borehole heat exchangers in a range of settings (e.g. GEL 2014, 2015b; Kavanagh 2014; Law 2014; Phillips 2015; GEL *et al.* 2016), which evidently incorporate technology that might be usable or adaptable in future for disued shale wells. However, although these projects have received substantial UK Government and Scottish Government funds, the author is unaware of any published technical discussion of the underlying concepts (see also below). The idea of installing an inner pipe to convert a single borehole into a subsurface heat exchanger was first noted in an Australian patent (Duerden 2011: granted 24 February 2011; lapsed 7 August 2014; Fig. 1) and was also discussed by Heller *et al.* (2014). Nonetheless, repurposing in this manner of individual deep boreholes might seem contrary to the point stated above, that for optimal efficiency BTES boreholes should be arranged in 'fields' rather than in isolation (Lanini *et al.* 2014). However, as will become clear, since the ambient temperature at ~2-3 km depths is many tens of °C higher than at the Earth's surface, BTES at such depths can be managed to balance storage and

extraction of heat about this ambient temperature, rather than involving net heat injection, only part of which is recovered. Furthermore, most of the cost of 'conventional' BTES projects is for drilling and for installation of thermal insulation to mitigate heat losses at the Earth's surface (Schmidt & Miedaner 2012). The former cost will be avoided if existing boreholes are to be repurposed; the location of the
5   heat storage at kilometre depths, beneath layers of rock that will serve as insulation, means that the latter cost will also be avoided. The potential of this form of heat storage technology thus warrants consideration, and indeed forms the topic of the rest of this account. A first order analysis is presented, it being clear that – as with many other energy technologies (e.g. Spitler, 2005; Murphy *et al*. 2015; Alahäivälä *et al*. 2015; Liu *et al*. 2015; Retkowski *et al*. 2015; Safdarnejad *et al*. 2015; Walraven *et al*.
10   2015; Yun *et al.* 2015) – great potential exists for optimizing the proposed general form of the solution.

The UK has a significant shale gas resource (e.g. Andrews 2013; Monaghan 2014; Fig. 2) and is otherwise increasingly dependent on energy imports given the declining production from the North Sea (DECC 2015). Shale gas has been widely criticized as an energy technology, given its CO_2 emissions
15   when burnt, its significant environmental impacts when extracted in unregulated jurisdictions, and the temporary nuisance arising during its development (e.g. UK Parliament 2014). A further area of potential concern is that the availability of an abundant supply of cheap natural gas might inhibit the development of lower-carbon forms of energy supply (e.g. Krupnick *et al*. 2013; UK Parliament 2014). The issue of nuisance during development is particularly relevant to the UK, as the resource areas have
20   substantial populations (Fig. 2), so local people will be affected more-or-less wherever any development is sited. The resource areas indeed encompass the largest cities in Scotland (Glasgow and Edinburgh) and the principal cities in five of the nine largest English conurbations (Manchester, Leeds, Liverpool, Nottingham, and Sheffield). The population thus potentially affected amounts to ~10 million or ~20% of the total in England (Fig. 2(b)) and ~2 million or ~40% of the total in Scotland
25   (Fig. 2(a)). This distribution is a legacy of the history of economic development, mainly fuelled from local coalfields, exploiting the same Carboniferous age sedimentary sequences as contain the shale resource (Fig. 3). Nonetheless, the aforementioned environmental impacts will be dramatically reduced in a highly regulated jurisdiction such as the UK (e.g. Westaway *et al*. 2015a). The CO_2 emissions for a given energy output will also be much less than from the principal alternative, coal
30   (e.g. Chang et al. 2015; EIA 2015). Another potential issue is the low production per well, possibly only ~1 bcf (billion cubic feet, measured under standard conditions) of shale gas (e.g. MacKay and Stone 2013; Bond et al. 2014; Westaway et al. 2015a), and the resulting many wells needed to contribute significantly to energy supply.

Wells engineered both for conventional production of hydrocarbons and for shale gas reach depths of
35   several kilometres where ambient temperatures – caused by the Earth's geothermal gradient – provide a substantial heat resource. The potential has already been recognized for repurposing conventional hydrocarbon wells, to utilize the hot water inevitably produced as a by-product (e.g. Younger *et al*. 2012; Gluyas *et al*. 2014). Given the many shale gas wells envisaged in the UK in coming
40   decades, consideration of the possibility of their reuse is timely. However, the impermeability of the shale precludes co-production of thermal water; the issue is thus repurposing for heat storage rather than net heat production (see, also, below). This study will outline how shale gas wells might thus be reused. The essential feature of the proposed solution is to install within each well a liner so it acts as a heat exchanger; in summer, hot water – containing waste heat – is circulated into the well, thus
45   heating the surrounding rock mass (Fig. 4(a)); in winter, heat stored within this rock mass is extracted and used for heat supply (Fig. 4(b)). The next section presents a first-order quantitative analysis of this

BTES configuration. This indicates energy storage and retrieval of ~6 TJ or ~2 GWh per well per annual cycle; when summed over the number of wells envisaged, the potential thus exists for significant heat supply.

5   This article is organized as follows. First, theory is presented to enable the above-mentioned heat storage calculations. Others have reported similar developments of theory previously (e.g. Fourier, 1822; Thomson 1884; Dahl 1924; Ingersoll & Plass 1948; Ingersoll *et al*. 1954; Carslaw & Jaeger 1959; Eskilson 1987). However, to the best of the author's knowledge, none of these earlier works has presented the theory in precisely the form required; some of them are also relatively inaccessible. For
10   both these reasons, therefore, rather than getting bogged down in deliberations regarding who said precisely what, and when, and how it needs to be modified for the purposes of the present study, the required theory will simply be derived directly from first principles. Appropriate numerical values for the parameters required for these calculations will then be deduced and the above-mentioned representative value for the energy storage per well per seasonal cycle thus estimated. Some of the
15   implications of these calculations are then discussed. These include: estimation of the overall contribution to seasonal energy storage of the many shale gas wells envisaged in the UK; financial considerations; possible extensions to the theory and design improvements beyond the basic configuration depicted schematically in Fig. 4(a)(b)); and discussion of how the possibility of repurposing for heat storage might influence public perception of shale gas.
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Heat storage calculations

Heat flow between a horizontal shale gas well lateral (Fig. 3) and the surrounding rock mass of thermal diffusivity κ, can be investigated by solving the standard diffusion equation for heat conduction in cylindrical polar co-ordinates,

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$$\frac{\partial T}{\partial t} = \kappa \left(\frac{\partial^2 T}{\partial r^2} + \frac{1}{r}\frac{\partial T}{\partial r} + \frac{1}{r^2}\frac{\partial^2 T}{\partial \theta^2} + \frac{\partial^2 T}{\partial z^2} \right) \quad . \tag{1}$$

(e.g. Thomson 1884; Carslaw & Jaeger 1959), for the temperature perturbation T as function of time t, where r, z and θ denote radial and axial distances and azimuth about the axis of the co-ordinate
30   system. Making the simplifying assumption that T depends only on r and t, this equation simplifies to:

$$\frac{\partial T}{\partial t} = \kappa \left(\frac{\partial^2 T}{\partial r^2} + \frac{1}{r}\frac{\partial T}{\partial r} \right) \quad . \tag{2}$$

It is also assumed that the temperature perturbation at the outer diameter of the lateral, at r=a,
35   resulting from its use for BTES, follows a sinusoidal seasonal pattern, with amplitude ΔT_o, such that, using complex number algebra,

$$T(r=a, t) = \Delta T_o \exp(i \omega t) \quad , \tag{3}$$

40   where $i \equiv \sqrt{(-1)}$ and $\tau \equiv 2\pi/\omega$ is the period of one year, or ~31.6×10^6 s, of the variation. This temperature perturbation will also satisfy the boundary condition that

$$T(r \rightarrow \infty, t) = 0 \quad . \tag{4}$$

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Separable solutions to equation (2) of the form

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$$T(r, t) \equiv R(r) \exp(i \omega t) \tag{5}$$

are sought, which is equivalent to solving

$$r^2 \frac{d^2R}{dr^2} + r \frac{dR}{dr} - \frac{i \omega r^2}{\kappa} R = 0 . \tag{6}$$

If one substitutes $z \equiv r \sqrt{(i \omega / \kappa)}$, then equation (6) reduces to

$$z^2 \frac{d^2R}{dz^2} + z \frac{dR}{dz} - z^2 R = 0 . \tag{7}$$

which is a form of the modified Bessel equation.

In general (e.g. Carslaw & Jaeger 1959), equation (7) has the solution

$$R(z) = C_1 I_0(z) + C_2 K_0(z) \tag{8}$$

where I_0 and K_0 are the zero-order modified Bessel functions of the first and second kinds and C_1 and C_2 are arbitrary constants whose values depend on the applicable boundary conditions. For the present problem, boundary condition (4) requires $C_1=0$. Boundary condition (3) thus enables C_2 to be evaluated, giving the solution

$$T(r,t) = \Delta T_0 \exp(i \omega t) \frac{K_0(r \sqrt{(i \omega / \kappa)})}{K_0(a \sqrt{(i \omega / \kappa)})} \quad (r \geq a). \tag{9}$$

The radial heat flow, $q \equiv -k\, \partial T(r,t)/\partial r$, where k is the thermal conductivity of the rock mass, can thus be determined as

$$q(r,t) = k \Delta T_0 \sqrt{(i \omega / \kappa)} \exp(i \omega t) \frac{K_1(r \sqrt{(i \omega / \kappa)})}{K_0(a \sqrt{(i \omega / \kappa)})} \quad (r \geq a). \tag{10}$$

where K_1 is the first-order modified Bessel function of the second kind.

The energy E thus extracted per seasonal heating cycle into a lateral of length L and radius a from the surrounding rock mass can therefore be calculated as

$$E = -2 \pi a L \int_{t=0}^{t=\pi/\omega} q(r=a,t)\, dt \tag{11}$$

or

$$E = 4 \pi a k L \Delta T_0 \sqrt{(i / (\omega \kappa))} \frac{K_1(a \sqrt{(i \omega / \kappa)})}{K_0(a \sqrt{(i \omega / \kappa)})} . \tag{12}$$

Equations (9), (10) and (12) (as well as equation (13), below) have been evaluated here using Matlab 8.3, which handles the required complex number algebra; the real part of each quantity thus determined provides the physically-meaningful part of the solution. The Matlab code used is listed in Fig. 5.

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It is noted in passing that equation (10), evaluated at r=a, is equivalent (after allowing for the different notations used) to equation (16) on page 194 of Carslaw & Jaeger (1959), thus providing a check; although the latter textbook did not state the equation for r≥a, creating the need to establish what the form of this equation indeed is. Furthermore, equation (9) can be compared with equation (13) on page 263 of Carslaw & Jaeger (1959) for an idealized infinitesimally thin 'line source' releasing heat per unit length at a rate of Q (k / κ) exp(i ω t):

$$T(r,t) \quad = \quad \frac{Q \exp(i \omega t)}{2 \pi \kappa} \; K_o(r \sqrt{(i \omega / \kappa)}) \quad (r>0); \qquad (13)$$

This solution is invalid at r=0 because $K_o(0) \to \infty$, but is valid for finite values of r (Fig. 6). It has been proposed (e.g. Eskilson 1987) that this solution, devised for a notional 'line source' of heat, can be applied to temperature variations in the surroundings to boreholes of radius a, subject to incorporating a phase lag ϕ, calculated as

$$\phi \quad = \quad \arctan \left(\frac{\pi}{2 \ln (2 \kappa \tau / (\pi a^2)) - 4 \gamma} \right) , \qquad (14)$$

where γ is Euler's constant (~0.5772), to represent the temperature variation at the borehole radius. For the parameter values used in Fig. 6 (κ=0.8 mm^2 s^{-1}, τ=1 yr, a=80 mm), equation (14) gives ~13.2° or ~0.44 month. As can be seen from Fig. 6(b), this phase angle correctly predicts the time lag for which the temperature perturbations at radius a are zero. Unfortunately, as can be seen from comparing Figs. 6(a) and (b), this calculation does not also correctly predict the phase lag of the temperature maxima and minima at r=a. This check thus vindicates the decision to revisit the analysis from first principles, rather than simply accepting from the literature that the solution to a different problem can be reused for the present problem with an ad hoc modification, thereby perpetuating a mistake that has entered the literature.

It is also noted in passing that other theory, likewise derived for notional infinitesimally thin 'line sources' of heat, is also routinely applied to problems involving boreholes of finite diameter, for example when conducting thermal response tests of heat exchangers for ground source heat pumps (e.g. Eskilson 1987; Banks 2012; Banks *et al*. 2013; Choi & Ooka 2015). By analogy with the present problem, such usage will not be completely accurate and re-derivation of the underlying theory, starting from first principles, assuming a finite diameter of borehole, is therefore warranted (cf. Lamarche & Beauchamp 2007; Li *et al*. 2014).

Operational parameters for a shale gas well repurposed for BTES
The mode of BTES operation envisaged is illustrated, using the phase diagram for water, in Fig. 7. During the summer heat storage phase, water at a suitably high temperature, containing waste heat from another source, is circulated into the well. In Fig. 7 the maximum temperature envisaged for this water is 180 °C; since this exceeds the usual 100 °C boiling point under standard surface atmospheric pressure, this heat exchanger has to be pressurized. A surface pressure of ~1.2 MPa will suffice (e.g. Engineering Toolbox 2016a); point A in Fig. 7 represents these conditions. As the water flows down the well, it becomes pressurized further, by the water above it, reaching point B in Fig. 7 in the well lateral. The resulting absolute pressure in a 3 km deep lateral is thus ~31.2 MPa. This is far below the pressure required during the fracking phase of well development for shale gas, and so poses no issues for well integrity; for example, from de Pater & Baisch (2011), fracking of the Preese Hall-1 well, at depths of 2-3 km (Fig. 3), utilized fluid pressures of ~60 MPa. Furthermore, the pressure in the lateral

will in reality be somewhat less than these hydrostatic calculations indicate, because the water is flowing. The difference depends (via the standard Darcy-Weisbach equation; see below) on factors such as the flow rate and the surface roughness of the heat exchanger liner and well casing; it is ignored in the present first-order analysis. As this hot water flows through the lateral, some of its heat conducts outward into the surrounding rock mass, as illustrated schematically in Fig. 4(a). The water thus cools, before returning to the surface (Fig. 4(a)).

During the winter heat extraction phase the flow is reversed (Fig. 4(b)). Relatively cold water (represented by point C in Fig. 7) flows downward, becoming pressurized in the process (reaching, in the lateral, point D in Fig. 7). This water absorbs heat from the surrounding rock mass (Fig. 4(b)), returning to the surface at a higher temperature; the heat therein can then be utilized. Taking account of current UK space heating standards (DECC 2012), ~20 °C is envisaged as the lowest temperature at which water might usefully be extracted (Fig. 7).

In thermal physics problems such as this, the temperature distribution in the material surrounding a heat source or heat sink depends on its thermal diffusivity κ, whereas heat transfer also depends on its thermal conductivity k. However, relatively little is currently known about these properties for Carboniferous age mudstones in the UK, analysis having been limited by poor core recovery (e.g. Bott *et al*. 1972; England *et al*. 1980). Furthermore, different analyses of these and other UK mudstones (e.g. Bloomer 1981; Blackwell & Steele 1989; Midttømme *et al*. 1998) have resulted in inconsistent numerical results (Westaway *et al*. 2015b). Guided by this experience, recent syntheses of data (Busby *et al*. 2009; Busby 2016), and the observation that the shale sequences (schematically depicted in Fig. 3) contain proportions of sandstone and limestone (e.g. Riley 1990), with higher k and κ than mudstones, nominal values of 2 W m^{-1} °C^{-1} and 0.8 mm^2 s^{-1} are estimated. These values are mutually consistent, given that k$\equiv\kappa\times\rho\times$c, where ρ and c are the density and specific heat capacity of the rock, with nominal values of ~2500 kg m^{-3} and ~1000 J kg^{-1} °C^{-1}.

The shale basins in Fig. 2 are characterized by heat flow of ~60 mW m^{-2} (Busby *et al*. 2011; Westaway & Younger 2013). With k=2 W m^{-1} °C^{-1}, the geothermal gradient is thus ~30 °C km^{-1}; with a ~10 °C annual mean surface temperature, the unperturbed temperature at the 3 km nominal depth of the proposed BTES is thus ~100 °C. BTES operation as envisaged in Fig. 7 will thus perturb temperature by ΔT_o=±80 °C about this value.

Theory for heat transfer to and from the surrounding rock mass, associated with sinusoidal oscillations in temperature of a cylindrical heat exchanger, was developed above. This is a rare example of a practical thermal physics problem with an analytic solution that was not solved in full in the classic Carslaw & Jaeger (1959) textbook (notwithstanding the other versions of it, reported elsewhere, noted above); hence the need to present the solution here. Although the present analysis clearly makes many simplifying assumptions, it can form the basis for further developments. Both temperature and heat flow variations are thus inferred to taper radially from the heat exchanger but modulated by the phase of the seasonal temperature forcing, this phase experiencing an increasing time lag with radial distance (Fig. 8).

It is noted in passing that this solution (equations (9) and (10); Fig. 8) has much in common with that of the more familiar problem of heat flow to and from a halfspace, representing the Earth's interior, as a result of sinusoidal seasonal variations in surface temperature (e.g. Carslaw & Jaeger 1959;

Turcotte & Schubert 1982), although in this latter case the perturbations decay exponentially with depth rather than as a Bessel function. Their decay with depth is characterized (Turcotte & Schubert 1982), for oscillations of period τ, by a skin depth δ, where

$$\delta \equiv \sqrt{\left(\frac{\kappa \tau}{2}\right)} \, , \tag{15}$$

over which the temperature oscillation decays by a factor of e. With $\tau=1$ yr and $\kappa=0.8$ mm^2 s^{-1}, as for Fig. 8, δ is ~3.6 m. However, for radial heat flow governed by equation (10), geometrical spreading causes the temperature oscillation to taper more abruptly. Moreover, its tapering geometry depends on a, as well as κ and τ; with a=80 mm (as used in Fig. 8), $\kappa=0.8$ mm^2 s^{-1} and $\tau=1$ yr, the temperature oscillation decreases to 1/e of its initial amplitude over a radial distance of ~0.8 m.

A related issue concerns the relative diameters of the inner pipe and the hole containing the heat exchanger. In a fluid of a given viscosity undergoing laminar flow within a pipe at a given average velocity, the pressure drop due to pipe wall friction is inversely proportional to the cross-sectional area of the flow, this being a consequence of the aforementioned Darcy-Weisbach equation (e.g., Gerhart *et al*. 2015). It follows that frictional pressure drop within a borehole heat exchanger of a given diameter is minimized by adopting a 'balanced' configuration with equal cross-sectional areas for the flow through the heat exchanger in both directions. Suppose the hole diameter is Φ, the internal diameter of the inner pipe is B, and that this pipe has wall thickness D. Given that the cross-sectional area of a cylinder is $(\pi/4)$ times the square of its diameter, one finds after several algebraic steps that if the outer diameter of the flow equals Φ, then

$$B = \sqrt{(\Phi^2 / 2 - D^2)} - D \tag{16}$$

whereas if the hole is 'sliplined' with an outer pipe of the same wall thickness as the inner pipe (see below) then

$$B = \sqrt{((\Phi - 2D)^2 / 2 - D^2)} - D \, . \tag{17}$$

In the limit of D$\rightarrow$0 these equations simplify to B=$\sqrt{2}\Phi/2$. It also follows that an optimum heat exchanger design should minimize the pipe wall thickness D to maximize the proportion of the cross-sectional area available for flow.

Furthermore, the governing equations (e.g., (12)) indicate that the ability of this technology to store heat in the subsurface depends on the combination of the values of k and κ (as k/$\sqrt{\kappa}$) for the rock mass and the period τ of the temperature forcing. This combination of parameters, together with the heat storage and heat extraction being 'matched' across each annual cycle, makes operation sustainable, temperature perturbations within the rock mass being effectively contained within a few metres of the heat exchanger (Fig. 8(a)). If, instead, heat storage were to exceed heat extraction over many annual cycles, heat would 'leak' away into the subsurface; whereas if extraction were to exceed storage, the rock mass around the heat exchanger would gradually cool, ultimately limiting the heat extraction. For a representative (e.g. Charpentier & Cook 2013) length L=2000 m, and with other parameter values as previously stated, the annual heat storage capacity of a single shale gas well lateral repurposed for BTES is calculated using equation (12) as 5.74 TJ or 1.59 GWh, which can be rounded to ~6 TJ or ~2 GWh. The corresponding peak energy storage rate, from Fig. 8(b), is ~600 W m^{-2}

$\times\, 2\,\pi \times 0.08$ m (i.e., ~600 W m^{-2} $\times$ the circumference of the borehole) or ~300 W m^{-1}, thus ~0.6 MW in total for a ~2000 m long lateral. With ΔT_o=80 °C, the flow rate of the circulating water would need to be ~0.6 MW $\div$ 1000 kg m^{-3} $\div$ 4185 J kg^{-1} °C^{-1} $\div$ 80 °C (i.e., the energy storage rate $\div$ the density of water $\div$ the specific heat capacity of water $\div$ the temperature difference) or ~2$\times$10^{-3} m^3 s^{-1}, at a typical flow velocity (assuming the balanced configuration in equation (16), with D=0) of ~2$\times$10^{-3} m^3 s^{-1} $\times$ 2 $\div$ π $\div$ 0.08^2 m^2 or ~0.2 m s^{-1}.

Discussion

The above-mentioned performance characteristics can be compared with those of conventional shallow BTES systems. For example, the aforementioned Crailsheim project has been reported (e.g. Schmidt & Miedaner 2012; Mielke *et al*. 2014) as consisting of 80 55-m-deep, 0.13 m diameter, boreholes arranged in a grid with 3 m spacings, this borehole field having an overall diameter of ~28 m. The heat storage volume is reported as 37,500 m^3, indicating a storage cross-sectional area of ~8.5 m^2 around each borehole, roughly equal to the 9 m^2 area between each borehole and its nearest neighbours. Projects of this type typically circulate unpressurized water with a maximum input temperature of ~90 °C (Schmidt & Miedaner 2012), ~80 °C above the typical annual mean surface temperature at sites in NW Europe, and provide seasonal heat storage of ~15-30 kWh m^{-3} at energy storage rates of ~20-30 W m^{-1} (Schmidt & Miedaner 2012). For this particular project, groundwater flow is contributing to dissipation of stored heat (Mielke *et al*. 2014) so, assuming storage at the lower end of the stated range, the energy stored per metre of borehole length can be estimated as ~15 kWh m^{-3} $\times$ ~8.5 m^2 or ~130 kWh m^{-1}. The total seasonal energy storage is thus ~15 kWh m^{-3} $\times$ 37,500 m^3 or ~0.56 GWh, from a total length of 80 $\times$ 55 m or 4400 m of borehole, with a peak energy storage rate of ~30 W m^{-1} $\times$ 4400 m or ~0.13 MW. For an 80 °C temperature difference, the flow rate of the circulating water would need to be ~0.13 MW $\div$ 1000 kg m^{-3} $\div$ 4185 J kg^{-1} °C^{-1} $\div$ 80 °C or ~0.4$\times$10^{-3} m^3 s^{-1}, corresponding to a typical flow velocity (again assuming a 'balanced' configuration, in accordance with equation (16), with minimal wall thickness) of ~4$\times$10^{-4} m^3 s^{-1} $\times$ 2 $\times$ 4 $\div$ π $\div$ 0.13^2 m^2 or ~0.06 m s^{-1}. These values are summarized in Table 1, along with the corresponding parameter values for the proposed shale gas well lateral-based BTES configuration.

The aforementioned performance characteristics can also be compared with those of the October 2014 demonstration of 'Deep Geothermal Single Well' (DGSW) heat extraction in southwest England (e.g. Cavanagh 2014; GEL 2014). This UK-government-funded project utilized one of the boreholes in the Variscan age Carnmenellis Granite at Rosemanowes near Falmouth in West Cornwall, originally drilled in the 1980s as part of the unsuccessful 'hot dry rock' (HDR) geothermal energy project there (e.g. Pine *et al*. 1983; Pine & Batchelor 1984; Richards *et al*. 1994). Notwithstanding the immense publicity it has received, few technical details of this work have been made public, however; this is also the case for a subsequent DGSW feasibility study funded by the Scottish Government (GEL *et al*. 2016). Nonetheless, a schematic diagram from Law (2014), the present Fig. 9, indicates that the concept involves lining the pre-existing borehole with an inner pipe; cold water flows down the annulus thus created, extracting heat from its surroundings, the resulting hot water flowing up the inner pipe for use as heat supply. This technology thus depends on heat extraction by conduction into the borehole from its surroundings, rather than (as in the original HDR project) extracting heat during flow of water through the mass of granite between two boreholes forming a conventional subsurface heat-exchanger 'doublet'. Indeed, if the technology were to rely on flow through the mass of granite it would almost certainly not work, this granite having been conclusively found to be highly impermeable in previous investigations (e.g. Pine *et al*. 1983; Richards *et al*. 1994), this having been

the essential technical issue that 'killed' the original HDR project in the first place. GEL (2015a) reported that DGSW technology might be used in disused shale gas wells, confirming that the intention is for it to work by heat conduction, given the impermeability of shale.

5 Law (2014) reported that this demonstration involved installation of the inner heat exchanger pipe to a depth of ~1800 m and that a peak water temperature of 63 °C was observed, with a coefficient of performance of 50 (meaning that the heat extracted exceeded by a factor of 50 the energy used to pump the water circulation), and a peak rate of heat extraction of 380 kW. According to Pine *et al*. (1983) the borehole used for this demonstration had a diameter (internal diameter of its casing) of
10 311 mm near the surface, decreasing to 216 mm at depth. The specification of the inner pipe used has not been reported, but illustrations presented by Law (2014) show stocks of green plastic pipe that appears to have a diameter of possibly 2 ½" or 64 mm; assuming a moderate wall thickness, its internal diameter might have been ~40 mm. This project evidently did not adopt the 'balanced' design consistent with equation (16); its inner pipe was much narrower than this equation would indicate,
15 possibly to minimize the downflow velocity in the annulus to maximize the time available for the downward flowing water to be warmed, and to also facilitate the subsequent upflow of warm water as fast as possible to minimize heat losses from it (cf. Fig. 9). To calculate the volume flow rate corresponding to the peak thermal power output, ~1.65 litres per second, the same method is used as before but assuming a 55 °C temperature difference between the reported peak temperature of
20 63 °C and an estimated ambient surface temperature of 8 °C, the latter value being reasonable for Cornwall in October. With the pipe dimensions previously estimated, this volume flow rate corresponds to a typical flow velocity of ~1.3 m s^{-1} in the relatively narrow inner pipe and ~0.05 m s^{-1} in the much wider annulus. The spatial average peak rate of energy extraction per unit length for this DSGW test is the peak output power, 380 KW, divided by the length, ~1800 m, or ~200 W m^{-1}. Due to
25 the geothermal gradient, the temperature in the granite will increase roughly linearly with depth; peak rates of heat extraction will thus increase from circa zero near the Earth's surface to roughly double the spatial average value at the bottom of the heat exchanger, hence the estimate of a peak rate of ~400 W m^{-1} in Table 1.

30 The 380 kW thermal power output reported by Law (2014) is, however, only an instantaneous initial transient. A graph presented by Law (2014) indicates that within ~9 hours of the start of operation the temperature had adjusted to ~40±5 °C throughout the vertical extent of the borehole heat exchanger. The heat output at this time, for the same volume flow rate as before, would thus have been ~32/55 or ~60% of the instantaneous initial maximum, thus ~220 kW. Furthermore, if an attempt were made
35 to extract heat at even this lower rate from such a system, say to heat a neighbouring building throughout a winter, the result would be progressive cooling of the rock mass surrounding the heat exchanger to ever-greater radial distances, resulting in progressive decreases over time in heat output. This point, which does not seem to have been taken on board by advocates of the 'DGSW' concept in Fig. 9, can be regarded as the 'heat extraction' analogue of the result (Lanini *et al*. 2014) that to
40 optimise heat storage a BTES borehole array should be broad, to minimise heat losses into the surroundings. It means that, although high rates of thermal output might be obtained in the short term, a borehole heat exchanger like that in Fig. 9, used solely for heat extraction, cannot be sustainable in the long term.

45 The Rosemanowes test nonetheless substantiates as reasonable many of the estimates of parameter values used to establish the BTES concept (Table 1). For example, it demonstrates the feasibility of

lining an existing borehole with plastic pipe, and shows that such pipe will support flow velocities of the required order-of-magnitude. Cavanagh (2014) reported a preliminary estimate, for which no supporting calculations were provided, that a single well purpose-drilled as a DGSW could support heat extraction at ~0.5 MW, an estimate that is roughly in accord with the present ~0.6 MW estimate of the peak rate of heat storage or extraction for a single BTES well. As already noted, the peak rate of heat storage or extraction scales, for different lithologies, with k / √κ (see, e.g., equation (12), also Westaway *et al*. 2015b). Thus, using the parameter values in Table 1, a well of given dimensions in granite will be able to store or supply ~17% more thermal energy than one of the same dimensions in shale. The present BTES estimate of ~0.6 MW for a BTES well in shale thus scales to ~0.7 MW for a well of equivalent dimensions in granite. The difference between this figure and the ~0.5 MW estimate from Kavanagh (2014) relates to the assumption a higher temperature difference and the resulting water circulation at higher pressure. Furthermore, the proposed mode of operation of a BTES would be sustainable over an indefinite number of years, whereas (as already noted) the estimate for a DGSW is an initial transient preceding a progressive decline in thermal output.

As Table 1 also indicates, the proposed BTES configuration also achieves significantly more energy storage than the Crailsheim project, despite involving a much shorter length of subsurface heat exchanger. This is partly because faster flow through the system is assumed, which achieves higher rates of energy transfer, this being partly a consequence of the larger diameter of the borehole. It is also partly a consequence of the thermal diffusivity of Carboniferous mudstones in Britain being assumed to be higher than the typical measured value (from Mielke *et al*. 2014) for the rocks utilized for the Crailsheim subsurface heat exchanger. An additional factor, recently recognized (Lanini *et al*. 2014), is that the design of this project was non-optimal from the point of view of efficiency of energy storage. It has indeed been reported (Lanini *et al*. 2014) that the most efficient design for such projects, to minimize radial heat losses to the surroundings, requires the form factor of the borehole field, the ratio of its diameter to its vertical extent, to be 2, whereas for the Crailsheim project this ratio was ~28 m / ~55 m or ~0.5. The main reason for the difference, however, is the different mode of operation envisaged, whereby heat storage in and heat extraction from a shale gas well repurposed for BTES are balanced, whereas the Crailsheim project involves net storage of heat in the subsurface. As already discussed, a balanced operational configuration, such as that envisaged, is only feasible if the ambient temperature at the depth of the heat exchanger is well above that at the Earth's surface. Otherwise, as is evident from the analysis of the Crailsheim project (Mielke *et al*. 2014), much of the heat stored in the subsurface diffuses outward and ends up so far away from the heat exchanger that it can never be recovered. An additional issue with this particular project, as already noted, is the presence of significant groundwater flow, which also acts to transport much of the injected heat away from the borehole heat exchanger (Mielke *et al*. 2014). Overall, in round numbers, Table 1 indicates that, using roughly half the length of heat exchanger, the proposed shale gas well lateral-based BTES design can provide roughly three times as much seasonal heat storage as the Crailsheim BTES project; per unit length of heat exchanger, it is thus roughly six times as effective.

The perceived disadvantages of 'conventional' BTES technology (Gao *et al*. 2015) relating to site complexity and the resulting complexity of heat transfer mechanisms will be mitigated by the proposed approach, since the rock mass used for heat storage will have homogenous thermal properties, and these properties will in due course become well-established as a result of previous shale gas development activities. The extremely low permeability of the shales means that effects of groundwater flow on heat transport can be discounted; the heat flow into and out of the borehole

heat exchanger will, thus, be purely conductive, and therefore much simpler to model than any corresponding calculations involving components of heat transport by groundwater flow. This can be seen by comparing, for example, the conductive calculations in the present account or, indeed, those by Busby *et al.* (2009), with the much more complex – and much more expensive, in terms of both time and computing resources – calculations incorporating groundwater flow for the Crailsheim BTES installation by Mielke *et al.* (2014).

Many possibilities exist for the source of the heat stored in shale gas well lateral-based BTES systems; these include waste heat from summer cooling systems (e.g., air conditioning) or industrial plant, or dissipation as heat of electricity generated by excess wind farm capacity. There is thus scope for exploring the possibilities for integrating these systems with other infrastructure, for example using heat pumps to match the required input and output temperatures (cf. Hesaraki *et al.* 2015; Liu *et al.* 2015; Retkowski *et al.* 2015), as well as investigating the ability of this technology to handle heat storage from intermittent sources such as those noted above.

Some key implications of the preceding analysis will now be addressed. These will include estimation of the overall impact of BTES based on shale gas well laterals in the UK, taking into account the number of wells envisaged, some preliminary financial considerations relating to repurposing of shale gas wells for BTES, some possible refinements to the preliminary design already presented, and consideration of how the possibility of repurposing for BTES might influence the current negative perception of shale gas development by much of the UK population.

Overall impact of shale gas well repurposing for BTES in the UK
The potential impact of BTES technology on heat supply depends on the overall number of wells available. One scenario for UK shale gas production (IOD 2013) envisages 50 drilling rigs operating during 2016-2032 to create 4000 wells, each costing ~£6 million to drill, with a peak rate of shale gas production of 1121 bcf yr^{-1}. This large number of wells is necessary because the production from each declines progressively over only a few years (e.g. Browning *et al.* 2013; IOD 2013; Lund 2014), so new wells are required to replace those where production has already ceased. Using the standard conversion factor (BP 2015) of 1.065 MJ cf^{-1}, the stated production rate would supply ~330 TWh yr^{-1} of energy, which would meet much of the ~800 TWh yr^{-1} present-day heat demand in the UK (DECC 2012) if used entirely for this purpose. However, this scenario was based on the assumption of 3.2 bcf of shale gas production per well (IOD 2013). As noted above, the lower alternative of ~1 bcf now seems more likely; if combined with the same assumptions as before about the duration of production per well, this would require development of 12,800 wells on the same timescale to sustain the output envisaged. If these wells were repurposed for BTES, operated in accordance with Figs. 7 and 8, the resulting annual energy storage capacity is estimated as 12,800 × ~1.6 GWh or ~20 TWh. The overall present-day UK annual heat demand (DECC 2012), for ~60 million people, equates to ~13 TWh per million people. The heat demand for the ~2 million population of the part of Scotland with the shale resource (Fig. 2(a)) can thus be estimated as ~26 TWh yr^{-1}; so if all the shale gas production were from here the BTES capacity that could be subsequently developed would meet most of the local heat demand. If, instead, much of the UK shale gas production were derived from northern England, with its larger population, the proportion of the overall heat supply provided by the BTES capacity thereby created would be lower, but would nonetheless remain a significant resource. In detail, the production per shale gas well correlates positively with the length of its lateral (e.g. Charpentier & Cook 2013); for example, for the Barnett Shale of Texas, ~2000 m laterals (adopted for the present calculations;

Fig. 8) correlate (e.g. Charpentier & Cook 2013) with mean production of 1.75 bcf, with an inter-quartile range of 1.00-2.35 bcf. The Barnett Shale has been proposed as an analogue of the Bowland Shale of northern England (Fig. 3) for forecasting physical properties (e.g. Westaway & Younger 2014); however, the extent of this analogy is currently unclear. Techniques exist for optimizing lateral length for each shale province (e.g. Chorn *et al*. 2014); the present calculations are readily scalable for any length of lateral or production figure per well. The aforementioned estimate for seasonal heat storage of ~6 TJ or ~2 GWh, derived for a 2000 m long lateral, can likewise be scaled to any other length of lateral and summed over whatever number of laterals of a given length is required to achieve a given shale gas production target.

Financial considerations

As already noted, expenditure on conventional BTES projects is dominated by the costs of drilling and of insulating the Earth's surface (Schmidt & Miedaner 2012). For example, for the aforementioned Crailsheim project, of the overall €520,000 cost, 52% was for the former and 24% for the latter (Schmidt & Miedaner 2012). Excluding these two contributions to the overall budget, but keeping the other components the same, the estimated 76% saving would reduce the cost of heat storage from ~€1.10 or ~£0.80 per kWh to a notional minimum of ~€0.26 or ~£0.20 per kWh, much lower amounts that make the technology more competitive compared with using gas for heating.

One can also draw preliminary cost data from the reporting of the Rosemanowes DGSW demonstration (Kavanagh 2014), notwithstanding (once again) the lack of supporting calculations. It was thus reported that a single well, purpose-drilled as a DGSW, might cost £1.4 million, whereas "If you can colonise a well, it could cost as little as £200,000. … It's logical to tap into energy underground and use it for buildings – it's low hanging fruit." However, it is not at all clear how this number was calculated, or whether it is based on 'one off' costs or presumes that adaptation of many wells using standard components, mass-produced for economies of scale, will result in significant future cost reductions. It is also difficult to convert this £0.2 million budget into an estimate of the resulting unit cost of heat production for a DGSW, because of the progressive heat production decline that is inherent in the concept (see above). However, if a single well could be repurposed for ~£0.2 million as a BTES, combining alternate cycles of storage of ~1.6 GWh of waste heat and production of ~1.6 GWh of useable heat each year, the unit cost of the heat thus generated in the first year would be ~£200,000 / (~1.6 GWh × 50) or £0.13 per kWh. If the resulting heat supply had, say, a ~50 year lifespan before renewal was necessary then, since the running costs of the installation would be near zero, the overall lifecycle cost of the heat production would be ~£0.003 per kWh, an extremely low value.

As a result of progressive efficiency savings, typical drilling costs for US shale gas wells continue to decline; for example, one company has reported a reduction from 4.5 million in early 2014 to a projected 2.6 million for 2016 (DiLallo 2015), far below the ~£6 million (~10 million) previously estimated for the UK (IOD 2013). Even with drilling costing as little as 2.6 million or ~£1.8 million to create ~1.6 GWh of annual subsurface heat storage, the overall capital cost of a purpose-drilled 'deep BTES' installation would exceed £1.10 per kWh of annual heat storage. Notwithstanding the use of highly efficient drilling procedures, this exceeds the cost of drilling for the Crailsheim BTES project, which (from Schmidt & Miedaner 2012) amounts to ~£0.40 per kWh of annual subsurface heat storage, the difference reflecting the expense inherent in deep drilling. If the ~£1.4 million drilling cost mentioned by Kavanagh (2014) is achievable, then including the estimated ~£0.2 million for the heat

exchanger, the cost would reduce to ~£1.00 per kWh of annual heat storage. Taking, as before, an estimated lifespan of 50 years, the overall lifecycle cost of the resulting useable heat output would reduce to ~£0.02 per kWh. Overall, these calculations indicate that, in terms of capital cost 'deep BTES' using purpose-drilled wells is likely to be more expensive than 'shallow BTES', but 'deep BTES' achieved by repurposing existing wells, drilled for another purpose, may well be achievable for a lower capital cost than 'shallow BTES'. Nonetheless, provided installations have minimum lifespans of several decades, both 'deep BTES' using purpose-drilled wells and 'deep BTES' by repurposing existing wells will be able to produce heat at much less cost than the current retail cost of natural gas in the UK. Wells might indeed be developed in future jointly both for shale gas and for subsequent heat storage and production, the potential future value for the latter purpose being factored into the initial costing (cf. Yuan *et al*. 2015).

For comparison, electricity storage technologies are generally only considered viable if their capital cost is ≤0.60 per kWh (e.g. Chu & Majumdar 2012), equivalent to ~≤£0.40 per kWh. The above estimates of £0.13-0.20 per kWh for seasonal storage capacity for deep BTES from well repurposing undercut this estimate considerably. This calls into question a long-standing assumption in energy research, that once buildings have been made highly energy-efficient the optimum solution for heating them will be to use electricity, potentially using some form of electricity storage or overnight storage of solar heat at solar power plants to overcome intermittency issues (e.g. King *et al.* 2015; Pfenninger & Keirstead 2015). More sophisticated cost calculations than those presented here, for example on 'levelized cost' or 'net present value' bases, might be also be presented, but are beyond the scope of the present study.

The possibility of repurposing shale gas wells for BTES bears upon discussion of whether shale gas developments should be regarded as high risk investments, because they might create 'stranded assets' (i.e., assets which have to be written off because they cannot comply with future regulatory requirements) given the possibility of future restrictions on burning fossil fuels to achieve a worldwide 'near zero carbon' energy future (e.g. Leaton *et al*. 2013; UNEP 2014a). Although popular with activist environmental objectors to shale gas, it is not self-evident that this argument makes sense, given that the production decline for any shale gas development has a much shorter timescale (e.g. Browning *et al*. 2013; IOD 2013; Lund 2014) than would the introduction of any new global environmental regulations. In any case, even if severe restrictions (e.g. UNEP 2014b) (or, conceivably, even a ban) on burning fossil fuels were introduced globally in the future, petrochemical feedstock will still be required (apart from other uses, it will provide the polymers required for 'deep BTES' heat exchangers). Although this feedstock might be derived from biofuels (e.g. Chu & Majumdar 2012; Georgianna & Mayfield 2012), sourcing from shale would not impinge on land use; moreover, the low production per well and its associated rapid decline would facilitate tailoring supply to demand. The ability to repurpose for BTES shale gas wells developed for this reason, with numbers increasing indefinitely and thus adding to the overall heat storage capacity, further guarantees the value of such investments; as was noted above, the potential reuse value of such infrastructure might indeed be factored into initial analyses of the economics of shale gas projects (cf. Yuan *et al.* 2015).

Design refinements
There is scope for more detailed consideration of the operational cycle design for a shale gas well repurposed for BTES (ABCD in Fig. 7) in relation to the phase diagram of water; for example, the optimum solution might involve greater pressurization to utilize higher temperatures. However, the

more extreme these conditions the more limited will be the choice of materials for the heat exchanger liner; even at the conditions specified here, a heat- and corrosion-resistant polymer such as polytetrafluoroethylene or fluorinated ethylene propylene might well be required (cf. Kalpakjian & Schmid 2008). On the other hand, it might instead turn out that the cost of such refinements might not be justified in terms of the increases in heat storage that they permit, making simpler options preferable. It is, indeed, conceivable that the extent of pressurization of the circulating water, envisaged in Fig. 7, might be too expensive to justify in comparison with a simpler system with water at atmospheric pressure at the Earth's surface, notwithstanding the reduction in heat storage capacity that would result. There is clearly also scope for refining the analytic solution presented above; for example, the water flow while a 'deep BTES' system is operating will create a temperature gradient along the length of its lateral, which will induce a corresponding component of heat flow in the surrounding rock mass, rather than the heat flow being only radial as currently assumed. The present analysis also neglects heat transport into and heat storage in the surroundings of the vertical part of a shale gas well. Indeed, since wells are typically wider at the surface than at depth, an optimum solution might utilize the upward increase in diameter by increasing the thickness of inner pipe to better insulate the downward and upward flows from each other. Furthermore, as already noted, the calculated pressure variations in the circulating water, ΔP, should also ideally include dynamic effects of the fluid motion, rather than being purely hydrostatic. The calculations should thus utilize the Darcy-Weisbach equation,

$$\Delta P \text{ (Pa)} = \pm \rho \, g \, \Delta z - \frac{f \, V^2}{2 \, g \, D} \Delta L \qquad (18)$$

(e.g. Lyons *et al*. 2009, p. 167), where ρ and V are its density and velocity along a cylindrical channel of length ΔL, vertical extent Δz and diameter D, g is the acceleration due to gravity, and f is the Darcy-Weisbach friction factor for the flow regime. The $\pm$ signs refer to the vertical component of flow; it is – if upward, where the two terms combine, and + if downward, where they partly cancel. The value of f itself depends on the Reynolds Number, Re, of the flow, where

$$Re \equiv \frac{V \, D}{\nu} \qquad (19)$$

ν being the kinematic viscosity of the water, equal to its (dynamic) viscosity divided by ρ. In general, if Re < ~2000, the flow is laminar, whereas at higher Re it is turbulent. In the latter case, f also depends strongly on the roughness of the surfaces of the pipe, being markedly higher the rougher these are. In contrast, for laminar flow f takes standard values as a function of Re (e.g. McKeon *et al*. 2004). Such complexities are neglected in the present analysis; the low flow velocities considered mean that the 'dynamic' pressure terms will be small and so the actual pressure variations will not differ much from the purely hydrostatic case, as was calculated, for instance, for the creation of Fig. 7.

One potential issue affecting 'deep BTES' design is that any disused shale gas well will have been fracked, so the casing of its lateral will have been perforated, probably at many points, to permit outflow of fracking fluid; the fracture network extending from each perforation will have dimensions of hundreds of metres (e.g. Fisher & Warpinski 2012; Davies *et al*. 2013; Westaway & Younger 2014). The analysis of 'deep BTES' operation assumes, on the contrary, no leakage of water from the lateral. The solution, to ensure no such leakage, might be 'sliplining' of the well: insertion of an outer liner, whose external diameter is slightly less than the internal diameter of the well casing, which contains the inner liner to create the heat exchanger, as illustrated schematically in Fig. 4(c). This is, however,

one aspect of BTES that is not demonstrated as feasible by the 2014 Rosemanowes demonstration, as the well used for this was cased (Fig. 9). It is thus unclear at this stage how wide a pipe might be 'sliplined' into a shale well of a given diameter, with its characteristic curved cross-section (Fig. 3), or how thick its walls would need to be (cf. equation (17)). A related issue is whether the optimum design

5   solution would be for the cross-sectional areas of both the inner pipe and its annulus to be equal or 'balanced' (cf. equations (16) and (17)), bearing in mind that the system will need to operate with flow in both directions (cf. Fig. 4), or whether characteristics of the seasonal patterns of heat storage and heat production will dictate a different configuration.

10   *Implications for public perception of shale gas*
The possibility of repurposing shale gas wells for BTES also influences perception of the balance between benefits and negative consequences of shale gas development on a local scale. In a jurisdiction such as the UK, with mineral rights owned by the government rather than by local landowners, residents faced with the possibility of a nearby shale gas project have to consider the

15   impact of the various temporary forms of nuisance that will occur while its development is in progress (drilling noise, increased traffic, visual intrusion, etc, plus the possibility of induced earthquakes large enough to be felt; e.g. Westaway & Younger 2014) against no clear direct benefit. Attempts by shale developers to offer 'community benefits' to mitigate opposition to their proposals are widely perceived by objectors as bribery, and also create difficulties over how to define the 'affected

20   community'. On the contrary, the potential for disused wells to be repurposed for BTES means that communities in close proximity have the opportunity, within a few years, of a sustainable heat supply. One might indeed factor this future direct benefit into the planning of a shale development; the optimum solution might involve siting near other infrastructure, or possibly as near as practicable to communities that will ultimately benefit from the heat supply, whereas if nuisance-mitigation were

25   the sole governing factor siting would be as far from residential properties as possible.

A related issue concerns the legality of repurposing any borehole. The environmental permitting regulations currently applicable in England (DEFRA 2013; and equivalent regulations for Scotland) require, in plain English, the purpose of any borehole to be specified in advance and do not permit

30   this to be changed; once use for the original purpose ends, the borehole must be plugged in a specified manner. It would therefore be illegal to obtain an Environmental Permit for a shale gas well then to retrospectively repurpose it for BTES. Under the present legal framework, the intention, once gas production ends, to convert the well for BTES must therefore be included in the initial application for an Environmental Permit. The need to address this issue in advance of any shale gas project introduces

35   urgency into consideration of eventual reuse for BTES and has prompted the present analysis.

Conclusions
A preliminary analytic model has been developed to investigate the potential of repurposing disused shale gas wells for seasonal BTES. Using representative parameter values, it is thus estimated that the

40   annual heat storage capacity of a single well lateral is 5.74 TJ or 1.59 GWh, which is rounded to ~6 TJ or ~2 GWh. The many thousands of shale gas wells that, it is envisaged, will be developed in the UK during coming decades will thus be adaptable to create a seasonal heat storage resource of many terawatt-hours, sufficient to account for a significant proportion of the heat load in the regions with the shale resource. The ability to repurpose shale gas wells for BTES, providing a sustainable winter

45   heat supply once gas production has finished, may well influence UK public opinion in favour of shale

gas. These considerations are particularly important for Scotland, given its concentration of population in the shale resource region.

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Figure captions

Figure 1. Schematic diagram illustrating the basic concept of converting a well into a heat exchanger by inserting an inner pipe. From Duerden (2011).

Figure 2. Maps (showing co-ordinates using the British National Grid [BNG]) of shale gas resource areas in Scotland (a) (modified after Fig. 67 of Monaghan 2014) and northern/central England (b) (modified after Fig. 43 of Andrews 2013). Both maps indicate, for each designated study region, the resource identified in those parts of the specified rock formations that are inferred to be mature for gas generation (vitrinite reflectance parameter R_o >1.1%) and deeper than a specified depth threshold. In Scotland, this threshold was set at 805 m (i.e., 500 m plus 1000 ft) below sea level or 805 m below the deepest level of coal mining in each locality, whichever is greater (Monaghan 2014). In northern/central England, it was set at 1524 m (i.e., 5000 ft) below the land surface in onshore areas and 1524 m below sea level in offshore areas (Andrews 2013). The principal cities in these study regions are indicated thus: EH, Edinburgh; G, Glasgow; LS, Leeds; L, Liverpool; M, Manchester; NG, Nottingham; and S, Sheffield. + symbol in (b) marks the position of the Preese Hall-1 well (Fig. 3). Inset shows locations.

Figure 3. Summary stratigraphic column for the Preese Hall-1 well in northwest England (located at BNG reference SD 37525 36584; + symbol in Fig. 2(b)), modified after Fig. 3 of de Pater & Baisch (2011), with shading to indicate the local stratigraphic positions of the Upper and Lower mudstone units depicted in Fig. 2(b). Also depicted is a schematic representation of hypothetical shale gas production well in this vicinity, where an initial vertical boring has been deviated at the depth of the producing formation into a horizontal lateral. This depiction, which is not to horizontal scale, has been annotated to indicate the meaning of the parameter L used in the calculations (equation (12)). It is noted in passing that, while the present manuscript was in preparation, it became apparent that considerable uncertainty exists regarding the published depiction of stratigraphic and structural data pertaining to the Preese Hall-1 well (Westaway 2016a). Furthermore, while the manuscript was under review, new information pertaining to these issues was placed in the public domain by Clarke (2016) and Kingdon (2016) as part of a wider online discussion. It thus became apparent that the depiction of the stratigraphy in this Figure is contradicted by biostratigraphic evidence and is thus incorrect: the rocks deeper than ~2000 m in reality represent the upper part of the Bowland Shale Formation, including interbedded limestone units that had previously been mistaken as older formations. Subsequent checking by Westaway (2016b) established that, although it had not been made public at the time, the 'correct' stratigraphy had been known to the British Geological Survey for some time and was incorporated into the Andrews (2013) publication; the summary depiction of the shale gas resource in the present Fig. 2(b) thus requires no revision.

Figure 4. Schematic enlargement of the end of the well lateral in Fig. 3 to indicate its seasonal mode of operation as a heat exchanger for BTES. (c) depicts a variant of (b) in which sliplining has been used rather than depending on the original well casing for the functioning of the heat exchanger.
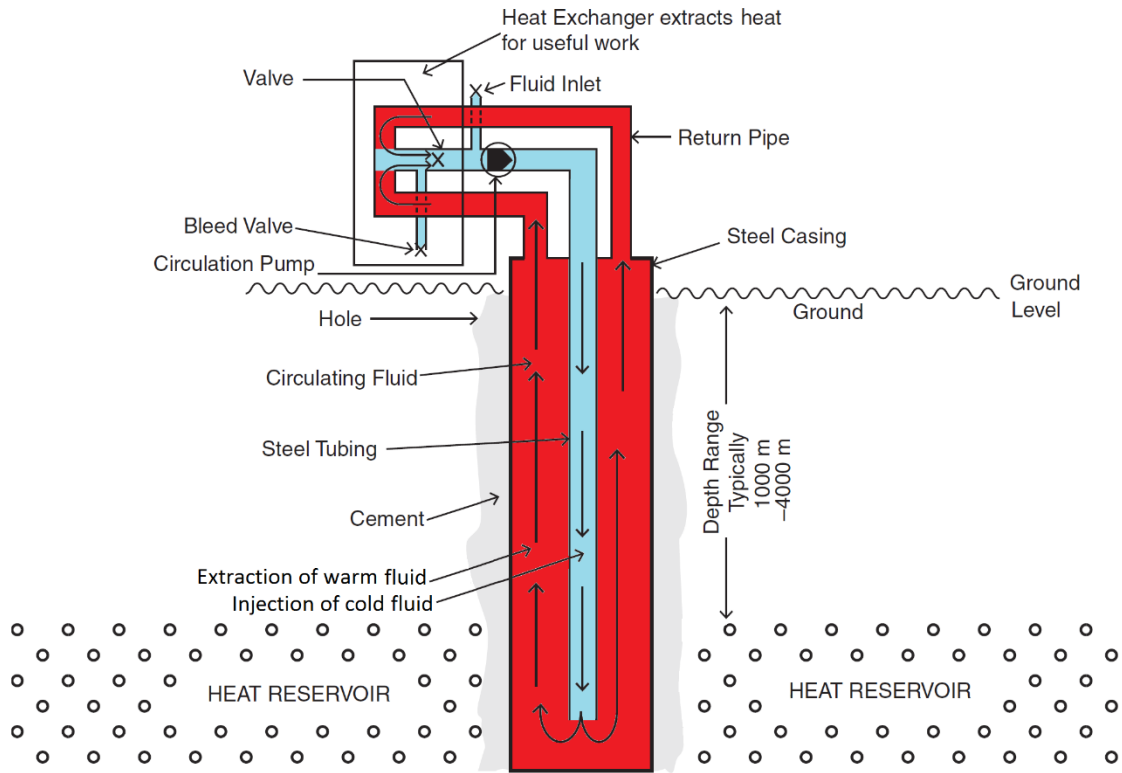
Figure 5. Listing of Matlab source code for creation of Figs. 6 and 8.

Figure 6. Graphs of the predicted temperature variation in the surroundings to a notional infinitesimally thin 'line source' of heat at r=0, which is experiencing seasonal temperature variations in accordance with equation (13), these variations being modulated by seasonal time lags (after Eskilson 1987) in an attempt use this equation to correctly predict the temperature in the surroundings to a borehole of finite radius. The calculations assume κ=0.8 mm^2 s^{-1}, t=1 yr, and Q=1.2×10^{-4} m^2 °C s^{-1}, this latter value being chosen to give (for k=2.0 W m^{-1} °C^{-1}), roughly the same peak radial heat flux per unit length (~300 W m^{-1}) at r=a=80 mm as the solution in Fig. 8. **(a)** for phase lag (ϕ, from equation (14)) zero. **(b)** for ϕ=0.44 month. See text for discussion.

Figure 7. Phase diagram for water, indicating the pressure-temperature regime under which shale gas well based BTES might operate. This regime, discussed in the text, is calculated for a 3 km deep well lateral in a region with an annual mean surface temperature of 10 °C and a geothermal gradient of 30 °C km^{-1}, so the ambient temperature at 3 km depth is 100 °C. The temperature in the immediate surroundings of the well lateral is assumed to vary about this mean value by ±80 °C, thus varying between 180 °C at the time of maximum heat storage (point A) and 20 °C at the time of maximum heat extraction (point D). At the start of heat extraction, water at a temperature of 180 °C will be returned to the surface (point C), so the system must be pressurized (at the surface) to at least ~1.2 MPa to prevent this water from boiling (e.g., Engineering Toolbox, 2015). The pressure at 3 km depth (points C and D) is depicted as exceeding this value by ~30 MPa, calculated for the hydrostatic case as the depth × the 1000 kg m^{-3} density of water × the acceleration due to gravity. Near the end of the winter heat-extraction cycle, the temperature in the heat exchanger will fall to ~20 °C, represented at the surface at point C and at depth at point D.

Figure 8. Predicted seasonal variations in temperature (a) and heat flow (b) with radial distance r in the surroundings of a well lateral repurposed for BTES. Seasonal timings are in months after the lateral reaches its maximum temperature. Predictions use equations (9) and (10) with the following parameter values: T_o (amplitude of the seasonal temperature variation; cf. Fig. 7) 80 °C; a (radius of the lateral) 80 mm; κ (thermal diffusivity of the surrounding rock mass) 0.8 mm^2 s^{-1}; and k (thermal conductivity of the surrounding rock mass) 2 W m^{-1} °C^{-1}.

Figure 9. Schematic diagram illustrating the operation of a 'Deep Geothermal Single Well' heat exchanger, from Law (2014). Compare with Figs 1, 3 and 4. See text for discussion.
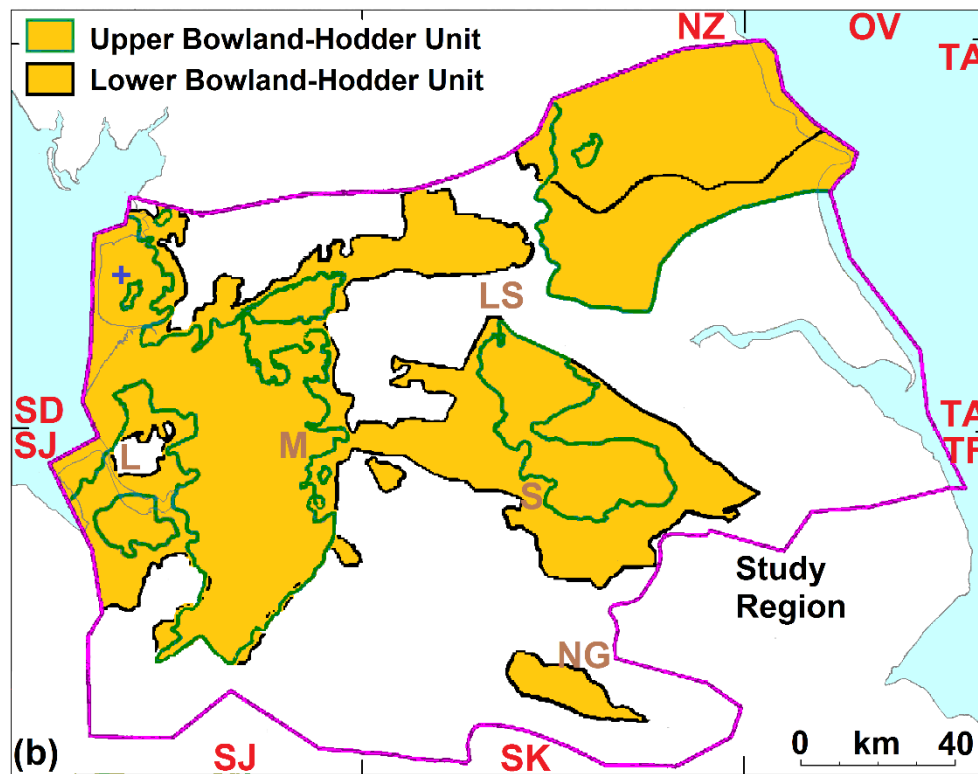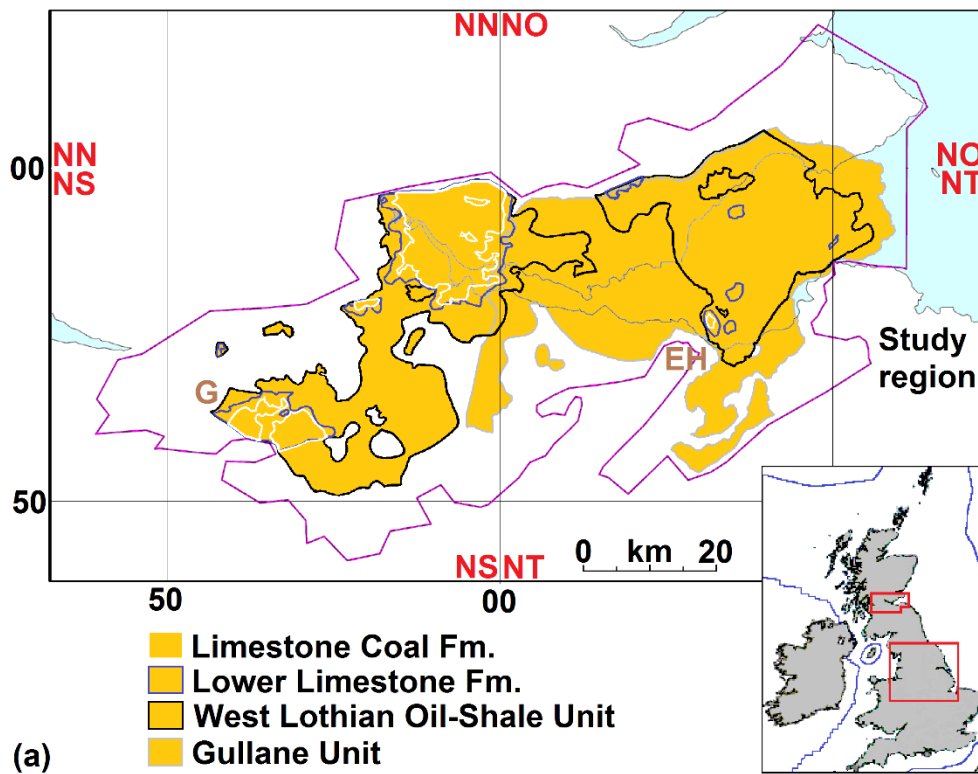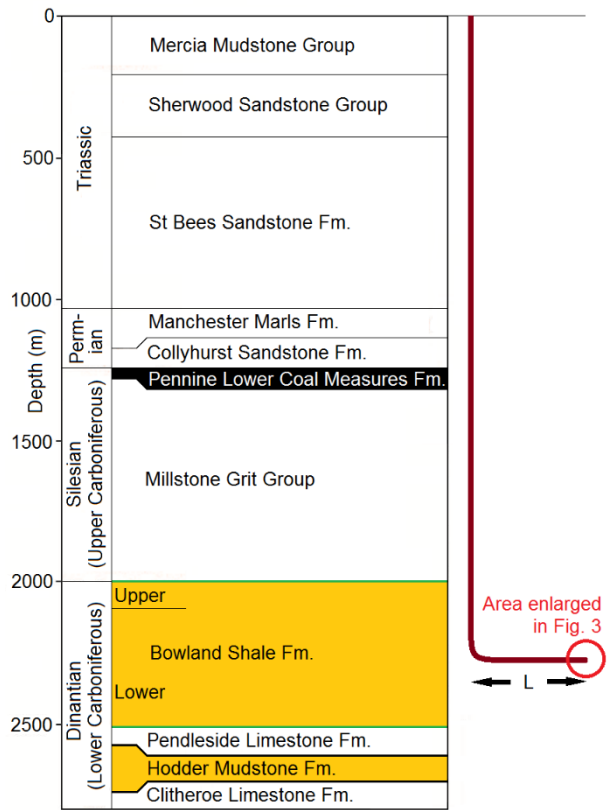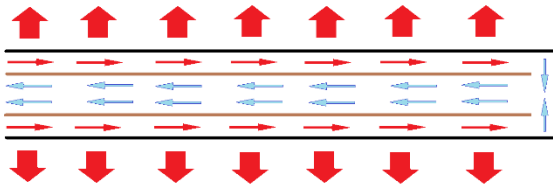
Heat Exchanger extracts heat for useful work

Valve

Fluid Inlet

Return Pipe

Bleed Valve

Circulation Pump

Steel Casing

Ground Level

Hole

Ground

Circulating Fluid

Steel Tubing

Depth Range Typically 1000 m –4000 m

Cement

Extraction of warm fluid

Injection of cold fluid

HEAT RESERVOIR

HEAT RESERVOIR

(a)

Limestone Coal Fm.
Lower Limestone Fm.
West Lothian Oil-Shale Unit
Gullane Unit

Upper Bowland-Hodder Unit
Lower Bowland-Hodder Unit

(b)

Figure 2

Figure 3

Heat storage phase (summer):

(a)

Heat extraction phase (winter):
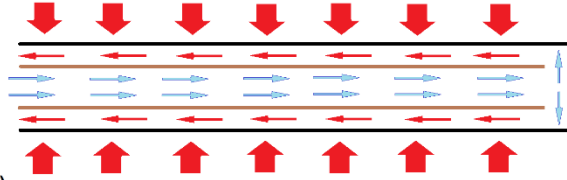
(b)

Or: Heat extraction phase (winter):
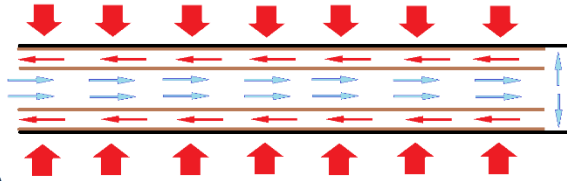
(c)

Key:

─────	Well casing
─────	Liner to create heat exchanger
──▷	Direction of flow of cooler water
──→	Direction of flow of warmer water
⬛➡	Direction of heat flow in surrounding rock mass

Figure 4

```matlab
% Matlab code, compatible with graphics
% for 2014 and 2015 versions of Matlab
%
% Rob Westaway, University of Glasgow, 28 June 2016
%
% Radial heat transport from a cylindrical lateral
% to a shale gas well
%
% Initial setup
%
clc;clf;clear all
kappa=8e-7;
k=2.0;
temp0=80;
a=0.08;
tau=31.6e6;
L=2000;
omega=2*pi/tau;
dt=0.44;%dt=0;
Afac=1.2e-4;
tpk=2*pi*kappa;
%
ifac=sqrt(i*omega/kappa);
Koa=besselk(0,a*ifac);
%
% Calculate seasonal temperature variation
%
ri=a;ro=8;
r=[ri:a:ro];
for t=[0,tau/4,tau/2,3*tau/4]
    n=4*t/tau;
    Ko=besselk(0,r*ifac);
    efac=exp(i*omega*t);
    temp=temp0*efac*Ko/Koa;
    if n==0
        plot(r,temp,'-','linewidth',1.5);
        elseif n==1
        plot(r,temp,'--','linewidth',1.5);
        elseif n==2
        plot(r,temp,':','linewidth',1.5);
        else
        plot(r,temp,'-.','linewidth',1.5);
    end
    xlabel('Radial distance, r (m)')
    ylabel('Temperature perturbation, T (deg C)')
    title('Temperature distribution around a horizontal well')
    grid on;hold on
end
text(1,28,'t=0')
text(3,12,'t=3 months')
text(1,-28,'t=6 months')
text(3,-12,'t=9 months')
```
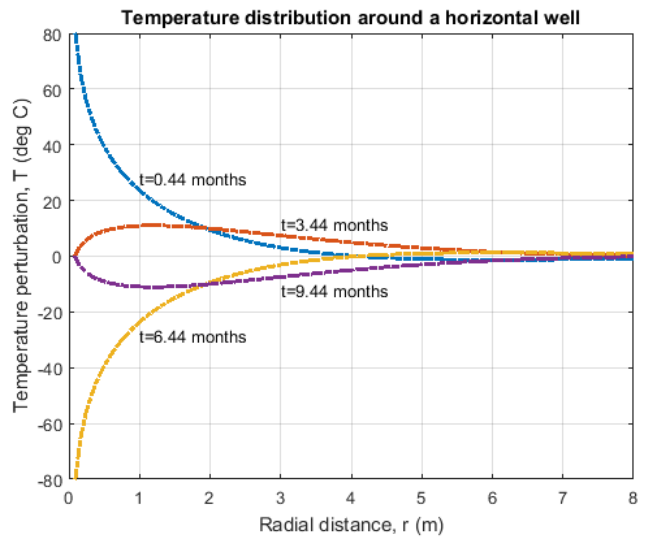
```matlab
%
% Calculate seasonal variation in heat flow
%
figure
ri=a;ro=4;
r=[ri:a/2:ro];
for t=[0,tau/4,tau/2,3*tau/4]
    n=4*t/tau;
    K1=besselk(1,r*ifac);
    efac=exp(i*omega*t);
    hf=temp0*k*ifac*efac*K1/Koa;
    if n==0
        plot(r,hf,'-','linewidth',1.5);
        elseif n==1
        plot(r,hf,'--','linewidth',1.5);
        elseif n==2
        plot(r,hf,':','linewidth',1.5);
        else
        plot(r,hf,'-.','linewidth',1.5);
    end
    xlabel('Radial distance, r (m)')
    ylabel('Heat flow perturbation, q (W / m^2)')
    title('Heat flow distribution around a horizontal well')
    grid on;hold on
end
text(0.2,280,'t=0')
text(0.2,-280,'t=6 months')
%
% Calculate temperature after Carslaw & Jaeger
%
figure
ri=a;ro=8;
r=[ri:a:ro];
for t=[tau*dt/12,tau*(3+dt)/12,tau*(6+dt)/12,tau*(9+dt)/12]
    n=4*t/tau;
    Ko=besselk(0,r*ifac);
    efac=exp(i*omega*t);
    temp=Afac*efac*Ko/tpk;
    if n==0
        plot(r,temp,'-','linewidth',1.5);
        elseif n==1
        plot(r,temp,'--','linewidth',1.5);
        elseif n==2
        plot(r,temp,':','linewidth',1.5);
        else
        plot(r,temp,'-.','linewidth',1.5);
    end
    xlabel('Radial distance, r (m)')
    ylabel('Temperature perturbation, T (deg C)')
    title('Temperature distribution around a horizontal well')
    axis([0 8 -80 80])
    grid on;hold on
end
text(1,28,'t=0.44 months')
text(3,12,'t=3.44 months')
text(1,-28,'t=6.44 months')
text(3,-12,'t=9.44 months')
%
% Calculate energy storage
%
K1a=besselk(1,a*ifac);
energy=4*pi*a*L*temp0*k*(ifac/omega)*K1a/Koa
```

Figure 5
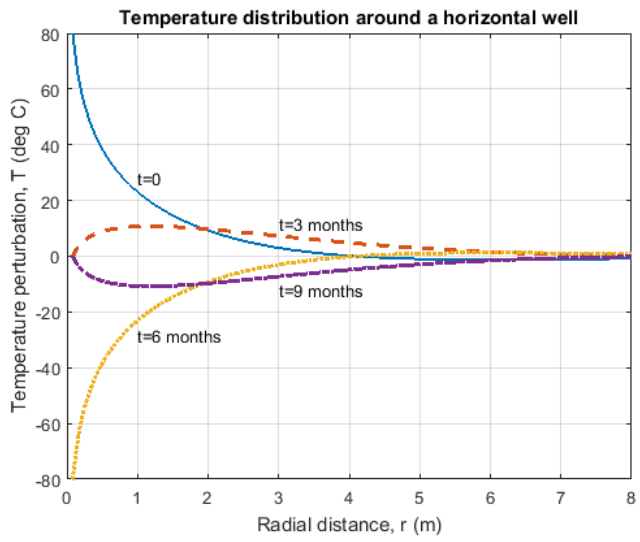
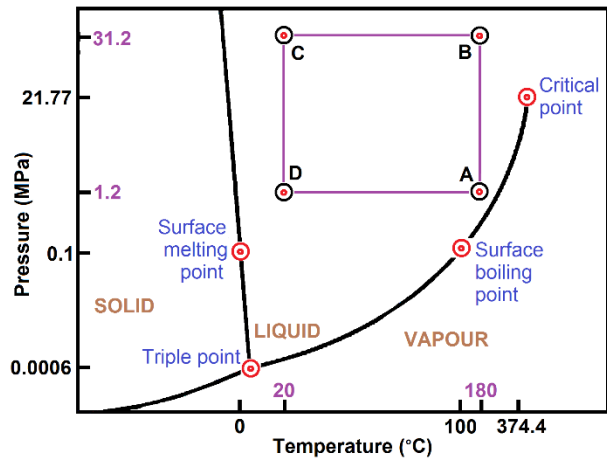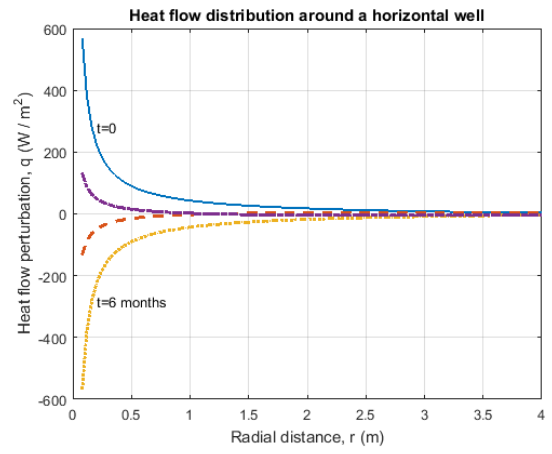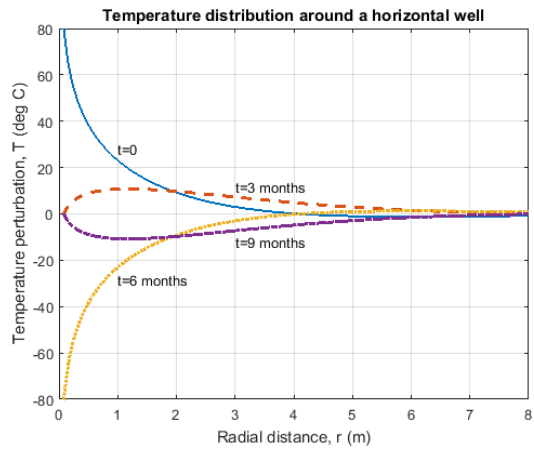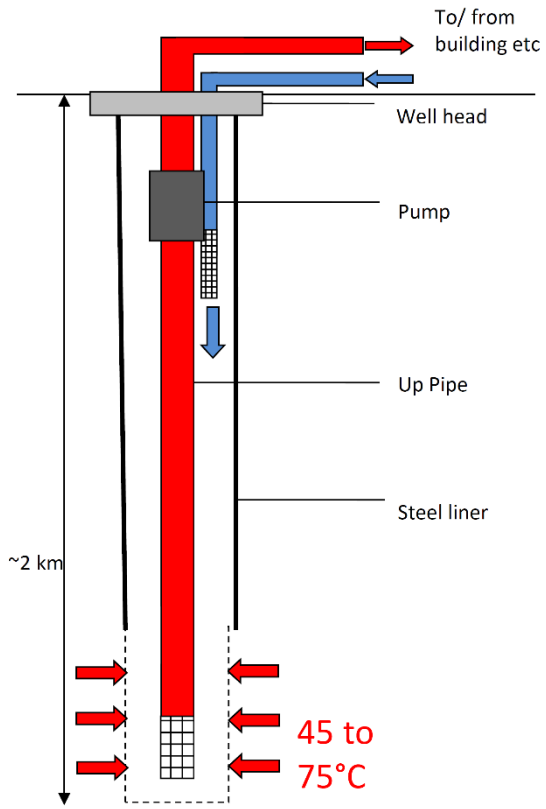(a)   (b)

Figure 6

Figure 7

(a)

(b)

Figure 8

To/ from building etc

Well head

Pump

Up Pipe

Steel liner

~2 km

45 to 75°C

Figure 9