8.4 Technological and economical aspects of geothermal energy

Geothermal energy, like other types of non-fossil, low carbon dioxide, renewable energies, will supply a greater and even more significant share of the future global electric power and heat demand only if it can be offered at a reasonable, if not competitive price. As a rule, competitiveness is defined with respect to the energy prices based on fossil fuels, i.e. oil, gas, and coal, but commonly the price of oil is used as a reference. This is an extremely volatile quantity. It adjusts itself not to demand and supply in a free market but is determined also by political boundary conditions. Over the past 35 years it has fluctuated to a great extent, by more than 120% around its 35-year average of 18.95 US$ (Fig. 8.36). As a consequence, the competitiveness of geothermal energy varied accordingly, becoming more or less attractive in times of high or low oil prices, respectively.

In spite and independently of these external circumstances, geothermal energy has experienced considerable growth in these 35 years (c.f. Sect. 8.3). This is due to its attractive features:

- It is available everywhere;
- Unlike some other forms of renewable energy, its supply does not vary with weather conditions, season or time of the day and is more or less constant over a long period of time, provided the resource is managed reasonably;
- It can be used for heat and power supply, depending on the subsurface geothermal conditions.

Its use is likely to increase further when new technologies for developing, production, and transformation of geothermal energy presently being developed and tested will become available commercially. These will contribute to a further increase in efficiency and cost reduction.

8.4.1 Direct use

Direct geothermal heat use of some sort is possible almost anywhere on the continents, with few exceptions. Requirements with respect to temperature or physical rock properties are less stringent than for electric power generation. However, different technological and economical aspects apply to the different types of direct geothermal energy use, i.e. shallow ground-source heat pump systems, deep borehole heat exchangers, and hydrothermal heating systems. This is owed to the fact that the corresponding heat production installations differ significantly in type, size, and both technological and economic expenditure. Various aspects of space and district heating with regard to building types, pipe systems, equipment and economics are discussed in Elíasson et al. [03Eli].

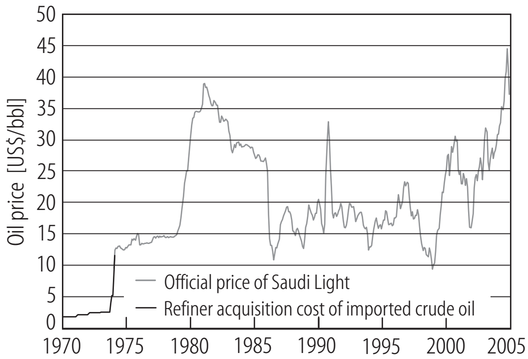

Fig. 8.36. Variation of the monthly average price of a barrel of crude oil in the period 1970-2004. Data: U.S. Energy Information Administration (EIA) [04EIA] and International Energy Agency (IEA) [05IEA].

8.4.1.1 Earth coupled heat extraction systems

A great number of Earth coupled heat extraction systems are currently in operation worldwide, more than 800000 at minimum (Table 8.21). Many of these systems have been operating for one or even several decades. Most of them are shallow borehole heat exchangers coupled to a heat pump. Therefore the following discussion is focused on shallow borehole heat exchangers. With the exception of the underground pipe system, most aspects also apply to horizontal Earth coupled heat exchangers. Deep borehole heat exchangers are discussed separately.

8.4.1.1.1 Ground-source heat pump systems

Ground-source heat pump systems consist of surface and subsurface installations (Fig. 8.28, Fig. 8.29). The surface installation consists of a heat pump which is connected at one end to the heat distribution system and on the other end to the sub-surface installation, i.e. the Earth coupled heat exchanger. The sub-surface installation consists of a horizontal heat exchanger (Fig. 8.28) or one or several borehole heat exchangers (Fig. 8.29). The components of the surface installation, i.e. heat pump and heat distribution system, are industry standard. The same components are used for geothermal heat production as for other heat pump and heat distribution applications. The effectiveness of heat pumps is characterized by their coefficients of performance (*COP*) and efficiency η. The *COP* is defined as the ratio of output energy (heat) to input energy (for instance electricity for the compressor). The *COP* of a heat pump is different in the heating and cooling modes (COP_h and COP_c, respectively). In the heating mode the total heating power is composed of the geothermal power and the electric power of the compressor. In the cooling mode, in contrast, the cooling power is simply the cooling power of the heat pump, and the electric heating of the compressor goes to waste. In the cooling mode, the coefficient of performance is accordingly lower. Thus, in general we have $COP_h > COP_c$. The maximum efficiencies $\eta_{h,\,max}$ or $\eta_{c,\,max}$ of a heat pump in heating or cooling modes, respectively, is defined as the ratio of heating or cooling power, respectively, and input power (commonly electric). It decreases in general with the temperature difference ΔT between output temperature T_{warm} and input temperature T_{cold} (Fig. 8.37):

$$\eta_{h,max} = T_{warm}/\Delta T = 1/\eta_{Carnot} \quad , \quad \eta_{c,max} = T_{cold}/\Delta T \quad , \quad \Delta T = T_{warm} - T_{cold} \qquad (8.62)$$

where $\eta_{Carnot}=\Delta T/T_{warm}$ is the efficiency of an ideal thermodynamic Carnot process.

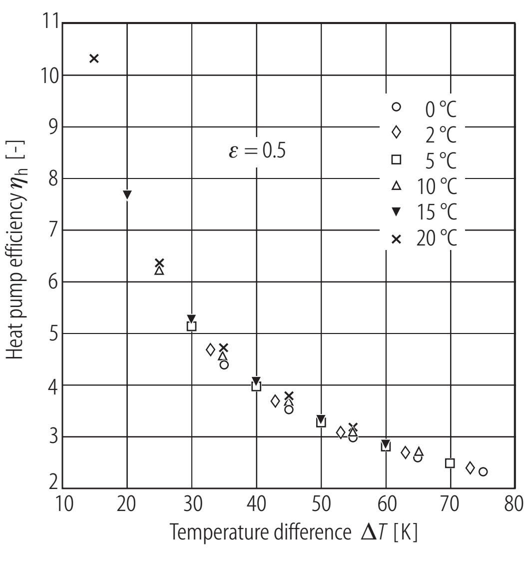

Fig. 8.37. Variation of heat pump efficiency η_h with temperature difference ΔT between input and output temperatures T_{cold} (see legend) and $T_{warm,}$ respectively (cf. (8.62) and (8.63)); ε: exergy factor).

In practice, however, heat pumps – like thermal power stations – cannot operate at maximum theoretical thermodynamic efficiency. This is inevitable and due to various factors, such as heat losses, energy required to drive the pumps for the primary circulation, to name just a few. Therefore, the effective efficiency η_h or η_c of a heat pump in heating or cooling modes, respectively, is determined by the theoretical maximum efficiency $\eta_{h,\,max}$ or $\eta_{c,\,max}$ diminished by the so-called exergy factor ε:

$$\eta_h = \varepsilon\, \eta_{h,max} \quad (\eta_c = \varepsilon\, \eta_{c,max}); \quad \text{with} \quad 0.4 \le \varepsilon = X/E \le 0.5, \tag{8.63}$$

where exergy $X = E\text{-}A$ is the fraction of energy E which can be freely converted into other forms of energy. This follows directly from the second law of thermodynamics which states that not all available heat energy can be converted into useful work. The fraction A of the energy E which cannot be converted into useful work is sometimes called anergy. Figure 8.37 shows the variation of the effective efficiency η_h with the temperature difference ΔT for an exergy factor of $\varepsilon = 0.5$.

Heat pumps differ with respect to the fluids in the primary and secondary circuits. Groundwater heat pumps usually use water in both circuits. Thus their input temperature T_{cold} equals about 10 °C in moderate latitudes; in lower or higher latitudes T_{cold} will be accordingly higher or lower, respectively. In contrast, heat pumps coupled to *borehole heat exchangers* usually are brine-water heat pumps which use some sort of brine in the primary, ground-coupled circuit, and water in the secondary one. Often the input temperature T_{cold} is chosen at or slightly above the freezing temperature of pure water. In this situation the use of brines instead of water in the primary circuit prevents the freezing of the borehole heat extraction system. Since the output temperature T_{warm} of the secondary circuit is defined by the requirements of the specific application, for instance the domestic space or water heating system, the efficiency η^{ww} of water-water heat pumps is therefore always superior to that of brine-water heat pumps, η^{bw}, at the same output temperature T_{warm} (cf. Fig. 8.37).

In the heating and cooling modes, the maximum coefficients of performance of modern brine-water heat pumps vary between $4 < COP_h < 5$ and $3 < COP_c < 4$, respectively. For water-water heat pumps the corresponding ranges are $5 < COP_h < 6$ and $4 < COP_c < 5$. This means that more primary energy is produced than used as input, given a thermodynamic efficiency η between $0.3 \le \eta \le 0.4$ (e.g. [97Die]) for the conversion of primary energy (e.g. coal, hydrocarbons) into electricity. The greater the efficiency, the greater is also the *COP*. An optimization, however, cannot be performed with respect to efficiency and *COP* alone, as some data cannot be chosen freely, such as the output temperature. This is generally defined by the requirements of the application. For groundwater heat pumps the input temperature T_{cold} is equal to the local groundwater temperature and more or less constant. With borehole heat exchangers, in contrast, T_{cold} must be optimized with respect to both *COP* and maximum heat extraction from the subsurface: While the *COP* decreases with temperature difference ΔT, the heat extraction increases with ΔT. The efficiency of the heat transfer between the sub-surface and the primary circuit in the borehole is governed mainly by the thermal properties of the subsurface, groundwater flow in the subsurface, and the volume flow rate in the primary circuit. Important rock thermal properties are both thermal conductivity and thermal diffusivity, since ground-source heat exchangers are commonly operated in a strongly transient fashion with respect to daily and seasonal operation cycles.

The effect of various rock properties and technical parameters on mean thermal power and output temperature can be studied comprehensively by detailed numerical simulations of the borehole heat exchanger system using appropriate software (e.g. [02Koh; 03Cla1; 03Cla2]). As an illustration, Fig. 3.38 shows the effect of thermal conductivity on the mean thermal power of a shallow coaxial borehole heat exchanger: A 50% increase in thermal conductivity in the range of 2 W m^{-1} K^{-1} - 3 W m^{-1} K^{-1} corresponds to an equal increase in mean thermal power. This illustrates the importance of good control of the thermal rock properties for an adequate design and dimensioning of ground-source heat pump systems (see Sect. 8.1.5.2). In contrast, if thermal properties are unknown or can only be estimated from literature data, this uncertainty is usually accommodated by the use of safety margins. A common result of this is an over-sizing of the system, i.e. the borehole is drilled to an unnecessarily great depth. As a consequence, the system will be unnecessarily expensive. The most critical technical parameter which can be optimized is the volume flow rate: Its variation affects both the mean thermal power and the mean output temperature of the borehole heat exchanger, but in opposite direction (Fig. 8.39). Thus an optimum flow rate can be defined for obtaining the required output temperature at an optimum thermal power.

The average thermal conductivity $\bar{\lambda}$ from the surface to the maximum depth of the borehole heat exchanger can be estimated from a *thermal response test*, a long-term in situ heat extraction or injection experiment involving the borehole heat exchanger (Fig. 8.40). Different analytical and numerical methods are available for the analysis of response test data (see e.g. [02Geh] for a discussion).

The infinite line source is one popular model for approximating the heat source (or sink) of a borehole heat exchanger with a constant cooling (or heating) rate Q in W m^{-1} as a function of time t and radius r from the line source. For long times, i.e. for large ratios $\kappa\, t/r^{-2}$, the temperature at the borehole wall ($r = r_b$) can be approximated by [59Car]

$$T(r_b,t) \approx \frac{Q}{4\pi\bar{\lambda}}\ \ln\left(4\kappa t/r_b^2\right) - \gamma\ + Q\,R_b + T_0\,, \tag{8.64}$$

where κ is the thermal rock diffusivity, R_b the borehole thermal resistance, T_0 the undisturbed temperature, and $\gamma \approx 0.5772$ Euler's constant. The maximum error of (8.64) is 2.5% and 10% for $\kappa\, t/r^{-2} \geq 20$ and 5, respectively. Collecting terms this yields an expression for the average fluid temperature $\bar{T}$:

$$\bar{T}(t) = a\ln(t) + b,\ \text{ with } a = \frac{Q}{4\pi\bar{\lambda}} \ \text{ and } \ b = Q\left(R_b + \frac{\ln\left(4\kappa/r_b^2\right) - \gamma}{4\pi\bar{\lambda}}\right). \tag{8.65}$$

The temperatures recorded in a thermal response test follow the linear relation of (8.65) in the steady-state approximation, i.e. for long times, commonly several hours. The average thermal conductivity $\bar{\lambda}$ can then be calculated from the slope of a linear regression of $\bar{T}$ versus the logarithm of time t. With $\bar{\lambda}$ known, the thermal resistance R_b can be calculated from the intercept value b, provided the thermal diffusivity is known independently. In the quasi steady-state regime described by (8.65), the storage effect of thermal capacity included in thermal diffusivity κ is not felt any more. Therefore, thermal conductivity and thermal capacity (and hence thermal diffusivity) cannot be determined simultaneously from this type of experiment.

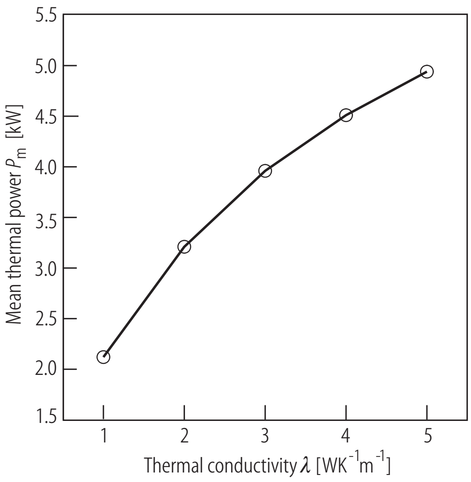

Fig. 8.38. Variation of the mean thermal power P_m (○) of a coaxial borehole heat exchanger (at a given volume flow rate of 1.8 m^3 h^{-1} at a constant inflow temperature of 0 °C) with rock thermal conductivity λ (length: 100 m; operation over 10 years: 12 h per day for 6 months – recovery during the following 6 months; after Geophysica Beratungsgesellschaft mbH, Stolberg).

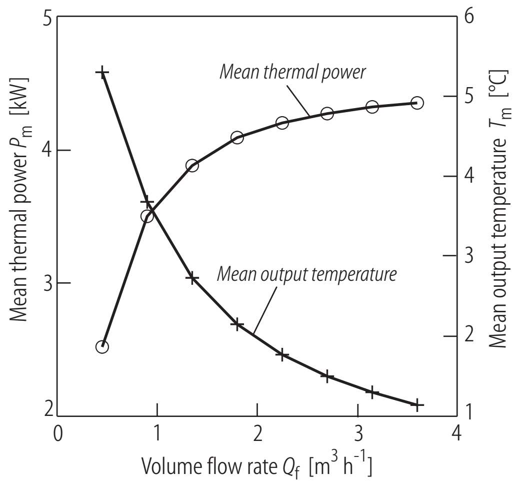

Fig. 8.39. Variation of mean thermal power P_m (○) and mean output temperature T_m (+) of a coaxial borehole heat exchanger with volume flow rate Q_f (length: 100 m; rock th. conductivity $\lambda = 2$ W m^{-1} K^{-1}; inflow temperature: 0°C; operation over 10 years: 12 h per day for 6 months – thermal recovery during the following 6 months; source: see Fig. 8.38).

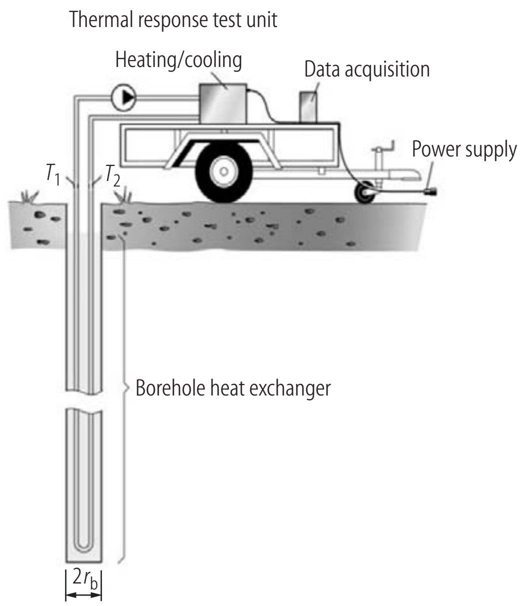

Fig. 8.40. Typical experimental set-up for a thermal response test in a borehole heat exchanger (after [02Geh]).

Several factors must be considered when interpreting the results of thermal response tests [see e.g. 02Koh; 02Geh; 03Cla2; 04Sig1]:

- $\bar{\lambda}$ is an average for the entire depth of the borehole and cannot account for contrasts in thermal conductivity, for instance due to layering;
- The analytical line- and cylindrical-source solutions cannot account for groundwater driven advective heat transport to and from borehole heat exchangers. This, however, is frequently observed with respect to both natural flow systems and free convection around the borehole induced by the test itself [cf. 02Geh for a discussion]. This yields unrealistically high values for thermal conductivity, if not accounted for properly. Thermal response tests run in the cooling mode seem to be less influenced by free convection induced due to the test itself than those in the heating mode;
- The thermal resistance of borehole heat exchangers depends critically on the technical quality of the backfilling and the thermal properties of the backfill material [see e.g. 01Pah];
- Heat losses between the heating or cooling unit and the borehole (cf. Fig. 8.40) may lead to significant errors in the analysis.

A number of technical recommendations are available for the design and layout of ground-source heat pump systems and borehole heat exchangers in particular [e.g. 96Ano1; 97Hub; 01Ano1; 01Ano3; 04Ano1], heat storage systems [01Ano2], and direct uses [04Ano2]. Also, commercial software is available for the planning of heat pump systems (e.g. *TRNSYS*[3], *YUM* [89Afj], WPcalc [94Nan]), the layout of systems consisting of one or several borehole heat exchangers (e.g. *EED*[4], *EWS*[5]) or heat exchanger piles (*PILESIM*[6] [99Pah]). As these codes are based on different simplifying assumptions (e.g. constant temperature gradient, constant thermal properties, etc.), they must be applied with appropriate care. While they can be very useful for the layout and design of individual and groups of shallow borehole heat exchangers, they should not, as a rule, be applied to deep borehole heat exchangers.

[3]) http://sel.me.wisc.edu/trnsys/default.htm
[4]) http://www.buildingphysics.com/index.htm
[5]) http://www.igjzh.com/huber/index.htm
[6]) daniel.pahud@geothermal-energy.ch

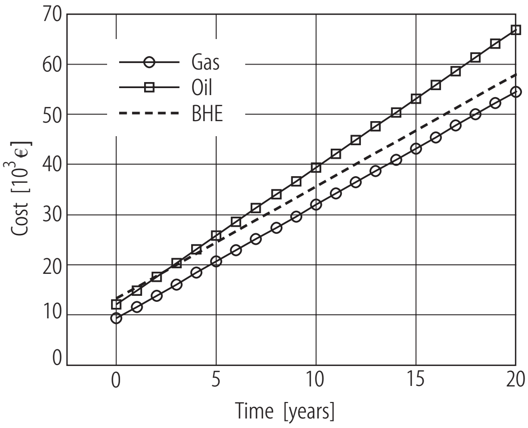

Fig. 8.41. Example for heating cost comparison of a typical single family home (150 m^2) based on oil and gas furnaces or borehole heat exchangers (BHE) in hard or soft rock (German year 2004 prices; data courtesy of ECOS Umwelt GmbH, Aachen).

Ground-source heat pump systems for heating or combined heating and cooling are a mature technology. Designed, laid-out, and installed properly, they have a proven life time equal to comparable investment goods, on the order of 30 years and more. With *COP* values between 4 and 5, modern brine-water heat pumps deliver between 4/3 and 5/3 more heat than primary energy used for generating the electric energy (at a thermodynamic efficiency of η = 1/3) required as input. This relation becomes even better if gas heat pumps are used instead of electric heat pumps. Except for the pollution associated with the generation of electric energy by burning of fossil fuels, ground-source heat pumps do not generate any pollution, unless their isolated circuits are damaged. Once they are installed, however, this is not very likely.

The cost of a ground-source heat pump system depends on its size. For a typical single-family home in Germany the investment for a borehole heat exchanger in soft or hard rock, is about 13000 €, roughly 1000 € or 4000 € more than what is required for a conventional oil or gas furnace, respectively. This relation will vary from country to country, but indicates an extra cost on the order of 10% - 40%. However, unlike ground-source heat pumps, oil and gas furnaces cannot provide any cooling during the warm season. Depending on summer temperatures, this option for cooling alone may well be worth the extra investment. Moreover, the higher investment cost for a ground-source heat pump system is balanced within a few years by the much lower annual cost (energy consumption, maintenance, and mortgage) compared to an oil furnace. An example based on German year 2004 prices illustrates that electrical ground-source heat pumps start saving money already after three years of operation compared to an oil furnace. At current German gas prices, however, the difference in annual cost of about 26 € between a gas furnace and an electrical ground-source heat pump is insufficient to offset the difference in investment cost within reasonable time (Fig. 8.41). This difference, however, is only about 1% of the total cost of a house. And beyond doubt, oil and gas prices will increase further in coming years. Therefore it can be expected that this relation will become even more favorable for ground-source heat pumps in the future.

In the long run, i.e. with respect to 20 years of operation in the example calculation of Fig. 8.41, ground-source heat pumps may help to cut down heating cost significantly, by about 15.000 € compared to an oil furnace. This is as much as the initial hardware investment for a ground-source heat pump system.

8.4.1.1.2 Deep borehole heat exchangers

Deep borehole heat exchangers can be designed for direct heat exchange in combination with a heat pump or without. The extracted heat can be used for space heating or, if used to drive adsorption or absorption cooling systems, for space cooling. Roughly speaking, temperatures below or above 75 °C are best suited to drive adsorption or absorption cooling systems, respectively [e.g. 02Gas; 03Raf1; 04Ano6].

The cost of deep borehole heat exchangers is dominated by the drilling cost. While drilling costs vary from country to country, a detailed recent cost analysis based on German prices [02Sch1; 02Sch2] provides some general orientation. In this analysis drilling cost amounted to about 47% of the total investment for a borehole heat exchanger system to a depth of 2500 m (Fig. 8.42). Depending on different cases considered, this corresponds to a specific cost for the borehole heat exchanger (excluding engineering, measurement and control systems, and heat pump) of between 550 € m^{-1} and 700 € m^{-1} drilling depth. The associated gas heat pump accounts for another 34%. In this study, specific drilling cost did not vary extremely up to a depth of 2500 m. A significant increase occurs for greater depths which require hydrocarbon special deep drilling technology. A total of four different scenarios was considered in this study [02Sch1; 02Sch2], with different boundary condition with respect to depth (2500 m - 2800 m), rock thermal conductivity (3.0 W m^{-1} K^{-1} - 4.5 W m^{-1} K^{-1}), temperature gradient (30 K km^{-1} - 35 K km^{-1}), bottom hole temperature (85 °C - 108 °C), and thermal power of the installed gas heat pump (310 kW_t - 790 kW_t). The resulting average heat cost and its variation is shown in Fig. 8.43. This demonstrates that deep borehole heat exchangers, even if operated almost year round (i.e. at 6000 h a^{-1} - 8000 h a^{-1}), deliver heat at a cost equal to or above the cost of a corresponding gas heating furnace. For instance, at the end of the year 2004 the corresponding gas price for the required amount varies in Germany between 34 € and 39 € per MW h, depending on location. However, economic feasibility will be reached as gas prices increase with an increasing oil price and if the produced heat can be used during summer as driving power for adsorption or adsorption space cooling systems.

Additionally, present and anticipated future financial incentives for CO_2 reductions will further increase the economic feasibility of deep borehole heat exchangers systems. For instance, since the end of the year 2004, the European Energy Exchange AG (EEX)[7] is publishing with its European Carbon Index a daily market price for CO_2 emission allowances. Since the official beginning of trading of EU allowances on 17 December 2004, prices rose from initial 8.45 € per ton of CO_2 to 23 € per ton of CO_2 on 26 June 2005 (Fig. 8.44a).

The range of installed thermal power of 310 kW_t - 790 kW_t and annual operation times of 6000 h a^{-1} - 8000 h a^{-1} considered in the scenarios of this study [02Sch1; 02Sch2] corresponds to maximum ranges of annual CO_2 reductions on the order of 250 t - 1260 t if geothermal heat replaces a gas furnace, and of 350 t - 1770 t if geothermal heat replaces an oil furnace. Based on the above price of 23 € per ton of CO_2 this corresponds to a financial bonus of about 5700 € - 29000 € if geothermal heat replaces a gas furnace, and about 8000 € - 40100 € if geothermal heat replaces an oil furnace.

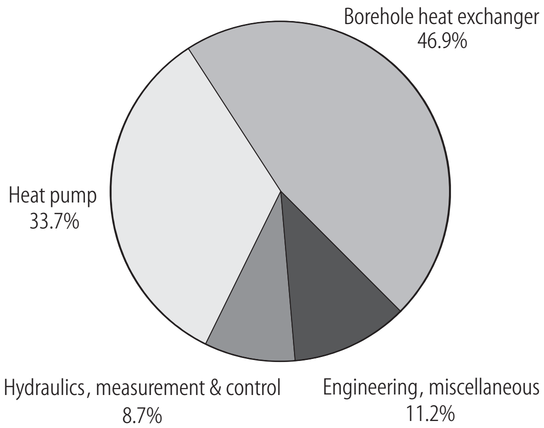

Fig. 8.42. Relative cost factors for deep borehole heat exchanger systems (depth 2500 m, German year 2002 prices) [02Sch1].

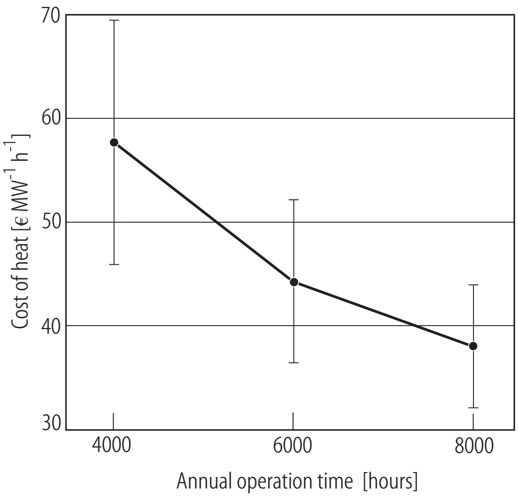

Fig. 8.43. Mean and standard deviations of average cost for deep borehole heat exchanger systems based on German year 2002 prices and four different scenarios considered [02Sch1].

[7]) http://www.eex.de

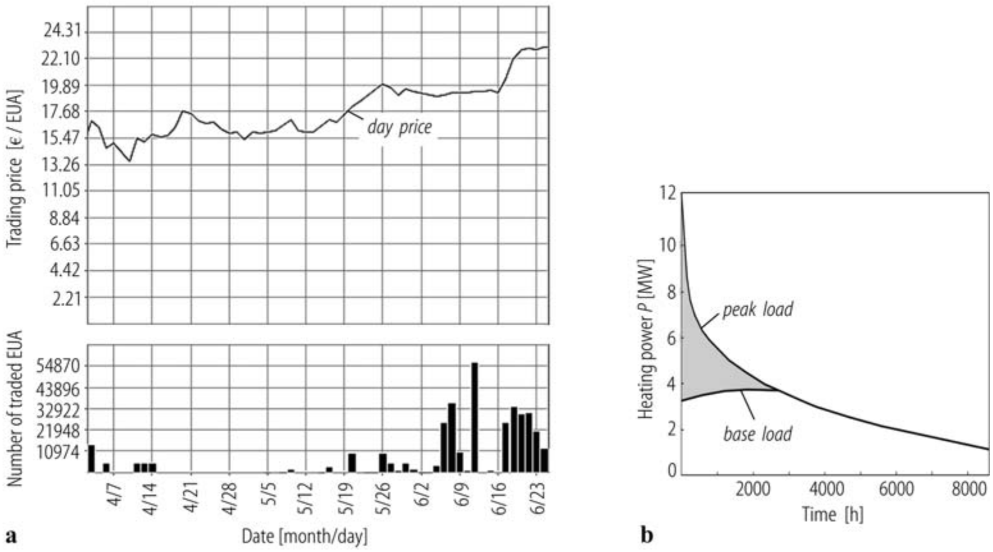

Fig. 8.44. (a) Trading prices (€ per ton CO_2) for EU CO_2 emission allowances (EUA) from 2 April – 24 June 2005 (Data: EEX[7]). **(b)** Typical annual time-variation curve of heating power *P* versus time (one year equals 8760 h): Peak load is required for much shorter times than base load.

8.4.1.2 Hydrothermal heating systems

Unlike local, Earth coupled heat extraction systems, hydrothermal heating systems are large installations with two or more boreholes deeper than 1000 m. While there are cases where they provide process heat mainly to one client, more often their heat is distributed to a large number of end users through a distribution grid. New grids require an additional major investment while existing grids already have a provider of heat, often excess heat from fossil power production. Therefore, market access is difficult for hydrothermal heat and often requires crowding out current heat providers. This will only occur if geothermal heat use is more attractive.

One clear advantage of geothermal heat is its unlimited availability, regardless of weather, time of day or time of year. This makes it an excellent choice for providing large base loads and less attractive for more transient systems requiring high peak loads (Fig. 8.44b). Therefore, geothermal heat becomes economically more attractive if, additional to space heating of apartments and houses, it can be used to provide a significant thermal base load, such as 2000 h - 4000 h per year, to major customers of space heating or commercial and industrial process heat (cf. Sect. 8.3.1.2).

Crowding-out of current heat providers usually requires a financial reward, i.e. geothermal heat must be less expensive. In existing, well developed heat markets, such as in the industrial world, cheap excess heat is often available from fossil and nuclear power production. In such an economic environment selling of geothermal heat is difficult and depends strongly on fuel prices, in particular for oil and gas. Therefore, conditions may vary between countries and even regions. As an example based on conditions in Germany, Fig. 8.45 shows results of a recent heat cost comparison for stations using natural gas and geothermal heat [02Sch1; 02Sch2]. The stations considered have an installed power of 11.4 MW_t, either based on burning natural gas or by producing geothermal heat using a gas motor heat pump or, in a second scenario, by an additional direct heat exchange providing an additional power of 2.1 MW_t.

It is evident that cumulative heating times of 4000 h a^{-1} and more are required for geothermal heat to become competitive if geothermal heat is produced by a gas motor heat pump alone. With the additional direct heat exchange the break even cost is considerably lower, making geothermal heat attractive for cumulative heating times as low as about 3000 h a^{-1}. This conclusion is based on Germany year 2004 large-consumer gas prices. In the past, the price of natural gas generally varied parallel to the oil price (see Fig. 8.36) which increased on average over the years with large fluctuations. When a detailed study based on German prices [02Sch1; 02Sch2] was prepared in May 2002, the price of natural gas was about 20 € per MW h. In contrast, it varies between 34 € and 39 € per MW h in November 2004. As a result, geothermal heat was too expensive in 2002, while at the end of 2004 it does appear attractive. There is a clear long-term trend of increasing oil and gas prices (Fig. 8.36), and both financial incentives for CO_2 reductions and additional taxation of CO_2 producing technologies can be anticipated in several industrial countries for the near future. In view of this it may be expected that, in the long run, the cost advantage of geothermal heat produced in hydrothermal plants will become stable or even larger. However, extending this conclusion based on German year 2005 conditions to other countries requires an appraisal of the local cost, mainly of drilling and natural gas. Since German energy prices are neither extremely high nor low it may be expected that results will be similar for a number of countries, and favor geothermal heat even more wherever fossil fuels are more expensive or the burning of fossil fuels is discouraged.

Burning of natural gas produces about 200 kg CO_2 per thermal MWh_t. At 4000 h a^{-1} cumulative heating time, the 11.4 MW fossil fuel heating plant discussed above ([02Sch1; 02Sch2]; Fig. 8.45) produces approximately 53000 MW h heat per year. This corresponds to an emission of about 10.6 kt of CO_2. Based on a cumulative heating time of 4000 h a^{-1} and a thermal COP_h = 1.6 for the gas fired adsorption heat pump, 28000 MW h a^{-1} are required to drive the gas motor heat pump. This corresponds to an emission of 5.6 kt of CO_2. Replacing gas by geothermal heat thus saves about half of the CO_2 emissions of a natural gas heating plant. Even for one single heating plant of 11.2 MW_t this amounts to 5 kt of CO_2 which are prevented from being emitted into the atmosphere. Based on the aforementioned allowance of 23 € per ton of CO_2 emission fixed at the European Energy Exchange AG (EEX)[7] in June 2005, this corresponds to a financial bonus of about 115000 € per year if geothermal heat replaces a gas furnace.

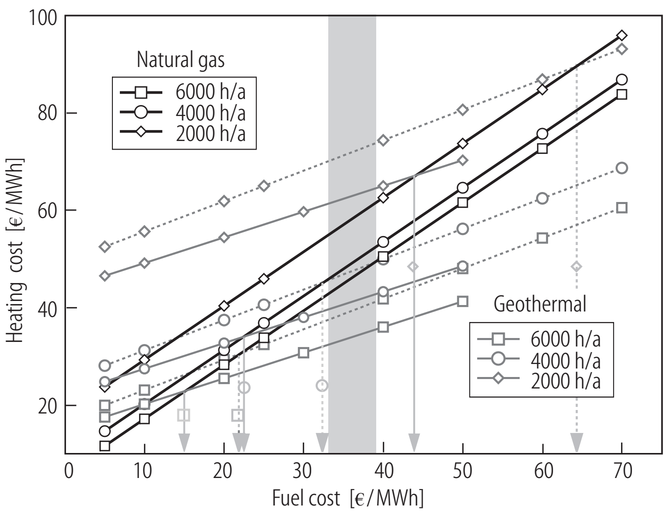

Fig. 8.45. Cost comparison for heating plants using natural gas (11.2 MW_t: black lines) and geothermal heat with heat pumps of 11.2 MW_t and 11.4 MW_t with and without direct heat exchange of 2.1 MW_t (full and broken grey lines, respectively)[8]. Solid and broken light gray arrows indicate break-even cost for geothermal heat with respect to fossil fuel for heat pumps with and without direct heat exchange, respectively. The shaded area indicates German year 2004 large-consumer price range for natural gas. Symbols correspond to different annual cumulative heating times (one year equals 8760 h). Data: [02Sch1].

[8]) Not shown: Heating cost for a 13.5 MW_t natural gas plant which is only slightly more than for a 11.2 MW_t plant.

8.4.2 Power generation

Vapor is required to drive turbines for generating electric power. In general, this is natural dry or wet, medium to high enthalpy steam at temperatures above 150 °C (cf. Table 8.19). For some time, binary systems employing substances with a lower boiling point than water in a secondary circuit have been used to generate vapor for driving turbines at a lower temperature level. This process is known as Organic Rankine Cycle (ORC) or Kalina Cycle (see Sect. 8.3.2 and Sect. 8.4.2.2). Binary systems are used in combination with low to moderate temperature, water dominated reservoirs. In absence of natural steam or hot water reservoirs, or in case of insufficiently permeable reservoirs, hydraulic fracturing provides additional permeability in engineered hot dry rock (HDR) or enhanced geothermal systems (EGS). Geothermal power production has more stringent requirements with respect to temperature or physical rock properties than direct use. However, different technological and economical aspects apply to the different types of geothermal power production, depending on whether they are natural or engineered systems, involve dry or wet steam, or ORC or Kalina Cycle technology. One of the advantages of geothermal power plants is that they can be built economically in much smaller units than e.g. hydropower stations. Geothermal power plant units range from less than 1 MW_e up to 30 MW_e. Thus, the capacity of geothermal power plants can be adjusted more easily to the growing demand for electric power in developing countries with their relatively small electricity markets than hydropower plants which come in units of 100 MW_e - 200 MW_e (Fig. 8.46). Geothermal power plants are very reliable: Both the annual load and availability factors are commonly around 90%. Additionally, geothermal fields are little affected by external factors such as seasonal variations in rainfall, since meteoric water has a long residence time in geothermal reservoirs [02Bar].

8.4.2.1 Natural steam power plants

8.4.2.1.1 Dry steam power plants

Dry steam power plants use dry saturated or superheated steam at pressures above atmospheric from vapor dominated reservoirs, an excellent resource that can be fed directly into turbines for electric power production. Permeability is generally lower in dry than in wet steam fields, and the reservoir requires a tight cap rock. Steam is the predominant continuous phase in control of reservoir pressure which is practically constant throughout the reservoir [02Bar]. On the surface, these fields may be indicated by boiling springs and geysers. In general, the produced steam is superheated, containing only small quantities of other gases, mainly CO_2 and H_2S. Superheating in dry steam reservoirs is caused by a transient heat trans

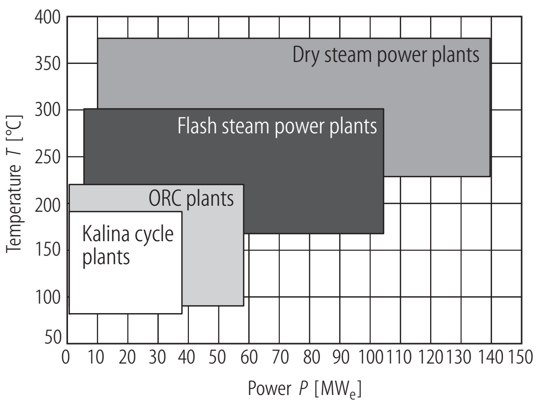

Fig. 8.46. Power range and characteristic reservoir temperatures for generation of electric power by direct-intake dry steam plants, single or multiple flash wet steam plants, ORC and Kalina cycle hot water plants (modified after [04Len1]).

fer between the reservoir rock and the steam phase: When production begins in a well penetrating such a reservoir, a low-pressure zone forms around the well screen, and nearby liquid water starts boiling and evaporates. This creates a zone void of liquid water through which steam flows towards the well. In this dry region the steam expands into the voids and cools. However, heat originally stored in the reservoir rock maintains a steam temperature above the local evaporation point, thus generating superheated steam. Superheating of up to 100 K results, for instance, for steam production temperatures hotter than 200 °C and well head pressures of 0.5 MPa - 1 MPa [02Bar]. Thus, superheating allows mining more heat from dry than from wet steam reservoirs. As a consequence, about half the global geothermal electric energy is produced from only six dry steam power plants: Lardarello (since 1904) and Monte Amiata in Italy; The Geysers, the only source of geothermal dry steam in the USA (since 1960); Matsukawa in Japan (since 1966); Kamojang (since 1983) and Darajat in Indonesia (see Fig. 8.47). With less than 10%, however, vapor dominated reservoirs are much less frequent than water dominated reservoirs which make up 60%, while the remaining 30% produce hot water [02Bar].

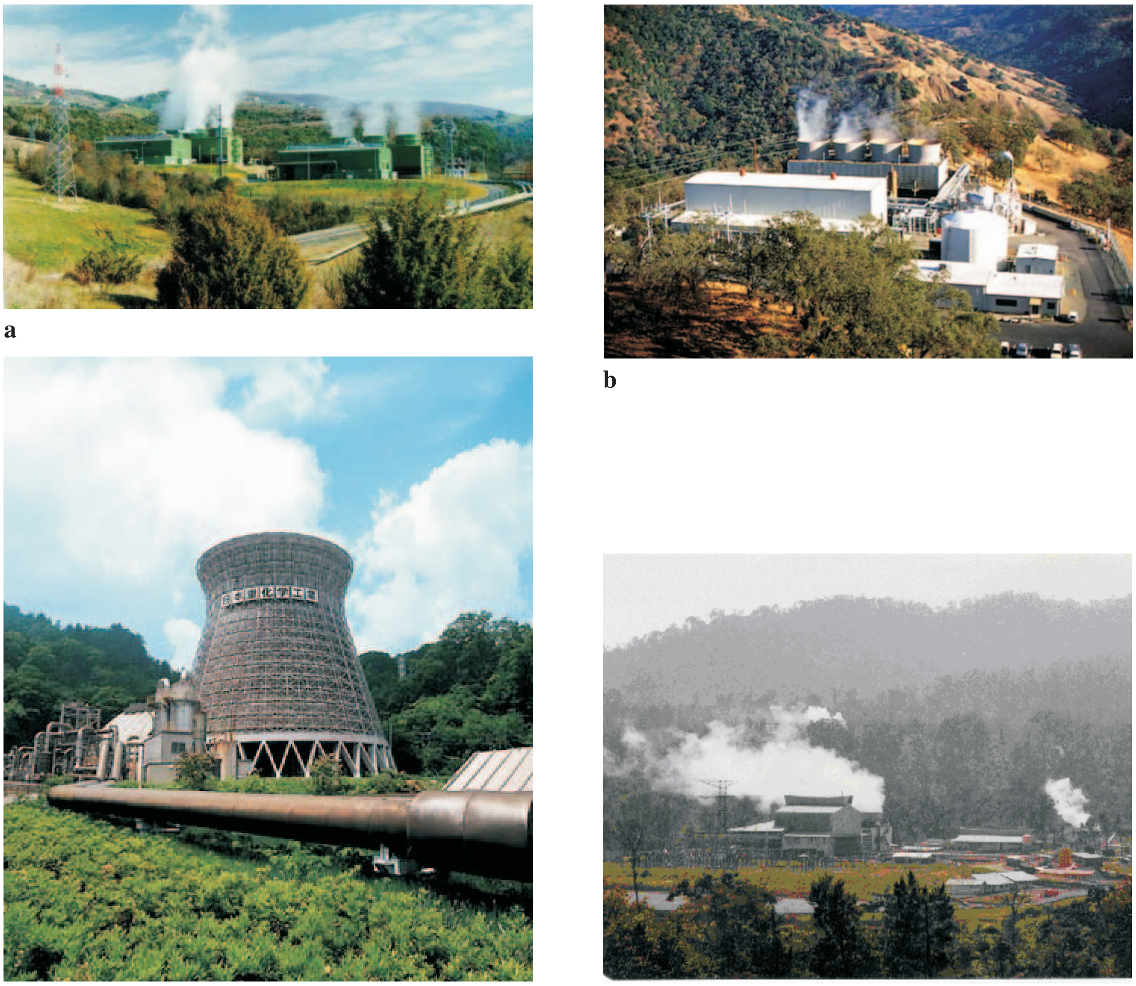

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Fig. 8.47. Dry steam geothermal power plants (top left to bottom right): Lardarello, Italy; The Geysers, USA; Matsukawa, Japan; Kamojang, Indonesia [01Ano4; 03Sat; 04Lun1; 04WOB].

Fig. 8.48. Direct-intake, non-condensing single flash geothermal power plant at Pico Vermelho (São Miguel Island, Azores) exhausting steam to the atmosphere [04Lun2].

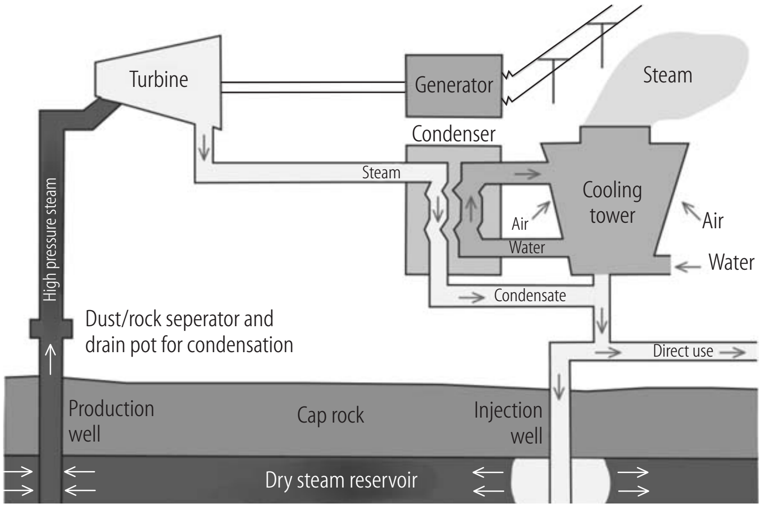

Fig. 8.49. Direct-intake, condensing power plant for heat production from dry steam fields (modified after [04Tri]).

In *condensing plants* steam is condensed at the outlet of the turbine and cooled in conventional cooling towers (Fig. 8.49). Condensing the steam at the turbine exhaust creates a vacuum of about 150 hPa (less than 15% atmospheric pressure), thus maximizing the pressure drop across the turbine and hence the power output [04Lun2]. Thus, condensing plants require substantially (i.e. about 50%) less steam than non-condensing ones, only 6 kg - 10 kg of steam per kW h_e generated. However, the steam may not contain more than 15% of non-condensable gases. The specific steam consumption of these units largely depends on the turbine inlet pressure: At pressures of 1.5 MPa - 2.0 MPa, the consumption is close to 6 kg of steam per kW h_e; at 0.5 MPa - 1.5 MPa it is 9 kg - 7 kg of steam per kW h_e, and for even lower pressures it becomes much larger [02Bar]. In power plants based on a *direct-intake condensing cycle,* dry or superheated steam is piped directly from the wells into the steam turbine. This is a well developed, commercially available technology. Capacities of typical turbine units range between 20 MW_e and 120 MW_e, but modular standard generating units of 20 MW_e are also available [02Bar].

8.4.2.1.2 Flash steam power plants

Flash steam power plants exploit water dominated, wet steam reservoirs in which most of the high-temperature geothermal resource is provided by pressurized water. These fields are much more common than vapor dominated ones. On the surface, they are often indicated by boiling springs and geysers.

When a well penetrates into such a reservoir, the pressurized water flows into the well because well pressure, in general, is lower than reservoir pressure. As a result of the pressure drop, a certain fraction of the liquid water evaporates and the well co-produces hot water and steam, with water as the dominant phase. Therefore, these fields are also called wet steam fields. The actual water-steam ratio varies from field to field and even among wells within the same field. The heat source is large, generally of magmatic origin, forming a resource of the hydrothermal type (see Sect. 8.2). The water produced often contains a large load of dissolved minerals (10^{-3} - 10^{-1} $kg_{mineral}$ per kg_{fluid}, in some fields up to 0.35 kg kg^{-1}), mainly chlorides, bicarbonates, sulfates, borates, fluorides, and silica [02Bar]. This can cause severe scaling in pipelines and plants. An important economic aspect in exploiting wet steam fields is the large quantity of brines produced with the steam (e.g. 6600 t h^{-1} at Cerro Prieto, Mexico): Owing to their large load of dissolved minerals, they need to be reinjected, preferably at the margins of the reservoir [02Bar].

Wet steam cannot be fed to standard turbines without risk of damage to the turbine blades. Therefore, separators are used in all installations exploiting wet steam reservoirs for separating steam from water. Single or multiple flash steam plants are used to produce energy from these fields by evaporating depressurized liquid water into steam in one or several separators at the surface. Single, double-, and triple flash systems are used (Fig. 8.50). Commercially available turbo-generator units are commonly in the range 10 MW_e – 55 MW_e, but modular standard generating units of 20 MW_e are also used [02Bar]. Examples for triple and dual flash cycle wet steam geothermal power plants are, among many others, Wairakei, New Zealand, and Imperial Valley, USA, respectively (Fig. 8.51).

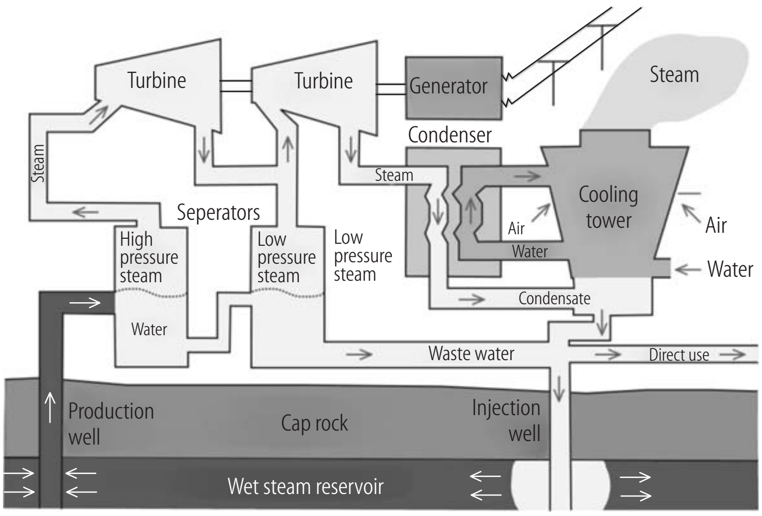

Fig. 8.50. Double flash, condensing power plant for heat production from wet steam fields (modified after [04Tri]).

a

b


Fig. 8.51. Wet steam geothermal power plants with triple and dual flash cycles (left to right): Wairakei, New Zealand (with prawn pond in foreground) and Imperial Valley, USA, respectively [01Ano4; 02Ano].

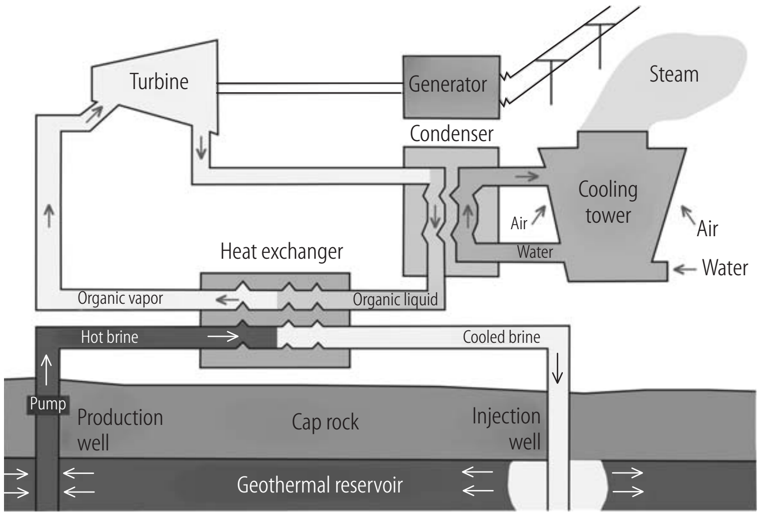

Fig. 8.52. Binary power plant (water-cooled) for heat production from hot water or low enthalpy wet steam fields (modified after [04Tri]).

8.4.2.2 Binary power plants

Binary power plants allow converting geothermal heat from low enthalpy, water dominated hot water reservoirs into electricity, provided reservoir temperatures exceed 85 °C. In addition to hot water reservoirs, this technology is also well suited to exploit medium enthalpy wet steam resources with high water-to-steam ratios at temperatures lower than practical for flash steam systems. Binary plants convert medium-temperature resources into electricity more efficiently than other technologies.

In binary plants a heat exchanger transfers heat from the produced hot brine in a primary loop to a low boiling-point working fluid in a secondary loop, such as halogenated hydrocarbons (e.g. Freon™, Frigen™), propane (C_3H_8), isobutane (C_4H_{10}), pentane (C_5H_{12}), ammonia (NH_3). This thermodynamic cycle is known as Organic Rankine Cycle (ORC) because initially organic compounds were used as working fluid. The working fluid in the secondary loop is evaporated in the vaporizer by the geothermal heat provided in the primary loop. The vapor expands as it passes through the organic vapor turbine which is coupled to the generator. The exhaust vapor is condensed in a water-cooled condenser or air cooler and is recycled to the vaporizer by the motive fluid cycle pump (Fig. 8.52). Binary cycle plants require 400 kg kW^{-1} h^{-1} of hot water from low-to-medium enthalpy resources (85 °C - 150 °C) [02Bar]. The cooled brine can be discharged or reinjected into the reservoir without flashing, which minimizes scaling problems. A typical unit size is 1 MW_e - 3 MW_e. However, the binary power plant technology has emerged as the most cost-effective and reliable way to convert large amounts of low temperature geothermal resources into electricity, and it is now well known that large low-temperature reservoirs exist at accessible depths almost anywhere in the world. The power rating of geothermal turbine/generator units tends to be smaller than in conventional thermal power stations. The most common unit capacities are 55 MW_e, 30 MW_e, 15 MW_e, 5 MW_e or smaller [02Bar].

ORC systems have been installed in significant numbers within the past 30 years because binary plants convert low enthalpy geothermal resources more efficiently into electricity than other technologies. This widens the spectrum of locations suitable for geothermal power production significantly. It makes decentralized geothermal power production feasible with unit sizes varying on the order of 0.1 MW_e - 100 MW_e (Fig. 8.53) and economically attractive in many remote or less developed regions of the world, but also in low enthalpy regions of developed countries where financial incentives promote low CO_2-emission energy production technologies. For instance, as a result of Germany's renewable energy act [04Ano4], which requires grid operators to feed geothermal electric energy into their grids at a certified price of up to 0.15 € kW^{-1} h^{-1}, low- to medium-enthalpy hot water resources are being developed in this

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country which is lacking natural steam reservoirs. As a result, the first geothermal power production in Germany went into commercial operation at Neustadt-Glewe in the Northern German Sedimentary Basin in November 2003 (0.2 MW_e, 98°C [03Ano2]). More projects are being developed in the upper Rhine Graben in France, Germany, and Switzerland, and the pre-Alpine Molasse Basin in Austria (the first installation went into operation in Altheim in 2000 with 0.7 MW_e at 106 °C [02Per]) and Germany with projected capacities of up to 5 MW_e.

Recently, the efficiency of binary power plants is further improved by the Kalina Cycle technology [84Kal; 89Wal]. Here, a mixture of water and ammonia (NH_3) is evaporated over a finite temperature

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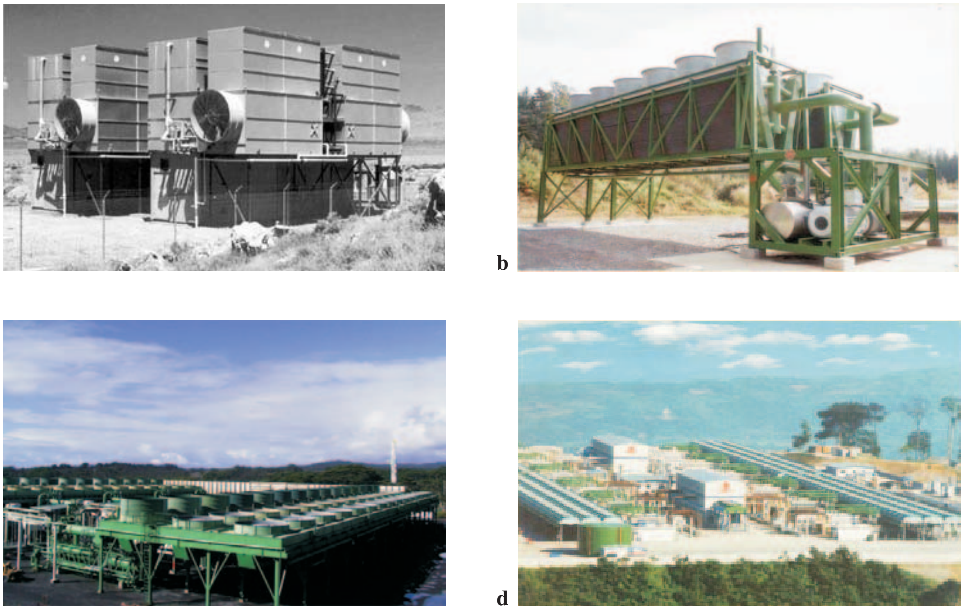

Fig. 8.53. Binary (top) and combined cycle (bottom) geothermal power plants (top left to bottom right): Wendel Hot Springs CA., USA (700 kW_e); Bad Blumau, Austria (250 kW_e); Puna District, Big Island HI, USA (30 MW_e); Leyte, The Philippines (125 MW_e), both the largest air-cooled and largest combined cycle power plant in the world [99Nic; 01Ano4; 04Ano3].

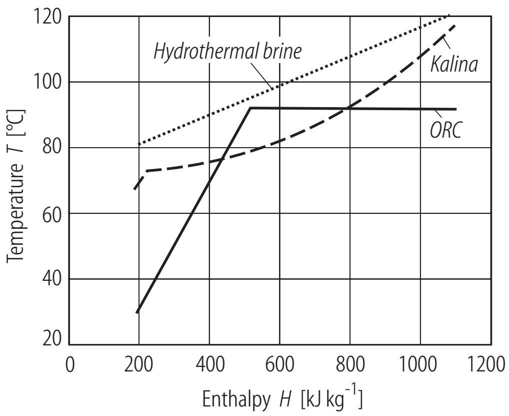

Fig. 8.54. Evaporation curves of working fluids in ORC and Kalina cycles, and hydrothermal brines showing temperature T versus enthalpy H (modified after [04Len1]).

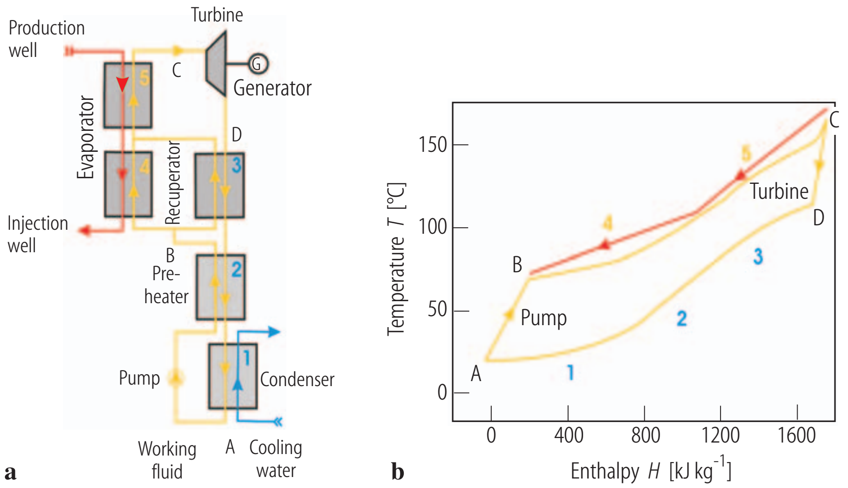

Fig. 8.55. **(a)** Schematic diagram of the Kalina process. **(b)** Thermodynamic cycle (right) showing the temperature *T* versus enthalpy *H* (modified after [04Len1]). The temperature range in this example is 150 K, from 21°C at point *A* to 171°C at point *C*.

range (Fig. 8.54), producing a two-component vapor (70% ammonia and 30% water) in contrast to the ORC process which is based on pure fluids evaporating at specific boiling temperatures. The main thermodynamic advantage of the Kalina over the Organic Rankine cycle is owed to the fact that the water-ammonia mixture, unlike pure fluids, boils at a variable temperature (Fig. 8.55). Therefore the working fluid temperature remains closer to that of the hot brine in the primary circuit which improves the exergy efficiency by 10% - 20% [89Wal].

While this fact has been known for some time, it is the Kalina cycle which, for the first time, provides a practical and efficient way to condense the mixture back to the liquid state for recycling. In particular, in the Kalina cycle the working fluid is circulated in different parts of the cycle at different compositions: A low ammonia concentration (40% ammonia and 60% water) is used during condensation (stages 1-3 in Fig. 8.55), while evaporation (stages 4-5 in Fig. 8.55) occurs at higher ammonia concentrations (70% ammonia and 30% water) for optimum cycle performance [04Ano5]. This provides an improved efficiency of at least 10% of the Kalina cycle over the conventional Organic Rankine Cycle [89Wal]. At present, however, there is just one geothermal Kalina cycle power plant in operation in Husavik, Iceland and available for comparisons [04DiP]; several more are under construction. In contrast, the ORC is a mature technology with hundreds of megawatts of various kinds of cycles installed throughout the world. A recent comparison based on simulated identical conditions observed a difference in performance of about 3% in favor of the Kalina cycle [04DiP].

8.4.2.3 Power plants for hot dry rock or enhanced geothermal systems

Hot dry rock (HDR) or enhanced geothermal reservoirs are engineered systems in contrast to natural geothermal hot or wet steam reservoirs. While natural systems are restricted to regions with geodynamic activity (plate boundaries, mid-ocean ridges, subduction zones, active volcanoes), engineered systems are not limited in distribution: In principle, they can be established in all places with sufficiently high rock temperature because lacking or insufficient hydraulic permeability is created artificially by hydraulic fracturing of the rock at depth. This way, any convenient volume of hot dry rock in the Earth's crust, at accessible (and affordable) depth, may become an engineered HDR or enhanced geothermal reservoir.

A number of wells, usually 2 to 3, are drilled into the rock, terminating several hundred meters apart. Water is circulated down the injection well(s) and through the HDR reservoir, which acts as a heat exchanger. The fluid then returns to the surface through the production well, and thus transfers heat to the surface as steam or hot water. Various concepts for generating different kinds of sub-surface heat exchangers have been proposed and studied, and various combinations of these three basic types are possible as well:

- Single and multiple coin-shaped vertical cracks, such as the first HDR system at Fenton Hill, NM [99Bro] or the system created at Falkenberg, Germany [89Jun] (Fig. 8.56a);
- Networks of micro-cracks, fissures and fractures, such as the systems at Rosemanowes, UK [99Par], Hijiori, Japan [99Kur], and Ogachi, Japan [99Hor] (Fig. 8.56b);
- Systems of reactivated, interconnected large-scale fractures and faults, such as Soultz-sous-Forêts, France [92Bre; 99Bar], and Fjällbacka, Sweden [99Wal] (Fig. 8.56c).

At present, a number of commercial projects based on the different approaches for engineering HDR systems (Fig. 8.56, or modifications and combinations of these types) are under way in countries without natural steam reservoirs, such as Australia [98Nar] and Germany [03Ano2]. Systems such as the one shown in Fig. 8.56c, sometimes referred to as "hot wet rock", fall in between a closed HDR system (Fig. 8.56a) and open, permeable hydrothermal systems [99Abe]. These enhanced geothermal systems are engineered in high-temperature, low-permeability fracture systems or on the margins of productive geothermal fields. They are currently the new frontier and may offer a way for economic geothermal power generation in places where heat is provided by nature not jointly with permeable reservoirs and sufficient suitable fluids.

Stimulation is generally related to rock permeability and well connectivity and aimed at creating highly conductive fractures. Stimulation techniques developed for HDR creating heat exchangers draw on experience from the hydrocarbon industry for enhancing reservoir permeability. The most common stimulation techniques are:

- *Hydraulic fracturing*: massive fluid injection (10 L s^{-1} - 100 L s^{-1}) at pressures of up to 100 MPa;
- *Chemical stimulation*: both *fracture acidizing* and *matrix acidizing*;
- *Explosive fracturing*: controlled underground explosions.

However, there are important differences between HDR systems and hydrocarbon reservoirs, the most significant ones being due to the different kinds of rock. While hydrocarbon reservoirs are mostly sandstones and limestones, HDR systems are often placed in basement or plutonic rocks, such as granite, gneiss, and basalt. These rocks differ significantly in their mechanical properties. Hydraulic fracturing in hydrocarbon reservoirs may create new fractures of several hundred meters in length. In contrast, new fractures in basement rock seem to be created more rarely, while existing and ancient, closed fractures are more often found to be widened and reactivated, respectively. Additionally, HDR systems require much larger fracture areas for heat exchange than required in hydrocarbon applications.

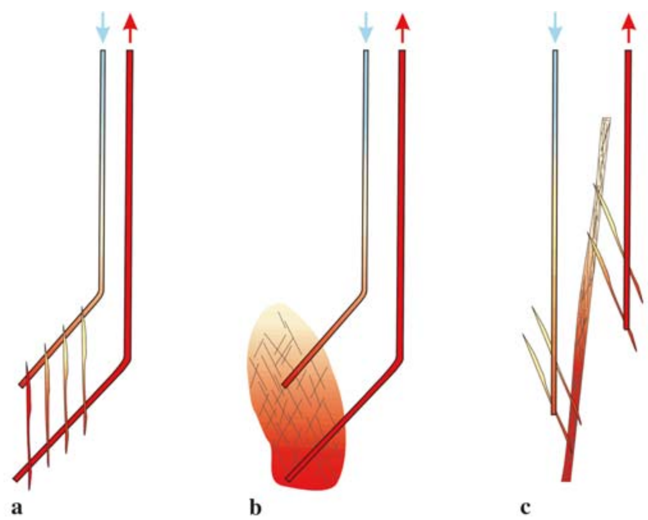

Fig. 8.56. Different kinds of subsurface heat exchanger systems in HDR and enhanced geothermal systems [03Jun]. **(a)** Coin-shaped vertical cracks. **(b)** Network of micro-cracks, fissures and fractures. **(c)** Interconnected large-scale fractures and faults.

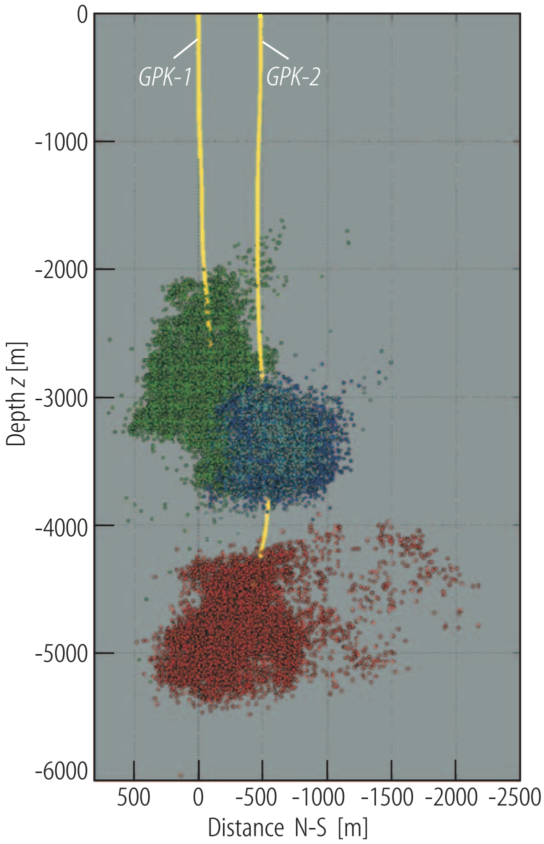

Fig. 8.57. Hypocenters of micro-seismicity generated by four massive hydraulic stimulations in 1993 (green), 1995 (blue), 1996 (cyan), and 2000 (red) in the boreholes GPK-1 and GPK-2 (yellow lines) of the European HDR experimental site at Soultz-sous-Forêts, France (modified after [02Wei]).

For the key parameters of a HDR installation, Barbier [02Bar] and Jung et al. [03Jun] specify the following minimum requirements for a commercial success:

- Production flow rate: 50 L s^{-1} - 100 L s^{-1};
- Flow losses: < 10% of injection flow or < 10 L s^{-1};
- Flow resistance, i.e. (injection pressure – prod. pressure)/ production flow rate: < 100 kPa s L^{-1};
- Effective heat exchange surface: > 5 km^2 - 10 km^2;
- Accessed rock volume: > 0.2 km^3.

Systems with these characteristics, developed by two 5 km deep boreholes about 1 km apart, aim for a thermal power of 50 MW_t - 100 MW_t corresponding to an electric power of 5 MW_e - 10 MW_e delivered over an operation time of 20 years at minimum [03Jun].

The creation of a sufficiently large and permeable underground heat exchanger can be verified by either active seismic tomography or passive monitoring of micro-seismicity. Results of the last method are illustrated in Fig. 8.57 which shows the effect of hydraulic fracturing performed at the European HDR experimental site at Soultz-sous-Forêts, France on four different occasions. Hydraulic overpressure causes the rock to crack at many places, indicated by the corresponding micro-seismic hypocenters. Connectivity between boreholes is indicated by a corresponding overlap of hypocenter locations. At Soultz-sous-Forêts, the stimulations do not result in a system as in Fig. 8.56b, but rather in one as in Fig. 8.56c, because ancient, large-scale fractures were reactivated by the hydraulic fracturing. Once created, these fractures and new pathways are prevented from closing again by the natural displacement of the fracture walls with respect to each other due to the natural stress field or, additionally, by injecting proppants. In enhanced geothermal systems, increasing the productivity of dry wells on the margins of existing productive geothermal fields by stimulation may turn these fields more profitable. It is assumed that dry wells exist where flow-paths are restricted and permeability k is on the order of 10^{-15} m^2 or less [02Bar].

8.4.2.4 Technical, economic and ecological aspects of geothermal power production

Efficiency, life time, and pollution all differ among the technologies used for converting geothermal heat into electric energy. Hudson [03Hud] discusses technical features of various plant options as well as economic aspects of well-head generating units, Bloomquist and Knapp [03Blo] economic and financial aspects, and Brown and Webster-Brown [03Bro] environmental impacts and mitigation. Case studies of various geothermal projects are discussed by Grant [96Gra] as an illustration for the methodology used from the exploration of the resource to the building of the surface installations. In particular, Grant's study [96Gra] includes an appraisal of the trade-offs between additional information and corresponding cost, aspects of field management, and guidelines – a spectrum well beyond this text but of great practical value.

8.4.2.4.1 Efficiency

Geothermal steam from natural and HDR systems is converted into electric energy with a thermal efficiency, the ratio of net electric power output to heat input rate, ranging from 10% to 17%, depending on the type of steam and its temperature [99Del; 02Bar; 03Jun]. This may appear low, by about a factor of three, compared to the efficiency of nuclear or fossil power plants, but is the result of the comparatively low temperature of geothermal steam, generally less than 250 °C. In addition, geothermal steam has a chemical composition different from pure water steam, containing, in general, the non-condensable gases CO_2, H_2S, NH_3, CH_4, N_2 and H_2 in concentrations varying from 1 g to 50 g per kg of fluid. Extracting these aggressive gases from the condensers of power plants additionally reduces the efficiency of electricity generation [02Bar]. However, geothermal steam power plants possess quite impressive utilization efficiencies, the ratio of net electric power output to exergy input rate (exergy: see Sect. 8.4.1.1.1), ranging from about 40% to 65% [97DiP]. This demonstrates that particularly direct steam power plants typically convert the bulk of the maximum available thermodynamic work into electric energy.

In general, the efficiency of binary cycle power plants is lower than that of steam power plants. It varies with the resource temperature: values reported for installations commissioned within the last decade range from about 5% to 14% (Fig. 8.58). Again, the utilization efficiency is larger, ranging from about 16% to 54% [97DiP; 04DiP].

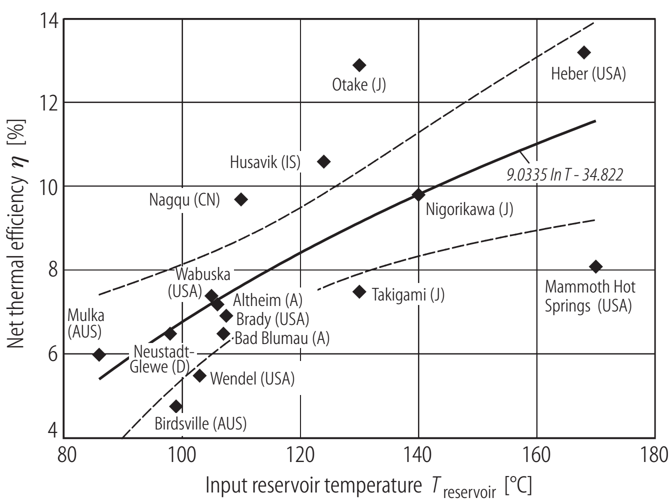

Fig. 8.58. Net thermal efficiency η (i.e. the ratio of output electric power to input thermal power) versus input reservoir temperature for various binary power plants (Husavik: Kalina cycle, all others: ORC). Full line indicates a possible, logarithmic trend defined by the associated nonlinear regression; broken lines indicate 95% confidence limits, notwithstanding the low number of data points (A: Austria, AUS: Australia, CN: People's Republic of China, D: Germany, IS: Iceland, J: Japan. Data: [86Cul; 97DiP; 00Bur; 00Low; 00Ura; 02Per; 03Ano2; 03Jun; 04DiP]).

Frequently, binary units are also combined with direct steam, single- or multiple flash systems in order to improve the use of the available resource. Then the additional efficiency provided by the binary units helps to raise the overall efficiency of the combined system. The binary ORC and Kalina cycle technologies have emerged as the most cost-effective and reliable way to convert large amounts of low temperature geothermal resources into electricity. In spite of the low efficiency and in view of the attractive pollution balance, this technology appears to be on the threshold to be used on a larger scale for the conversion into electric energy in particular of the large low- to medium-enthalpy reservoirs abundant at accessible depth at numerous locations in the world.

The same considerations as for natural systems apply to the efficiency of engineered HDR systems as far as the surface installations are concerned. As for natural steam reservoirs, the thermal efficiency of HDR systems critically depends on the temperature and flow rates to be realized over a long period of operation. Thus the main challenge in engineering these systems lies not in the energy conversion efficiency of the surface installations, but in creating an adequately sized reservoir with sufficient permeability for sustaining sufficient flow rates at a high temperature.

8.4.2.4.2 Cost and life time

Among the renewables, geothermal energy has a remarkably long and proven record of reliability, both for direct use and electric energy production, dating back over 100 years. Indeed, the oldest geothermal field for generation of electric energy at Lardarello (Italy) is looking back today on a continuous operation of over a century. Other fields, such as at The Geysers (USA) and Wairakei (New Zealand), have been operating for more than seven and five decades, respectively. Experience thus proves that geothermal fields, both vapor and water dominated, can be operated economically over a century. Prudent reinjection of spent fluids will help to constrain the decline of reservoir pressure and thus flow rate and the associated land subsidence.

Accordingly, substantial investments have been made for developing geothermal fields, but unfortunately the last survey of investments made in the main geothermal countries in the world in the period 1973-1992 dates back already 10 years [94Fri]. It indicated a total investment of around 22,000 million US$. Of these, 7,600 M$ were invested between 1973 and 1982, and 14,300 M$ between 1983 and 1992. This corresponds to an increase in total investments of 89% in the second decade analyzed. In detail, 17,600 M$ (80%) were invested in industrialized countries, 3,500 M$ (16%) in developing countries, and 800 M$ (4%) in Eastern European countries.

As for oil and gas, much of this money is spent for technological research and development, geothermal exploration based on geological, geophysical, and geochemical surveys, drilling, field development, and surface installations for power generation or direct uses. However, geothermal projects are more closely linked to the specific site than oil and gas projects since geothermal fluids are normally used at or near the producing field. This is due to the cost of insulation for minimizing heat losses from pipelines which makes pumping fluids over long distances uneconomical. This is also reflected in the more than ten-fold larger enthalpy of oil (41800 kJ kg^{-1}) compared to that of high-enthalpy geothermal steam (3000 kJ kg^{-1}) or hot water (209 kJ kg^{-1}) for a production and injection temperature of 80 °C and 30 °C, respectively [02Bar].

8.4.2.4.2.1 Natural steam systems

A time of about 3 years is required to develop new geothermal dry or wet steam fields and to install corresponding power plants [96Ano2; 96Gra; 02Ste]. This is reasonably short and in keeping with the construction times of power stations based on other fuels ([96Ano2; 00Tur]; Fig. 8.59). Available numbers for the specific investment required for large geothermal steam power plants vary little and are consistently on the order of 1 million US$ per installed MW (Fig. 8.59) or 1 million € per installed MW [96Ano2; 99Del; 03Kal; 03Pas] (Fig. 8.60). Depending on plant type and size, costs range from 0.8 M$ MW^{-1} to 3.0 M$ MW^{-1} [96Ano2; 00Tur] and 0.6 M€ MW^{-1} to 2.4 M€ MW^{-1} [99Del; 03Kal;

03Pas]. Corresponding production costs of 0.045 € kW^{-1} h^{-1} - 0.091 € kW^{-1} h^{-1} [96Ano2; 99Del] are not too far above the energy price of a clean coal power plant and competitive compared to other sources of renewable energy, i.e. comparable to biomass and wind, and one or two orders of magnitude below concentrating solar or photovoltaic, respectively (Fig. 8.60).

In a comparison based on five geothermal power plants built in Iceland between 1994 and 1999, Stefansson [02Ste] reports that, on average, surface installations contribute about 977 ± 215 \$ kW^{-1} to the capital cost. Notwithstanding the small number of data points he finds a good correlation ($R^2 = 0.97$) for a linear trend between surface cost and installed capacity:

$$\text{surface cost [M\$]} = -0.9 \pm 4.6 \;+\; (1.0 \pm 0.1) \times \text{capacity [MW]}. \qquad (8.66)$$

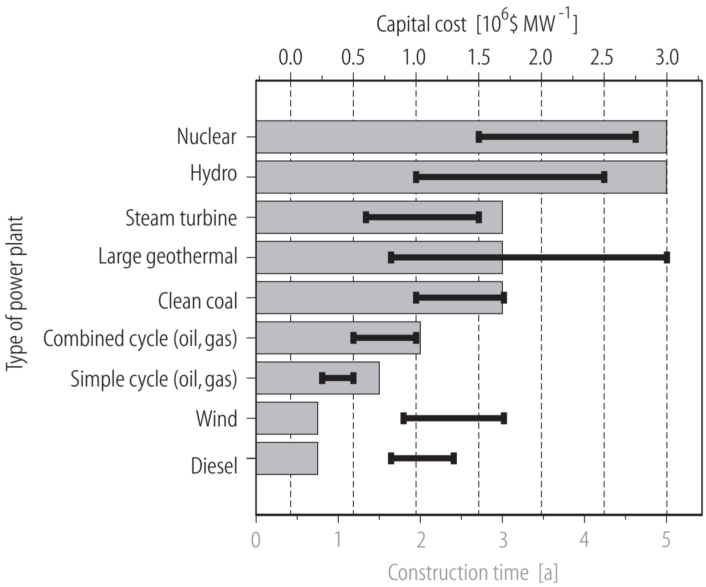

Fig. 8.59. Turnkey investment in US\$ (black bars) and average time required for power plant construction (grey bars) based on various kinds of conventional and renewable energy. Data: [96Ano2; 00Tur].

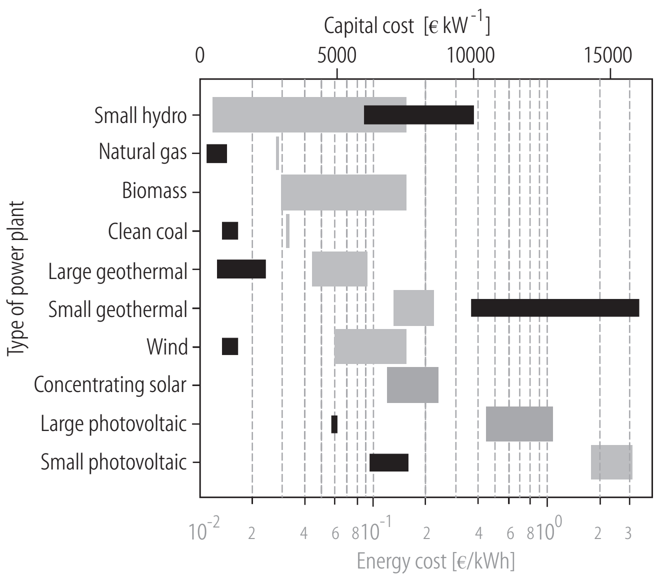

Fig. 8.60. Cost range for electricity produced from various fossil and renewable sources of energy (grey bars) and specific investment cost range for various fossil and renewable power plants (black bars). “Large geothermal” and “small geothermal” refers to steam power plants exploiting natural fields and HDR or enhanced geothermal systems with binary power plants, respectively. Data: [96Ano2; 99Del; 03Jun; 03Kal; 03Pas].

Table 8.24. Characteristics of steam fields [92Ste2].

Average yield per well [MW_e]	Average yield per drilled km [MW_e]	Average number of wells for achieving maximum yield
4.2 ± 2.2	3.4 ± 1.4	9.3 ± 6.1

He combines this with results of an earlier survey of data from 31 geothermal steam fields world-wide (Table 8.24) and arrives at an expression for the total capital cost for a known geothermal field:

$$\text{cost [M\$]} = -0.9 \pm 4.6 \ + \ (1.29 + 0.31/-0.19) \times \text{capacity [MW]}\,. \tag{8.67}$$

Assuming that exploration in an unknown field requires an additional 50% of the average number of wells (9.3 ± 6.1, Table 8.24), i.e. 4.6 ± 3.0 at a cost of 1.5 M$ each corresponding to an additional cost of 6.9 ± 4.5 M$, Stefansson [02Ste] arrives at an expression for the total capital cost for an unknown geothermal field:

$$\text{cost [M\$]} = 6.0 \pm 9.1 \ + \ (1.29 + 0.31/-0.19) \times \text{capacity [MW]}\,. \tag{8.68}$$

8.4.2.4.2.2 HDR and enhanced systems

HDR or enhanced geothermal systems differ from conventional reservoirs in so far as they require additional hydraulic stimulation of the reservoir's permeability to obtain the required flow rate of 50 L s^{-1} - 100 L s^{-1}. In general, stimulation is accomplished by hydraulic fracturing of the rock at depth. This involves injection of large quantities of fluid, typically several hundred cubic meters of water, at flow rates between 10 L s^{-1} -100 L s^{-1} and high pressures of up to 100 MPa. This operation requires large powerful pumps, a drill rig, and miscellaneous surface installations on site which involve an additional cost.

A pioneer HDR project at Los Alamos (USA) reached the threshold of economic feasibility at a cost of 175 million US$ in 1993 [02Bar]. However, this sum comprises much research and "learning-by-doing" in this prototype installation. Current cost can be expected to be an order of magnitude less as two recent studies conducted for Central European conditions demonstrate:

- Jung et al. [03Jun] calculate the cost for two such installations in Germany consisting of two boreholes each, 2.2 km and 4.6 km deep, located in the Upper Rhine Graben and in the North German Sedimentary Basin, respectively, a production temperature of 150 °C at a volume flow rate of 100 L s^{-1}, with a binary power plant at the surface; they arrive at total costs of roughly 8.5 M€ and 13.6 M€, respectively (cf. Fig. 8.60, "small geothermal"). The 60% difference is mostly due to the larger borehole depth required in the second case to secure the desired production temperature of 150 °C.
- For a similar system of three 5.5 km deep boreholes in the Upper Rhine Graben and a production temperature of 200 °C at 70 kg s^{-1} mass flow rate, Delacroix [99Del] discusses three cases: The first one corresponds to verified costs in the past, the second one to current costs, and the third one to costs which can expected for the near future, given the decrease in cost between the two previous cases and future technical improvements. For this "optimistic but nevertheless not unrealistic" [99Del] scenario, Delacroix [99Del] arrives at a total cost of 27.5 M€. Considering the additional cost for the third borehole and the greater borehole depth, this estimate is in reasonable agreement with that of Jung et al. [03Jun], particularly when considering the period of four years between these two studies.

In summary, while experience is still lacking for commercial geothermal HDR power plants, it appears that this technology is on the verge of becoming economical. This development can certainly be supported and accelerated by national legislation, as for instance in Germany, by allowing geothermal electric energy to be fed into the grid at a certified price (cf. Table 8.26). If successful, this technology will make it possible to generate electric energy from geothermal heat nearly everywhere, even in lack of geothermal anomalies and natural steam reservoirs.

8.4.2.4.3 Pollution

Large volumes of steam (or steam and water) need to be produced in the process of generating electric energy from geothermal heat. For instance 8000 t h^{-1} are required at The Geysers in California, with a current capacity of 1036 MWe, and 3000 t h^{-1} at Larderello in Italy, with an installed capacity of 547 MWe. These geothermal fluids vary in chemical composition depending on the reservoir rocks. The major environmental impact of geothermal power production therefore corresponds to the discharge of various gases dissolved in the geothermal fluids into the atmosphere and of water into bodies of surface water, such as rivers and lakes. Minor environmental impacts are connected to land subsidence, induced seismicity, and noise. In his review on “Geothermal Energy Technology and Current Status”, Barbier [02Bar] discusses all these aspects in detail. Where not stated differently, the following discussion in this paragraph summarizes his synopsis. Further aspects are discussed in [98Ren; 00Hun; 03Dic].

8.4.2.4.3.1 Air pollution

Steam from major geothermal fields contains an amount of non-condensable gases, CO_2, H_2S, NH_3, CH_4, N_2, and H_2, ranging from 1.0 g to 50 g per kg of steam. Carbon dioxide is the major component, but much less is discharged into the atmosphere per kW h generated from geothermal power plants than from gas-, oil- or coal-fired ones (Fig. 8.61). Even with respect to natural gas, most existing geothermal power plants discharge significantly less CO_2 into the atmosphere. Based on a price for European Emission Allowances of 23 € per ton of CO_2 traded at the European Energy Exchange[6], regulations within European Union member states with respect to permissible CO_2 emissions for various industries provide significant incentives for CO_2 reduction and for low CO_2 energy production and emission. Geothermal emissions of carbon dioxide are in the range of 0.010 kg kW^{-1} h^{-1} - 0.380 kg kW^{-1} h^{-1} with the exception of one plant on the Azores islands where the geodynamic setting is responsible for a large CO_2 content in the produced steam [97Bar; 98Ren; 02Bar]. In fact, most existing plants emit clearly less than 0.200 kg kW^{-1} h^{-1} of CO_2 (Fig. 8.61). This is significantly less than the CO_2 emissions of power plants based on fossil fuels which are in the range of 0.450 kg kW^{-1} h^{-1} - 1.040 kg kW^{-1} h^{-1}. Thus replacing existing oil, gas or coal fired plants by geothermal plants will yield a reduction of an order 0.250 kg kW^{-1} h^{-1}, 0.700 kg kW^{-1} h^{-1} or 0.850 kg kW^{-1} h^{-1}, respectively. Based on the number of 23 € per ton of CO_2 traded at the European Energy Exchange (EEX)[6] on 24 June 2005, this corresponds to minimum incentives of 0.006 € kW^{-1} h^{-1}, 0.016 € kW^{-1} h^{-1} or 0.02 € kW^{-1} h^{-1}, if natural gas, oil or coal is replaced.

Apart from the greenhouse gas carbon dioxide, hydrogen sulfide is an air pollutant of major concern in geothermal development. Its emissions are in the range 0.03 g kW^{-1} h^{-1} - 6.4 g kW^{-1} h^{-1}. H_2S is oxidized to sulfur dioxide and then to sulfuric acid, the major source of acid rain. Without extraction, the specific emissions of sulfur from geothermal power plants are about half of those from coal-fired plants (Fig. 8.61). There are no emissions of toxic nitrogen oxides from geothermal power plants, in contrast to fossil fuel plants. However gases in geothermal steam may also contain ammonia (NH_3), traces of mercury (Hg), boron vapors (B), hydrocarbons such as methane (CH_4), and radon (Rn). Boron, ammonia, and − to a smaller amount − mercury are leached from the atmosphere by rain and may contaminate soil and vegetation. Boron, in particular, can have a serious impact on vegetation. Salt water spray from well testing is also reported as a significant source of plant damage within about 50 m - 350 m from the well heads [05Tuy]. These contaminants may also affect surface waters with a corresponding negative impact on aquatic life. Geothermal literature reports that mercury emissions from geothermal power plants range between 45 µg kW^{-1} h^{-1} and 900 µg kW^{-1} h^{-1}, comparable to those from coal-fired power plants. Ammonia is discharged into the atmosphere in concentrations between 57 mg kW^{-1} h^{-1} and 1938 mg kW^{-1} h^{-1}, but

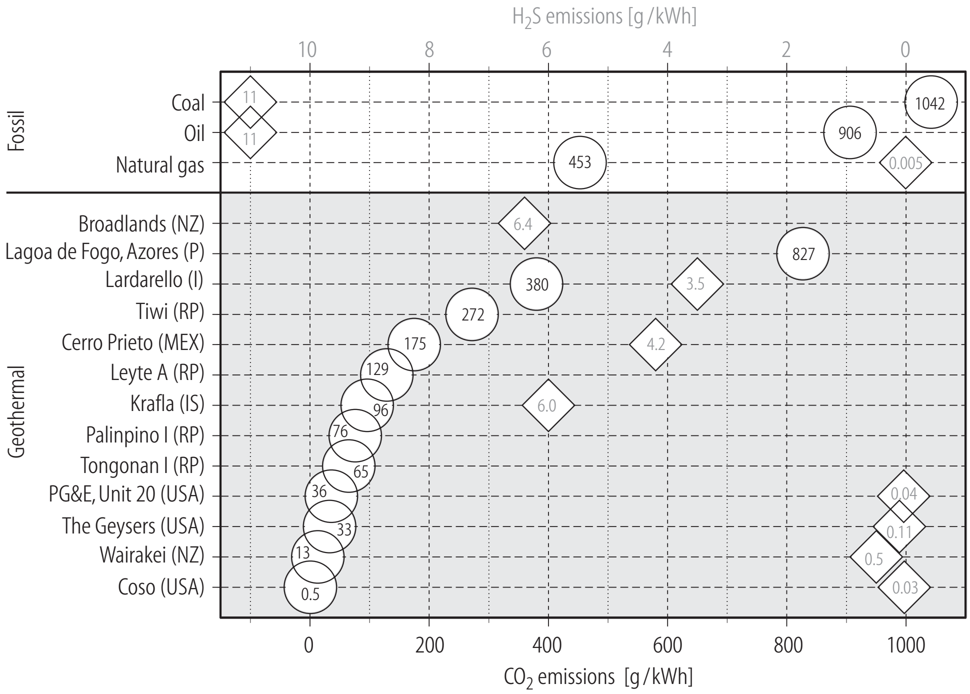

Fig. 8.61. Emission of carbon dioxide (CO_2, circles) and hydrogen sulfide (H_2S, diamonds) per kW h produced electric energy reported for geothermal power plants in Asia, Europe, North America and typical fossil power plants (I: Italy, IS: Iceland, MEX: Mexico, NZ: New Zealand, P: Portugal, RP: The Philippines). Data: [97Bar; 98Ren; 02Bar].

atmospheric circulation leads to rapid dispersion and dilution. Radon (^{222}Rn), a radioactive gas isotope which occurs naturally in the Earth's crust, is contained in geothermal steam and discharged into the atmosphere in concentrations between 3700 Bq kW^{-1} h^{-1} and 78000 Bq kW^{-1} h^{-1}. The radon concentration in air at ground level is 5.5 Bq m^{-3} at Larderello (Italy), and varies from mere traces up to 6.0 Bq m^{-3} at The Geysers (USA). By comparison, average levels of radon in air elsewhere are around 3 Bq m^{-3}. Although its levels should be monitored, there is little evidence that radon concentrations are raised above background level by geothermal emissions.

With respect to air and water pollution it merits mention that closed-loop installations, such as binary plants, in which the geothermal fluid is passed through a heat exchanger and reinjected without contact with the atmosphere, will discharge neither gas nor fluid to the environment during normal operation.

Much as stated before with respect to the direct use of geothermal energy, the economics of geothermal power production is ultimately defined by the cost of energy from other, mainly fossil sources, in particular by the price for oil and gas. As a result of the Kyoto protocol [9,10], many countries accepted obligations for reducing their CO_2 emissions to the atmosphere, on average, to a level of 92% of their emissions in the year 1990 (Table 8.25). The Kyoto protocol went into effect by 25 February 2005 after having been ratified by 55 countries which are responsible for at least 55% of the global CO_2 emissions in 1990. The protocol specifies no limitations for the CO_2 emissions of the People's Republic of China and other developing countries. By 25 February 2004, the Kyoto protocol had been ratified by 141 countries representing 85% of the world population and 62% of the current CO_2 emissions; notable exceptions are Australia, Croatia, Monaco, and the USA.

Corresponding policies of other member states of the European Union consist in a combination of penalties and incentives for the production and reduction of CO_2 emissions to the atmosphere, respectively. In combination with the long-term trend of increasing prices for hydrocarbon fuels (Fig. 8.36), this will make geothermal power production increasingly competitive. Additional national legislation can support this process. For instance, in Germany grid operators are required to feed geothermal electric energy into their grids at a certified price of up to 0.15 € kW^{-1} h^{-1} until the end of 2009 (Table 8.26); from 2010 onwards this reimbursement is diminished annually by one per cent relative to the preceding year's compensation.

Pollution is not considered a cost factor as long as its impact on the environment is small and can be neglected. Today, this is generally no longer the case, and national legislation regularly both requires provisions for limiting the environmental burden and provides incentives for the use of environmentally more benign technologies. The effect of both factors is to make low emission technologies more economical. In this context, the interrelation between pollution and cost has been analyzed using the so-called "eco-efficiency analysis" [00Kic]. Developed by BASF, the world's largest producer of base chemicals, for analyzing jointly the economic and ecologic characteristics of products and industrial procedures, it has recently been applied by Siemens, a leading producer of equipment for generating electric

Table 8.25. Emission limitations or reduction commitments under the Kyoto protocol[9, 10].

Country	Percentage of emissions by the year 2012 relative to the level of 1990 (or the base period)	Country	Percentage of emissions by the year 2012 relative to the level of 1990 (or the base period)
Austria	87.0	Liechtenstein	92.0
Belgium	92.5	Lithuania	92.0
Bulgaria	92.0	Luxembourg	72.0
Canada	94.0	Netherlands	94.0
Czech Republic	92.0	New Zealand	100.0
Denmark	79.0	Norway	101.0
Estonia	92.0	Poland	94.0
Finland	100.0	Portugal	127.0
France	100.0	Romania	92.0
Germany	79.0	Russia	100.0
Greece	125.0	Slovakia	92.0
Hungary	94.0	Slovenia	92.0
Iceland	110.0	Spain	115.0
Ireland	113.0	Sweden	104.0
Italy	93.5	Switzerland	92.0
Japan	94.0	Ukraine	100.0
Latvia	92.0		

Table 8.26. Reimbursement for geothermal electric energy according to the German Renewable Energy Act [04Ano4].

Installed capacity [MW]	Reimbursement [€ kW^{-1} h^{-1}]
0 - 5	0.1500
5 - 10	0.1400
10 - 20	0.0895
> 20	0.0716

[9]) http://unfccc.int/essential_background/kyoto_protocol/background/items/1351.php
[10]) http://www.bmu.de/files/pdfs/allgemein/application/pdf/kyoto_denkschr.pdf

energy from a variety of different sources of primary energy, to determine which among the renewable energies appear most attractive with respect to both ecology and economy [04Len2]. The result summarized in Fig. 8.62 illustrates that geothermal energy is attractive in both respects and well ahead of all kinds of fossil and nuclear energy. Among the renewables it is surpassed in this particular analysis only by hydro and wind energy, and clearly ahead of biomass and photovoltaic energy. Needless to say that analysis requires values to be assigned for various parameters, and Fig. 8.62 does not make their choice transparent. Still, this is an interesting result for two reasons:

- It demonstrates that even today and even under less than optimum premises for the generation of electric energy – in a developed economy such as Germany without natural steam reservoirs, but with many competitors among well developed and well established technologies for energy production – geothermal energy is attractive and competitive with respect to fossil and nuclear as well as other renewable sources of primary energy;
- While hydro and wind energy appear more attractive at present, both have already reached or are close to their maximum development: At least in Germany (and certainly in many other countries) there are few or no sites for new hydropower dams, and similarly, all of the optimum locations for wind turbines are already used. New development appears possible only off-shore, where an additional price must be paid for enforced structures, additional grid lines and ecological safeguarding. In contrast, geothermal energy in countries without natural steam reservoirs is just at the beginning of its development.

8.4.2.4.3.2 Water pollution

As a rule, the discharge of geothermal fluids into surface waters leads to pollution of rivers and lakes and is a potential hazard associated with geothermal electric energy production [05Sim]. In vapor dominated reservoirs most of the pollutants are in the vapor state, and pollution of surface waters is controlled easier than in water dominated reservoirs. There, waste steam condensate (20% of the steam supply) must be added to the waste water. The water and the condensate generally carry a variety of toxic chemicals in suspension and solution: arsenic, mercury, lead, zinc, boron and sulfur, together with significant amounts

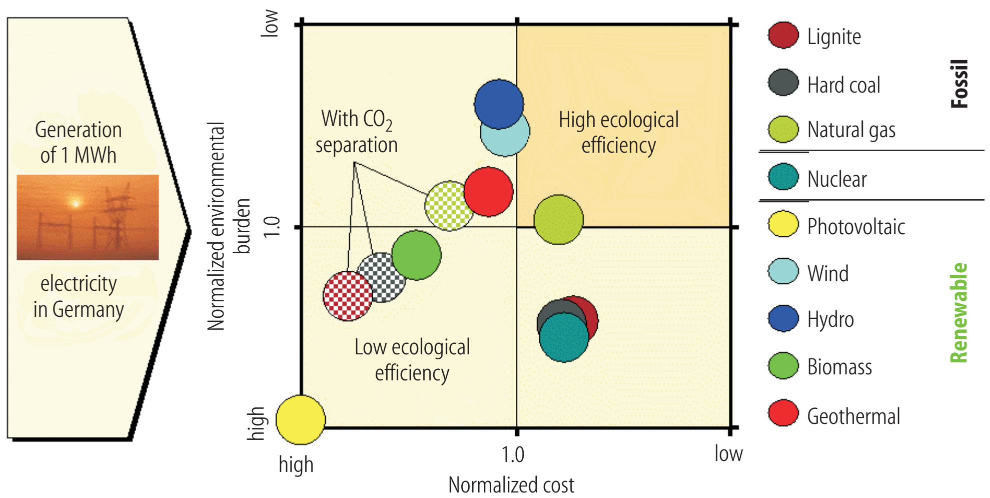

Fig. 8.62. Environmental burden vs. cost associated with the generation of electric energy in Germany based on different sources of fossil and renewable primary energy (wind: 5.5 m s^{-1} at 50 m above land surface; biomass: wood). Modified after [04Len2].

of carbonates, silica, sulfates and chlorides (see e.g. [05Mro] for a field example). In water dominated and in hot water reservoirs, water and steam (if present) are separated at the surface. The steam is used for generating electric energy, and the volume of water to be disposed of can be as much as 70 kg kW^{-1} h^{-1}, more than four times the steam supply, and up to 400 kg kW^{-1} h^{-1} in binary cycle plants. Often this water contains large amounts of dissolved salts, even above 300 g per kg of extracted fluid. Reinjection into the reservoir is the most common method of disposal. This also helps to control reservoir pressure (in order to prevent an unwanted, premature pressure decline) and to extract additional heat from the rock, thus helping to extend the useful life of the resource. At first sight, reinjection might seem expensive, as it requires additional wells, surface piping, and continuous pumping. But in the long run it is very helpful and, calculated over the entire lifetime of a geothermal project, normally helps to save cost compared to a scenario without reinjection.

8.4.2.4.3.3 Land subsidence

As fluids are produced from a reservoir, pore pressure declines causing the ground to subside. Less subsidence occurs for harder than for softer reservoir rocks. The order at which geothermal fluids are produced is comparable to that in large groundwater production for agriculture where land subsidence has been a problem in some cases. Water dominated fields subside more than vapor dominated fields. For example, the Wairakei (New Zealand) water dominated geothermal field (currently at 220 MW_e running capacity) experienced a localized subsidence of 4.5 m in the period 1964-1974 (corresponding to a production of 622 Mt of fluid) and a total subsidence of 14 m at maximum in the period 1950-1998 [00All]. In contrast, The Geysers (USA) vapor dominated field (currently at 888 MW_e running capacity) subsided only by 14 cm in the period 1973-1977, and Larderello (Italy) − also a vapor dominated field (currently at 473 MW_e running capacity) − subsided by 1.7 m in the period 1923-1986. Subsidence can be controlled or prevented by the reinjection of spent fluids. On the other hand, reinjection may give rise to micro-seismicity.

8.4.2.4.3.4 Induced seismicity

Many geothermal reservoirs, in particular at high temperature, are located in geologically active zones of the Earth's crust. These are characterized by volcanic activity, deep earthquakes, and a heat flow larger than average resulting in a natural seismicity which is more frequent than elsewhere. In such a geodynamic framework, water injection into a reservoir may create additional seismicity by increasing pore pressure, reducing rock stress, thus triggering the release of accumulated tectonic stress. A study of the correlation between seismicity and water injection into wells of the Larderello (Italy) geothermal area suggested an increase of low-magnitude events but not an increase in the maximum value of the event magnitudes. Reinjection of waste fluids may therefore have even a positive effect, triggering a higher number of low intensity shocks, but favoring the progressive, non instantaneous release of the stress accumulated in the rocks. This has been known also for some time from experience in fluid injection in oil fields in regimes of tectonic stress and from experiments at the Rocky Mountain Arsenal, near Denver (USA) [68Hea; 81Her]. Although this has not yet emerged as a technology by which seismic risk can be managed actively, it deserves greater attention and systematic, focused research in the context of creating and managing HDR or enhanced geothermal reservoirs. While ambitious programs are being discussed in some countries aiming to use this technique massively for developing geothermal energy for electric energy production, the public acceptance of an increasing number of these systems depends critically on whether associated safety concerns of the public can be addressed adequately.

8.4.2.4.3.5 Noise

During drilling or maintenance, a noise level of 90 dBA[11] - 122 dBA or 75 dBA - 90 dBA is associated with wells at free discharge or through silencers, respectively. Testing of the wells is associated with noise levels of between 70 dBA and 110 dBA (if silencers are used), and Diesel engines for driving drill rigs with 45 dBA - 55 dBA (if suitable muffling is used). The pain threshold lies at 120 dBA in the frequency range 2000 Hz - 4000 Hz. By comparison, at a distance of 60 m a jet takeoff corresponds to a noise level of 125 dBA, a noisy urban environment to 80 dBA - 90 dBA, and a quiet suburban residence to 50 dBA. On a drill site itself the noise level can be kept below 60 dBA during normal operation. At a distance of one kilometer it should be practically indistinguishable from other background noises [98Ren].

Summary

Geothermal heat flows to the surface of the Earth from great depth. In order to use this source for providing heat and electric energy, the governing processes must be understood and the associated physical properties must be known. This chapter hopefully provides a sound starting point for more detailed study and work on this subject.

Geothermal energy can be used in a variety of ways: directly as industrial process heat or for space heating (and even cooling). This chapter introduced the most important current concepts in geothermal energy use. However, those wishing to pursue this topic further are advised to consult the special literature much of which is referenced in this text (without claiming completeness).

Sometimes questions are raised whether geothermal is a truly renewable source of energy or whether much of the heat stored in the Earth is not absorbed from solar radiation. While these questions have been addressed earlier in this chapter so much only in this summary: On a human time scale, the produced heat produced is normally not replaced. In general, replenishing the heat takes longer than producing it. This is why the term “heat mining” is frequently used. However, on a geological scale the produced heat is indeed replenished. This is why geothermal is a truly renewable form of primary energy. On a cosmological time scale all forms of life on earth as we know it today – and thus also all forms of energy production – are limited by the life span of our solar system. What may come after the time when the sun will have become a white giant and subsequently a black dwarf is fortunately beyond our imagination. It certainly poses a limit to the concept of something being renewable.

The advantages and disadvantages of geothermal energy in our present life can be summarized as follows:

+ Very small CO_2 output;
+ Comparatively small environmental burdens involved;
+ Very little land use: Production facilities below the Earth’s surface;
+ Installations inconspicuous for direct use and comparable to conventional installations with respect to power production;
+ Well suited to provide thermal and electric base loads; does not suffer from large peaks which require buffering when fed into grids.

– Generation of electric energy currently restricted basically to regions with natural steam reservoirs;

[11]) dBA: Unit of sound intensity, exactly like the decibel (dB) except that prior to a measurement sounds of high and low frequencies, heard poorly or not at all by the human ear, have been filtered out. The letter A refers to one of two customary filtering methods.

- HDR and enhanced geothermal technology not yet industry standard; further research in generating and localizing fractures required;
- Competitiveness of direct use heat hampered by existing sources of (waste) heat with associated difficulty in crowding out and market penetration;
- Larger use in regions lacking natural steam reservoirs often hampered by inadequate information on thermal and hydraulic rock properties.

Already today geothermal energy is an important source of electric energy in many countries. It is particularly valuable for many developing and emerging national economies as it is an indigenous source of energy providing a degree of independence from the variability of the price of hydrocarbons. Even in some of the developed economies it contributes on the order of 0.5% - 16% to the national production of electric energy. In countries without natural steam reservoirs it is just at the beginning of its development. The years to come will show whether the existing potential can be put to an economic use. Direct use of geothermal heat is more ubiquitous. Rather than on geological and economic conditions, its use depends on market access, penetration and, in part, crowding out of other sources of available heat. Some countries have made considerable progress in direct use of geothermal heat, both in developed and emerging economies. Similar to the conversion into electric energy, direct use of geothermal heat will benefit from an increase in the price of fossil fuels, in particular hydrocarbons, which can be anticipated for the future based on the historical development and the natural limitation of the resource base.

In summary, geothermal energy appears an attractive, promising, clean, and renewable source of energy.

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