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Chapter 9

Geothermal energy

By John Garnish and Geoff Brown

9.1 Introduction

Geothermal energy – heat from the Earth – is one of the less well recognized forms of renewable energy. This chapter explains the nature of geothermal energy, why it is treated as renewable even though locally heat is being mined, its usage over the past hundred years and its probable future. It is one of the few renewables that is constantly available. Although it used to be thought the preserve of regions prone to volcanic activity, that has now changed; new technologies are making this energy source available almost everywhere and it is realistic to think that geothermal energy could meet a significant fraction of energy demand within the twenty-first century. This chapter documents its current usage and outlines the steps that are being taken to make this forecast a reality.

Geothermal energy – The mining of geothermal heat

In the continuing search to find cost-effective forms of energy that neither contribute to global warming nor threaten national security, geothermal energy has become a significant player. This is the only form of 'renewable' energy that is independent of the Sun, having its ultimate source within the Earth. It is a comparatively diffuse resource; the amount of heat flowing through the Earth's surface, 10^{21} J y^{-1}, is tiny in comparison with the massive 5.4×10^{24} J y^{-1} solar heating of the Earth which also drives the atmospheric and hydrological cycles. Fortunately, there are many places where the Earth's heat flow is sufficiently concentrated to have generated natural resources in the form of steam and hot water (180–250 °C), available in rocks within feasible drilling distance of the ground surface and suitable for electricity generation. These are the so-called 'high-enthalpy' resources (see Box 9.1).

BOX 9.1 Enthalpy

Enthalpy is defined as the heat content of a substance per unit mass, and is a function of pressure and volume as well as temperature.

Geothermal resources are usually classified as 'high enthalpy' (water and steam at temperatures above about 180–200 °C), 'medium enthalpy' (about 100–180 °C) and 'low enthalpy' (<100 °C). The term 'enthalpy' is used because temperature alone is not sufficient to define the useful energy content of a steam/water mixture. A mass of steam at a given temperature and pressure can provide much more energy than the same mass of water under the same conditions. The distinction is important to geothermal practitioners so the term has entered into general use.

For the purposes of this chapter, however, it is usually sufficient to think of temperature and enthalpy as going hand in hand.

The techniques for exploiting the resources are very simple in principle, and are analogous to the well-established techniques for extracting oil and gas. One or more boreholes are drilled into the reservoir, the hot fluid flows or is pumped to the surface and it is then used in conventional steam turbines or heating equipment. Typically, geothermal wells are drilled to depths from 700 to 3000 m.

Obviously, electricity is a more valuable and versatile end-product than hot water, so most attention tends to be focused on those resources capable of supporting power generation, i.e. hot enough to make electricity generation economic. By 2010 world electrical power-generating capacity from geothermal resources had reached 10.7 gigawatts electrical (10.7 GW_e), a small but significant contribution to energy needs in some areas (Table 9.1). It will be seen also that a further 11 countries intend to have geothermal generation plant in service by 2015, with total world capacity forecast to increase to 18.5 GW_e.

About a further 50 gigawatts thermal (50 GW_t) is also being harnessed in non-electrical 'direct use' applications, principally for space heating, agriculture, aquaculture and a variety of industrial processes. Many of these applications occur outside high-enthalpy regions where geological conditions are nevertheless suitable to allow warm water (less than 100 °C) to be pumped to the surface. In many cases, the heat from the water can be used directly, and in other cases the temperature may be increased by the use of heat pumps (see Chapter 2). These are 'low-enthalpy' resources; in 2010, these installations supplied a total of 122 000 GWh (Table 9.2), equivalent to nearly 10 million tonnes of oil.

In almost all these situations heat is being removed faster than it is replaced, so the concept of 'heat mining' is appropriate. Although geothermal resources are non-renewable on the scale of human lifetimes and, strictly, fall outside the remit of this book, they are included because they share many features with true renewable resources. For example, geothermal energy is a natural energy flow rather than a store of energy like fossil or nuclear fuels. At one time it was thought that many high-enthalpy resources were indeed renewable, in the sense that they could be exploited indefinitely, but experience of declining temperatures in some steam producing fields and simple calculations of heat supply and demand show that – locally - heat is being mined on a non-sustainable basis (see Box 9.2). Nevertheless, and especially as techniques become available for extracting energy from rocks that do not support natural water flows (the so-called Hot Dry Rock concept, now more correctly termed Enhanced – or Engineered – Geothermal Systems (EGS): see Section 9.4), the volumes of rock that are potentially exploitable are so large in comparison to an individual reservoir that – to use an agricultural analogy – the resource could be 'cropped' on a

Table 9.1 Geothermal electricity generation: installed capacity and energy produced in 2005 and 2010 and forecast capacity in 2015

Country	Installed in 2005 /MW	Energy in 2005 /GWh	Installed in 2010 /MW	Energy in 2010 /GWh	2015 forecast /MW
Argentina	–	–	–	–	30
Australia	0.2	0.5	1.1	0.5	40
Austria	1.1	3.2	1.4	3.8	5
Canada	–	–	–	–	20
Chile	–	–	–	–	150
China	28	96	24	150	60
Costa Rica	163	1 145	166	1 131	200
El Salvador	151	967	204	1 422	290
Ethiopia	7.3	0	7.3	10	45
France	15	102	16	95	35
Germany	0.2	1.5	6.6	50	15
Greece	–	–	–	–	30
Guatemala	33	212	52	289	120
Honduras	–	–	–	–	35
Hungary	–	–	–	–	5
Iceland	202	1 483	575	4 597	800
Indonesia	797	6 085	1 197	9 600	3 500
Italy	791	5 340	843	5 520	920
Japan	535	3 467	536	3 064	535
Kenya	129	1 088	167	1 430	530
Mexico	953	6 282	958	7 047	1 140
Nevis	–	–	–	–	35
New Zealand	435	2 774	628	4 055	1 240
Nicaragua	77	271	88	310	240
Papua New Guinea	6.0	17	56	450	75
Philippines	1 930	9 253	1 904	10 311	2 500
Portugal	16	90	29	175	60
Romania	–	–	–	–	5
Russia	79	85	82	441	190
Spain	–	–	–	–	40
Slovakia	–	–	–	–	5
Thailand	0.3	1.8	0.3	2.0	1
The Netherlands	–	–	–	–	5
Turkey	20	105	82	490	200
USA	2 564	16 840	3 093	16 603	5 400
TOTAL	**8 933**	**55 709**	**10 717**	**67 246**	**18 500**

Source: Bertani, 2010

9.2 Summary of geothermal direct-use data worldwide, 2010 (included heat from ground source heat pumps)

try	Capacity /MWt	Annual Use /GWh y^{-1}	Capacity factor
a	11.5	11.2	0.11
a	55.6	478.7	0.98
tina	307.5	1 085.3	0.40
nia	1	4.2	0.48
alia	33.3	65.3	0.22
a	662.9	1 035.6	0.18
s	3.42	9.4	0.31
n	117.9	151.9	0.15
& govina	21.7	70.9	0.37
	360.1	1 839.7	0.58
ia	98.3	380.6	0.44
a	1126	2 464.9	0.25
ean Islands	0.1	0.8	0.85
	9.1	36.6	0.46
	8 900	20 931.8	0.27
bia	14.4	79.7	0.63
Rica	1	5.8	0.67
a	67.5	130.3	0.22
Republic	151.5	256.1	0.19
ark	200	694.5	0.40
or	5.2	28.4	0.63
	1	4.2	0.48
ador	2	11.1	0.63
a	63	98.9	0.18
ia	2.2	11.6	0.60
l	857.9	2 325.2	0.31
	1 345	3591.7	0.30
a	24.5	183.1	0.85
ny	2 485.4	3 546.0	0.16
e	134.6	260.5	0.22
nala	2.31	15.7	0.78
ras	1.93	12.5	0.74
ry	654.6	2 713.3	0.47
	1 826	6 767.5	0.42
	265	707.0	0.30
sia	2.3	11.8	0.59
	41.6	295.6	0.81
	152.9	212.2	0.16
	82.4	609.2	0.84

Country	Capacity /MWt	Annual Use /GWh y^{-1}	Capacity factor
Italy	867	2 761.6	0.36
Japan	2 100	7 138.9	0.39
Jordan	153.3	427.8	0.32
Kenya	16	35.2	0.25
Korea (South)	229.3	543.0	0.27
Latvia	1.6	8.8	0.62
Lithuania	48.1	114.3	0.27
Macedonia	47.2	167.1	0.40
Mexico	155.8	1 117.5	0.82
Mongolia	6.8	59.2	0.99
Morocco	5.0	22.0	0.50
Nepal	2.72	20.5	0.86
The Netherlands	1 410	2 972.3	0.24
New Zealand	393	2 653.5	0.77
Norway	3 300	7 000.6	0.24
Papua New Guinea	0.1	0.3	0.32
Peru	2.4	13.6	0.65
Philippines	3.3	11.0	0.38
Poland	281	417.0	0.17
Portugal	28.1	107.3	0.44
Romania	153.2	351.5	0.26
Russia	308.2	1 706.7	0.63
Serbia	100.8	391.7	0.44
Slovak Republic	132.2	852.1	0.74
Slovenia	104.2	315.7	0.35
South Africa	6.0	31.9	0.61
Spain	141.0	190.0	0.15
Sweden	4 460	12 584.6	0.32
Switzerland	1 061	2 143.1	0.23
Tajikistan	2.9	15.4	0.60
Thailand	2.5	22.0	0.99
Tunisia	43.8	101.1	0.26
Turkey	2 084	10 246.9	0.56
Ukraine	10.9	33.0	0.35
United Kingdom	186.6	236.1	0.14
United States	12 611	15 710.1	0.14
Venezuela	0.7	3.9	0.63
Vietnam	31.2	25.6	0.09
Yemen	1	4.2	0.48
Total	**50 583**	**121 696**	**0.27**

Lund et al. (2010)

rotational basis. Once a particular zone has been depleted, further boreholes could be drilled to a deeper layer, or a few kilometres further away, and production continued. After a few such operations, each with a lifetime of 20–30 years, the original zone would have regenerated to economically exploitable levels.

BOX 9.2 Deep geothermal extraction and recharge rates

The following simple calculations show the order of magnitude discrepancy between commercial geothermal extraction rates and thermal recharge by the Earth's natural heat flow. They demonstrate that it is *not the heat flow but the heat store that is being exploited*, even in high-enthalpy areas.

(a) The currently exploited area of Tuscany, northern Italy, totals about 2500 km^2. This is a generous estimate that ignores the fact that the active fields are only a small subset of this. The average heat flow is about 200 mW m^{-2} so the total heat flow through this surface is:

$$2500 \times 10^6 \text{ (m}^2\text{)} \times 200 \times 10^{-3} \text{ (W m}^{-2}\text{)} = 500 \text{ MW}_t$$

The region currently supports generating capacity of >700 MW$_e$; at a mean generating efficiency of 15%, this would require 4600 MW$_t$. Moreover, steam supplies have been proved to support an electricity-generating capacity of 1500 MW$_e$, which would require an input of approximately 10 000 MW$_t$. So the ratio of forecast commercial production rate to thermal recharge is at least:

$$\frac{10\,000 \text{ MW}_t}{500 \text{ MW}_t} \text{ or } 20{:}1.$$

(b) In the Imperial Valley of California, USA, a commercial lease of 4 km^2 is expected to support generating capacity of some 40 MW$_e$ (which will require at least 250 MW$_t$). Assuming an average heat flow of 200 mW m^{-2}, the thermal recharge is less than 1 MW$_t$, giving a ratio of:

$$\frac{250 \text{ MW}_t}{1 \text{ MW}_t} \text{ or } 250{:}1.$$

(c) The well field in Krafla, Iceland, covers an area of some 50 km^2. It currently generates some 60 MW$_e$, implying heat extraction of some 400 MW$_t$. To recharge the field on a sustainable basis, the heat flow would have to be 8 W m^{-2}. Again, this is much higher than could be expected even in this very active area. Of course, there is recharge by the Earth's natural heat flow but a thermally depleted reservoir may take many tens or even hundreds of years to regenerate. However, in regions of large geothermal resources this is generally a minor problem.

Note: MW$_t$ denotes megawatts of thermal energy; MW$_e$ denotes megawatts of electrical energy.

The source of heat

Heat flows out of the Earth because of the massive temperature difference between the surface and the interior: the temperature at the centre is around 7000 °C. So why is the Earth hot? There are two reasons: first, when the Earth formed around 4600 million years ago the interior was heated rapidly as the kinetic and gravitational energy of accreting material was converted into heat. If this were all, however, the Earth would have cooled within 100 million years. Of much greater importance today is the second mechanism: the Earth contains tiny quantities of long-lived radioactive isotopes, principally thorium 232, uranium 238 and potassium 40, all of which liberate heat as they decay. These radiogenic elements are concentrated in the upper crustal rocks. Cumulative heat production from these radioactive isotopes (approximately 5×10^{20} J y^{-1} today) accounts for about half the surface heat flow, though the exponential decay laws for radioactivity imply that heat production was about five times greater soon after the Earth formed. Heat is transferred through the main body of the Earth principally by convection, involving motion of material mainly by creep processes in hot deformable solids. This is a very efficient heat transport process resulting in rather small variations of temperature across the depth of the convecting layer. Closer to the surface, across the outer 100 km or so of the Earth, the material is too rigid to convect because it is colder, so heat is transported by conduction and there are much larger increases of temperature with depth (i.e. larger 'thermal gradients': see Section 9.2). This rigid outer boundary layer, or shell, is broken into a number of fragments, the **lithospheric plates**, which move around the surface at speeds of a few centimetres a year in concert with the convective motions beneath (Figure 9.1). Only this last point is of direct relevance to geothermal exploitation; our ability to drill into the Earth is restricted to the upper few kilometres, so we have to look for mechanisms and locations where the Earth's interior heat is brought within our reach.

From our point of view, it is mainly at the boundaries between plates, particularly where they are in relative extension or compression, that heat flow reaches a maximum. Here, the heat energy flowing through the surface averages around 300 milliwatts per square metre (300 mW m^{-2}) as compared with a global mean of 60 mW m^{-2}.

However, along plate margins heat flow can be even more concentrated locally because rock material reaches the surface in a molten form, resulting in volcanic activity that is often spectacular. Storage of molten, or partially molten, rock at about 1000 °C just a few kilometres beneath the surface strongly augments the heat flow around even dormant volcanoes. These heat flows result in high thermal gradients, really the hallmark of high-enthalpy areas, which are further enhanced in the upper regions by induced convection of hot water. Over geological periods of time, this high heat flow has resulted in large quantities of heat being stored in the rocks at shallow depth, and it is these resources that are mined by geothermal exploitation and commonly used for electricity generation. In areas of lower heat flow, where convection of molten rock or water is reduced or absent, temperatures in the shallow rocks remain much lower, so any resources are likely to be suitable only for direct use applications. So we see that high-enthalpy resources, including all those currently exploited for geothermal electric power (see Figure 9.1), are associated with volcanically active plate margins or localized hot spots like the Hawaiian islands. Boiling mud pools, geysers and volcanic vents with hot steam are characteristic features of such geothermal areas.

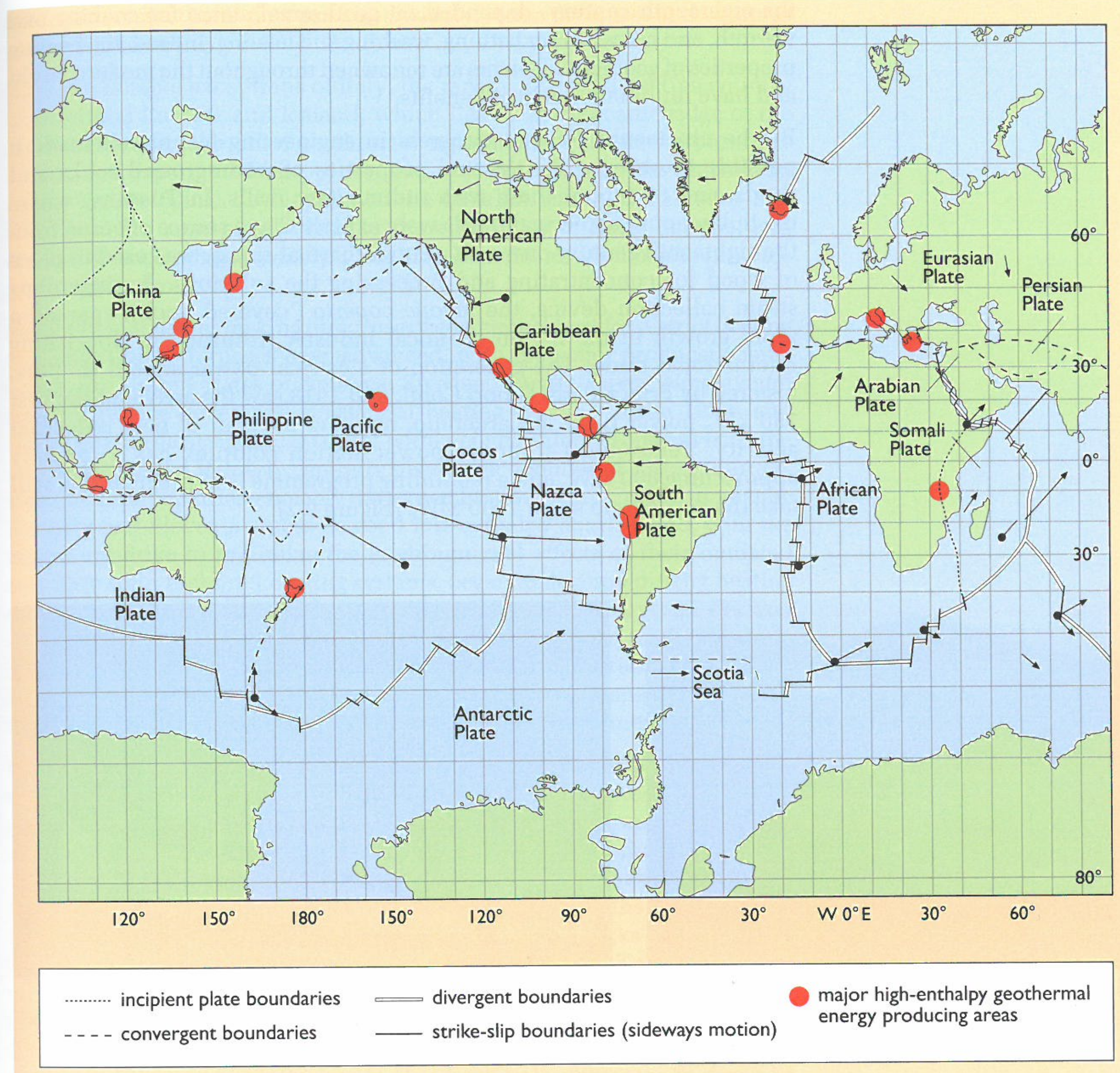
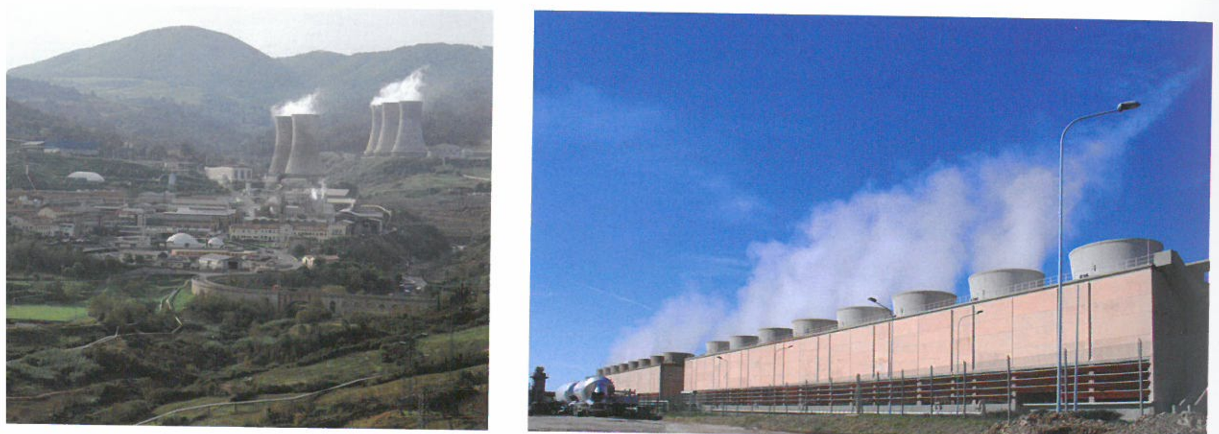


Figure 9.1 Map of the earth's lithospheric plates indicating the relative speeds of motions by the lengths of the arrows (generally 1–10 cm per annum). Large dots indicate major high-enthalpy geothermal energy-producing areas

Historical perspective

The historical exploitation of geothermal resources dates back to Greek and Roman times, with early efforts made to harness hot water for medicinal, domestic and leisure applications. Roman spa towns in Britain generally sought to exploit natural warm water springs with crude but reliable plumbing technology. The early Polynesian settlers in New Zealand, who lived undisturbed by European influence for several hundred years until the eighteenth century, depended on geothermal steam for cooking and warmth, and hot water for bathing, washing and healing. Indeed, the healing properties of geothermal waters are renowned throughout the modern world and have important medical benefits.

By the nineteenth century, progress in engineering techniques made it possible to observe the thermal properties of underground rocks and fluids, and to exploit these with rudimentary drills. In Tuscany, where the indigenous geothermal fluids were exploited as a source of boron from the eighteenth century onwards, natural thermal energy was used in place of wood for concentrating and processing the solutions. An ingenious steam collection device, the *lagone coperto* ('covered pool'), sparked a rapid growth in the Italian chemical industry, resulting in flourishing international trade. The generation of electrical power started in 1904, fostered by Prince Piero Ginori Conti, and 1913 saw the arrival of the first 250 kW_e power plant at Larderello, marking the start of new industrial activity. Today the Larderello power station complex has a capacity approaching 800 MW_e and a rebuilding programme is in progress that will take the capacity to some 1000 MW_e (Figure 9.2).



(b)

9.2 (a) The old geothermal power station at Larderello (b) the new power station

The Wairakei field in New Zealand was the second to be developed for commercial power generation, though not until the early 1950s. It was followed closely by the Geysers field in northern California where electricity was first generated in 1960. With an installed capacity that peaked at 2800 MW_e in the early 1990s, the Geysers field is still the most extensively developed in the world, though it will be overtaken soon by the Philippines. The Geysers field, however, illustrated the dangers of uncoordinated exploitation; the field was exploited independently by several different companies. In particular, little of the extracted water was reinjected into the reservoir after use. The result was a decline in steam pressure and a reduction in output capacity by several hundred megawatts. It was this decline that accounted for the very low net growth in world capacity during the second half of the 1990s. Fortunately, the problem was recognized in

time, and reinjection is now practised widely; steam pressures and volumes are now recovering.

With the notable exceptions of Italy, the most volcanically active country in mainland Europe, and Iceland, which lies on the volcanic ridge of the central Atlantic, the chief geothermal nations are clustered around the Pacific rim. Japan, the Philippines, Indonesia and Mexico have shared in recent technological developments; the installations in El Salvador and Nicaragua are strategically vital to the economies of those nations, and several other countries, notably Costa Rica, Ecuador and Chile, also produce geothermal electricity.

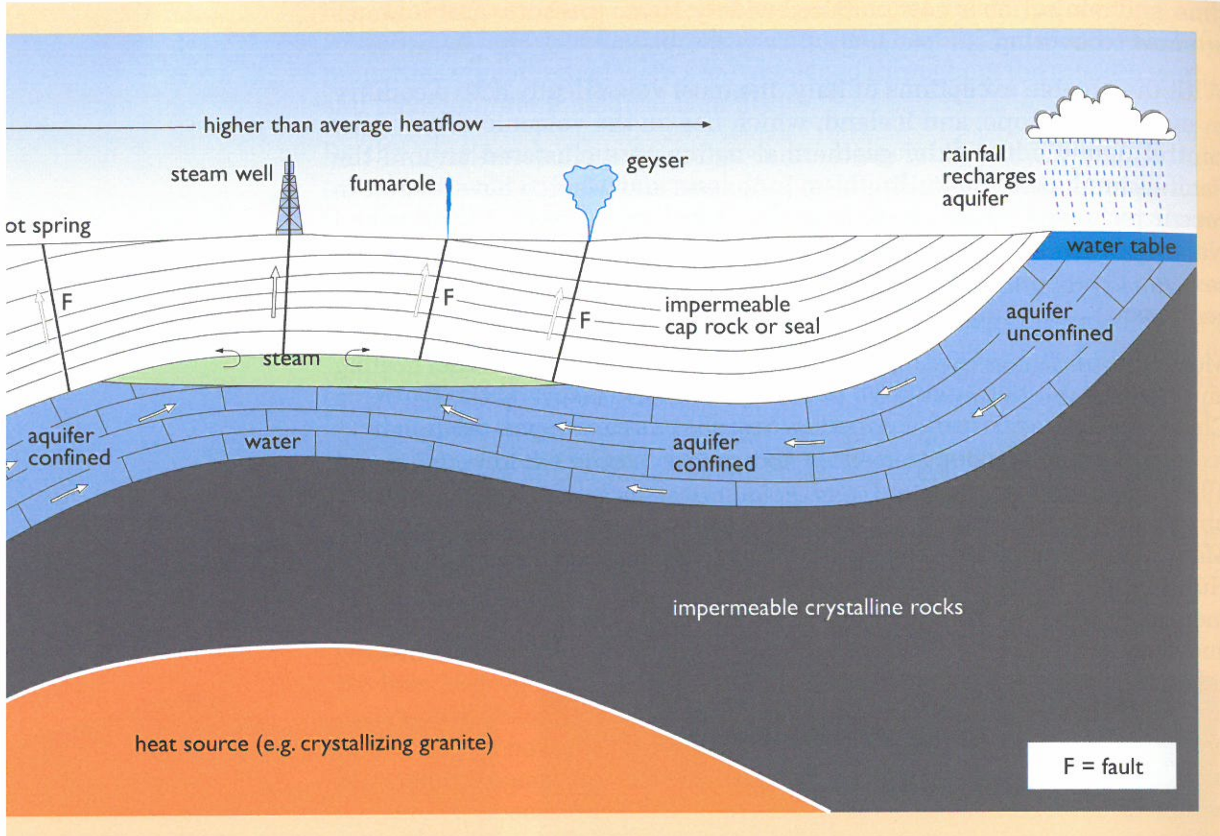
Meanwhile, schemes making direct use of geothermal heat for district heating and agricultural purposes have advanced, with the major producers being China, the United States of America, Sweden, Turkey, Japan, Norway and Iceland. France developed substantial heating systems in the 1970s and 1980s, but the most significant event within continental Europe has been the opening up of the formerly centrally planned economies of eastern Europe. Many of these countries – notably the former East Germany, Poland, Romania, Hungary and Slovenia – possess good low-enthalpy aquifers and, with the increasing drive to minimize the environmental effects of their outdated and dirty solid fuel fired heating systems, began to develop district heating schemes along the lines of those in Paris. (The technology had evolved independently in eastern Europe and a few schemes were already in operation before the borders were opened, but progress was hampered by the lack of high-grade materials for pipelines, pumps and heat exchangers that could withstand the corrosive effects of brines in poorly maintained systems.)

Finally, there has been a quiet revolution in the use of 'shallow' geothermal energy, especially in Europe and the USA, with the widespread adoption of ground source heat pumps (GSHPs). Whereas 'deep' geothermal installations are mainly large scale schemes, the scale for GSHPs can be that of the single dwelling. Larger installations use multiple shallow boreholes feeding large heat pumps. They extract heat at only 12–15 °C from depths of 100–150 m and do not depend on the presence of water-bearing rocks at that depth. Consequently, they can be exploited almost anywhere. Taking a typical unit as having a 12 kW_t output, the most recent survey estimates that there is now the equivalent of nearly 3 million units installed worldwide (Lund et al., 2010). They are particularly valuable when a building requires cooling or air conditioning in summer as well as heating in winter, as they can be designed to reverse the cycle, extracting heat from a building and depositing it in the ground (and thereby helping also to regenerate the resource).

9.2 The physics of deep geothermal resources

Primary ingredients

Geothermal resources of most types must have three important characteristics, as shown in Figure 9.3: an aquifer containing water that can be accessed by drilling; a cap rock to retain the geothermal fluid; and a heat source.



ıre 9.3 Simplified schematic cross-section to show the three essential characteristics of a geothermal site: an aquifer (e.g. ured limestone with solution cavities); an impermeable cap rock to seal the aquifer (e.g. clays or shales); and a heat source crystallizing granite). Steam and hot water escape naturally through faults (F) in the cap rock, forming fumaroles (steam only), ers (hot water and steam), or hot springs (hot water only). The aquifer is unconfined where it is open to the surface in the arge area, where rainfall infiltrates to keep the aquifer full, as indicated by the water table just below the surface. The aquifer nfined where it is beneath the cap rock. Impermeable crystalline rocks prevent downward loss of water from the aquifer

First, what is an aquifer? **Natural aquifers** are porous rocks that can store water and through which water will flow. **Porosity** refers to the cavities present in the rock, whereas the ability to transmit water is known as **permeability**. A geothermal aquifer must be able to sustain a flow of geothermal fluid, so even highly porous rocks will only be suitable as geothermal aquifers if the pores are interconnected. In Figure 9.4, rocks (a) and (c) are porous and likely to be highly permeable, whilst (b) and (d) have low porosity and permeability. Example (e), however, has low permeability despite its high porosity whereas cavities developed in (f) by dissolution of more soluble components give high porosity and permeability. Permeability due to fracturing ('fracture permeability'), as in (g), is particularly important in many geothermal fields.

A good measure of the permeability of a rock is its hydraulic conductivity (K_w). Darcy's Law states that the speed (v) of a fluid moving through a porous medium is proportional to the hydraulic pressure gradient causing the flow:

$$v = K_w \frac{H}{L} \qquad (1)$$

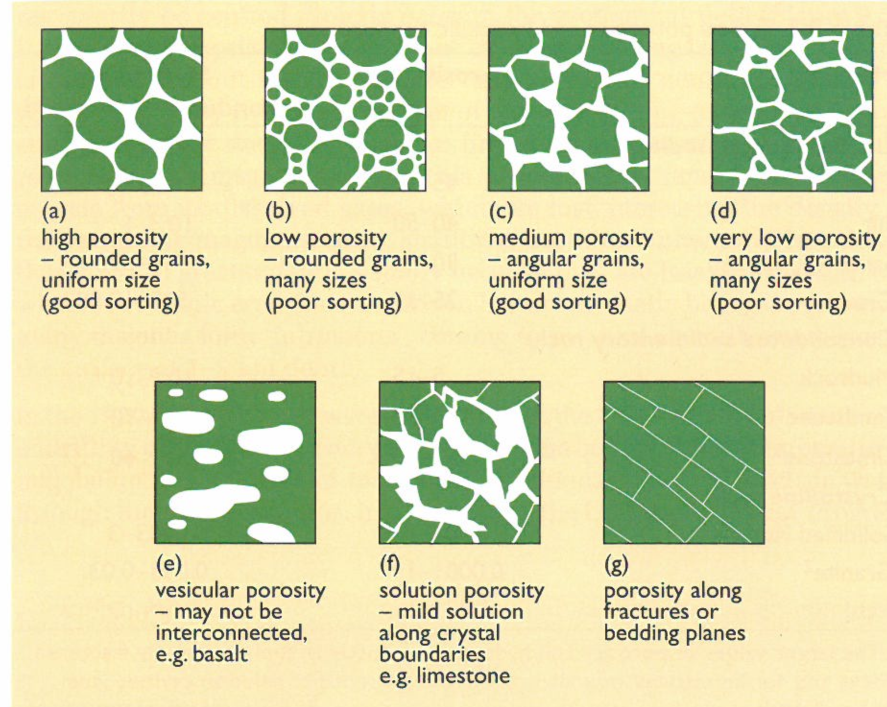


Figure 9.4 The relationship between grain size, shape and porosity in sedimentary rocks, especially sandstones (a–d); vesicular porosity in crystallized lava flows due to gas bubbles (e); and solution porosity resulting from rock dissolution, especially where acid groundwaters attack limestone (f). Porosity also develops in rocks along original planes of weakness, especially bedding planes and fractures (joints and faults) (g)

Here, H is the effective head of water driving the flow, and is measured in metres of water. The pressure gradient, or hydraulic gradient (H/L) is the change in this head per metre of distance L along the flow direction.

The volume of water (Q) flowing in unit time through a cross-sectional area A m^2 is v times A. So Darcy's Law may also be written:

$$Q = AK_w \frac{H}{L} \qquad (2)$$

and K_w (the hydraulic conductivity) may be interpreted as the volume flowing through one square metre in unit time under unit hydraulic gradient. Some values of hydraulic conductivity for different rocks are given in Table 9.3.

Notice that the highest values of K_w occur in coarse-grained unconsolidated rocks, such as the ash layers, which are particularly common in volcanic areas, but that values are also quite high in some limestones and sandstones. These are aquifer rocks, with high permeability. It should be remembered also that fracture permeability is often important in geothermal aquifers (see Figure 9.4(g)), and is central to the Hot Dry Rock/Enhanced Geothermal System (HDR/EGS) concept.

In a confined aquifer, such as in Figure 9.3, the fluid pressure beneath the extraction point is high because there is a **cap rock**, a relatively impermeable rock, or seal, to prevent fluid escaping upwards. A cap rock is essential if a

Table 9.3 Typical porosities and hydraulic conductivities

Material	Porosity/%	Hydraulic conductivity/m day^{-1}
Unconsolidated sediments		
Clay	45–60	$<10^{-2}$
Silt	40–50	10^{-2}–1
Sand, volcanic ash	30–40	1–500
Gravel	25–35	500–10 000
Consolidated sedimentary rocks		
Mudrock	5–15	10^{-8}–10^{-6}
Sandstone[1]	5–30	10^{-4}–10
Limestone[1]	0.1–30	10^{-5}–10
Crystalline rocks		
Solidified lava[1]	0.001–1	0.0003–3
Granite[2]	0.0001–1	0.003–0.03
Slate	0.001–1	10^{-8}–10^{-5}

[1] The larger values of porosity and hydraulic conductivity apply to heavily fractured rocks and, for limestones, may also reflect the presence of solution cavities (see Figure 9.4(f)).
[2] Granite is a coarsely crystalline rock that has cooled down slowly from a melt at depth in the Earth. Such rocks are generally non-porous and impermeable, but contain many natural fractures and acquire limited permeability.

steam field is to develop. Mudrocks, clays and unfractured lavas are ideal. The importance of cap rocks was demonstrated in the early 1980s during exploration for geothermal resources in a very obvious place, the flanks of the volcano Vesuvius. Only small amounts of low-pressure fluid were discovered because the volcanic ashes that form its flanks are apparently quite permeable throughout. Given time, alteration of the uppermost deposits or overlying sediments by hot water and steam can create clays or deposit salts in pore spaces, so producing a seal over the aquifer, and in this way many geothermal fields eventually develop their own cap rocks. For this reason, however, the youngest volcanic areas, like Vesuvius, are not necessarily the most productive from a geothermal viewpoint.

The third prerequisite for exploitable geothermal resources is the presence of a heat source. In high-enthalpy regions, abundant volcanic heat is available, but in low-enthalpy areas the heat source is less obvious. In such regions there are two main types of resource: (a) those located in deep sedimentary basins where aquifers carry water to depths where it becomes warm enough to exploit, and (b) those located in 'hot dry rocks' where natural heat production is high but an artificial aquifer must be created by enhancing the rock fractures in order that the geothermal resource may be exploited. Let us now look at each type of resource in more detail.

Volcano-related heat sources and fluids

The heat supply for a high-enthalpy field is usually derived from a cooling and solidifying body of magma (partially molten rock), which need not

necessarily be centred directly beneath the geothermal field (Figure 9.5). It may seem surprising that much of the magma rising beneath a volcano is not erupted but instead reaches only a level of neutral buoyancy at which its density is the same as that of the surrounding rocks. Two factors conspire to halt the rising magma: first the pressure of overlying rocks reduces as the magma ascends; this promotes the separation of liquid magma from its dissolved gases, which are lost, increasing the density of the remaining magma; second, shallower rocks are inherently less dense than rocks at greater depth, usually because they are less compressed. So, whereas volcanic eruptions are driven by exceptionally high gas pressures, many magmas form 'intrusions', coming to rest and crystallizing beneath the surface at 1–5 km depth.

In the 1980s, experiments were undertaken in the USA with the ultimate aim of drilling directly into or very close to magma bodies, where temperatures may be up to 1800 °C, and to harness geothermal power by cycling water through their outer margins. In preparation, the US Magma Energy Program

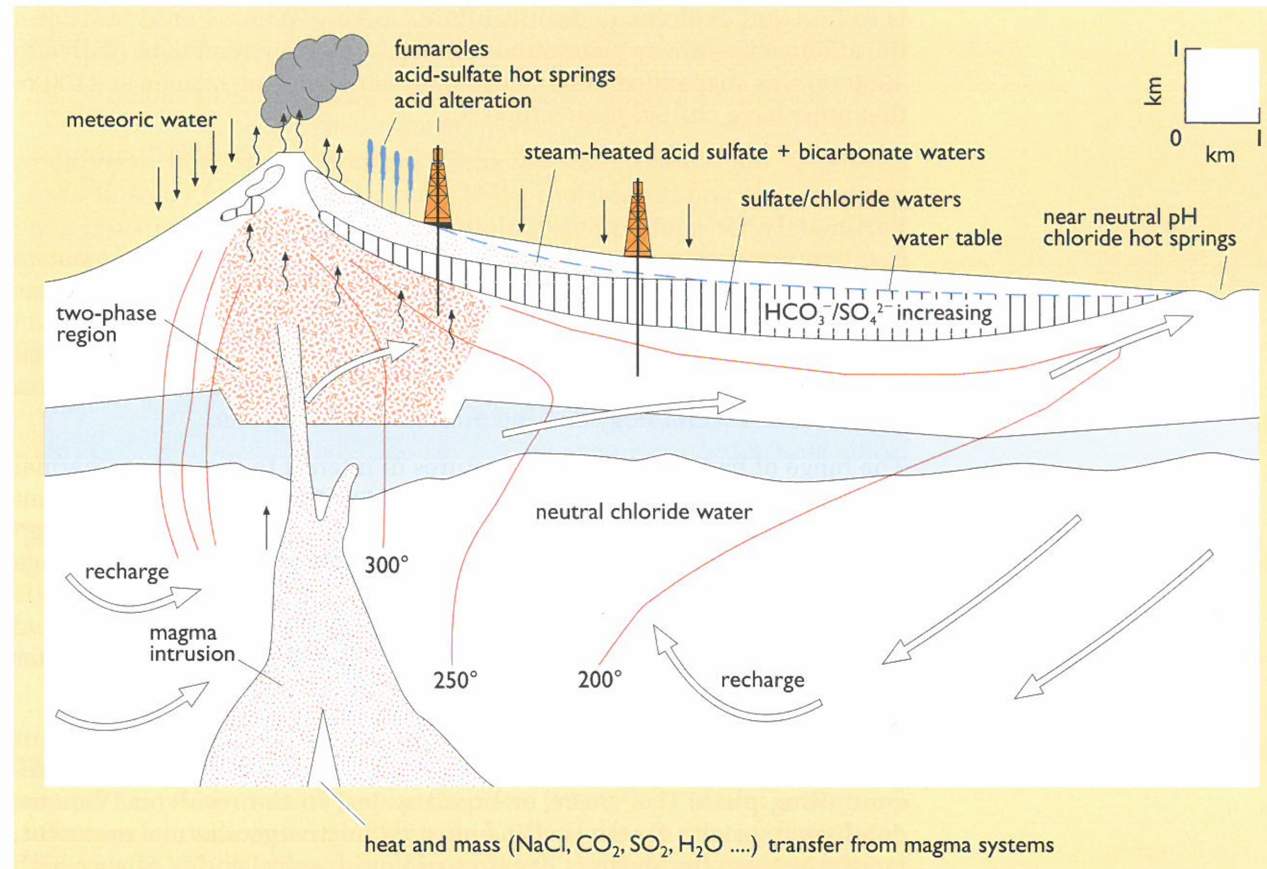


Figure 9.5 Conceptual model of a typical volcanic geothermal system in which meteoric (rain) waters percolate deep into the volcanic superstructure where they are heated by a body of magma that loses dissolved gases as it rises, and forms an intrusion (see text). The hot aqueous fluid rises and may reach the point at which water boils to form steam, producing a two-phase (steam + water) zone. The hydraulic gradient causes the geothermal fluid to migrate through any permeable rocks in the volcano flank. Here the fluids may be accessed by drilling (see drill rig symbols); the chemistry of the fluid changes during migration due to mixing with CO_2-saturated rain water

succeeded in drilling into the molten Kilauea lava lake (Hawaii) and ran successful energy extraction experiments. In any drilling operation, the drill bit is cooled and lubricated by circulating fluid (referred to as **mud** even though, usually, it is mainly water), which also lifts cuttings to the surface. In this case, as was expected, the circulating water solidified a thin shell of lava around the drill bit. The resulting tube of solid but thermally fractured rock acted as a heat exchanger, with heat being transferred to the drill hole by convecting magma. While a useful test, this is still a long step from drilling into a live magma chamber with high-pressure dissolved gases, and no further work has been undertaken in recent years.

A close encounter with magma occurred during the development of the Krafla field in northern Iceland when, in 1977, rising magma reached the depth of a borehole at 1138 m and three tonnes of magma was erupted through the hole in 20 minutes! Quite by chance, the development history of this field was dogged by a series of eruptions in 1975 and 1984, the first at Krafla for over 250 years, but progress improved once the eruptions ceased and the field now supports 60 MW_e of power generation. Krafla is also the site of the Icelandic Deep Drilling Project (IDDP), the aim of which is to find and exploit supercritical fluids (>350 °C) that would transform the efficiency of power generation. The first hole, intended to be drilled to 4500 m, was suspended late in 2010 after encountering magma at 2100 m that must have chilled from >1000 °C.

Several of the world's most advanced geothermal sites (for example in northern Italy and the western USA) are located in extinct volcanic areas. Fortunately for geothermal exploitation, because rocks are such good insulators, magmatic intrusions may take millions of years to cool to ambient conditions. Such intrusions, therefore, continue to act as a focus for 'hot fluid', or hydrothermal convective cycles in permeable strata as in Figure 9.5. The nature of the resource then depends on the local conditions of pressure and temperature in the aquifer, and this determines the extraction technology and the profitability of the site.

The range of pressures and temperatures of interest to current geothermal developments lies typically between 100 and 300 °C, below the critical point at which liquid water and water vapour become indistinguishable (though conditions in parts of some fields exceed 400 °C), and in the pressure range up to about 20 megapascals (20 MPa). As noted above, however, there is increasing research interest in the possible exploitation of supercritical geothermal fluids, which would offer the prospect of very much greater conversion efficiencies.

In simple terms, high-enthalpy systems are subdivided into vapour dominated and liquid dominated, depending on the main pressure-controlling phase (i.e. steam or liquid water) in the reservoir. Vapour-dominated systems are the best and most productive geothermal resources, largely because the steam is dry (free of liquid water) and is of very high enthalpy. Where reservoir rocks are at pressures below hydrostatic, which promotes steam formation (perhaps 3–3.5 MPa at depths down to 2 km), there must be some barrier to direct vertical groundwater infiltration. The Larderello field in Italy (Figure 9.2) is of this type.

In contrast, liquid-dominated systems are at higher than hydrostatic pressures, exceeding 10 MPa at depths below 1 km (because at 1 km depth the hydrostatic pressure is about 100 bars, i.e. 10 MPa, see Box 9.3). Production of electricity from liquid-dominated systems benefits from the higher fluid pressures at depth, and water can 'flash' into steam en route to the surface. That is to say, the pressure-temperature curve in liquid-dominated systems is *below* the boiling curve for water at all depths, but when the thermal aquifer is punctured by boreholes, the reduced pressure in the well means that the rising water crosses the boiling point curve on its way to the surface. However, the steam is often wet and of lower enthalpy, which adds to the technical problems for electricity production. The famous Wairakei field in New Zealand is liquid-dominated but, typically for such systems, has developed a two-phase zone as pressures have fallen during exploitation. Fortunately, the groundwater zone has a relatively low permeability, which suppresses the tendency for natural venting of steam over most of the Wairakei area.

BOX 9.3 Pressure and depth

As noted in Chapter 5, Box 5.6, hydrostatic pressure increases by about 1 atmosphere for an increase of 10 m in depth. It follows that a geothermal aquifer 1 km thick will produce a pressure increase of 100 atmospheres (100 bar). (A pressure of 1 bar is approximately equal to 1 atmosphere.)

The SI unit for pressure is the pascal or, more appropriately for the high pressures in geothermal systems, the megapascal (MPa). One megapascal is approximately 10 atmospheres, and the 20 MPa mentioned in the text is thus 200 atmospheres.

Many geothermal aquifers also contain a steam zone and, since steam has a much lower density than water, the **vapourstatic** increase in pressure with depth (i.e. the pressure due to the weight of the column of steam) is much smaller than the hydrostatic increase. Note that it is not strictly correct to refer to water vapour as steam. Steam is condensed droplets of water (as in clouds), which is why it can be seen. Water vapour is an invisible gas. However, 'steam' is often used as a synonym for 'water vapour', though the meaning should generally be clear from the context.

The heat source in sedimentary basins

An important key to understanding many geothermal resources is the heat conduction equation:

$$q = K_T \frac{\Delta T}{z} \quad (3)$$

This is analogous to Darcy's Law, but here q is the one-dimensional vertical **heat flow** in watts per square metre (W m^{-2}). ΔT is the temperature difference across a vertical height z, and $\Delta T/z$ is thus the **thermal gradient**. The constant K_T relating these quantities is the **thermal conductivity** of the rock (in W m^{-1} K^{-1}) and is equal to the heat flow per second through an area of 1 m^2 when the thermal gradient is 1 °C per metre along the flow direction.

Values of K_T for most rock types are quite similar, in the range 2.5–3.5 W m^{-1} $°K^{-1}$ for sandstones, limestones and most crystalline rocks. However, mudrocks (clays and shales) are the exceptions, with lower values of

1–2 W m^{-1} °K^{-1}. These are also among the most impermeable rocks (Table 9.3), so mudrocks contribute two of the essential characteristics for geothermal resources: they act as impermeable cap rocks and as an insulating blanket, enhancing the geothermal gradient above aquifers in regions of otherwise normal heat flow.

So, even under conditions of average heat flow (60 mW m^{-2}), it is possible to obtain temperatures of 60 °C within the top 2 km of the Earth's crust. Box 9.4 demonstrates how the differing insulating properties of rocks influence the way the temperature varies with depth. To maintain the same vertical heat flow, low-conductivity rocks require a steeper temperature gradient than a relatively good conductor, and are accordingly important in augmenting temperatures at depth.

BOX 9.4 Thermal gradient and heat flow

Consider the situation where there is a steady upward flow of heat through the top few kilometres of the Earth's crust. We can use Equation 3 to relate this flow to the temperature at any depth if we know the thermal conductivity of the rock.

If, for instance, the temperature is found to be 58 °C at a depth of 2 km (2000 metres) and the surface temperature is 10 °C, the temperature gradient is:

$(58 - 10)/2000 = 0.024$ °C m^{-1}

and if the thermal conductivity of the rock is 2.5 W m^{-1} °C^{-1}, the heat flow rate is:

$2.5 \times 0.024 = 0.060$ W m^{-2}

or 60 mW m^{-2}.

Suppose, however, that this same 60 mW flows up through several layers with different thermal conductivities. Equation 3 tells us that the thermal gradient must be different in each layer, with the temperature changing most rapidly through the layer with the lowest conductivity, as in Figure 9.6 below.

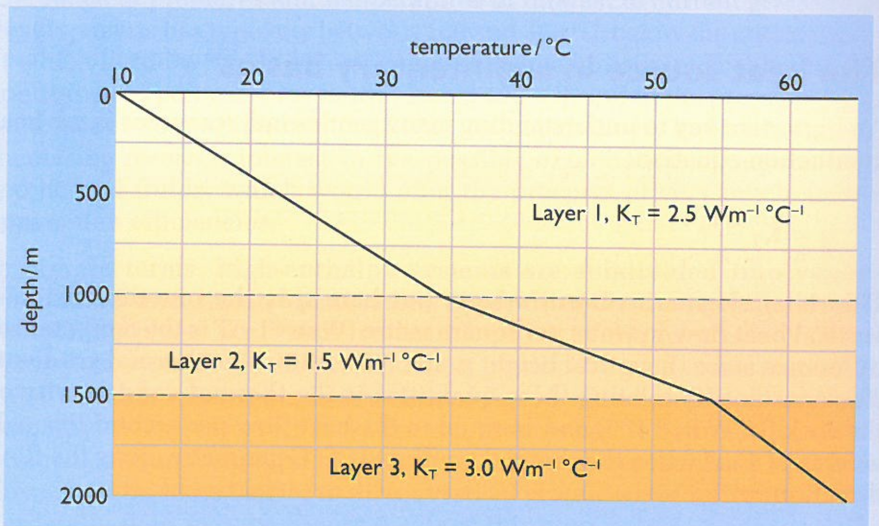


Figure 9.6 Variation of temperature with depth across three zones of differing thermal conductivity, K_T

We can check that the diagram shows the correct temperatures by using Equation 3 to calculate the temperature gradient for each layer and comparing this with the gradient read from the graph:

Layer 1

The calculated gradient is $0.060/2.5 = 0.024$ °C m^{-1}

The measured gradient is $(34.5 - 10.0)/1000 = 0.0245$ °C m^{-1}

Layer 2

The calculated gradient is $0.060/1.5 = 0.040$ °C m^{-1}

The measured gradient is $(54.5 - 34.5)/500 = 0.040$ °C m^{-1}

Layer 3

The calculated gradient is $0.060/3.0 = 0.020$ °C m^{-1}

The measured gradient is $(64.5 - 54.5)/500 = 0.020$ °C m^{-1}

Within the precision of the data therefore, the temperatures shown are consistent with a heat flow rate of 60 mW m^{-2} through each layer. Comparing this case (Figure 9.6) with the uniform rock considered above, it is obvious that the presence of the thin layer with low thermal conductivity has appreciably enhanced the temperature at a depth of 2 km.

This has led to exploration programmes aimed at locating natural waters in areas of thick sedimentary rock sequences containing mudrocks and permeable limestones or sandstones. For example, the Paris area is at the centre of a 200 km wide depression in the crystalline basement rocks. Exploration for hydrocarbon resources in the 1960s and 1970s found very little oil or gas, but was extremely successful in locating hot water between 55 °C and 70 °C at depths of 1–2 km. While low-enthalpy water resources are unsuitable for power generation (no high-pressure steam can be produced, and temperatures are too low to permit an acceptable generation efficiency), they can be of considerable benefit in meeting demands for low-grade heat (space heating, etc.). However, to be economic they must be located close to a heat load. The Paris area is ideal in this respect. Similar resources occur in some of the sedimentary basin areas of the UK, such as beneath the Yorkshire–Lincolnshire coast and in Hampshire, where the only commercial UK geothermal scheme operates in Southampton, but most are remote from suitable heat loads.

Finally, there are two extensions of the criteria discussed above which make some sedimentary basin resources more attractive:

(1) There are some basins where the background heat flow is above average, and these have led to large-scale non-electrical applications of geothermal energy in a number of countries (Table 9.2). The geological reasons for the association of high heat flow with sedimentary basins are not altogether surprising: stretching processes within the Earth's outer plate layer induce thinning that can radically raise the heat flow as well as creating a surface depression on which sedimentation occurs. Beneath the south Hungarian Plain, for example, geothermal gradients as high as 0.15 °C m^{-1} have been recorded and 120 °C water occurs at 1 km depth.

(2) In other areas, larger sedimentary thicknesses may occur. For example, high-pressure fluids at temperatures of 160–200 °C occur at 3–5 km depth in the Gulf of Mexico, southern Texas and Louisiana. Because of chemical processes occurring as a result of the depth and temperature of burial and the efficient sealing of the aquifers by impermeable rocks, pressures greatly exceed hydrostatic and 100 MPa has been recorded in local pockets of fluid. The fluids are highly saline brines with trapped gas, especially methane. These so-called **geopressured brines** are a potentially important geothermal resource for power generation, a resource that has remained untapped to date but on which there is intermittent government funding for research in the USA. The great advantage of geopressured resources is that they offer three kinds of energy: geothermal heat, 'hydraulic' energy (in water at high pressure), and the chemical energy in the large quantities of methane that are found dissolved in the fluid.

Geothermal waters

Most of the foregoing has been concerned with the source of geothermal heat. Exploitation of the heat, however, requires that the geothermal water be brought to the surface, and that brings with it a different set of problems. Water that has been in contact with rock for long periods (and geothermal waters can be thousands or even millions of years old) contains dissolved minerals. Hot water tends to be more reactive than cold water, so geothermal waters can often contain around 1% of dissolved solids. Typically, these will be carbonates, sulfates or chlorides, and dissolved silica becomes significant where waters have been in contact with rocks above 200 °C. For this reason, geothermal fluids are often called 'brines'. Dissolved gases are also common, especially at higher temperatures. Techniques are available to deal with all of these, but it is essential that they be taken into consideration at the design stage of the plant. With correct design, these contaminants can all be handled and disposed of without either operational or environmental difficulty. If they are ignored, however, or the plant designed before the water has been properly characterized, the entire system can fail within a matter of months. The various techniques that can be used are beyond the scope of this chapter, but some examples are quoted in Section 9.3.

'Hot dry rocks' or engineered geothermal systems (EGS)

Our attention now turns from sedimentary strata to the underlying crystalline 'basement'. Most rocks, especially crystalline and basement rocks, do not contain sufficient water to provide a viable geothermal resource, although far greater amounts of heat are stored in such rocks than are available in aquifers. It was thought initially that deep basement rocks would indeed be dry, and so the term **hot dry rock** (HDR) was coined around 1970 to describe the heat stored in impermeable (or poorly permeable) rock strata and the process of trying to extract that heat. More recently, it has been recognized that few if any rocks are actually dry, and there is now a general acceptance of the term 'enhanced' – or 'engineered' – 'geothermal systems' (EGS) to categorize the various projects aimed at extracting this heat.

When the permeability is too poor to allow the necessary flow of fluid, what is required is the creation of an artificial heat exchanger zone within suitably hot rocks. Because rocks are (by normal standards) poor conductors of heat, very large heat transfer surfaces (of the order of square kilometres) are required if heat is to be extracted at useful rates. This can be achieved by enhancing the natural fracture system that occurs in all such crystalline rocks. Water can then be circulated through the enhanced zone so that heat may be extracted, ideally to generate steam and, hence, electrical power. Although the technology to create suitable arrangements for reproducible heat recovery has not yet been perfected, in theory at least EGS technology could be applied over a significant proportion of the Earth's surface.

Because drilling is expensive, with costs rising exponentially with depth, only the upper 6–7 km of the Earth's crust is generally used in calculating geothermal energy potential (though some hydrocarbon and research drilling has gone as deep as 15 km). Given current technical and economic constraints on drilling depths, a minimum geothermal gradient of around 0.025 °C m^{-1} is required if development is to be economic. With a typical thermal conductivity of 3 W m^{-1} $°C^{-1}$, this requires (from Equation 3) a heat flow of 75 mW m^{-2}, only a little above the Earth's average. In practice, however, to minimize expenditure it is customary to look for rocks with much higher heat flows (as at experimental sites in the USA, Japan and France). Granite bodies are ideal targets, because such rocks occupy large volumes of the upper crust and they crystallized from magmas that had naturally high concentrations of the chemical elements with long-lived radioactive isotopes – uranium, thorium and potassium. Here we reach a situation in which heat flow through the Earth's surface is augmented (perhaps by a factor of 2) by heat production within certain shallow crystalline rocks. If, in addition, a layer of poorly conducting sedimentary rocks overlies the granite, its 'blanketing' effect will increase the temperature gradient and make higher temperatures available at shallower depths.

9.3 Technologies for exploiting high-enthalpy steam fields

The first stage in prospecting for geothermal resources in volcanic areas involves a range of geological studies aimed at locating rocks that have been chemically altered by hot geothermal brines, and finding surface thermal manifestations, such as hot springs or mud pools. Investigations of fluid chemistry and, increasingly, the release of gases through fractured rocks allow assessment of the composition and resource potential of trapped fluids. These studies provide the first clues to the likely presence and location of exploitable resources. However, geophysical prospecting techniques, particularly resistivity surveying and other electrical methods designed to detect zones with electrically conducting fluids (i.e. brines), are probably the most effective for precise location of buried geothermal resources. Once a suitable geothermal aquifer has been located, exploration and production wells are drilled using special techniques to cope with the much higher temperatures and, in some cases, harder rock conditions than in oil and water wells. Since fluid pressures in the aquifer range up to about 10 MPa, the driller must ensure that the mud is dense enough to counteract these pressures and avoid '**blow out**', where an uncontrollable column of gas is discharged. The well is lined ('cased') with steel tubing that is cemented in place, leaving an open section or a perforated steel casing at production depths. As each string of casing has to be inserted through its predecessors as the well depth increases, the well diameter decreases with depth from perhaps 50 cm near the surface to 15 cm at production depths. A wellhead with valve gear is welded to the steel casing at ground level. This allows the well to be connected to a power plant via the network of insulated pipes that are a familiar sight in geothermal areas.

Technologies for electrical power generation depend critically on the nature of the resource – not just the fluid temperature and pressure but also its salinity and content of other gases, all of which affect plant efficiency and design. The size of any power station is determined by the economics of scale; conventional coal- or oil-fired stations are typically a few hundred megawatts per unit. A typical geothermal unit, by contrast, is usually 30–50 MW_e. This is because the amount of steam delivered by one well is usually sufficient to generate only a few MW_e, and wells are linked across the field and back to the station by pipeline. Above a certain capacity, the cost of the pipelines is such that it is cheaper to develop a separate station in another part of the field.

Given the fact that most of the costs of the electricity derived from geothermal resources are accounted for by the need to pay back the capital investment, with day-to-day operating costs being relatively minor (and insensitive to output variation), there is a great incentive to maximize the efficiency with which the relatively low-grade heat (by power generation standards) is converted into useful energy. Today there are several hundred installations operating worldwide and these include four main types, described below.

Dry steam power plant

As the name implies, this type of system (Figure 9.7(a)) is ideal for vapour-dominated resources where steam production is not contaminated with liquid. The reservoir produces superheated steam, typically at 180–225 °C and 4–8 MPa, reaching the surface at several hundred kilometres per hour and, if vented to the atmosphere, sounding like a jet engine at close proximity. Passing through the turbine, the steam expands, causing the blades and shaft to rotate and hence generating power. Temperatures up to 300–350 °C and correspondingly greater pressures are increasingly being exploited, leading to greater efficiency in electricity production.

In the simplest form of power plant, a 'back-pressure' unit, the low-pressure exhaust steam is vented directly to the atmosphere. Although such units are simple, they are also very inefficient; their main use is as temporary transportable units during the development of a new field. Once the steam supply is ensured, normal practice is then to install 'condensing' plant as shown in Figure 9.7(a). These achieve greater efficiency by condensing the exhaust steam to liquid, thus dramatically increasing the pressure drop across the turbine because liquid water occupies a volume roughly 1000 times less than the same mass of steam. Of course, the cooling towers generate waste heat in just the same way as conventional coal- and oil-power stations (or, indeed, any heat engine). At temperatures typical of geothermal fluids,

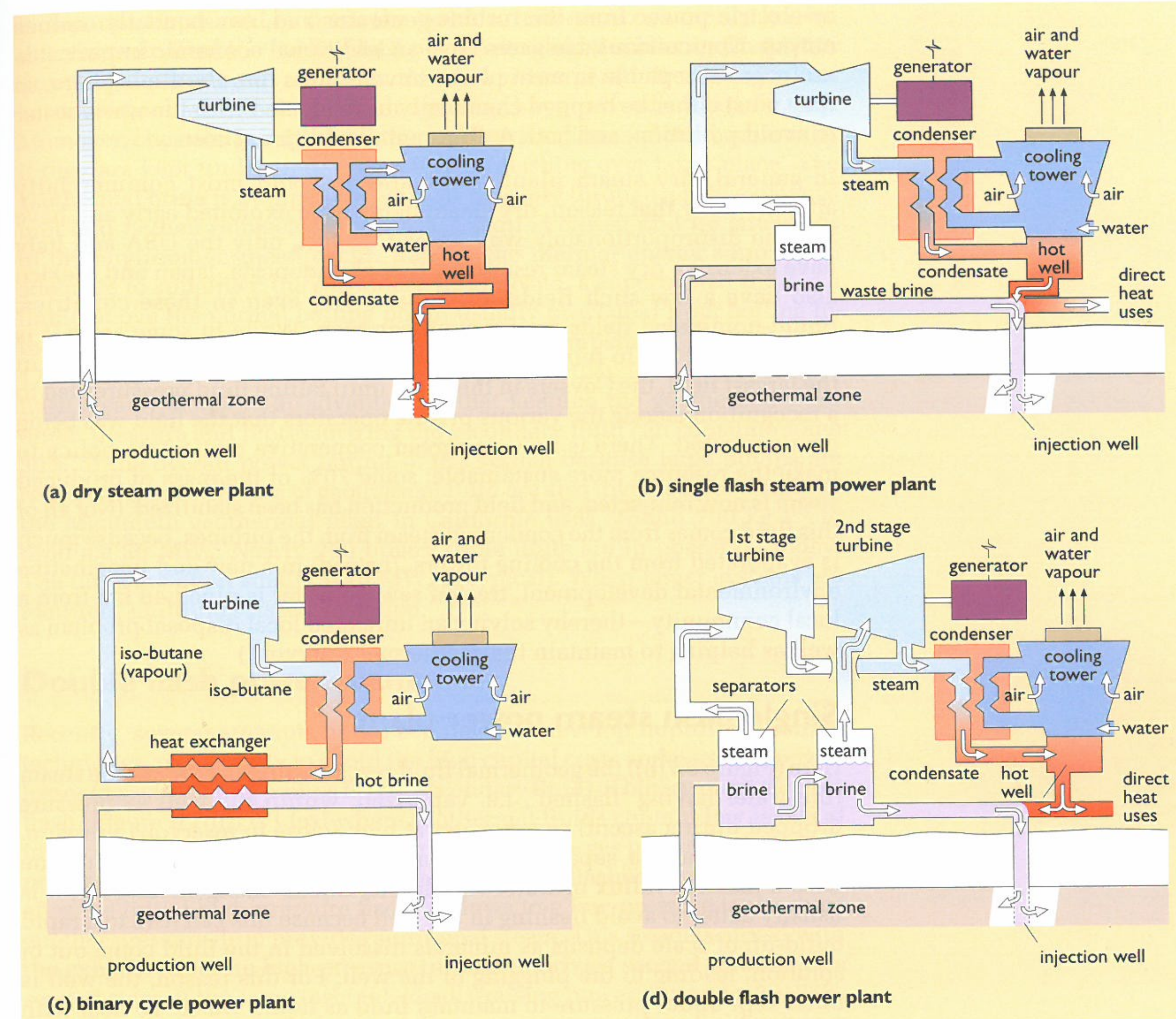


Figure 9.7 Simplified flow diagrams (a–d) showing the four main types of geothermal electrical energy production

efficiencies are low and, despite the use of high-temperature superheated steam, rarely exceed 20%. Nevertheless, whereas a 1960s plant required almost 15 kg steam per saleable kWh in optimum conditions, modern dry steam plant with higher temperature steam and better turbine designs can achieve 6.5 kg per kWh, so a 55 MW_e plant requires 100 kg s^{-1} of steam.

Plant efficiency, and therefore profitability, is strongly affected by the presence in the geothermal fluid of so-called 'non-condensable' gases, such as carbon dioxide and hydrogen sulfide. When the turbine exhaust gases are cooled, achieving a suction effect on the turbine as the water condenses into liquid at around 100 °C, gases that do not similarly condense cause higher residual pressures at the back end of the turbine. Even a small percentage of such gases reduces suction efficiency and so impacts on the economics of the system; for this reason, many geothermal plants are fitted with gas ejectors. However, the ejectors themselves require either a steam supply or electric power from the turbine-generator and, consequently, reduce output. Non-condensable gases have an additional economic impact: it is no longer acceptable in most places to vent them into the atmosphere, so they must either be trapped chemically or reinjected with the waste water to avoid pollution, and both options entail additional costs.

In general, dry steam plant is the simplest and most commercially attractive. For that reason, dry steam fields were exploited early and have become disproportionately well known. In fact, only the USA and Italy have extensive dry steam resources, though Indonesia, Japan and Mexico also have a few such fields. Elsewhere, and even in these countries, liquid-dominated fields are far more common. While in some areas it is common practice to reinject the spent fluid, very little was reinjected in the largest field, the Geysers in the USA, until falling fluid pressures led to a recognition among the various private operators that the field was being over-exploited. There is now an agreed cooperative reinjection policy to make the resource more sustainable; some 70% of the mass of produced steam is now reinjected, and field production has been stabilized. (Not all of this fluid comes from the condensed steam from the turbines, because much is evaporated from the cooling towers. Instead, in a new and imaginative environmental development, treated sewage water is piped 48 km from a local community – thereby solving an unrelated local disposal problem as well as helping to maintain the geothermal reservoir.)

Single flash steam power plant

Here (Figure 9.7(b)) the geothermal fluid reaching the surface may be steam (the water having 'flashed', i.e. vaporized, within the well as pressure dropped during ascent) or hot water at high (close to reservoir) pressure. In the first case, a separator is installed simply to protect the turbine from a massive influx of water should conditions change. However, it is usually better to avoid flashing in the well because this can lead to a rapid build-up of scale deposits as minerals dissolved in the fluid come out of solution, leading to the plugging of the well. For this reason, the well is often kept under pressure to maintain fluid as liquid water. To deal with hot high-pressure water requires complex equipment designed to reduce the pressure in a controllable manner and induce flashing so that steam may be separated. Again, a conventional condensing steam turbine is at the heart of the plant, but lower steam pressures and temperatures (0.5–0.6 MPa, 155–165 °C) are common, so the plant typically requires more steam per kWh than would be required in a dry steam plant, say around 8 kg per kWh. Moreover, the bulk of the fluid produced, often up to 80%, may remain as unflashed hot brine which is then reinjected unless there are local direct use heating applications available. In general, therefore, reinjection wells must be available for fluid disposal both at single flash plants and at plants incorporating the newer types of technology described below. Increasingly, the provision of reinjection is becoming a standard requirement of many licensing schemes.

Binary cycle power plant

This type of power plant (Figure 9.7(c)) uses a secondary working fluid with a lower boiling point than water, such as pentane or butane, which is vaporized and used to drive the turbine. It is more commonly known as an organic Rankine cycle (ORC) plant (introduced earlier in Chapter 2, Box 2.4). Its main advantage is that lower-temperature resources can be developed where single flash systems have proved unsatisfactory. Moreover, chemically impure geothermal fluids can be exploited, especially if they are kept under pressure so that no flashing ever takes place. The geothermal brine is pumped at reservoir pressure through a heat exchange unit and is then reinjected; the surface loop is closed and no emissions to the environment need occur. Ideally, the thermal energy supplied is adequate to superheat the secondary fluid. (Note: a superheated fluid is a liquid above the normal boiling point, usually prevented from boiling by increasing the pressure). For geothermal fluid temperatures below about 170 °C, higher generating efficiencies are possible than in low-temperature flash steam plants. A disadvantage is that keeping the geothermal fluid under pressure and repressurizing the secondary fluid can consume some 30% of the overall power output of the system because large pumps are required. Large volumes of geothermal fluid are also involved; for example, the Mammoth geothermal plant in California uses around 700 kg s^{-1} to produce 30 MW_e. Nearly 250 binary cycle units are in operation today. The units are often small (5–10 MW_e is typical). When larger systems are required, multiple sets are installed.

Double flash power plant

Recently, several attempts have been made to develop improved flashing techniques, particularly to avoid the high capital costs and parasitic power losses (e.g. circulating pumps for the secondary fluid) of binary plant. Double flash (Figure 9.7(d)) is ideal where geothermal fluids contain low levels of impurities and so the scaling and non-condensable gas problems that affect profitability are at a minimum. Quite simply, unflashed liquid remaining after the initial high-pressure flashing flows to a low-pressure tank where another pressure drop provides additional steam. This steam is mixed with the exhaust from the high-pressure turbine to drive a second turbine (or a second stage of the same turbine), ideally raising power output by 20–25% for only a 5% increase in plant cost. Even so, extremely large fluid volumes are required. The East Mesa plant in southern California, for example, commissioned in 1988, uses brine at 1000 kg s^{-1} from 16 wells to generate 37 MW_e; i.e. around five times as much fluid as for similar dry steam plant (though temperatures would be much higher in the latter case).

Future developments

As the geothermal industry continues to expand, there will be a need to develop technologies that can produce geothermal power from a variety of resources that are less ideal than dry steam. Increasing use is being made of geothermal fluids that are at either lower temperature than (but similar pressure to) those in dry steam fields, or at the same or higher temperature and much higher pressure. These are essentially liquid-dominated resources, albeit of high enthalpy, and they exist in large volumes. Inevitably, variants on the binary and double flash systems will continue to be developed; they are at the leading edge of current research. More recently, greater use has been made of the produced fluids by operating combined or hybrid cycles, using an ORC to extract further work from the main turbine exhaust or the separated water.

A number of other approaches are being developed to increase the efficiency of generation from lower temperature fluids, using either different working fluids or new power cycles, such as the Kalina cycle. The working fluid for the Kalina cycle is an ammonia-water mixture, the composition of which varies throughout the cycle. The net generating efficiency is expected to be up to 40% higher than for an ORC under the same conditions; at an inlet temperature of 130 °C the net efficiency is estimated at over 13% (58% of the theoretical Carnot efficiency – see Box 2.4). The early demonstration units (one in Iceland, one in Japan and two in Germany) are all essentially prototypes and are still showing teething problems, but the operators remain optimistic.

9.4 Technologies for direct use of geothermal energy

Some of the countries that are exploiting geothermal resources for non-electrical purposes have chosen to develop these direct use applications in areas flanking the main steam fields. Japan, New Zealand, Iceland and Italy are obvious examples, where wet steam or warm water at a range of temperatures is readily available for industrial, domestic and leisure applications. In this section, however, we leave these aside and concentrate principally on the low-temperature resources found in regions remote from plate boundaries, typically in sedimentary basins, several of which have been developed across central Europe. Drilling techniques resemble those discussed earlier, but the process is generally less hazardous since the geothermal fluid is found under much lower pressure and temperature conditions than in hot steam fields, and pumps are often required to bring the fluid to the surface at adequate flow rates. However, the hot water is usually too saline and corrosive to be allowed directly into heating systems, so once again corrosion-resistant heat exchangers are widely used. It should be pointed out that, given the cost of deep boreholes, a large market is required if sales of heat are to be large enough to pay for the development. Typical heat loads might be a vast greenhouse complex using both overhead and underground pipes, or a domestic group scheme with a combination of underfloor and radiator heaters. The dense multi-storey apartment blocks of the Paris suburbs are ideal heat loads for such local resources.

The French led the development of these low-enthalpy resources in Europe. Over the past 40 years no fewer than 55 geothermally fed group heating schemes were installed in the Paris Basin, with several more in south-western France. At the design stage, a twin production and reinjection borehole system would be planned on the basis of supplying 3–5 MW_t of heat energy (25–50 l s^{-1} of water at 60–70 °C) over a lifetime of 30–50 years. The spacing of the wells must be designed to maintain high fluid pressures by reinjection while avoiding the advance of a 'cold front' (i.e. fluid at reinjection temperatures) towards the production well until capital costs are paid back, and this means that flow conditions in the aquifer need detailed study. A typical layout for a twin production well scheme, with a schematic of the heat transfer technology, is shown in Figure 9.8. Note

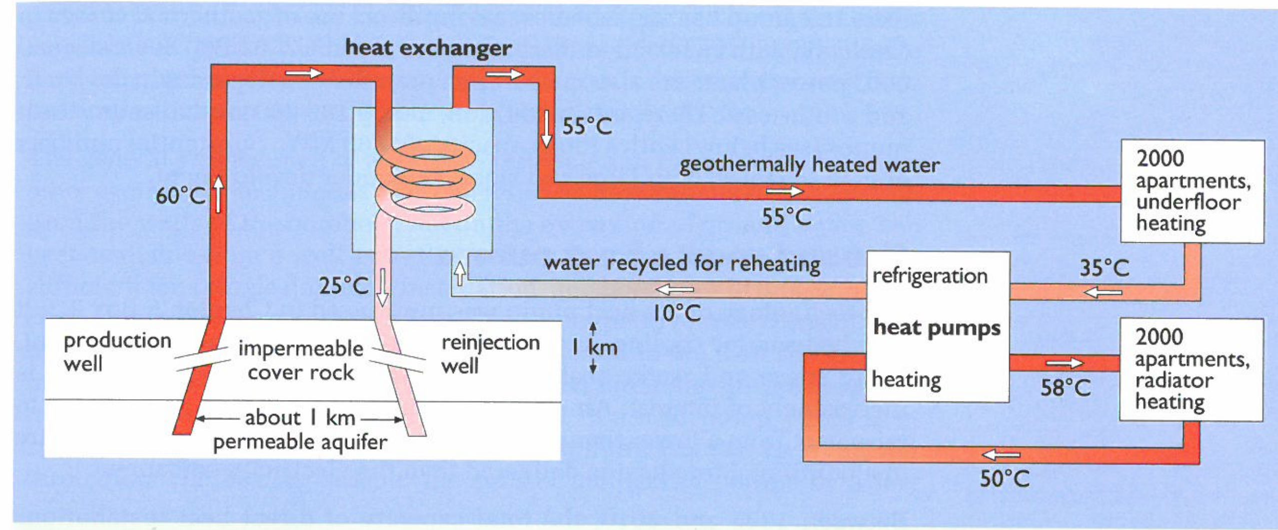


Figure 9.8 An example of a district heating scheme installed in the Paris region. This shows how the geothermal heat is exchanged to a secondary freshwater circuit. The circuit is used first to heat 2000 apartments by underfloor heating; the residual energy is then boosted using heat pumps to provide radiator heating in a further 2000 apartments. Note that the main function of the heat pumps is to lower the reinjection temperature and so extract more heat from the geothermal fluid rather than to raise the production temperature

in this example the interesting application of heat pumps to enhance the system efficiency by reducing the reinjection temperature. Heat pumps work on the same principle as refrigerators, but here produce a concentrated high temperature output. Of course, they consume electrical energy but, in the example shown in Figure 9.8, they enable the number of heated apartments to be doubled.

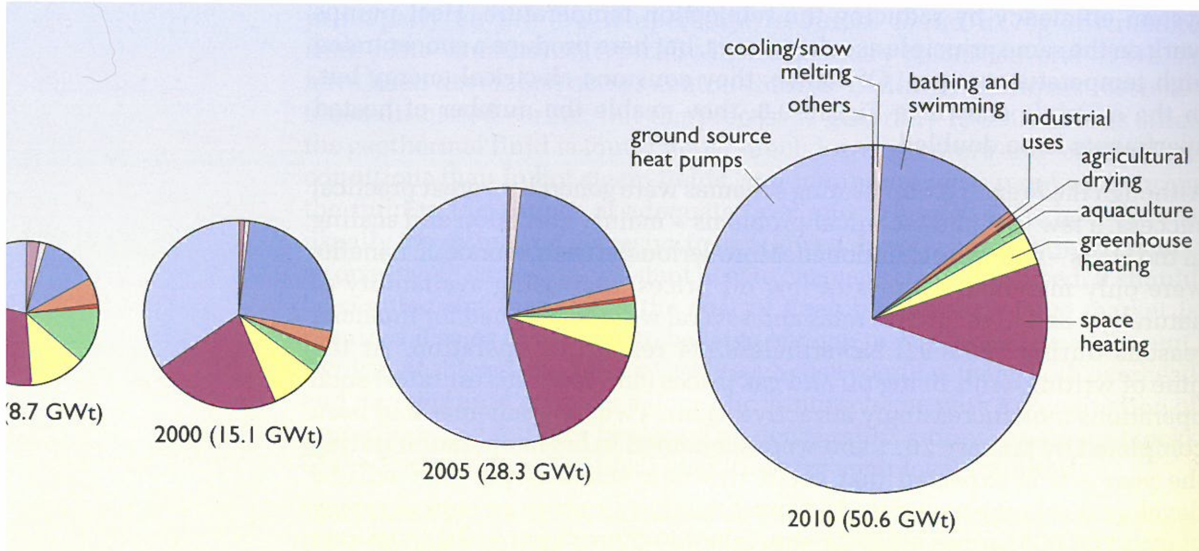
Although the French group heating schemes were generally a great practical success, a few suffered technical problems – mainly corrosion and scaling in the wells – and were abandoned. More seriously, their economic benefits were only marginal at times of low oil prices, increasing availability of natural gas and high interest rates and several were abandoned for financial reasons during 1989–92. Nevertheless, 34 remain in operation. At the time of writing, with rising oil and gas prices (and low interest rates) such operations look increasingly attractive again. Two new schemes had been completed by January 2011 and were scheduled to begin operation during the year – it is expected that about two new schemes per year will be developed over the next decade. Currently, they produce an annual saving of over 200 000 tonnes of oil (or equivalent in other fossil fuels) in an area which, 40 years ago, had no obvious geothermal potential. The same concept applies to the analogous UK scheme in Southampton.

In Germany, reunification had a significant effect on the way in which geothermal developments occurred, as the better (though still low temperature) resources tend to be concentrated in the eastern part of the country. Although a few schemes existed before reunification, with the freeing of capital following unification, combined with concerns about CO_2 emissions from fossil fuels, the geothermal market really began to take off. Several large-scale district heating schemes are already in operation and even more are under active development. By the end of 2009 there were 162 group heating schemes making direct use of geothermal energy in Germany, with an installed thermal power of some 250 MW_t. Several small ORC power plants are also in operation or under development in the south and south-west. There are, in addition, nearly 180 000 ground source heat pumps (see below) with a total capacity of 1860 MW_t. Substantial numbers of new schemes, both large and small, are under development.

Ground source heat pumps

The technology of the heat pump was introduced in Chapter 2, Box 2.3. It may be used for cooling, as in a refrigerator or an air conditioning plant, or for space and water heating in buildings. It is this latter use that is increasingly of interest. An electrically driven compressor can be used to raise heat from a lower temperature and deliver it at a higher temperature to a building. More heat is delivered than the electricity consumed.

Between 1995 and 2010, the total capacity of direct heat installations worldwide increased from 8664 MW_t to over 50 000 MW_t. In fact, the increase in large direct-use installations like those described above has been quite modest (for the same reasons, until recently, of high interest rates and low fossil fuel prices). Eighty percent of the increase has been accounted for by a new type of geothermal installation, the ground source heat pump (GSHP) – see Figure 9.9. In the EU Renewable Energy Directive (CEC, 2009) the energy gain is defined as 'renewable energy'.



9.9 The growth worldwide of different direct geothermal applications. The area of the circles is proportional to the d capacity

As described earlier in Chapter 2, Box 2.3, a key parameter of a heat pump is its *coefficient of performance* (COP), the ratio of the heat (or cooling energy) produced to the electricity used to drive its compressor and associated pumps. The maximum possible COP is limited by the same considerations of Carnot efficiency that limit electricity generation efficiency (see Box 2.4 and Everett et al, 2012). Heat can be raised through a small temperature difference with a high COP but, as the temperature difference increases the

possible COP will decrease. Results from well-designed UK borehole GSHPs suggest that typical COPs can range from 3 to 4.5 (EEPH, 2005). Where used for space heating GSHPs may be used in conjunction with underfloor heating, which can be carried out with water at only 40 °C.

The general arrangement of a GSHP is illustrated in Figure 9.10(a). Unlike other geothermal techniques, this one relies on heat transfer by conduction from the walls of the borehole, not on the extraction of groundwater. The heat available from a well 100–150 m deep is only a few kW_t, but that is sufficient for a single domestic installation, and boreholes of this depth are often cheap enough to make the installation competitive with conventional heating systems. A simple loop of pipe is inserted in the well and grouted in place. A heat transfer fluid (usually water) circulates in the loop and transfers heat from the surrounding subsoil to a heat pump. More than 20 years' experience has shown that a few kilowatts can be extracted throughout the heating season; the subsoil temperature drops by a few

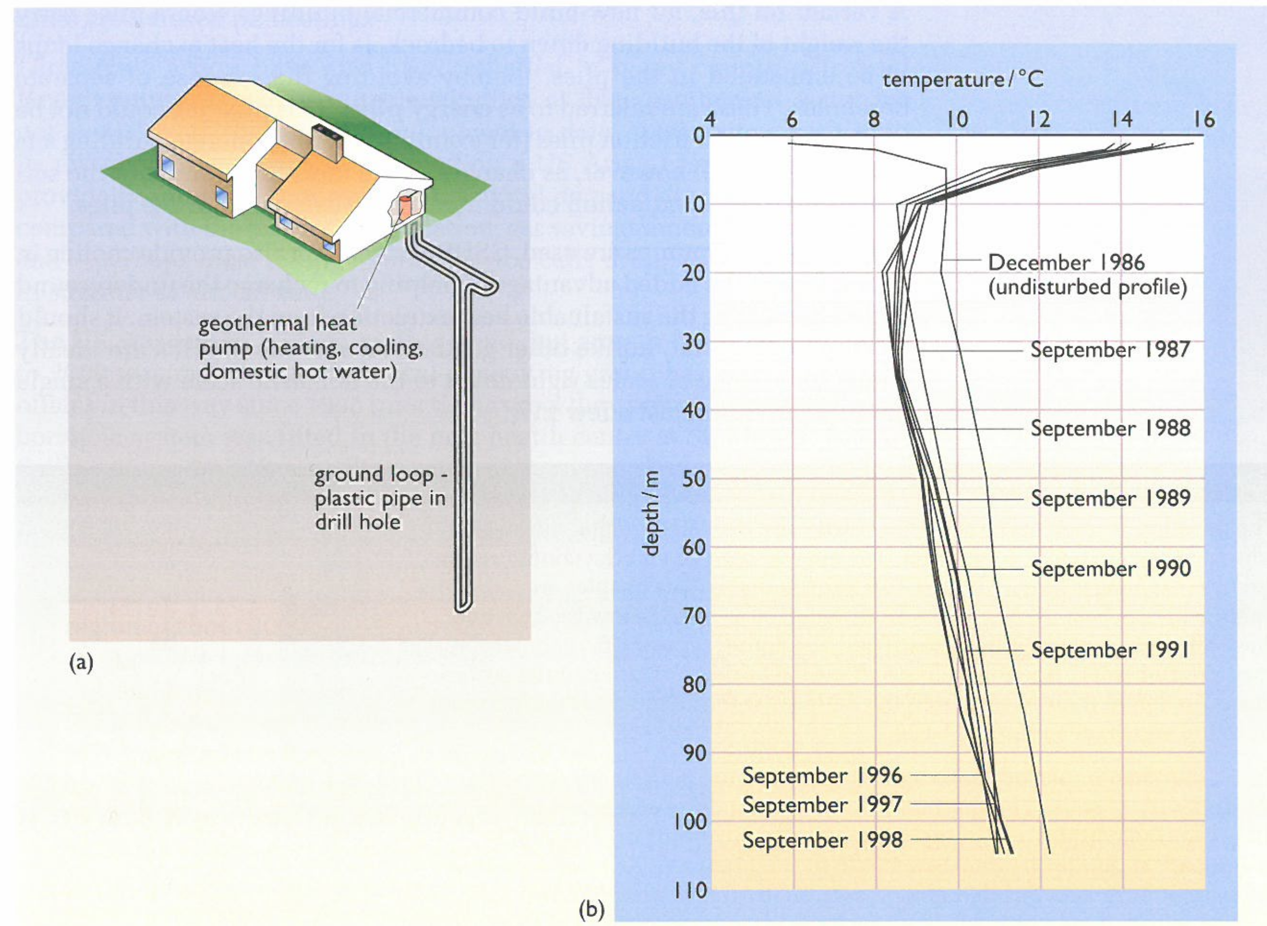


Figure 9.10 (a) The geothermal heat pump (GHP) concept, used to extract heat from warm shallow groundwater to supply a single domestic dwelling. In the winter heat is removed from the earth and delivered in a concentrated form via the heat pump. Because electricity is used, in effect, to increase the temperature of the heat, not to produce it, the GHP can deliver three to four times more energy as heat than the energy content of the electricity it consumes (b) Measured data from a Swiss GSHP installation; though old, the data remain valid. After an initial drop, the ground temperature below the solar-controlled surface zone recovers to the same value year after year. If the scheme is designed correctly, this would be a truly renewable operation

degrees but regenerates over the remainder of the year (Figure 9.10(b)). Table 9.4 shows the rate at which energy can be extracted – on a quasi-continuous basis – from typical 100–150 m deep holes.

Table 9.4 Borehole heat exchanger performance in different rock types

Rock type	Thermal conductivity /W m^{-1} K^{-1}	Specific extraction rate/W m^{-1}	Energy yield per metre of borehole /kWh m^{-1} a^{-1}
Hard rock	3.0	max. 80	135
Unconsolidated rock, saturated	2.0	45–50	100
Unconsolidated rock, dry	1.5	max. 30	65

Source: Rybach and Eugster, 1998

A variant on this, for new-build commercial buildings where piles carry the weight of the building down to bedrock, is for the heat exchange loops to be embedded in the piles, thereby avoiding the expense of separate boreholes. These are referred to as **energy piles**. This practice could not be recommended for friction piles (for example where a concrete building sits in a clay subsoil), however, as changes in the moisture content of the soil as a result of heat extraction could modify the behaviour of the piles.

If reversible heat pumps are used, GSHP systems can also provide cooling in summer with the added advantage of helping to recharge the underground and so increasing the sustainable heat extraction from the system. It should be emphasized that, unlike other geothermal systems, GSHPs are ideally suited for a range of scales right down to the domestic scale with a single module providing just a few kW_t.

9.5 Solar or geothermal?

uestion is often asked whether GSHPs are truly geothermal devices, or ıer they are really solar units. The answer depends on the configuration of ıat exchanger loop. All the GSHPs discussed in this chapter are 'borehole' with the heat exchanger located some 100 m or so below ground, and are true geothermal systems. There is another type of GSHP, however, that ground coils', horizontal loops of piping buried just beneath the surface. do derive their energy from the daily solar input and their performance ore varies on a seasonal basis.

lifference in performance again has its origins in the poor thermal ıctivity of soils. The thermal pulse from the daily and seasonal input penetrates very slowly, and for practical purposes virtually pears at depths greater than 15–20 m (Figure 9.11). At greater depths, mperature is controlled almost entirely by the geothermal heat flow ɔt where it may be influenced by local groundwater flow). If the system designed correcty, there is a possibility that the rate of heat extraction xceed the recharge rate, resulting in a year-on-year reduction in ground ɪrature.

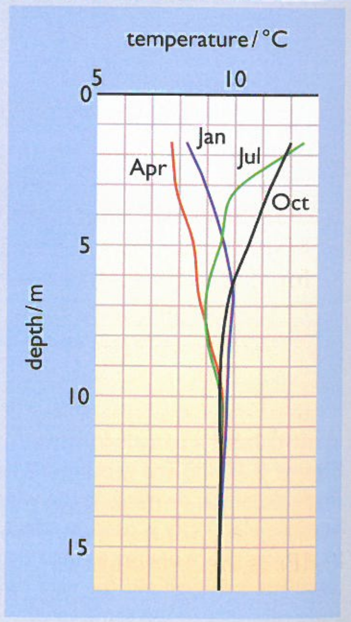


Figure 9.11 Ground temperatures typical of northern Europe (source: Sanner, 2001)

Because the presence of groundwater is not a prerequisite, this technology can be applied almost anywhere. The types of buildings that are using ground source heating and cooling in this manner range from domestic, utility or public housing, through to very large (megawatt-sized) institutional or commercial buildings exploiting multiple units. This technology can offer up to 40% reductions in CO_2 emissions against competing technologies. Better still, if the electricity to drive the heat pump is supplied from non-fossil sources, then there should be no CO_2 emissions associated with heating and cooling a building.

The concept was developed independently in the USA and Europe. While uptake seems to have been concentrated in the northern hemisphere (North America, Europe and China), the installed capacity has grown at an annual rate of around 20% over the past 15 years. It is estimated that there is now the installed equivalent of nearly 3 million 12 kW_t units (the typical size of a single dwelling installation in the USA and western Europe). In the USA, most units are sized to handle peak cooling loads, whereas most European units are focused on heating.

Large-scale arrays have also been installed in many countries to feed larger complexes where suitable supplies of deep geothermal water are not available. In the largest development to date, 4000 units – each with its own borehole – were established on a US Army base in Louisiana to provide heating and cooling. Peak electrical demand dropped by 6.7 MW_e compared with the previous installation, gas savings amounted to 2.6 TJ y^{-1} and – perhaps most telling of all – service calls dropped from 90 per day in summer to almost zero.

The UK was late in picking up this trend, but growth from the mid-1990s to 2009 was rapid. A geotechnical consulting group has been heating its offices in this way since 1996 (practising what they preach!). In 1998 a four-borehole system was fitted in the new health centre at St. Mary's, Isles of Scilly, using a 25 kW reversible heat pump to supply hot water, heating and cooling to the building. There are probably now around 12–15 000 units in operation. The situation in late 2010 was summarized as follows:

> Starting from a very low base, the level of activity is probably in the region of about 3000 – 5000 installations per year. Whilst a handful of these are larger scale open-loop systems (~500 kW – 2 MW), the majority are closed-loop systems. These range in size from 3.5 kW heating only systems in social housing, through to multi MW installations delivering heating and cooling. The main driver for this activity has been the realization that GSHPs connected to the UK grid can offer significant reductions in overall carbon emissions compared to traditional methods of heat delivery. With projected improvements in the carbon intensity of the UK electricity generation grid, GSHPs will be able to deliver even larger carbon reductions with time.
>
> (Batchelor et al., 2010)

It is worth stressing that the major driving force behind the uptake of GSHPs is the reduction in CO_2 emissions from heating and cooling systems, even though the heat pumps are electrically driven. With **coefficients of performance (COP)** – the ratio of heat output to electrical input – now in the range of 3–4.5 for borehole units in the UK (EEHP, 2005), the CO_2 savings are significant.

As other renewables start to feed into the generation mix, the CO_2 penalty of the heat pump drives may reduce even further.

Enhanced (or engineered) geothermal systems

All conventional geothermal systems (except, perhaps, GSHPs) rely on the presence of water circulating through the rock to extract heat and bring it to the surface. However, even in a good aquifer more than 90% of the heat is contained in the rock rather than in the water. Moreover, the vast majority of rocks are poorly permeable at best and the occurrence of an exploitable geothermal reservoir is a rarity. On the other hand, heat exists everywhere, and the amount of energy stored within accessible drilling depths (say, down to 7000 m, where temperatures of >200 °C would be widespread) is colossal. Cooling one cubic kilometre of rock (which is about the scale of a geothermal reservoir) by 1 °C will provide the energy equivalent of 70 000 tonnes of coal.

To put this in context, a report prepared by the Massachusetts Institute of Technology for the US Department of Energy in 2006 (MIT, 2006) calculated the heat in place at various depths in the continental USA (excluding Alaska, Hawaii and Yellowstone National Park) (Figure 9.12). The estimate was 13 million exajoules (13×10^{24} joules); by comparison, the total annual energy consumption in the USA is about 100 exajoules. Even though only a small fraction of this resource is likely to be developable, the potential of such an energy resource cannot be ignored.

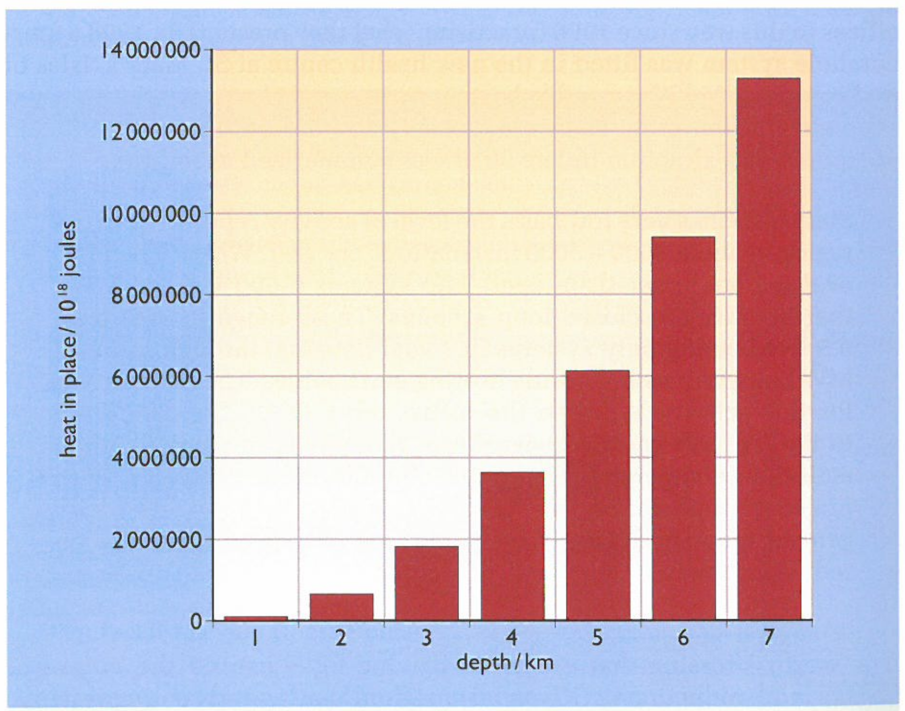


Figure 9.12 The total heat in place at various depths beneath the continental USA, excluding Alaska, Hawaii and Yellowstone (source: adapted from MIT, 2006)

This situation is not confined to the USA. All over the world, temperatures around 200 °C are accessible under a high percentage of the landmass. If this store of heat could be exploited, it would give almost every country the opportunity to generate electricity from an indigenous and (for all practical purposes) renewable resource. It is this prospect that has motivated a number of countries to spend over US$350 million over the past 40 years to find a way to exploit the resource.

The familiar concept of twin production and injection boreholes provides the basis of system designs, but here drilled into relatively hard crystalline rock and terminating several hundred metres apart. In principle, water can then be pumped down one hole, flow through the rock picking up heat, and return to the surface via the second borehole. The fundamental problem is that, as mentioned in Section 9.2, rocks are very poor conductors of heat and, to extract energy at a rate sufficient to pay back the high cost of the boreholes needed to reach these depths, very large heat transfer surfaces are needed – of the order of several square kilometres! There is now a consensus that the only practical way of achieving this figure is to work with nature, exploiting the fact that most deep rocks contain extensive networks of natural fractures. In principle, a suitable heat exchange surface can be created by opening these pre-existing fractures.

The focus has, therefore, been on learning how to stimulate and manage the fracture networks to support a useful and controllable flow of water between boreholes. The stimulation is done by using a variant of an oil industry technique known as hydro-fracturing, which consists of pumping water down the borehole at increasing pressure until fractures in the rock are opened. The progressive development of the opening fractures is followed by listening to and locating the sound of rock surfaces moving over one another. This is known as microseismic monitoring.

If the second borehole has already been drilled, it may be necessary to repeat the stimulation in that hole in order to link up with the first zone. Alternatively, the second hole may be drilled after the first stimulation to intersect the stimulated zone. A closed circuit water circulation through the fracture system is thereby generated. The trick has been in learning precisely how to control the injection conditions in each hole to ensure that water can flow through the system with a minimum of resistance. At the same time, the stimulated zones around each hole must link up in such a way that water losses are minimized, because water losses mean wasted pumping costs (and in many regions water itself is a valuable commodity). Water is circulated down the injection well, through the reservoir and up the production well to a heat exchanger and turbo-generator where the thermal energy is converted to electricity. (Lower-temperature district heating schemes are also under consideration, but the high capital costs of such an operation require an extremely large local market for the heat produced.)

Pioneering work took place at Fenton Hill in New Mexico in the 1970s and 1980s where the Los Alamos National Laboratory (LANL) developed two systems at temperatures of 200 °C and >300 °C. The Fenton Hill project proved the principle in 1979, when a 60 kW_e ORC generator operated for a month on the produced water. The operating parameters were very far from those that would be needed in a commercial system, however, and a number of teams in various countries (USA, Japan, UK, France, Germany and, most recently, Switzerland) have worked cooperatively in the intervening years to understand and refine the techniques required. Notable among these activities was the full-scale (but comparatively shallow – 2000 m – and deliberately low-temperature) rock mechanics experiment at Rosemanowes Quarry in Cornwall, England, which began in 1975 and laid many of the foundations for our current understanding of the behaviour of natural fracture systems and how they might be managed.

At the beginning, it was assumed that basement rocks at depth would be devoid of fluids, so the technology was termed Hot Dry Rock (HDR). Over the years, however, it has become clear that 'Dry' is a misnomer; very few basement rocks have proved to be completely dry. Water has been found in fractured basement even at the deepest levels in the exploration boreholes in the Kola Peninsula, Russia (15 km) and in the Black Forest, Germany (>8 km). More recently, the term 'Enhanced' (or 'Engineered') 'Geothermal Systems' (EGS) has come to replace the original name, though the phrase 'hot dry rock' is too catchy to disappear easily. The overall technology has been broadly defined as 'any system in which reinjection is necessary to maintain production at commercially useful levels'. This redefinition also emphasizes the continuity which exists in the spectrum of reservoir permeabilities and geothermal technologies. A more detailed definition is given in the MIT report:

> The U.S. Department of Energy has broadly defined Enhanced (or engineered) Geothermal Systems (EGS) as engineered reservoirs that have been created to extract economical amounts of heat from low permeability and/or porosity geothermal resources. For this assessment, we have adapted this definition to include all geothermal resources that are currently not in commercial production and require stimulation or enhancement. EGS would exclude high-grade hydrothermal but include conduction dominated, low-permeability resources in sedimentary and basement formations, as well as geopressured, magma, and low-grade, unproductive hydrothermal resources. In addition, we have added coproduced hot water from oil and gas production as an unconventional EGS resource type that could be developed in the short term and possibly provide a first step to more classical EGS exploitation.
>
> (MIT, 2006, p. 1.10)

The countries principally involved in the research worked closely together throughout the 1980s and 1990s; this type of research makes great demands on both money and expertise and is aimed at what should prove to be a generally applicable technology, so it is an ideal subject for international collaboration. Following this logic, during the 1980s the various teams in the UK, France and Germany, with the support of the European Commission, agreed to pool their resources to develop a single experimental site at Soultz-sous-Forêts in the Upper Rhine Valley. The aim was to build on the results derived from the work in Cornwall, but at a site where temperatures at depth were expected to be higher. As it turned out, temperatures at depth were similar to those expected in SW England, but the work led eventually to demonstration of the practicability of the EGS concept, in this case a three-well system that has now started delivering power to the French national grid (see Box 9.6).

BOX 9.6 The EGS site at Soultz-sous-Forêts

The Soultz site, like Fenton Hill, benefits from the blanketing effect of 1000 m of sedimentary rock above the crystalline basement. The geothermal gradients through the sediments average 0.08–0.1 $^{\circ}C\ m^{-1}$, falling to 0.028–0.05 $^{\circ}C\ m^{-1}$ in the crystalline basement beneath. Teams from France, Germany, the UK, Italy and Switzerland worked together on the site, eventually drilling four deep boreholes (>3800 m, 170 °C to 5000 m, 200 °C) as well as several shallower boreholes that are used for the microseismic monitoring system (Figure 9.13). Geologically, the site is located in the Upper Rhine Graben, where E–W tensional forces have stretched the crust and caused the granitic basement to subside. The basement is heavily fractured and even supports a small amount of natural fluid flow.

During more than 20 years of operation, the project at Soultz, coordinated and part-funded by the European Commission, became recognized as the world leader in developing EGS technology. It has been shown that with careful control of the pressure and density of the stimulation fluid the stimulated zone can be persuaded to develop laterally so that it can be accessed by a conventional arrangement of two or more boreholes deviated in opposite directions. In late 1997, after several years of testing and hydraulic stimulation of the fracture system at 3.5 km depth, a 4-month circulation test was carried out. 25 $kg\ s^{-1}$ of water was circulated on a continuous basis between wells GPK1 and GPK2. The system operated in a closed loop, with the heat produced (ca. 10 MW_t) being dumped via a heat exchanger. The overall loss rate was zero and no make-up water was required. In a two-well system like this, such a result was possible only because a down-hole pump was used in the production well, altering the sub-surface pressure field to ensure that losses from the injection well could be balanced by input from the natural *in situ* fluids. Tracers added to the injected fluid proved that circulation was occurring; production also

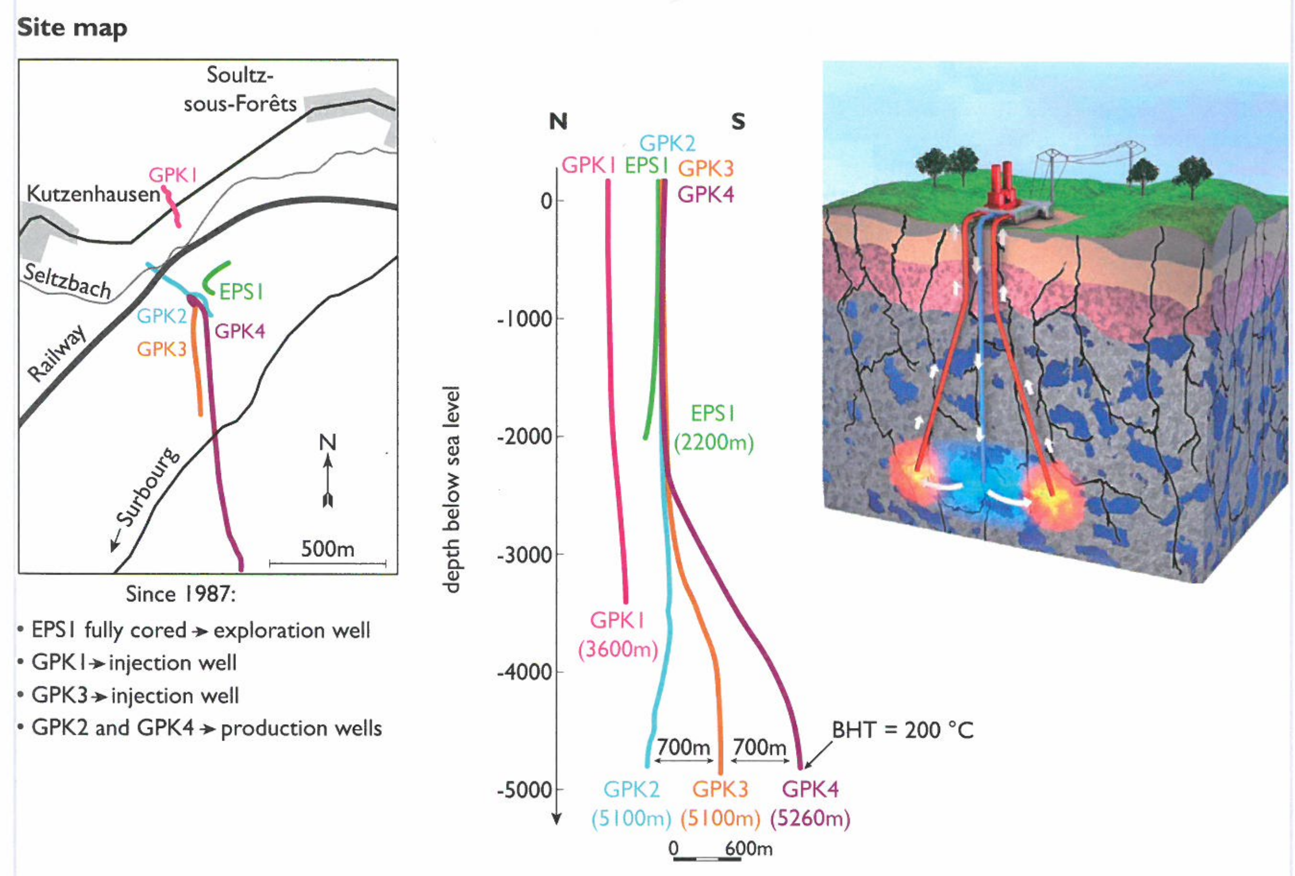


Figure 9.13 The arrangement of wells at Soultz (adapted from Genter et al., 2009)

lined very rapidly when reinjection was stopped, ı observations demonstrating that this is a true ; system under the above definition. Of equal ıortance was the finding that the overall system impedance was less than 0.2 MPa l^{-1} s^{-1}, closer to the targets than any previous project (target parameters for EGS developments are discussed later and are summarized in Table 9.6).

Figure 9.14 The EGS site at Soultz-sous-Forêts

lowing this success, it was decided to continue he pilot plant/proof-of-concept stage. To improve flow distribution in the reservoir, a three-well tem was designed, with two production wells ıking a single injector. GPK2 was deepened, and <3 and GPK4 drilled, to about 5000 m, where bottom hole temperatures were 200 °C. The ls were deviated to give bottom hole separations '00 m. After stimulation of the fracture zones between the wells, a 1.5 MW_e ORC turbo-generator was installed. The first power was produced in June 2008, and continuous production started in January 2011, albeit at a low initial flow rate (<35 l s^{-1}) as a precaution against induced seismicity (see Box 9.7).

After testing the system for a couple of years, the aim will be to enlarge the power plant to 6 MW_e.

As mentioned earlier, the increasing emphasis in recent years on the need to reduce CO_2 emissions and dependence on fossil fuels has caused a number of countries to increase their efforts to develop geothermal resources. Notable among these have been Germany and Australia. Germany has been involved in EGS research since the earliest days of the work at Los Alamos but, following experience gained from its work at Soultz, has begun to apply the techniques at home. Indeed, the first commercial EGS system has been completed at Landau, also in the Upper Rhine Valley about 50 km north of Soultz, to provide both heat and power to the town. It is a two-well system, with a depth of about 2700 m, producing water at 70 l s^{-1} and 160 °C. The Landau power plant was inaugurated in November 2007 and since then has been running continuously, except for some maintenance work. It is able to deliver about 3 MW_e and about 4 MW_t.

Perhaps the most surprising entrant in the geothermal stakes over the past decade has been Australia. Previously, it had been assumed that the age of the Australian crust meant that accessible temperatures would be too low

to be useable, but all that changed after 2000; with Federal government support, both in terms of legislation and finance, there has been an explosion of commercial interest in geothermal prospects. By the beginning of 2011, some 56 companies held exploration licences in 418 areas (Figure 9.15). Primarily, the interest centres around the potential of EGS technology, although hot aquifers are now also being targeted in the south-west and north-east.

By 2011 it was estimated that more than AU\$671 million (US\$663 million) had been spent on studies, geophysical surveys, drilling, reservoir stimulation and flow tests. By 2015, investment for proof-of-concept geothermal projects is forecast to exceed AU\$3227 million (US\$3187 million). In a departure from practice in other countries, a significant fraction of this funding has been provided by companies and private shareholders.

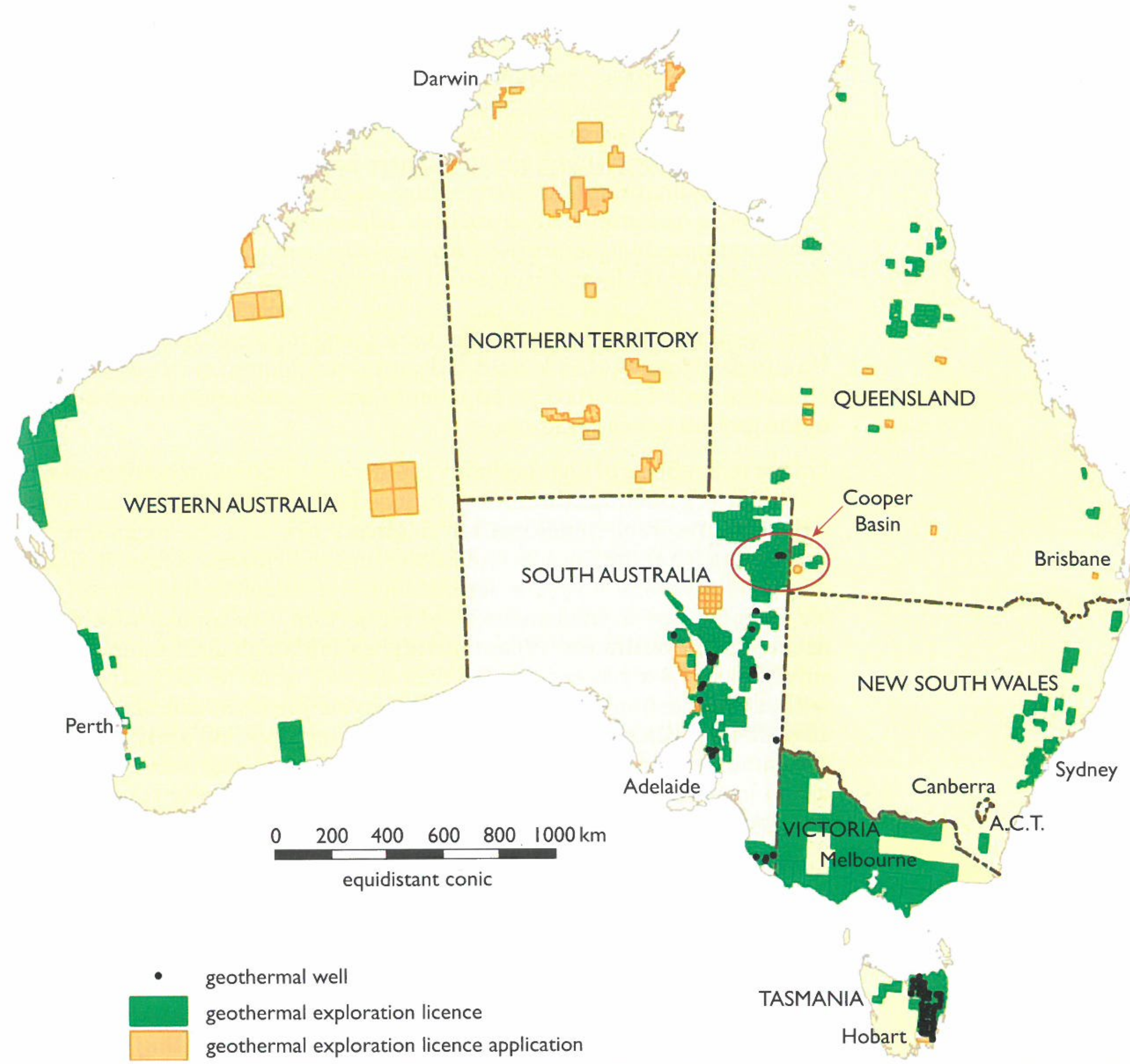


Figure 9.15 Geothermal exploration in Australia in 2011 (source: Goldstein et al., 2011)

The most advanced EGS project is that being developed by Geodynamics in the Cooper Basin. In this region Geodynamics is exploring three separate fields (Habanero, Jolokia and Savina) and has drilled a total of five wells into the granite basement to depths of 3800–5000 metres, with the aim of assessing the nature and extent of the resource present. In 2009 proof of concept was achieved at Habanero, when circulation tests confirmed sub-surface flow between Habanero #1 and #3 wells through a stimulated sub-horizontal fracture network at a depth of 4400 m. Further drilling is to be undertaken before confirming the location of a 25 MW_e commercial demonstration project (CDP), which aims to demonstrate that EGS technology is cost effective at a commercial scale. The operators expect to commission the 25 MW_e CDP geothermal power plant in 2012.

9.5 Environmental implications

The main environmental concerns associated with 'conventional' geothermal energy development are focused on those to do with site preparation, such as noise pollution during the drilling of wells, and the disposal of drilling fluids, which requires large sediment-settling lagoons. Noise is also an important factor in high-enthalpy geothermal areas during well-testing operations when steam is allowed to escape, but once a field comes into production noise levels rarely exceed those of other forms of power plant. Accidents during site development are rare, though a notable exception in 1991 was the failure of a well originally drilled in 1981 at the Zumil geothermal station on the flanks of Santiaguito volcano in Guatemala. Hundreds of tonnes of rock, mud and steam were blown into the atmosphere when the well 'blew its top', apparently because of gravitational slippage of the ground beneath the site.

Longer term effects of high-enthalpy geothermal production include ground subsidence, gaseous pollution and induced seismicity. In dry steam fields, where the reservoir pressures are relatively low and the rocks are self-supporting (as at the Geysers and Larderello), subsidence is rare. In liquid-dominated systems, however, significant reduction of the higher pressures, for example due to inadequate fluid reinjection, can induce subsidence, usually on the millimetre to centimetre scale (although maximum localized subsidence of 3 m has occurred at Wairakei as a result of early exploitation without reinjection). Reductions in reservoir pressure can also have an adverse effect on the natural manifestations (geysers, hot springs) that are a common accompaniment of high-enthalpy fields and often important to the local tourist industry. Such concerns have severely restricted the development of geothermal power generation in Japan.

Geothermal 'pollutants' are chiefly confined to the non-condensable gases: principally CO_2, with lesser amounts of hydrogen sulfide (H_2S) or sulfur dioxide (SO_2), hydrogen (H_2), methane (CH_4) and nitrogen (N_2). In the produced water there is also dissolved silica, heavy metals, sodium and potassium chlorides and sometimes carbonates, depending on the nature of the water–rock interaction at reservoir depths. Today these are almost always reinjected and this also removes the problem of dealing with waste water. Traditionally, geothermal fields have received a bad press on account of their association with the 'rotten eggs' smell of H_2S. However, this and other gaseous products of old leaking plant have now been reduced so that the environmental impact of thermal production is at a minimum. Modern plants are fitted with elaborate chemical systems to trap and destroy H_2S. Interestingly, the level of atmospheric H_2S over the Geysers field is now lower than that emitted naturally from hot springs and geysers before geothermal developments began. Nevertheless, the image of polluting geothermal systems has slowed developments at several new sites. For example, environmental legislation covering the Miravalles plant, located on the periphery of a rainforest conservation area in northern Costa Rica, delayed completion of the plant for four years. A project on Mount Apo on Mindanao Island in the Philippines was turned down by the World Bank and the Asian Development Bank on social and environmental grounds. Objectors claimed that 111 hectares of forest would be threatened, 28 rivers polluted and a national park destroyed.

The position over emissions of CO_2, an important greenhouse gas, is rather more complicated. Geothermal reservoirs often contain significant quantities of CO_2, so emissions from those power plant will also be higher in CO_2 than might otherwise have been expected. On the other hand, exploitation of the field often reduces natural emissions. Leaving aside that possible benefit, however, a survey carried out by the International Geothermal Association (IGA, 2002) shows a wide variation in CO_2 emissions from existing plant, ranging from 4 g per kWh to 740 g per kWh (though the latter figure is extreme, from a field that is naturally high in CO_2 and undoubtedly leaking large quantities long before geothermal development began). The weighted average is 122 g per kWh. Typical CO_2 emission rates from fossil-fired power stations range from about 400 g per kWh for the most up-to-date natural gas fired combined cycle plant to about 900 g per kWh for the best coal-fired stations (see Chapter 10).

Induced seismicity

The question of whether there is induced seismicity around conventional geothermal sites has been much debated, and in the case of high-enthalpy systems it must be recognized that most steam fields are located in regions already prone to natural earthquakes because of their proximity to plate boundaries. There is evidence that fluid injection lubricates fractures and increases pressures, creating small earthquakes (microseismicity), especially when reinjection is not at the same depth as the producing aquifer (mainly for reasons of fluid disposal). However, in cases where reinjection is designed to maintain reservoir pressures, seismicity is not greatly increased by geothermal production.

In conventional low-enthalpy systems, where reinjection merely maintains the natural level of reservoir pressure, induced seismicity is rare or absent.

In EGS systems, on the other hand, injection occurs at higher pressures and induced seismicity is common, at least in the project development stages (see Box 9.7). Although the vast majority of induced events are small and detectable only instrumentally, a few are large enough to be felt at the surface. This is giving rise to public concern that could severely inhibit further development, and a multinational research programme has been mounted to understand and minimize these effects.

BOX 9.7 Induced seismicity in EGS projects

Although induced seismicity has rarely been a problem in conventional geothermal developments, the question has assumed far greater significance in the context of EGS projects. The stress fields in hard crystalline rocks, which are the typical targets for EGS, are invariably anisotropic, i.e. the three principal stresses (that is, the stress field resolved along three orthogonal axes) are of different magnitudes. This means that any fracture that is not precisely aligned with the stress field will have a tendency to slip. The EGS technique of stimulating the natural fracture system exploits this property; increasing the fluid pressure within the fracture reduces the forces that are keeping it closed and allows the two surfaces to slip past one another. As fractures will always be rough, the misalignment as the fracture closes will tend to keep it propped open, and this is the basis of the stimulation. This slippage of the fracture, usually of the order of millimetres, is in fact a micro-earthquake, and locating the noise generated by these events – called 'microseismicity' – is the principal tool used to follow the progress of the stimulation. A typical stimulation operation will generate tens of thousands of micro-events, virtually all of them far below the threshold of human perception.

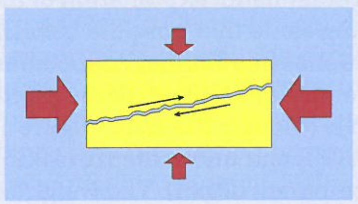


Figure 9.16 Schematic diagram of a fracture subjected to a non-uniform stress field

However, just occasionally an event will occur that is large enough to be detected at the surface, sometimes during stimulation but more commonly after the wells have been shut in. Typically, each of the stimulation procedures at Soultz resulted in up to five 'felt' events, all with local magnitudes (M_L) less than 3. Events of this size are very unlikely to cause material damage – they are similar to the effect of a heavy lorry passing nearby – but they can alarm the local population.

Although this may be a matter of a perceived rather than an actual problem, public perception is becoming a critical factor in EGS planning in Europe and the USA (where reinjection into the Geysers – itself an example of EGS in an already seismically active area – has resulted in enhanced seismic activity). In Landau, a succession of small seismic events – although in an area already known for low level but persistent seismic activity – has prompted the operators to reduce flow rates (and therefore output) until the causes of the increased seismicity are better understood.

Even more seriously, a proposed EGS project in Basel, Switzerland (Figure 9.17), intended to provide heat and power to the city, was forced to close when an hydraulic stimulation operation in the first borehole triggered several small events up to M_L 3.4. Although no one was hurt and material damage was minimal, pressure of public opinion forced the abandonment of the project.

Those organizations and companies who are aiming to develop EGS systems have recognized the seriousness of this problem. It may well be true that induced seismicity is very unlikely ever to pose a real threat to life or property (except perhaps in those areas with a history of significant natural seismicity), but negative public opinion could prove to be a real show-stopper. For that reason, there is a multinational research programme underway that is aiming to understand the reasons for the occurrence of these sporadic 'felt' events, and so devise methods to minimize or eliminate them.

Figure 9.17 The EGS rig at Basel

9.6 Economics and world potential

On an international scale, geothermal energy is one of the most significant 'renewable' energy resources. Its strength in this respect is that it can provide firm, predictable power on a 24-hour per day basis. Table 9.5 shows the performance of some typical high-enthalpy power plants; note the high capacity and availability factors. This high resource availability distinguishes geothermal energy from many other renewables, and results in significantly greater amounts of energy being supplied for a given installed capacity.

There was quite spectacular growth in geothermal installed capacity of approximately 14% per year following the oil embargoes of the early 1970s, at a time when conventional generating capacity grew at between 0 and

Table 9.5 Performance of typical geothermal power plant

	Italian 60 MW	Italian 20 MW	Japanese 50 MW
Year	1999	1999	1/4/97–31/3/98
Installed capacity/MW_e	60	20	50
Maximum load/MW_e	55	17	48.3
Annual produced electricity/MWh	462 845	142 248	361 651
Hours of operation of plant	8748	8483	8112
Capacity factor/%	96.1	95.5	85.5
Availability factor/%	99.9	96.8	92.6

Source: IGA, 2001

3% per year. Stabilization of oil prices brought the growth rate down to about 8% per year by the early 1990s and cheap natural gas together with liberalization of electricity markets further reduced rates to 3% during the 1990s. This trend has now reversed, driven in part by concerns about climate change and also by rising fossil fuel prices. The underlying trend is again close to 10% per year, though it has been masked in recent years by the downturn in production of the Geysers during the period of over-exploitation.

It is difficult to discuss the economics of geothermal development except in the most general terms, because the details are so location-specific. While running costs are relatively minor, geothermal projects are capital intensive and the main element of annual costs is amortization of capital. The biggest single item is drilling costs, which rise exponentially with depth. Consequently, in common with other mining operations, costs are very dependent on the quality of the resource (depth, temperature, flow rate, etc.), and hence vary greatly from country to country and from place to place. Particularly in a new area, there is also a high initial risk that the borehole will be unsuccessful in locating an exploitable resource. Moreover, the economics are also strongly dependent on country-specific fiscal and regulatory issues like interest rates, subsidies, feed-in-tariffs, carbon credits, the cost of competing fuels, etc. On the other hand, successful geothermal projects benefit from the high availability of the resource and the consequent avoided cost of back-up plant.

The best illustration of the economics of geothermal plant, therefore, is the willingness of private industry to become involved and the rate at which new plants are being commissioned. In New Zealand, for instance, where the electricity industry was privatized during the 1990s and different fuels have to compete on equal terms with hydroelectricity, a new privately owned 55 MW_e plant was commissioned in 1996, a second in 1999 and several more in the period 2003–2010. Generating equipment in some of the older fields that have now been in use for nearly 50 years is also being upgraded. A recent study by the Ministry of Economic Development (Figure 9.18) showed that geothermal is currently the most competitive new-build option (Harvey et al., 2010).

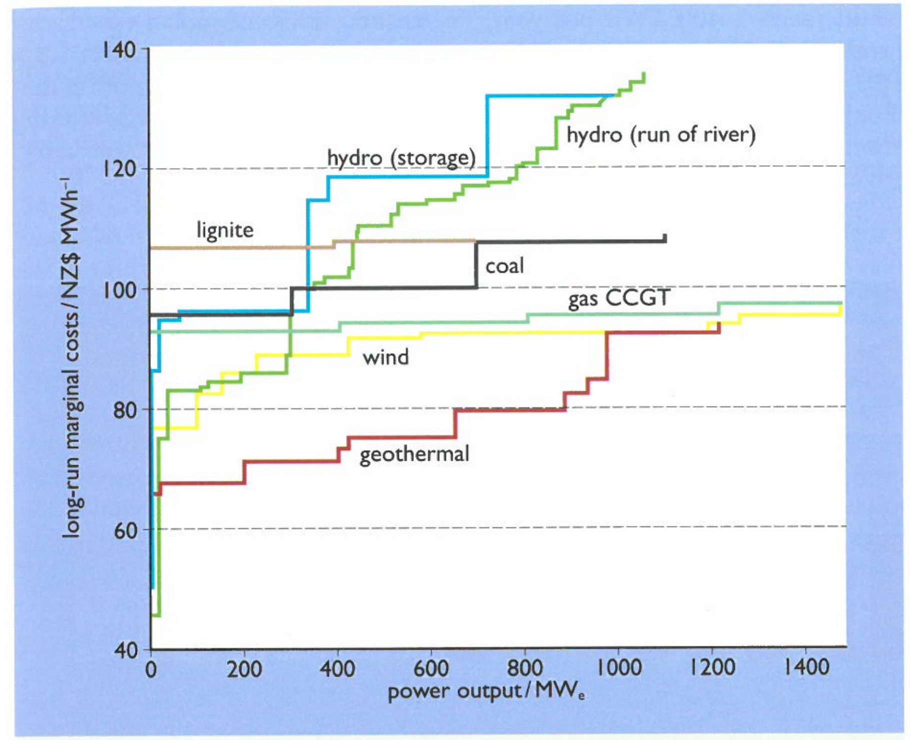
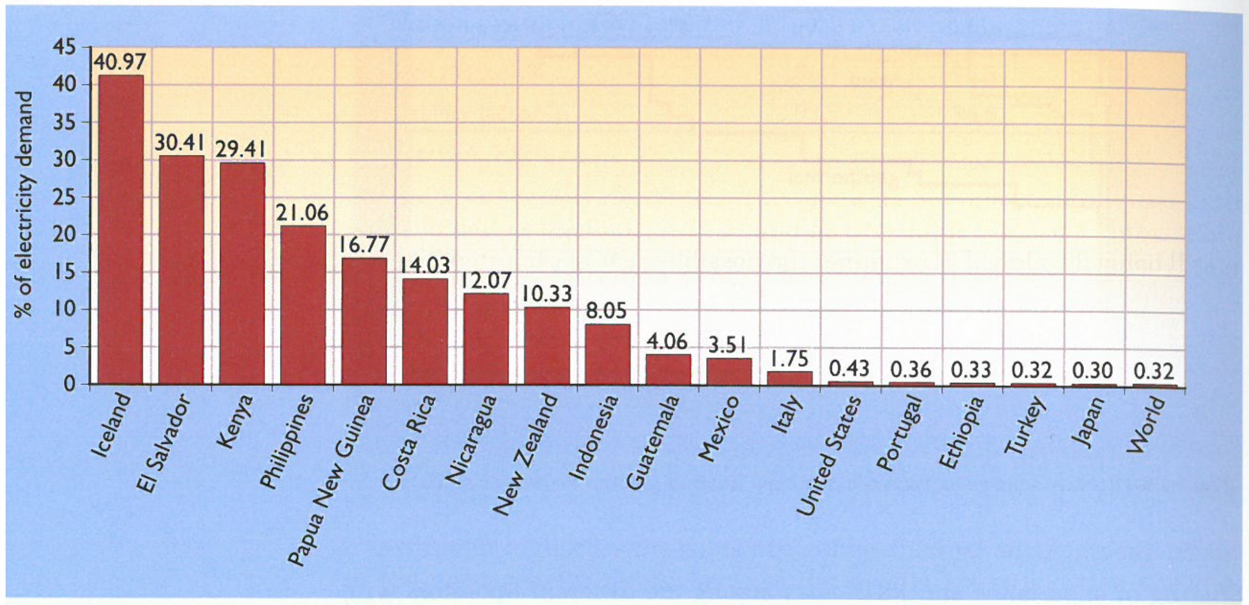


Figure 9.18 New build generation costs in New Zealand (source: Harvey et al., 2010)

Sharing of experience and R&D costs among the different operators will be a vital factor in achieving targets. The obvious economic advantages of high-enthalpy resources in providing a good return on capital have stimulated loan investments in geothermal developments by international agencies, such as the World Bank, especially in Central and South American countries. But perhaps the greatest economic gain to society in general lies in the 112 million barrels of oil a year that is already being saved (or over 200 million barrels if the electricity would otherwise have been generated by fossil fuels at 30% efficiency).

Although geothermal resources make a significant contribution in some high-enthalpy areas (e.g. 30% of energy usage in Kenya and El Salvador, 21% in the Philippines and 10% in New Zealand), the total amount of geothermal electricity produced in 2010 (some 67 TWh) accounted for only about 0.32% of global electricity consumption (Figure 9.19). Yet the long-term potential is much higher, especially in volcanically active countries, and may be realized as the technology improves. As suggested earlier, as EGS techniques improve the potential will rise dramatically, even in countries that lack high-enthalpy resources. In principle, successful development of EGS could allow most countries, even those in 'normal' areas, to generate 10% or more of their power needs from geothermal resources.

In support of this suggestion, in mid-2011 the International Energy Agency published its 'Technology Roadmap for Geothermal Heat and Power' (IEA, 2011). This roadmap foresees that by 2050 geothermal electricity generation could reach 1 400 TWh per year, i.e. around 3.5% of global electricity production. It also estimates that geothermal heat could contribute 5.8×10^{18} J annually by 2050. It qualifies the forecasts, however, by noting that 'For geothermal energy for heat and power to claim its share of the coming energy revolution, concerted action is required by scientists, industry, governments, financing institutions and the public.'



ure 9.19 Percentage of countries' electricity demand supplied by geothermal energy in 2010

The economics of lower-grade geothermal resources are more marginal and depend on local political and economic conditions, such as the availability and price of fossil fuels, the willingness of governments to invest in new energy concepts, the degree of environmental awareness and the related tax incentives to promote 'clean' energy commercially. The awareness of the problem of greenhouse gas emissions and climate change in recent years has nevertheless provoked many governments into support of what until recently has been a neglected 'renewable' resource.

It is worth pointing out that the economics of space heating operations are also dependent on making maximum use of the geothermal resource (which is capital intensive but has low running costs). If the geothermal system is sized to meet the maximum demand of the heat load, it will lie idle for much of the year; typically, the shape of a domestic heating load duration curve throughout the year is such that some 80% of the total energy needs can be met by a system with a power output of only 40% of the peak demand. Consequently, the geothermal component of the system should be (and, in successful schemes, is) designed to meet less than half of peak demand, with the shortfall being made up by an auxiliary fossil fuel boiler.

Looking to the economic future

The economics of future EGS developments are speculative at the time of writing, and will remain so until the technology is fully demonstrated. The best estimates, derived from recent progress in reservoir development and reductions in drilling cost, and for sites with a mean temperature gradient of 35–40 °C km^{-1}, are that electricity might be produced for about €0.12–0.20 per kWh in the early pilot plant (2010 prices), reducing to half these figures for a multi-module commercial system. There is an important caveat, however: these estimates come from cost models not financial analysis, and the distinction is important.

Financial analysis can be applied to an existing operation or to a technology that is proven; all the steps in the process are known, and the costs of each step can be calculated. This information can be used to derive the break-even cost of the product in an unambiguous way. **Cost modelling**, on the other hand, is usually applied to an unproven technology – often one that is still being developed. It examines the possible costs of each step in terms of assumptions about the performance of the step itself and each preceding step. It says only that '...*if the technology performs in this way, then the cost will be...*'. The result is only as good as the initial assumptions. Cost modelling is a useful tool for setting the targets that various elements of the technology must achieve, or for establishing which aspects of the research offer the best opportunities for improvement, but it does not predict prices. This often gives rise to misconceptions, and ones that EGS research has suffered from, particularly in the UK. Used correctly, however, such analyses can be very useful.

Cost analyses of this type have been carried out for two-well systems by all the research teams involved in EGS, and resulted in general agreement on the target parameters to be achieved for a two-well EGS reservoir, aiming to produce 200 °C water for electricity generation over a 20-year reservoir life (Table 9.6).

Table 9.6 Target parameters for a two-well EGS system

Flow rate/kg s^{-1}	75–100
Effective heat exchange area/m^2	$>2 \times 10^6$
Accessible rock volume/m^3	$>2 \times 10^8$
Impedance[1]/MPa l^{-1} s^{-1}	0.1
Water losses/%	<10

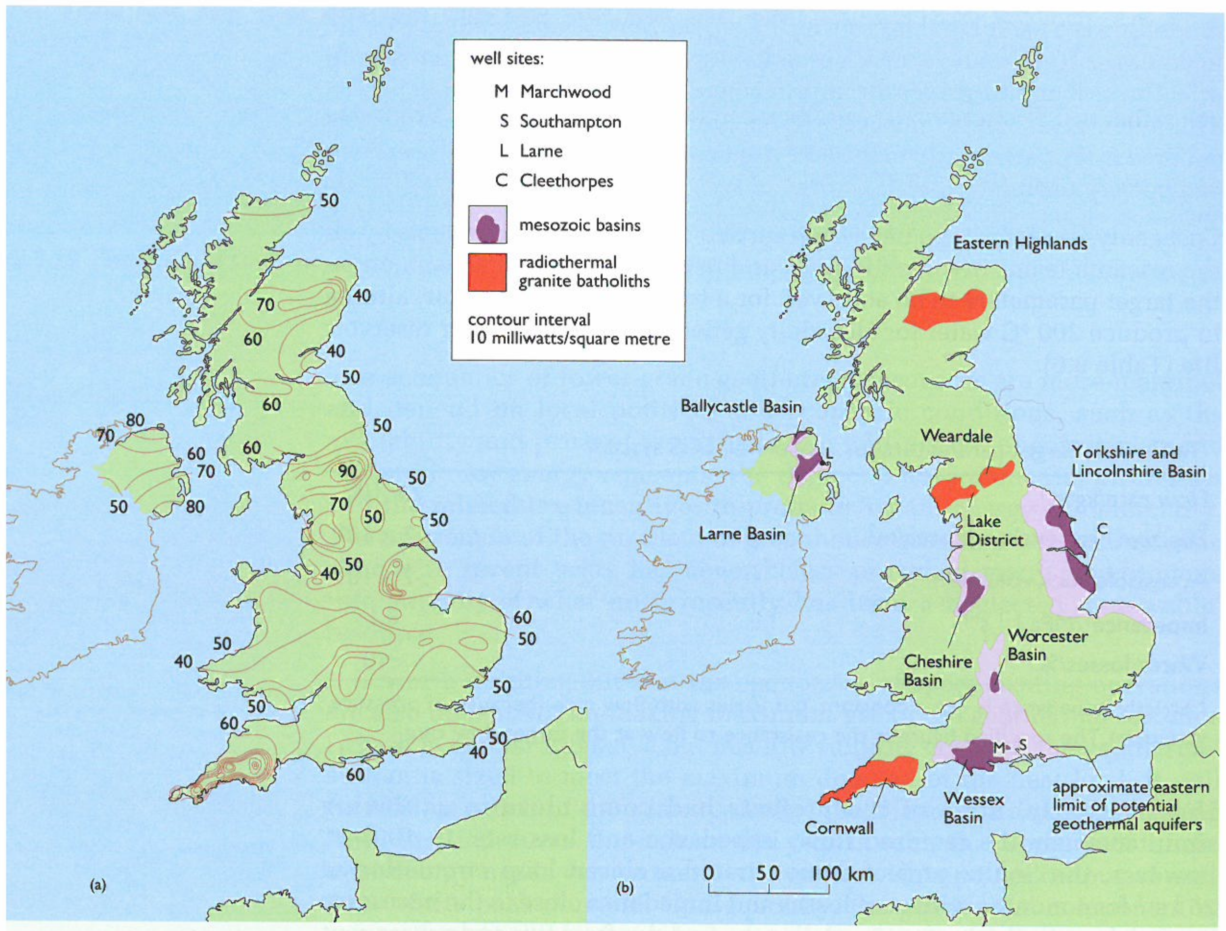
[1] Strictly, impedance is not a constant, but varies with flow rate (because of pressure variation). The specified figure is the resistance to flow at the target flow rate.

Until recently, none of the projects had come close to achieving simultaneously the required flow, impedance and loss rate. In 1997–8, however, the Soultz project demonstrated a closed loop circulation at 25 l s^{-1} for 4 months with zero losses and impedance close to the necessary target. It is on the basis of extrapolating the findings from this and subsequent experiments that the previously mentioned cost estimates are derived. It is still worth repeating, however, that these figures come from cost modelling, not financial analysis. Although we can make reasonable estimates of the capital costs of EGS schemes, we still do not know for certain how to construct a good reservoir, so we can only base our estimates on what its performance and properties ought to be. Predictions of the cost of power from EGS are arguably premature until further technological developments have provided better reservoir performance data. The existing developments at Landau and Soultz, and the imminent systems in Australia and Germany will go some way towards clarifying the issues.

9.7 Geothermal potential in the United Kingdom

Sedimentary basin aquifers

As in many other countries, it was the oil crisis of the mid-1970s that spurred geothermal resource evaluation in the UK. By 1984, new maps of heat flow (Figure 9.20(a)) and of promising geothermal resource sites (Figure 9.20(b))



e 9.20 (a) Heat flow map of the UK based on all available measurements to 1984 compiled and published by the British gical Survey (b) Distributions of radiothermal crystalline rocks (granites) and major sedimentary basins likely to contain cant geothermal aquifers in the UK

had been produced. Three radiothermal granite zones stand out with the highest heat flow values, but significant heat flow anomalies also occur over the five sedimentary basins identified, partly because these are regions of natural hot water upflow. Many shallow boreholes were drilled during this period to measure heat flow, as were four deep exploration wells that are shown in Figure 9.20(b) and Table 9.7. In each case the main aquifer is the permeable Lower Triassic Sherwood Sandstone (named after its most notable outcrops in the East Midlands).

Table 9.7 Characteristics of UK deep exploration wells

Location	Completion	Well depth (m)	Bottom hole temperature /°C	Main aquifer depth (m)	Temperature of aquifer/°C
Marchwood	Feb 1980	2609	88	1672–1686	70
Larne	July 1981	2873	91	960–1247	40
Southampton	Nov 1981	1823	77	1725–1749	76
Cleethorpes	June 1984	2092	69	1093–1490	44–55

Source: Downing and Gray (1986)

The shallower intersections with this aquifer at Larne and Cleethorpes are at a rather low temperature for geothermal exploitation but have reasonably high fluid flow rates because of the large aquifer thickness. Unfortunately, the other two wells, which intersect the aquifer at a better temperature, produce rather low flow rates because of the restricted vertical height of good aquifer rock. The yield is reduced not just because the sedimentary sequence is thinner in the Southampton area, but also because much of the Sherwood Sandstone proved to be more highly cemented and therefore less permeable. The resources are nevertheless substantial (Table 9.8).

Table 9.8 Potential UK geothermal energy resources at different temperatures

Basin	Potential resource at 40–60 °C (10^{18} J)	Potential resource at > 60 °C (10^{18} J)
East Yorks and Lincs	26.2	0.2
Wessex	2.8	1.8
Worcester	3.0	–
Cheshire	8.9	1.5
Northern Ireland	6.7	1.3
Total	**47.6**	**4.8**

Source: Downing and Gray (1986)

Assumptions behind these estimates are that the 40–60 °C resource would be exploited with the use of heat pumps, producing a reject temperature of 10 °C, whereas use of the >60 °C resource would not involve heat pumps, giving a 30 °C reject temperature. The latter resources could be doubled with heat pumps. For comparison, current UK electrical energy demand is around 350 TWh per year (1.3×10^{18} J per year, or about 30 GW_e as equivalent continuous power), so we are considering here quite large resources of renewable energy, but as heat rather than electricity.

So why are geothermal aquifers not being exploited much more widely? The problem is not just one of marginal economics and geological uncertainty, but rather the mismatch between resource availability and heat load, itself a function of population density. More than half the UK resources are located in East Yorkshire and Lincolnshire, essentially rural areas lacking the concentrated populations of the Paris basin. While electricity can readily be transported over long distances from source to market, hot water is more of a problem. Transmission distances for the latter under UK conditions are likely to be restricted to just a few kilometres so the resources are likely to remain undeveloped. It is interesting to note, however, that the distance limitation arises from cost rather than heat loss; some Icelandic pipelines exceed 50 km in length with a temperature drop of only about 1 °C.

The consequence of this is that Southampton, where the geothermal borehole contributes some 2 MW_t to the city's group heating system, remains the only direct use of a deep geothermal resource yet in operation in the UK. At the end of 2010, it was reported that two UK universities had been awarded government support for exploratory boreholes aimed at extracting useful heat. Subsequently, Newcastle University had an intention to drill and test a 2000 m borehole near the city centre, but a project to be carried out by Keele University has been abandoned.

In the meantime, however, as indicated in Section 9.4, the UK has begun to adopt ground source heat pumps (GSHP) on a substantial scale. One estimate of the rate of uptake is given in Figure 9.21. It can be seen that growth was particularly rapid from 2005 to 2009; this was driven in part by government incentive schemes. What is claimed to be one of Europe's largest GSHP system was commissioned at the end of 2010 in a large shopping centre/office complex in central London. It has 13 GSHPs drawing on more

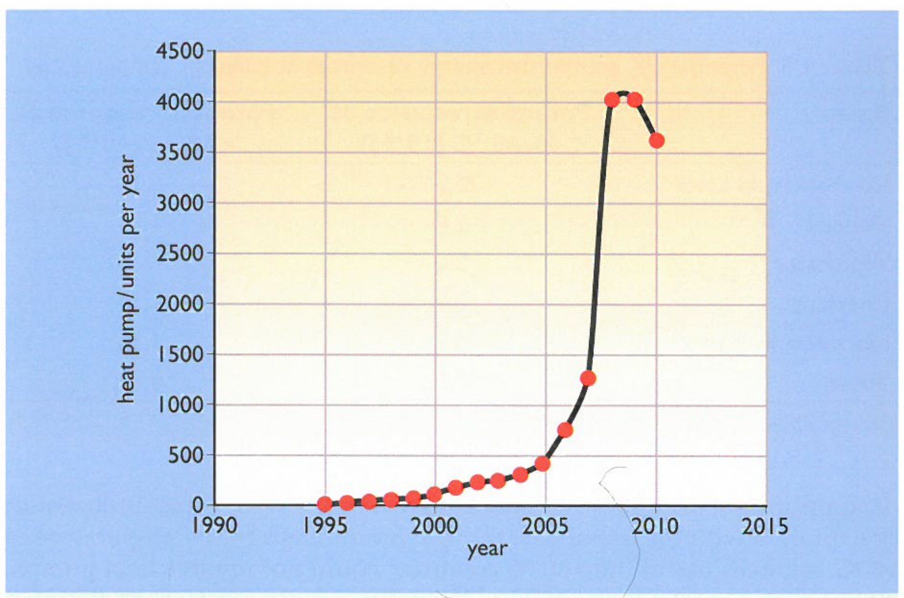


Figure 9.21 Estimated number of heat pump units installed each year in the UK (source: private communication)

than 200 energy piles and rated at 1.7 MW_t. Providing both heating and cooling, it is expected to save some 350 tonnes CO_2 per year and £300 000 in fuel costs.

However, Figure 9.21 also shows a substantial downturn since 2008, this is attributable to a number of factors such as a recession and collapse in the construction sector, temporary reduction in the oil price from an all time high and a combination of the withdrawal of one incentive scheme and delay in implementation of a new subsidy arrangement.

This is an unfortunate illustration of the fact that barriers to geothermal uptake are more often the result of non-technical and regulatory issues than of technical uncertainties.

Engineered geothermal systems

Of the three principal granite zones – in the eastern Highlands, northern England and south-west England – the latter is characterized by the highest heat flow, as shown in Figure 9.20(a). However, large areas of the more northerly granite masses are covered by low thermal conductivity sedimentary rocks and so temperatures will be higher at depth than if the granite bodies came to the surface (Figure 9.6). Nevertheless, substantial areas of Cornwall and Devon are projected in Figure 9.22 as having temperatures above 200 °C at 6 km depth and it has been estimated that the EGS resource base in south-west England alone might match the energy content of current UK coal reserves. One estimate suggests that 300–500 MW_e (about 10^{16} J y^{-1}) could be developed in Cornwall over the next 20–30 years with much more to follow later.

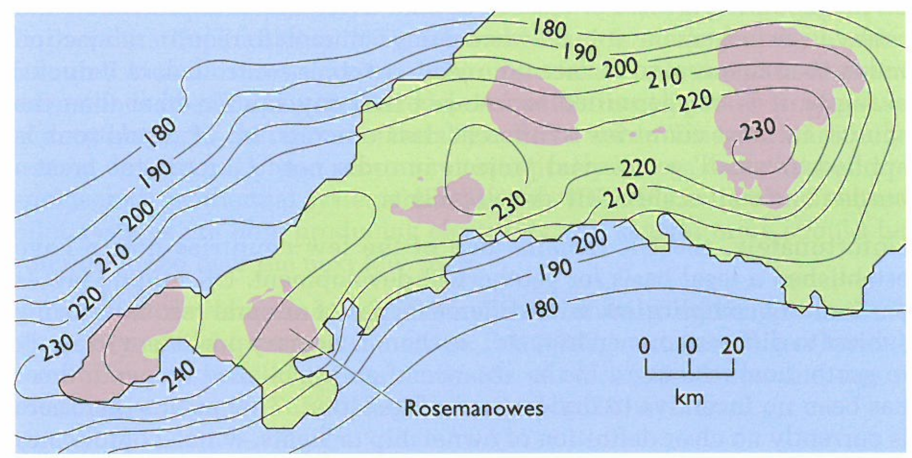


Figure 9.22 Projected temperature (°C) at 6 km depth beneath south-west England. Granite bodies that crop out at the surface are shaded

From 1976–92, Cornwall was the site of a major EGS research project that laid the foundations for the subsequent multinational European project at Soultz. Following Soultz's demonstration of the feasibility of generating power from deep fractured granite, plans are in hand for two possible EGS projects to begin in Cornwall during 2012. The first will start with a 5 km exploratory borehole on the northern edge of the Carnmenellis granite (labelled 'R' for Rosemanowes, the site of the earlier project, in Figure 9.22), with the aim of constructing a multi-well system to generate 10 MW_e of power. The second will be on the St Austell granite and is designed to produce 4 MW_e and several MW_t of heat, primarily to supply the Eden Project (an eco-centred visitor attraction).

9.8 Legal and regulatory issues

As the exploitation of geothermal resources has moved in each country from being a technical novelty to a commercial reality, and one with serious financial implications for the developers, so it has been necessary for each country to incorporate geothermal resources into its regulatory system.

Central to this is the question of resource ownership. Not only must developers (or their banks) be confident that they have a right to the resource that they will be extracting, but there must also be provision: (a) to protect the developer's rights, and (b) to protect the rights of third parties (such as neighbouring developers or property owners). Just as every country has its own legal code, so every country with a geothermal industry has defined these rights and responsibilities according to its own background legal framework and conditions.

In the majority of cases, if not all, ownership of the resource has been reserved to the national or regional authority, which then has the power to grant licences and exact royalties under specified conditions. Typically, these conditions will impose obligations to explore and develop the resource within a defined area and within a specified period, and will include provision to protect shallow water sources and to limit the impact on neighbouring areas. For reasons of both environmental protection and reservoir management, it is now becoming common to require reinjection rather than disposal to surface. Reinjection, too, is controlled; in Italy, for example, it is not permitted to re-inject into any aquifer other than the source. In most countries a different, less onerous, set of regulations is applied to 'small' geothermal projects in order not to impose too great a burden on small-scale GSHP developments.

Unfortunately, the UK remains one of the few countries not to have established a legal basis for geothermal development. UK mining law is particularly complicated, with different types of mineral resources being subject to different ownership, etc., so there is no easy precedent to apply to geothermal resources. In the absence of an established demand, there has been no incentive to draw up new legislation. That means that there is currently no clear definition of ownership or rights, which complicates the financing of projects. Now that interest is beginning to develop, that situation will need to change. Appropriate discussions have already begun at ministerial and parliamentary level.

9.9 Summary

Over geological periods of time, the Earth's crust has accumulated a vast store of heat, principally through the decay of radioactive elements. Like any mineral deposit, this store is uneven and the highest-grade sites

have been the first to be exploited. However, over more than a century of commercial exploitation technologies have been developed to allow economic exploitation of progressively lower-grade and more widespread resources.

It is a fact that exploitation of the resource at any given location entails 'mining' the heat in the short term but, given the enormous scale of the resource and the fact that exploited zones will regenerate in a comparatively short timescale, geothermal energy is ranked with the other renewable energy sources. Its major advantage is that it is continuously available irrespective of climate or daylight, while emitting few, if any, greenhouse gases.

Until recently, the principal interest in geothermal resources has focused on the availability of steam or high-temperature hot water in porous rock formations and the use of the extracted steam to generate electricity. Initially the preserve of a few countries located in volcanically-active areas, commercial use over the past 100 years has spread to more than 20 countries and should exceed 30 countries by 2015. While the impact is still minor in most of these countries, geothermal electricity is already a key component of the supply system in some.

In parallel with these developments, lower temperature waters – which have been used on a small scale throughout recorded history – are now in widespread commercial use for space heating and agriculture in more than 70 countries. Over the past 20 years or so, smaller scale systems involving heat pumps have developed even more rapidly. Exploitation at the scale of the individual dwelling has been made possible and is implemented to the extent that this application has far outstripped the deeper resources in terms of energy supplied.

To overcome the limitation that geothermal steam is available only in a few favoured locations, research has been undertaken over the past 40 years on methods of extracting the stored heat from the much greater proportion of deep hot rocks that do not naturally contain water. This work, initially termed 'hot dry rock' and now more realistically known as 'enhanced (or engineered) geothermal systems' (EGS), is now bearing fruit. The first two pilot systems are now producing electricity and several more should be commissioned over the next few years.

Successful development of EGS systems should make geothermal electricity available in most countries. Estimates are that such geothermal developments could supply around 10% of electricity demand in many countries, and some 3.5% of world demand by 2050.