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Geothermal Energy

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Executive Summary

Geothermal energy has the potential to provide long-term, secure base-load energy and greenhouse gas (GHG) emissions reductions. Accessible geothermal energy from the Earth's interior supplies heat for direct use and to generate electric energy. Climate change is not expected to have any major impacts on the effectiveness of geothermal energy utilization, but the widespread deployment of geothermal energy could play a meaningful role in mitigating climate change. In electricity applications, the commercialization and use of engineered (or enhanced) geothermal systems (EGS) may play a central role in establishing the size of the contribution of geothermal energy to long-term GHG emissions reductions.

The natural replenishment of heat from earth processes and modern reservoir management techniques enable the sustainable use of geothermal energy as a low-emission, renewable resource. With appropriate resource management, the tapped heat from an active reservoir is continuously restored by natural heat production, conduction and convection from surrounding hotter regions, and the extracted geothermal fluids are replenished by natural recharge and by injection of the depleted (cooled) fluids.

Global geothermal technical potential is comparable to global primary energy supply in 2008. For electricity generation, the technical potential of geothermal energy is estimated to be between 118 EJ/yr (to 3 km depth) and 1,109 EJ/yr (to 10 km depth). For direct thermal uses, the technical potential is estimated to range from 10 to 312 EJ/yr. The heat extracted to achieve these technical potentials can be fully or partially replenished over the long term by the continental terrestrial heat flow of 315 EJ/yr at an average flux of 65 mW/m^2. Thus, technical potential is not likely to be a barrier to geothermal deployment (electricity and direct uses) on a global basis. Whether or not the geothermal technical potential will be a limiting factor on a regional basis depends on the availability of EGS technology.

There are different geothermal technologies with distinct levels of maturity. Geothermal energy is currently extracted using wells or other means that produce hot fluids from: a) hydrothermal reservoirs with naturally high permeability; and b) EGS-type reservoirs with artificial fluid pathways. The technology for electricity generation from hydrothermal reservoirs is mature and reliable, and has been operating for more than 100 years. Technologies for direct heating using geothermal heat pumps (GHP) for district heating and for other applications are also mature. Technologies for EGS are in the demonstration stage. Direct use provides heating and cooling for buildings including district heating, fish ponds, greenhouses, bathing, wellness and swimming pools, water purification/desalination and industrial and process heat for agricultural products and mineral drying.

Geothermal resources have been commercially used for more than a century. Geothermal energy is currently used for base load electric generation in 24 countries, with an estimated 67.2 TWh/yr (0.24 EJ/yr) of supply provided in 2008 at a global average capacity factor of 74.5%; newer geothermal installations often achieve capacity factors above 90%. Geothermal energy serves more than 10% of the electricity demand in 6 countries and is used directly for heating and cooling in 78 countries, generating 121.7 TWh/yr (0.44 EJ/yr) of thermal energy in 2008, with GHP applications having the widest market penetration. Another source estimates global geothermal energy supply at 0.41 EJ/yr in 2008.

Environmental and social impacts from geothermal use are site and technology specific and largely manageable. Overall, geothermal technologies are environmentally advantageous because there is no combustion process emitting carbon dioxide (CO_2), with the only direct emissions coming from the underground fluids in the reservoir. Historically, direct CO_2 emissions have been high in some instances with the full range spanning from close to 0 to 740 g CO_2/kWh_e depending on technology design and composition of the geothermal fluid in the underground reservoir. Direct CO_2 emissions for direct use applications are negligible and EGS power plants are likely to be designed with zero direct emissions. Life cycle assessment (LCA) studies estimate that full lifecycle CO_2-equivalent emissions for geothermal energy technologies are less than 50 g CO_2eq/kWh_e for flash steam geothermal power plants, less than 80 g CO_2eq/kWh_e for projected EGS power plants, and between 14 and 202 g CO_2eq/kWh_{th} for district heating systems and GHP. Local hazards arising from natural phenomena, such as micro-earthquakes, may be influenced by the operation of geothermal fields. Induced seismic events have not been large enough to lead to human injury or relevant property

damage, but proper management of this issue will be an important step to facilitating significant expansion of future EGS projects.

Several prospects exist for technology improvement and innovation in geothermal systems. Technical advancements can reduce the cost of producing geothermal energy and lead to higher energy recovery, longer field and plant lifetimes, and better reliability. In exploration, research and development (R&D) is required for hidden geothermal systems (i.e., with no surface manifestations such as hot springs and fumaroles) and for EGS prospects. Special research in drilling and well construction technology is needed to reduce the cost and increase the useful life of geothermal production facilities. EGS require innovative methods to attain sustained, commercial production rates while reducing the risk of seismic hazard. Integration of new power plants into existing power systems does not present a major challenge, but in some cases can require extending the transmission network.

Geothermal-electric projects have relatively high upfront investment costs but often have relatively low levelized costs of electricity (LCOE). Investment costs typically vary between USD_{2005} 1,800 and 5,200 per kW, but geothermal plants have low recurring 'fuel costs'. The LCOE of power plants using hydrothermal resources are often competitive in today's electricity markets, with a typical range from US cents_{2005} 4.9 to 9.2 per kWh considering only the range in investment costs provided above and medium values for other input parameters; the range in LCOE across a broader array of input parameters is US cents_{2005} 3.1 to 17 per kWh. These costs are expected to decrease by about 7% by 2020. There are no actual LCOE data for EGS power plants, as EGS plants remain in the demonstration phase, but estimates of EGS costs are higher than those for hydrothermal reservoirs. The cost of geothermal energy from EGS plants is also expected to decrease by 2020 and beyond, assuming improvements in drilling technologies and success in developing well-stimulation technology.

Current levelized costs of heat (LCOH) from direct uses of geothermal heat are generally competitive with market energy prices. Investment costs range from USD_{2005} 50 per kW_{th} (for uncovered pond heating) to USD_{2005} 3,940 per kW_{th} (for building heating). Low LCOHs for these technologies are possible because the inherent losses in heat-to-electricity conversion are avoided when geothermal energy is used for thermal applications.

Future geothermal deployment could meet more than 3% of global electricity demand and about 5% of the global demand for heat by 2050. Evidence suggests that geothermal supply could meet the upper range of projections derived from a review of about 120 energy and GHG reduction scenarios summarized in Chapter 10. With its natural thermal storage capacity, geothermal energy is especially suitable for supplying base-load power. By 2015, geothermal deployment is roughly estimated to generate 122 TWh_{e}/yr (0.44 EJ/yr) for electricity and 224 TWh_{th}/yr (0.8 EJ/yr) for heat applications. In the long term (by 2050), deployment projections based on extrapolations of long-term historical growth trends suggest that geothermal could produce 1,180 TWh_{e}/yr (~4.3 EJ/yr) for electricity and 2,100 TWh_{th}/yr (7.6 EJ/yr) for heat, with a few countries obtaining most of their primary energy needs (heating, cooling and electricity) from geothermal energy. Scenario analysis suggests that carbon policy is likely to be one of the main driving factors for future geothermal development, and under the most favourable climate policy scenario (<440 ppm atmospheric CO_2 concentration level in 2100) considered in the energy and GHG scenarios reviewed for this report, geothermal deployment could be even higher in the near and long term.

High-grade geothermal resources have restricted geographic distribution—both cost and technology barriers exist for the use of low-grade geothermal resources and EGS. High-grade geothermal resources are already economically competitive with market energy prices in many locations. However, public and private support for research along with favourable deployment policies (drilling subsidies, targeted grants for pre-competitive research and demonstration to reduce exploration risk and the cost of EGS development) may be needed to support the development of lower-grade hydrothermal resources as well as the demonstration and further commercialization of EGS and other geothermal resources. The effectiveness of these efforts may play a central role in establishing the magnitude of geothermal energy's contributions to long-term GHG emissions reductions.

4.1 Introduction

Geothermal resources consist of thermal energy from the Earth's interior stored in both rock and trapped steam or liquid water. As presented in this chapter, climate change has no major impacts on the effectiveness of geothermal energy utilization, but its widespread deployment could play a significant role in mitigating climate change by reducing greenhouse gas (GHG) emissions as an alternative for capacity addition and/or replacement of existing base load fossil fuel-fired power and heating plants.

Geothermal systems as they are currently exploited occur in a number of geological environments where the temperatures and depths of the reservoirs vary accordingly. Many high-temperature (>180°C) hydrothermal systems are associated with recent volcanic activity and are found near plate tectonic boundaries (subduction, rifting, spreading or transform faulting), or at crustal and mantle hot spot anomalies. Intermediate- (100 to 180°C) and low-temperature (<100°C) systems are also found in continental settings, where above-normal heat production through radioactive isotope decay increases terrestrial heat flow or where aquifers are charged by water heated through circulation along deeply penetrating fault zones. Under appropriate conditions, high-, intermediate- and low-temperature geothermal fields can be utilized for both power generation and the direct use of heat (Tester et al., 2005).

Geothermal resources can be classified as convective (hydrothermal) systems, conductive systems and deep aquifers. Hydrothermal systems include liquid- and vapour-dominated types. Conductive systems include hot rock and magma over a wide range of temperatures (Mock et al., 1997) (Figure 4.1). Deep aquifers contain circulating fluids in porous media or fracture zones at depths typically greater than 3 km, but lack a localized magmatic heat source. They are further subdivided into systems at hydrostatic pressure and systems at pressure higher than hydrostatic (geo-pressured). Enhanced or engineered geothermal system (EGS) technologies enable the utilization of low permeability and low porosity conductive (hot dry rock) and low productivity convective and aquifer systems by creating fluid connectivity through hydraulic stimulation and advanced well configurations. In general, the main types of geothermal systems are hydrothermal and EGS.

Resource utilization technologies for geothermal energy can be grouped under types for electrical power generation, for direct use of the heat, or for combined heat and power in cogeneration applications. Geothermal heat pump (GHP) technologies are a subset of direct use. Currently, the only commercially exploited geothermal systems for power generation and direct use are hydrothermal (of continental subtype). Table 4.1 summarizes the resources and utilization technologies.

Hydrothermal, convective systems are typically found in areas of magmatic intrusions, where temperatures above 1,000°C can occur at less than 10 km depth. Magma typically emits mineralized liquids and gases, which then mix with deeply circulating groundwater. Such systems can last hundreds of thousands of years, and the gradually cooling magmatic heat sources can be replenished periodically with fresh intrusions from a deeper magma chamber. Heat energy is also transferred by conduction, but convection is the most important process in magmatic systems.

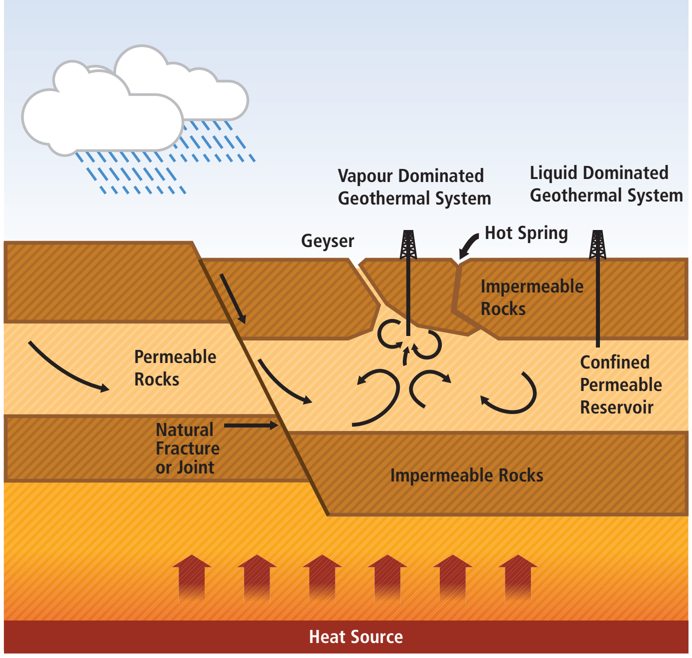

Figure 4.1a | Scheme showing convective (hydrothermal) resources. Adapted from Mock et al. (1997) and from US DOE publications.

Subsurface temperatures increase with depth and if hot rocks within drillable depth can be stimulated to improve permeability, using hydraulic fracturing, chemical or thermal stimulation methods, they form a potential EGS resource that can be used for power generation and direct heat applications. EGS resources include hot dry rock (HDR), hot fractured rock (HFR) and hot wet rock (HWR), among other terms. They occur in all geothermal environments, but are likely to be economic in geological settings where the thermal gradient is high enough to permit exploitation at depths of less than 5 km. In the future, given average geothermal gradients of 25 to 30°C/km, EGS resources at relatively high temperature (≥180°C) may be exploitable in broad areas at depths as shallow as 7 km, which is well within the range of existing drilling technology (~10 km depth). Geothermal resources of different types may occur at different depths below the same surface location. For example, fractured and water-saturated hot-rock EGS resources lie below deep-aquifer resources in the Australian Cooper Basin (Goldstein et al., 2009).

Direct use of geothermal energy has been practised at least since the Middle Palaeolithic when hot springs were used for ritual or routine bathing (Cataldi, 1999), and industrial utilization began in Italy by exploiting boric acid from the geothermal zone of Larderello, where in 1904 the first kilowatts of geothermal electric energy were generated and in 1913 the first 250-kW_e commercial geothermal power unit was installed (Burgassi, 1999). Larderello is still active today.

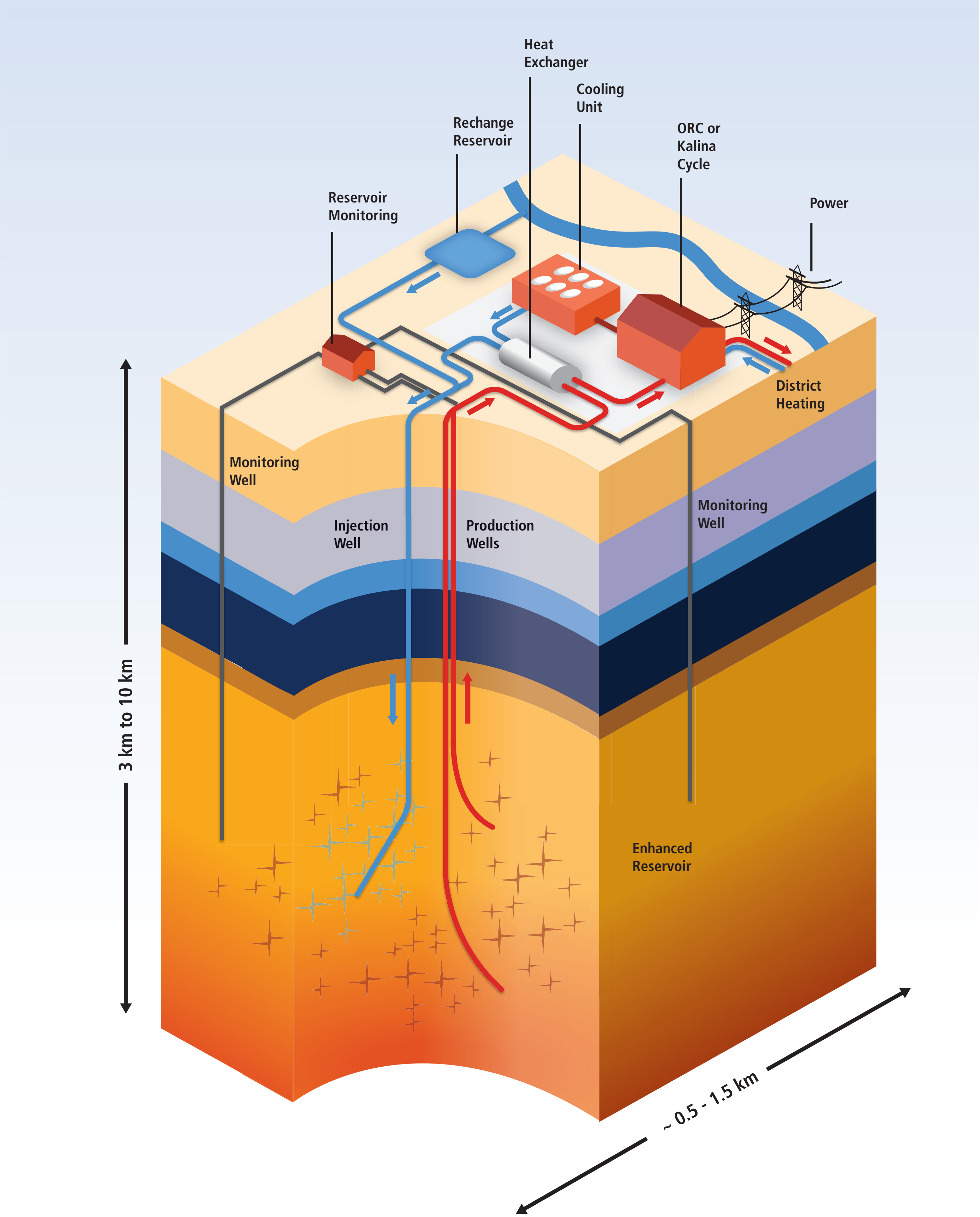

Figure 4.1b | Scheme showing conductive (EGS) resources. Adapted from Mock et al. (1997) and from US DOE publications.

Table 4.1 | Types of geothermal resources, temperatures and uses.

Type	In-situ fluids	Subtype	Temperature Range	Utilization	
				Current	Future
Convective systems (hydrothermal)	Yes	Continental	H, I & L	Power, direct use	
		Submarine	H	None	Power
Conductive systems	No	Shallow (<400 m)	L	Direct use (GHP)	
		Hot rock (EGS)	H, I	Prototypes	Power, direct use
		Magma bodies	H	None	Power, direct use
Deep aquifer systems	Yes	Hydrostatic aquifers	H, I & L	Direct use	Power, direct use
		Geo-pressured		Direct use	Power, direct use

Note: Temperature range: H: High (>180°C), I: Intermediate (100-180°C), L: Low (ambient to 100°C). EGS: Enhanced (or engineered) geothermal systems. GHP: Geothermal heat pumps.

Geothermal energy is classified as a renewable resource (see Chapter 1) because the tapped heat from an active reservoir is continuously restored by natural heat production, conduction and convection from surrounding hotter regions, and the extracted geothermal fluids are replenished by natural recharge and by injection of the depleted (cooled) fluids. Geothermal fields are typically operated at production rates that cause local declines in pressure and/or in temperature within the reservoir over the economic lifetime of the installed facilities. These cooler and lower-pressure zones are subsequently recharged from surrounding regions when extraction ceases.

There are many examples where for economical reasons high extraction rates from hydrothermal reservoirs have resulted in local fluid depletion that exceeded the rate of its recharge, but detailed modelling studies (Pritchett, 1998; Mégel and Rybach, 2000; O'Sullivan and Mannington, 2005) have shown that resource exploitation can be economically feasible in practical situations, and still be renewable on a time scale of the order of 100 years or less, when non-productive recovery periods are considered. Models predict that replenishment will occur in hydrothermal systems on time scales of the same order as the lifetime of the geothermal production cycle where the extraction rate is designed to be sustainable over a 20 to 30 year period (Axelsson et al., 2005, 2010).

This chapter includes a brief discussion of the theoretical potential of geothermal resources, the global and regional technical potential, and the possible impacts of climate change on the resource (Section 4.2), the current technology and applications (Section 4.3) and the expected technological developments (Section 4.6), the present market status (Section 4.4) and its probable future evolution (Section 4.8), environmental and social impacts (Section 4.5) and cost trends (Section 4.7) in using geothermal energy to contribute to reduced GHG emissions.

4.2 Resource Potential

The total thermal energy contained in the Earth is of the order of 12.6 x 10^{12} EJ and that of the crust of the order of 5.4 x 10^9 EJ to depths of up to 50 km (Dickson and Fanelli, 2003). The main sources of this energy are due to the heat flow from the Earth's core and mantle, and that generated by the continuous decay of radioactive isotopes in the crust itself. Heat is transferred from the interior towards the surface, mostly by conduction, at an average of 65 mW/m^2 on continents and 101 mW/m^2 through the ocean floor. The result is a global terrestrial heat flow rate of around 1,400 EJ/yr. Continents cover ~30% of the Earth's surface and their terrestrial heat flow has been estimated at 315 EJ/yr (Stefansson, 2005).

Stored thermal energy down to 3 km depth on continents was estimated to be 42.67 x 10^6 EJ by EPRI (1978), consisting of 34.14 x 10^6 EJ (80%) from hot dry rocks (or EGS resources) and 8.53 x 10^6 EJ (20%) from hydrothermal resources. Within 10 km depth, Rowley (1982) estimated the continental stored heat to be 403 x 10^6 EJ with no distinction between hot dry rock and hydrothermal resources, and Tester et al. (2005) estimated it to be 110.4 x 10^6 EJ from hot dry rocks and only 0.14 x 10^6 EJ from hydrothermal resources. A linear interpolation between the EPRI (1978) values for 3 km depth and the values from Rowley (1982) results in 139.5 x 10^6 EJ down to 5 km depth, while linear interpolation between the EPRI (1978) values and those from Tester et al. (2005) only for EGS resources results in 55.9 x 10^6 EJ down to 5 km depth (see second column of Table 4.2). Based on these estimates, the theoretical potential is clearly not a limiting factor for global geothermal deployment.

In practice geothermal plants can only utilize a portion of the stored thermal energy due to limitations in drilling technology and rock permeability. Commercial utilization to date has concentrated on areas in which geological conditions create convective hydrothermal reservoirs where drilling to depths up to 4 km can access fluids at temperatures of 180°C to more than 350°C.

4.2.1 Global technical potential

Regarding geothermal technical potentials,[1] one recent and comprehensive estimate for conventional hydrothermal resources in the world was presented by Stefansson (2005). For electric generation, he calculated the global geothermal technical potential for identified hydrothermal

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[1] Definition of technical potential is included in the Glossary (Annex I).

Table 4.2 | Global continental stored heat and EGS technical potentials for electricity.

Depth range (km)	Technically accessible stored heat from EGS		Estimated technical potential (electric) for EGS (EJ/yr)
	(10^6 EJ)	Source	
0–10	403	Rowley, 1982	1051.8
0–10	110.4	Tester et al., 2005	288.1
0–5	139.5	Interpolation between values from Rowley (1982) and EPRI (1978)	364.2
0–5	55.9	Interpolation between values from Tester et al. (2005) and EPRI (1978)	145.9
0–3	34.1	EPRI, 1978	89.1

resources as 200 GW_e (equivalent to 5.7 EJ/yr with a capacity factor (CF)[2] of 90%), with a lower limit of 50 GW_e (1.4 EJ/yr). He assumed that unidentified, hidden resources are 5 to 10 times more abundant than the identified ones and then estimated the upper limit for the worldwide geothermal technical potential as between 1,000 and 2,000 GW_e (28.4 and 56.8 EJ/yr at 90% CF), with a mean value of 1,500 GW_e (~42.6 EJ/yr). Mainly based on those numbers, Krewitt et al. (2009) estimated geothermal technical potential for 2050 at 45 EJ/yr, largely considering only hydrothermal resources.

No similar recent calculation of global technical potential for conductive (EGS) geothermal resources has been published, although the study by EPRI (1978) included some estimates as did others (Armstead and Tester, 1987). Estimating the technical potential of EGS is complicated due to the lack of commercial experience to date. EGS field demonstrations must achieve sufficient reservoir productivity and lifetime to prove both the viability of stimulation methods and the scalability of the technology. Once these features have been demonstrated at several locations, it will be possible to develop better assessments of technical potential, and it is possible that EGS will become a leading geothermal option for electricity and direct use globally because of its widespread availability and lower exploration risk relative to hydrothermal systems.

More recently, Tester et al. (2006; see their Table 1.1) estimated the accessible conductive resources in the USA (excluding Alaska, Hawaii and Yellowstone National Park) and calculated that the stored heat at depths less than 10 km is 13.4 x 10^6 EJ (in conduction-dominated EGS of crystalline basement and sedimentary rock formations). Assuming that 2% of the heat is recoverable and that average temperatures drop 10°C below initial conditions during exploitation, and taking into account all losses in the conversion of recoverable heat into electricity over a lifespan of 30 years, electrical generating capacity from EGS in the USA was estimated at 1,249 GW_e, corresponding to 35.4 EJ/yr of electricity at a CF of 90% (Tester et al., 2006; see their Table 3.3). Based on the same assumptions for the USA,[3] estimates for the global technical potential of EGS-based energy supply can be derived from estimates of the heat stored in the Earth's crust that is both accessible and recoverable (see Table 4.2, fourth column).

Therefore, the global technical potential of geothermal resources for electricity generation can be estimated as the sum of the upper (56.8 EJ/yr) and lower (28.4 EJ/yr) of Stefansson's estimate for hydrothermal resources (identified and hidden) and the EGS technical potentials of Table 4.2 (fourth column), obtaining a lower value of 117.5 EJ/yr (down to 3 km depth) to a maximum of 1,108.6 EJ/yr down to 10 km depth (Figure 4.2). It is important to note that the heat extracted to achieve these technical potentials can be fully or partially replenished over the long term by the continental terrestrial heat flow of 315 EJ/yr (Stefansson, 2005) at an average flux of 65 mW/m^2. Although hydrothermal resources are only a negligible fraction of total theoretical potential given in Tester et al. (2005), their contribution to technical potential might be considerably higher than implied by the conversion from theoretical potential data to technical potential data. This is the rationale for considering the Rowley (1982) estimate for EGS technical potential only and adding the estimate for hydrothermal technical potential from Stefansson (2005).

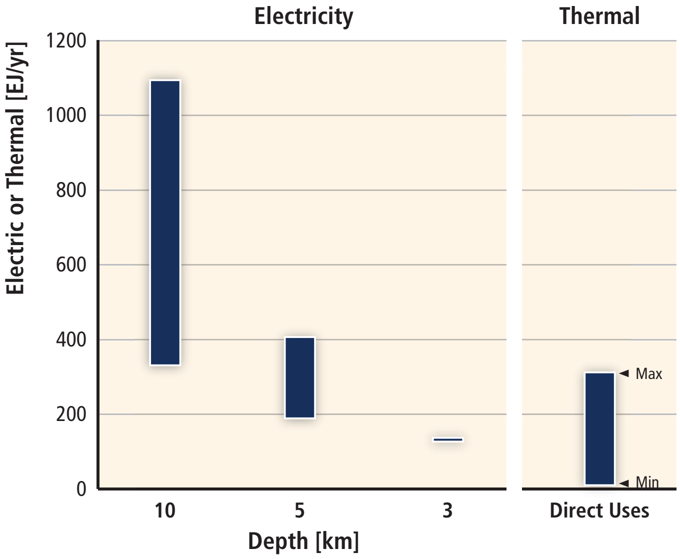

Figure 4.2 | Geothermal technical potentials for electricity and direct uses (heat). Direct uses do not require development to depths greater than approximately 3 km (Prepared with data from Tables 4.2 and 4.3).

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[2] Capacity factor (CF) definition is included in the Glossary (Annex I).

[3] 1 x 10^6 EJ stored heat equals approximately 2.61 EJ/yr of technical potential for electricity at a 90% CF for 30 years.

For hydrothermal submarine vents, an estimate of >100 GW_e (>2.8 EJ/yr) offshore technical potential has been made (Hiriart et al., 2010). This is based on the 3,900 km of ocean ridges confirmed as having hydrothermal vents,[4] with the assumption that only 1% could be developed for electricity production using a recovery factor of 4%. This assumption is based on capturing part of the heat from the flowing submarine vent without any drilling, but considering offshore drilling, a technical potential of 1,000 GW_e (28.4 EJ/yr) from hydrothermal vents may be possible. However, the technical potential of these resources is still highly uncertain, and is therefore not included in Figure 4.2.

For geothermal direct uses, Stefansson (2005) estimated 4,400 GW_{th} from hydrothermal systems as the world geothermal technical potential from resources <130°C, with a minimum of 1,000 GW_{th} and a maximum, considering hidden resources, of 22,000 to 44,000 GW_{th}. Taking a worldwide average CF for direct uses of 30%, the geothermal technical potential for heat can be estimated to be 41.6 EJ/yr with a lower value of 9.5 EJ/yr and an upper value of 312.2 EJ/yr (equivalent to 33,000 GW_{th} of installed capacity) (Figure 4.2). Krewitt et al. (2009) used the same values estimated by Stefansson (2005) in GW_{th}, but a CF of 100% was assumed when converted into EJ/r, leading to an average upper limit of 33,000 GW_{th}, or 1,040 EJ/yr.

In comparison, the IPCC Fourth Assessment Report (AR4) estimated an available energy resource for geothermal (including potential reserves) of 5,000 EJ/yr (Sims et al., 2007; see their Table 4.2). This amount cannot be properly considered as technical potential and looks overestimated compared with the geothermal technical potentials presented in Figure 4.2. It is important to note, however, that technical potentials tend to increase as technology progresses and overcomes some of the technical constraints of accessing theoretically available resources.

4.2.2 Regional technical potential

The assessed geothermal technical potentials included in Table 4.2 and Figure 4.2 are presented on a regional basis in Table 4.3. The regional breakdown in Table 4.3 is based on the methodology applied by EPRI (1978) to estimate theoretical geothermal potentials for each country, and then countries were grouped into the IEA regions. Thus, the present disaggregation of the global technical potentials is based on factors accounting for regional variations in the average geothermal gradient and the presence of either a diffuse geothermal anomaly or a high-temperature region, associated with volcanism or plate boundaries as estimated by EPRI (1978). Applying these factors to the global technical potentials listed in Table 4.2 gives the values stated in Table 4.3. The separation into electric and thermal (direct uses) technical potentials is somewhat arbitrary in that most higher-temperature resources could be used for either or both in combined heat and power applications depending on local market conditions and the distance between geothermal facilities and the consuming centres. Technical potentials for direct uses include only identified and hidden hydrothermal systems as estimated by Stefansson (2005), and are presented independently from depth since direct uses of geothermal energy usually do not require developments over 3 km in depth.

4.2.3 Possible impact of climate change on resource potential

Geothermal resources are not dependent on climate conditions and climate change is not expected to have a significant impact on the geothermal resource potential. The operation of geothermal heat pumps will not be affected significantly by a gradual change in ambient temperature associated with climate change, but in some power plants it may affect the ability to reject heat efficiently and perhaps adversely impact power generation (Hiriart, 2007). On a local basis, the effect of climate change on rainfall distribution may have a long-term effect on the recharge to specific groundwater aquifers, which in turn may affect discharges from some hot springs, and could have an effect on water levels in shallow geothermally heated aquifers. Also, the availability of cooling water from surface water supplies could be affected by changes in rainfall patterns, and this may require air-cooled power plant condensers (Saadat et al., 2010). However, each of these effects, if they occur, can be remedied by adjustments to the technology, generally for an incremental cost. Regarding future EGS projects, water management may impact the development of EGS particularly in water-deficient regions, where availability is an issue.

4.3 Technology and applications

For the last 100 years, geothermal energy has provided safe, reliable, environmentally benign energy used in a sustainable manner to generate electric power and provide direct heating services from hydrothermal-type resources, using mature technologies. Geothermal typically provides base-load generation, but it has also been used for meeting peak demand. Today's technologies for using hydrothermal resources have demonstrated high average CFs (up to 90% in newer plants, see DiPippo (2008)) in electric generation with low GHG emissions. However, technologies for EGS-type geothermal resources are still in demonstration (see Section 4.3.4).

Geothermal energy is currently extracted using wells or other means that produce hot fluids from: (a) hydrothermal reservoirs with naturally high permeability; or (b) EGS-type reservoirs with artificial fluid pathways. Production wells discharge hot water and/or steam. In high-temperature hydrothermal reservoirs, as pressure drops a fraction of the liquid water component 'flashes' to steam. Separated steam is piped to a turbine to generate electricity and the remaining hot water may be flashed again at lower pressures (and temperatures) to obtain more steam. The

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[4] Some discharge thermal energy of up to 60 MW_{th} (Lupton, 1995) but there are other submarine vents, such as the one known as 'Rainbow', with an estimated output of 1 to 5 GW_{th} (German et al., 1996).

Table 4.3 | Geothermal technical potentials on continents for the International Energy Agency (IEA) regions (prepared with data from EPRI (1978) and global technical potentials described in section 4.2.1).

REGION*	Electric technical potential in EJ/yr at depths to:						Technical potentials (EJ/yr) for direct uses	
	3 km		5 km		10 km			
	Lower	Upper	Lower	Upper	Lower	Upper	Lower	Upper
OECD North America	25.6	31.8	38.0	91.9	69.3	241.9	2.1	68.1
Latin America	15.5	19.3	23.0	55.7	42.0	146.5	1.3	41.3
OECD Europe	6.0	7.5	8.9	21.6	16.3	56.8	0.5	16.0
Africa	16.8	20.8	24.8	60.0	45.3	158.0	1.4	44.5
Transition Economies	19.5	24.3	29.0	70.0	52.8	184.4	1.6	51.9
Middle East	3.7	4.6	5.5	13.4	10.1	35.2	0.3	9.9
Developing Asia	22.9	28.5	34.2	82.4	62.1	216.9	1.8	61.0
OECD Pacific	7.3	9.1	10.8	26.2	19.7	68.9	0.6	19.4
Total	**117.5**	**145.9**	**174.3**	**421.0**	**317.5**	**1108.6**	**9.5**	**312.2**

Note: *For regional definitions and country groupings see Annex II.

remaining brine is sent back to the reservoir through injection wells or first cascaded to a direct-use system before injecting. A few reservoirs, such as The Geysers in the USA, Larderello in Italy, Matsukawa in Japan, and some Indonesian fields, produce vapour as 'dry' steam (i.e., pure steam, with no liquid water) that can be sent directly to the turbine. In these cases, control of steam flow to meet power demand fluctuations is easier than in the case of two-phase production, where continuous up-flow in the well bore is required to avoid gravity collapse of the liquid phase. Hot water produced from intermediate-temperature hydrothermal or EGS reservoirs is commonly utilized by extracting heat through a heat exchanger for generating power in a binary cycle, or in direct use applications. Recovered fluids are also injected back into the reservoir (Armstead and Tester, 1987; Dickson and Fanelli, 2003; DiPippo, 2008).

Key technologies for exploration and drilling, reservoir management and stimulation, and energy recovery and conversion are described below.

4.3.1 Exploration and drilling

Since geothermal resources are underground, exploration methods (including geological, geochemical and geophysical surveys) have been developed to locate and assess them. The objectives of geothermal exploration are to identify and rank prospective geothermal reservoirs prior to drilling, and to provide methods of characterizing reservoirs (including the properties of the fluids) that enable estimates of geothermal reservoir performance and lifetime. Exploration of a prospective geothermal reservoir involves estimating its location, lateral extent and depth with geophysical methods and then drilling exploration wells to test its properties, minimizing the risk. All these exploration methods can be improved (see Section 4.6.1).

Today, geothermal wells are drilled over a range of depths down to 5 km using methods similar to those used for oil and gas. Advances in drilling technology have enabled high-temperature operation and provide directional drilling capability. Typically, wells are deviated from vertical to about 30 to 50° inclination from a 'kick-off point' at depths between 200 and 2,000 m. Several wells can be drilled from the same pad, heading in different directions to access larger resource volumes, targeting permeable structures and minimizing the surface impact. Current geothermal drilling methods are presented in more detail in Chapter 6 of Tester et al. (2006). For other geothermal applications such as GHP and direct uses, smaller and more flexible rigs have been developed to overcome accessibility limitations.

4.3.2 Reservoir engineering

Reservoir engineering efforts are focused on two main goals: (a) to determine the volume of geothermal resource and the optimal plant size based on a number of conditions such as sustainable use of the available resource; and (b) to ensure safe and efficient operation during the lifetime of the project. The modern method of estimating reserves and sizing power plants is to apply reservoir simulation technology. First a conceptual model is built, using available data, and is then translated into a numerical representation, and calibrated to the unexploited, initial thermodynamic state of the reservoir (Grant et al., 1982). Future behaviour is forecast under selected load conditions using a heat and mass transfer algorithm (e.g., TOUGH2)[5], and the optimum plant size is selected.

Injection management is an important aspect of geothermal development, where the use of isotopic and chemical tracers is common. Cooling of production zones by injected water that has had insufficient contact with hot reservoir rock can result in production declines. In some circumstances, placement of wells could also aim to enhance deep hot recharge through production pressure drawdown, while suppressing shallow inflows of peripheral cool water through injection pressure increases.

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[5] More information is available on the TOUGH2 website: esd.lbl.gov/TOUGH2/.

Given sufficient, accurate calibration with field data, geothermal reservoir evolution can be adequately modelled and proactively managed. Field operators monitor the chemical and thermodynamic properties of geothermal fluids, and map their flow and movement in the reservoir. This information, combined with other geophysical data, is fed back to recalibrate models for better predictions of future production (Grant et al., 1982).

4.3.3 Power plants

The basic types of geothermal power plants in use today are steam condensing turbines and binary cycle units. Steam condensing turbines[6] can be used in flash or dry-steam plants operating at sites with intermediate- and high-temperature resources (≥150°C). The power plant generally consists of pipelines, water-steam separators, vaporizers, de-misters, heat exchangers, turbine generators, cooling systems, and a step-up transformer for transmission into the electrical grid (see Figure 4.3, top). The power unit size usually ranges from 20 to 110 MW_e (DiPippo, 2008), and may utilize a multiple flash system, flashing the fluid in a series of vessels at successively lower pressures, to maximize the extraction of energy from the geothermal fluid. The only difference between a flash plant and a dry-steam plant is that the latter does not require brine separation, resulting in a simpler and cheaper design.

Binary-cycle plants, typically organic Rankine cycle (ORC) units, are commonly installed to extract heat from low- and intermediate-temperature geothermal fluids (generally from 70 to 170°C), from hydrothermal- and EGS-type reservoirs. Binary plants (Figure 4.3, bottom) are more complex than condensing ones since the geothermal fluid (water, steam or both) passes through a heat exchanger heating another working fluid. This working fluid, such as isopentane or isobutene with a low boiling point, vaporizes, drives a turbine, and then is air cooled or condensed with water. Binary plants are often constructed as linked modular units of a few MW_e in capacity.

There are also combined or hybrid plants, which comprise two or more of the above basic types, such as using a binary plant as a bottoming cycle with a flash steam plant, to improve versatility, increase overall thermal efficiency, improve load-following capability, and efficiently cover a wide resource temperature range.

Cogeneration plants, or combined or cascaded heat and power plants (CHP), produce both electricity and hot water for direct use. Relatively small industries and communities of a few thousand people provide sufficient markets for CHP applications. Iceland has three geothermal cogeneration plants with a combined capacity of 580 MW_{th} in operation (Hjartarson and Einarsson, 2010). At the Oregon Institute of Technology, a CHP plant provides most of the electricity needs and all the heat demand (Lund and Boyd, 2009).

4.3.4 Enhanced Geothermal Systems (EGS)

EGS require stimulation of subsurface regions where temperatures are high enough for effective utilization. A reservoir consisting of a fracture network is created or enhanced to provide well-connected fluid pathways between injection and production wells (see Figure 4.1). Heat is extracted by circulating water through the reservoir in a closed loop and can be used for power generation with binary-cycle plants and for industrial or residential heating (Armstead and Tester, 1987; Tester et al., 2006).

Knowledge of temperature at drillable depth is a prerequisite for site selection for any EGS development. The thermo-mechanical signature of the lithosphere and crust are equally important as they provide critical constraints affecting the crustal stress field, heat flow and temperature gradients. Recently developed analogue and numerical models provide insights useful for geothermal exploration and production, including improved understanding of fundamental mechanisms for predicting crustal stress and basin and basement heat flow (Cloetingh et al., 2010).

EGS projects are currently at a demonstration and experimental stage in a number of countries. The key challenge for EGS is to stimulate and maintain multiple reservoirs with sufficient volumes to sustain long-term production at acceptable rates, and flow impedances, while managing water losses and risk from induced seismicity (Tester et al., 2006).

4.3.5 Direct use

Direct use provides heating and cooling for buildings[7] including district heating, fish ponds, greenhouses, bathing, wellness and swimming pools, water purification/desalination, and industrial and process heat for agricultural products and mineral extraction and drying.

For space heating, two basic types of systems are used: open or closed loop. Open loop (single pipe) systems utilize directly the geothermal water extracted from a well to circulate through radiators (Figure 4.4, top). Closed loop (double pipe) systems use heat exchangers to transfer heat from the geothermal water to a closed loop that circulates heated freshwater through the radiators (Figure 4.4, bottom). This system is commonly used because of the chemical composition of the geothermal water. In both cases the spent geothermal water is disposed of into injection wells and a conventional backup boiler may be provided to meet peak demand.

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[6] A condensing turbine will expand steam to below atmospheric pressure to maximize power production. Vacuum conditions are usually maintained by a direct contact condenser. Back-pressure turbines, much less common and less efficient than condensing turbines, let steam down to atmospheric pressure and avoid the need for condensers and cooling towers.

[7] Space and water heating are significant parts of the energy budget in large parts of the world. In Europe, 30% of energy use is for space and water heating alone, representing 75% of total building energy use (Lund et al., 2010a).

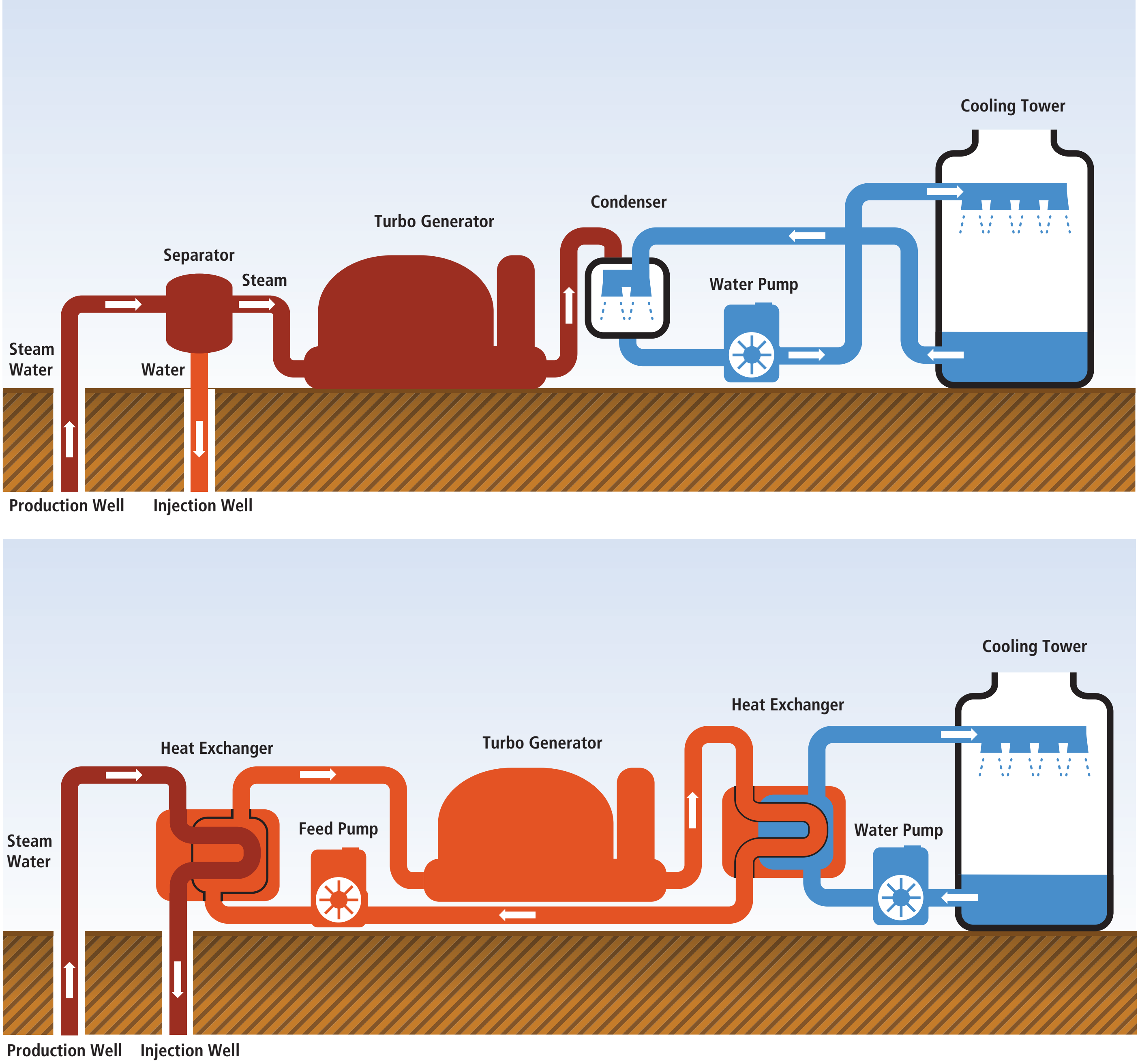

Figure 4.3 | Schematic diagram of a geothermal condensing steam power plant (top) and a binary-cycle power plant (bottom) (adapted from Dickson and Fanelli (2003)).

Transmission pipelines consist mostly of steel insulated by rock wool (surface pipes) or polyurethane (subsurface). However, several small villages and farming communities have successfully used plastic pipes (polybutylene) with polyurethane insulation, as transmission pipes. The temperature drop is insignificant in large-diameter pipes with a high flow rate, as observed in Iceland where geothermal water is transported up to 63 km from the geothermal fields to towns.

Although it is debatable whether geothermal heat pumps, also called ground source heat pumps (GHP), are a 'true' application of geothermal energy or whether they are partially using stored solar energy, in this chapter they are treated as a form of direct geothermal use. GHP technology is based on the relatively constant ground or groundwater temperature ranging from 4°C to 30°C to provide space heating, cooling and domestic hot water for all types of buildings. Extracting energy during heating periods cools the ground locally. This effect can be minimized by dimensioning the number and depth of probes in order to avoid harmful impacts on the ground. These impacts are also reduced by storing heat underground during cooling periods in the summer months.

There are two main types of GHP systems: closed loop and open loop. In ground-coupled systems a closed loop of plastic pipe is placed into

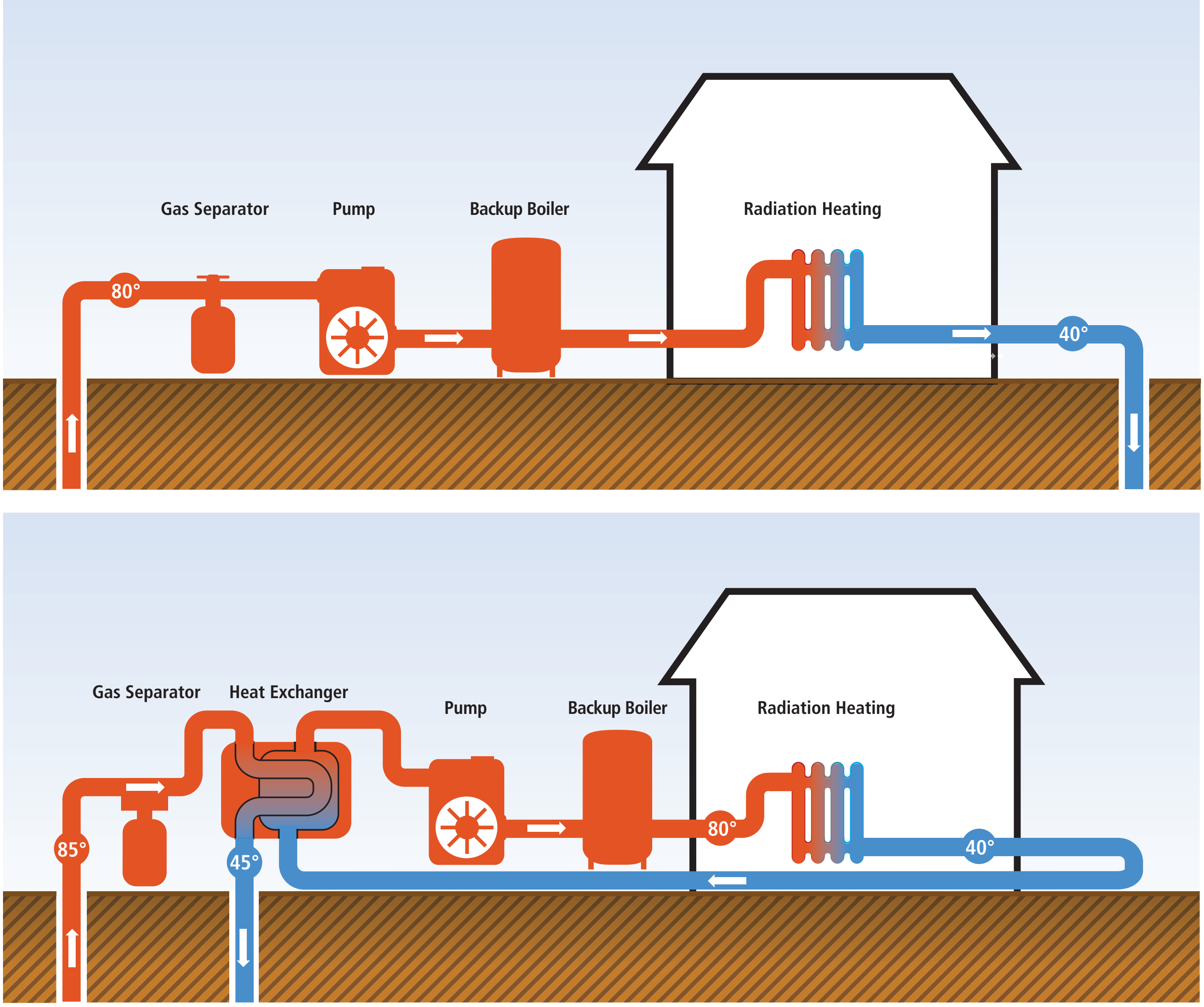

Figure 4.4 | Two main types of district heating systems: top, open loop (single pipe system), bottom, closed loop (double pipe system) (adapted from Dickson and Fanelli, (2003)).

the ground, either horizontally at 1 to 2 m depth or vertically in a borehole down to 50 to 250 m depth. A water-antifreeze solution is circulated through the pipe. Heat is collected from the ground in the winter and rejected to the ground in the summer. An open loop system uses groundwater or lake water directly as a heat source in a heat exchanger and then discharges it into another well or into the same water reservoir (Lund et al., 2003).

Heat pumps operate similarly to vapour compression refrigeration units with heat rejected in the condenser used for heating or extracted in the evaporator used for cooling. GHP efficiency is described by a coefficient of performance (COP) that scales the heating or cooling output to the electrical energy input, and typically lies between 3 and 4 (Lund et al., 2003; Rybach, 2005). The seasonal performance factor (SPF) provides a metric of the overall annual efficiency. It is the ratio of useful heat to the consumed driving energy (both in kWh/yr), and it is slightly lower than the COP.

4.4 Global and regional status of market and industry development

Electricity has been generated commercially by geothermal steam since 1913. Currently, the geothermal industry has a wide range of participants, including major energy companies, private and public utilities, equipment manufacturers and suppliers, field developers and drilling companies. The geothermal-electric market appears to be accelerating compared to previous years, as indicated by the increase in installed and planned capacity (Bertani, 2010; Holm et al., 2010).

4.4.1 Status of geothermal electricity from conventional geothermal resources

In 2009, electricity was being produced from conventional (hydrothermal) geothermal resources in 24 countries with an installed capacity of 10.7 GW$_{e}$ (Figure 4.5), with an annual increase of 405 MW (3.9%) over the previous year (Bertani, 2010, see his Table X). The worldwide use of geothermal energy for power generation was 67.2 TWh/yr (0.24 EJ/yr)[8] in 2008 (Bertani, 2010) with a worldwide CF of 74.5% (see also Table 4.7). Many developing countries are among the top 15 in geothermal electricity production.

Conventional geothermal resources currently used to produce electricity are either high-temperature systems (>180°C), using steam power cycles (either flash or dry steam driving condensing turbines), or low to intermediate temperature (<180°C) using binary-cycle power plants. Around 11% of the installed capacity in the world in 2009 was composed of binary plants (Bertani, 2010).

In 2009, the world's top geothermal producer was the USA with almost 29% of the global installed capacity (3,094 MW$_{e}$; Figure 4.5). The US geothermal industry is currently expanding due to state Renewable Portfolio Standards (RPS) and various federal subsidies and tax incentives (Holm et al., 2010). US geothermal activity is concentrated in a few western states, and only a fraction of the geothermal technical potential has been developed so far.

Outside of the USA, about 29% of the global installed geothermal capacity in 2009 was located in the Philippines and Indonesia. Mexico, Italy, Japan, Iceland and New Zealand together account for one-third of the global installed geothermal capacity. Although some of these markets have seen relatively limited growth over the past few years, others

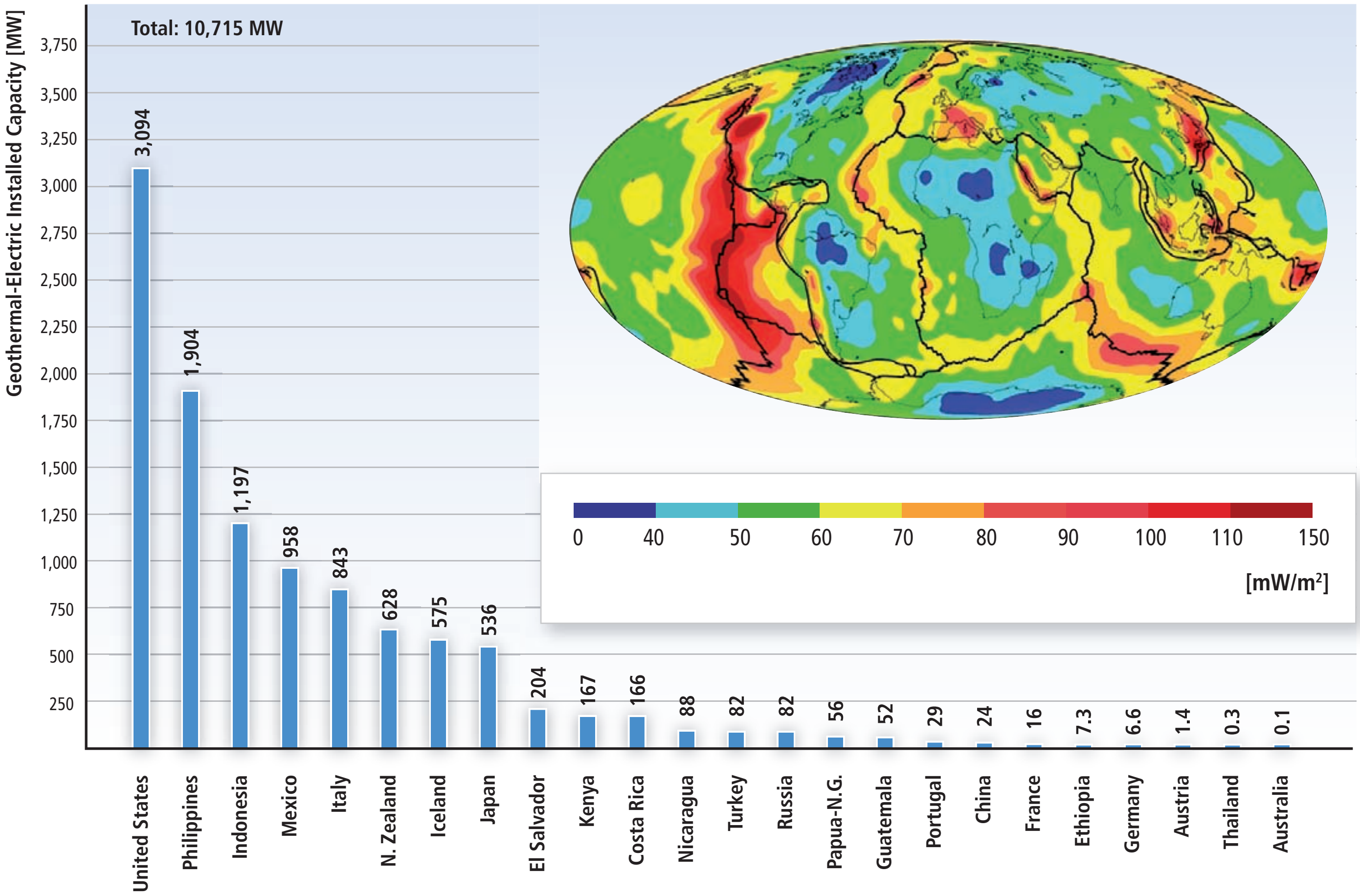

Figure 4.5 | Geothermal-electric installed capacity by country in 2009. Inset figure shows worldwide average heat flow in mW/m² and tectonic plates boundaries (figure from Hamza et al. (2008), used with kind permission from Springer Science+Business Media B.V.; data from Bertani (2010)).

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[8] Based on IEA data presented in Chapter 1, electricity production from geothermal energy in 2008 equaled 65 TWh/yr.

such as Iceland and New Zealand doubled the installed capacity from 2005 to 2009 (IEA-GIA, 2009). Moreover, attention is turning to new markets such as Chile, Germany and Australia.

The majority of existing geothermal assets are operated by state-owned utilities or independent power producers. Currently, more than 30 companies globally have an ownership stake in at least one geothermal field. Altogether, the top 20 owners of geothermal capacity control approximately 90% of the installed global market (Bertani, 2010).

At the end of 2008, geothermal electricity contributed only about 0.3% of the total worldwide electric generation. However, 6 of the 24 countries shown in Figure 4.5 (El Salvador, Kenya, Philippines, Iceland, Costa Rica and New Zealand) obtained more than 10% of their national electricity production from high-temperature geothermal resources (Bromley et al., 2010).

Worldwide evolution of geothermal power and geothermal direct uses during the last 40 years is presented in Table 4.4, including the annual average rate of growth over each period. The average annual growth of geothermal-electric installed capacity over the last 40 years is 7%, and for geothermal direct uses (heat applications) is 11% over the last 35 years.

Table 4.4 | Average annual growth rate in geothermal power capacity and direct uses (including GHP) in the last 40 years (prepared with data from Lund et al., 2005, 2010a; Fridleifsson and Ragnarsson, 2007; Gawell and Greenberg, 2007; Bertani, 2010).

Year	Electric capacity		Direct uses capacity	
	MW_e	%	MW_{th}	%
1970	720	—	N/A	—
1975	1,180	10.4	1,300	—
1980	2,110	12.3	1,950	8.5
1985	4,764	17.7	7,072	29.4
1990	5,834	4.1	8,064	2.7
1995	6,833	3.2	8,664	1.4
2000	7,972	3.1	15,200	11.9
2005	8,933	2.3	27,825	12.9
2010*	10,715	3.7	50,583	12.7
Total annual average:		**7.0**		**11.0**

Notes:

%: Average annual growth in percent over the period.
N/A: Reliable data not available.
*End of 2009.

4.4.2 Status of EGS

While there are no commercial-scale operating EGS plants, a number of demonstrations are active in Europe, the USA and Australia. In the latter, by 2009, 50 companies held about 400 geothermal exploration licences to develop EGS (AL-AGEA, 2009) with investments of USD_{2005} 260 million and government grants of USD_{2005} 146 million (Goldstein et al., 2009). In France, the EU project 'EGS Pilot Plant' at Soultz-sous-Forêts started in 1987 and has recently commissioned the first power plant (1.5 MW_e) to utilize the enhanced fracture permeability at 200°C. In Landau, Germany, a 2.5 to 2.9 MW_e EGS plant went into operation in late 2007 (Hettkamp et al., 2010). Deep sedimentary aquifers are being tapped at the geothermal test site in Groß Schönebeck, Germany, using two research wells (Huenges et al., 2009). These demonstration prototypes have provided data on the performance of the EGS concepts subject to real field conditions. Nonetheless, sustained multiyear commitments to field-scale demonstrations in different geologic settings are still needed to reduce technical and economic risks.

The USA has recently increased support for EGS research, development and demonstration as part of a revived national geothermal program. Currently the main short-term goals for the US program are to demonstrate commercial viability of EGS and upscale to several tens of megawatts (Holm et al., 2010). A US commitment to multiyear EGS demonstrations covering a range of resource grades is less certain.

The availability of water, other lower-cost renewable resources, transmission and distribution infrastructure, and most importantly project financing, will play major roles in regional growth trends of EGS projects (Tester et al., 2006).

4.4.3 Status of direct uses of geothermal resources

The world installed capacity of direct-use geothermal energy in 2009 was estimated at 50.6 GW_{th} (Table 4.4), with a total thermal energy usage of about 121.7 TWh_{th}/yr (0.44 EJ/yr) in 2008, distributed in 78 countries, with an annual average CF of 27.5% (Lund et al., 2010a). Another source (REN21, 2010) estimates geothermal direct use at 60 GW_{th} as of the end of 2009.

Direct heat supply temperatures are typically close to actual process temperatures in district heating systems that range from approximately 60°C to 120°C. In 2009 the main types (and relative percentages) of direct applications in annual energy use were: space heating of buildings[9] (63%), bathing and balneology (25%), horticulture (greenhouses and soil heating) (5%), industrial process heat and agricultural drying (3%), aquaculture (fish farming) (3%) and snow melting (1%) (Lund et al., 2010a).

When the resource temperature is too low for other direct uses, it is possible to use GHP. GHP contributed 70% (35.2 GW_{th}) of the worldwide installed geothermal heating capacity in 2009, and has been the fastest growing form of all geothermal direct use since 1995 (Rybach, 2005; Lund et al., 2010a).

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[9] China is the world's largest user of geothermal heat for space heating (Lund et al., 2010a).

Bathing, swimming and balneology are globally widespread. In addition to the thermal energy, the chemicals dissolved in the geothermal fluid are used for treating various skin and health diseases. Greenhouses heated by geothermal energy and heating soil in outdoor agricultural fields have been developed in several countries. A variety of industrial processes utilize heat applications, including drying of forest products, food and minerals industries as in the USA, Iceland and New Zealand. Other applications are process heating, evaporation, distillation, sterilization, washing, and CO_2 and salt extraction. Aquaculture using geothermal heat allows better control of pond temperatures, with tilapia, salmon and trout the most common fish raised. Low-temperature geothermal water is used in some colder climate countries for snow melting or de-icing. City streets, sidewalks and parking lots are equipped with buried piping systems carrying hot geothermal water (Lund et al., 2005, 2010a).

Geothermal direct uses have experienced a significant global increase in the last 15 years (Table 4.4) after a period of stagnation (1985 to 1995), mainly due to the increasing costs of fossil fuels for heating and cooling and the need to replace them with renewable sources. The technical potential of direct-use applications for heating and cooling buildings is still largely unrealized (Lund et al., 2010a).

4.4.4 Impact of policies[10]

For geothermal to reach its full capacity in climate change mitigation it is necessary to address the following technical and non technical barriers (Wonstolen, 1980; Mock et al., 1997; Imolauer et al., 2010).

Technical barriers. Distributions of potential geothermal resources vary from being almost site-independent (for GHP technologies and EGS) to being much more site-specific (for hydrothermal sources). The distance between electricity markets or centres of heat demand and geothermal resources, as well as the availability of transmission capacity, can be a significant factor in the economics of power generation and direct use.

Non-technical barriers.

- Information and awareness barriers. Lack of clarity in understanding geothermal energy is often a barrier, which could be overcome by dissemination of information on reliable and efficient geothermal technologies to enhance governmental and public knowledge. On the other hand, for deep geothermal drilling and reservoir management, skilled companies and well-trained personnel are currently concentrated in a few countries. For GHP installation and district heating, there is also a correlation between local availability and awareness of service companies and technology uptake. This constraint could be overcome by an improved global infrastructure of services and education programs (geothermal engineering programs) for an expanding workforce to replace retiring staff.

- Market failures and economic barriers, due to un-priced or underpriced environmental impacts of energy use, and poor availability of capital risk insurance.

- Institutional barriers due in many countries to the lack of specific laws governing geothermal resources, which are commonly considered as mining or water resources.

Policies set to drive uptake of geothermal energy work better if local demand and risk factors are taken into account (Rybach, 2010). For example, small domestic heat customers can be satisfied using GHP technologies, which require relatively small budgets. For other countries, district heating systems and industrial heat applications are more efficient and provide greater mitigation of CO_2 emissions, but these markets typically require larger-scale investments and a different policy framework.

Policies that support improved applied research and development would benefit all geothermal technologies, but especially emerging technologies such as EGS. Specific incentives for geothermal development can include fiscal incentives, public finance and regulation policies such as targeted grants for pre-competitive research and demonstration, subsidies, guarantees, tax write-offs to cover the commercial upfront exploration costs, including the higher-risk initial drilling costs, feed-in tariffs and additional measures like portfolio standards (Rybach, 2010). Feed-in tariffs (FITs, see Section 11.5.4.3) with defined geothermal pricing have been very successful in attracting commercial investment in some European countries such as Germany, Switzerland, Belgium, Austria, Spain and Greece, among others (Rybach, 2010). Direct subsidies for new building heating, refurbishment of existing buildings with GHP, and for district heating systems may be also applicable.

Experience has shown that the relative success of geothermal development in particular countries is closely linked to their government's policies, regulations, incentives and initiatives. Successful policies have taken into account the benefits of geothermal energy, such as its independence from weather conditions and its suitability for base-load power. Another important policy consideration is the opportunity to support the price of geothermal kWh (both power and direct heating and cooling) through the United Nations' Clean Development Mechanism (CDM) program. A recent example is the Darajat III geothermal power plant, developed by a private company in Indonesia in 2007, and registered with the CDM. The plant currently generates about 650,000 carbon credits (or certified emission reductions, CER) per year, thus reducing the lifecycle cost of geothermal energy by about 2 to 4% (Newell and Mingst, 2009).

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[10] Non-technology-specific policy issues are covered in Chapter 11 of this report.

4.5 Environmental and social impacts[11]

In general, negative environmental impacts associated with geothermal energy utilization are minor. Hot fluid production can emit varying quantities of GHGs, which are usually small. These originate from naturally sourced CO_2 fluxes that would eventually be released into the atmosphere through natural surface venting. The exploitation of geothermal energy does not ultimately create any additional CO_2 from the subsurface, since there is no combustion process, though the rate of natural emissions can be altered by geothermal production depending on the plant configuration.

Water is not a limiting factor for geothermal power generation, since geothermal fluids are usually brines (i.e., not competing with other uses). Flash power plants do not consume potable water for cooling and yield condensed water that can, with proper treatment, be used for agricultural and industrial purposes. Binary power plants can minimize their water use with air cooling.

Potential adverse effects from disposal of geothermal fluids and gases, induced seismicity and ground subsidence can be minimized by sound practices. Good practice can also optimize water and land use, improve long-term sustainability of production and protect natural thermal features that are valued by the community. The following sections address these issues in more detail.

4.5.1 Direct greenhouse gas emissions

The main GHG emitted by geothermal operations is CO_2. Geothermal fluids contain minerals leached from the reservoir rock and variable quantities of gas, mainly CO_2 and a smaller amount of hydrogen sulphide. The gas composition and quantity depend on the geological conditions encountered in the different fields. Depending on technology, most of the mineral content of the fluid and some of the gases are re-injected back into the reservoir. The gases are often extracted from a steam turbine condenser or two-phase heat exchanger and released through a cooling tower. CO_2, on average, constitutes 90% of these non-condensable gases (Bertani and Thain, 2002). A field survey of geothermal power plants operating in 2001 found a wide spread in the direct CO_2 emission rates. The average weighted by generation was 122 g CO_2/kWh, with values ranging from 4 to 740 g CO_2/kWh (Bertani and Thain, 2002). In closed-loop binary-cycle power plants, where the extracted geothermal fluid is passed through a heat exchanger and then completely injected, the operational CO_2 emission is near zero.

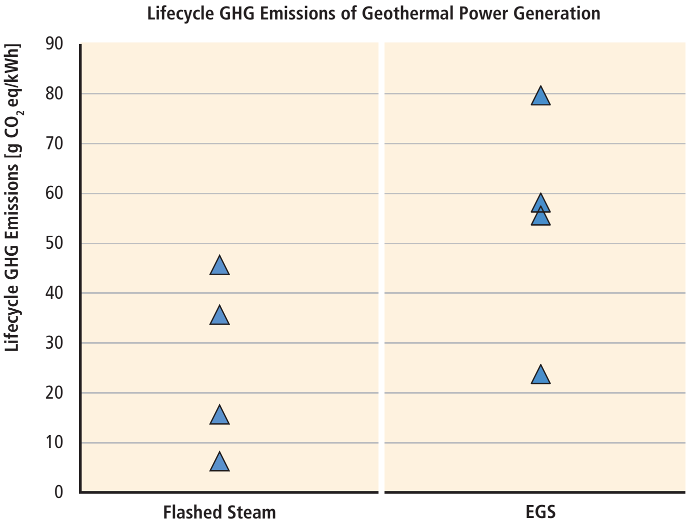
In direct heating applications, emissions of CO_2 are also typically negligible (Fridleifsson et al., 2008). For instance, in Reykjavik, Iceland, the CO_2 content of thermal groundwater used for district heating (0.05 mg CO_2/kWh_{th}) is lower than that of the cold groundwater. In China (Beijing, Tianjin and Xianyang) it is less than 1 g CO_2/kWh_{th}. In places such as Iceland, co-produced CO_2, when sufficiently pure, may also be used in greenhouses to improve plant growth, or extracted for use in carbonated beverages. In the case of Iceland, the replacement of fossil fuel with geothermal heating has avoided the emission of approximately 2 Mt of CO_2 annually and significantly reduced air pollution (Fridleifsson et al., 2008). Other examples of the environmental benefits of geothermal direct use are at Galanta in Slovakia (Fridleifsson et al., 2008), the Pannonian Basin in Hungary (Arpasi, 2005), and the Paris Basin (Laplaige et al., 2005).

EGS power plants are likely to be designed as liquid-phase closed-loop circulation systems, with zero direct emissions, although, if gas separation occurs within the circulation loop, some gas extraction and emission is likely. If the current trend towards more use of lower-temperature resources and binary plants continues, there will be a reduction in average emissions.

4.5.2 Lifecycle assessment

Life-cycle assessment (LCA) analyzes the whole lifecycle of a product 'from cradle to grave'. For geothermal power plants, all GHG emissions directly and indirectly related to the construction, operation and decommissioning of the plant are considered in LCA.

Figure 4.6 shows the result of a comprehensive literature review of geothermal electricity generation LCA studies published since 1980, which were screened for quality and completeness (see Annex II for details on methodology). All estimates of lifecycle GHG emissions are less than 50



	Flashed Steam	EGS
Estimates:	4	4
References:	3	3

Figure 4.6 | Estimates of lifecycle GHG emissions from geothermal power generation (flashed steam and EGS technologies). Unmodified literature values, after quality screen. (See Annex II and Section 9.3.4.1 for details of literature search and citations.)

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[11] A comprehensive assessment of social and environmental impacts of all RE sources covered in this report can be found in Chapter 9.

g CO_2eq/kWh for flash steam plants and less than 80 g CO_2eq/kWh for projected EGS plants.

The Bertani and Thain (2002) estimates are higher than these for several reasons. First, Bertani and Thain collected information from a very large fraction of global geothermal facilities (85% of world geothermal capacity in 2001), whereas qualifying LCA studies were few. Some open-loop facilities with high dissolved CO_2 concentrations can emit CO_2 at very high rates, though this is relevant for a minority of installed capacity only. For closed-loop geothermal systems with more common dissolved CO_2 concentrations, most lifecycle GHG emissions are embodied in plant materials and emitted during construction. These were the cases examined in the qualifying LCA literature displayed in Figure 4.6. Despite few available studies, it is tentatively observed that systems using flashed or dry geothermal steam appear to have lower GHG emissions than do systems combining EGS reservoir development with binary power conversion systems, though this difference is small relative to, for instance, coal-fired electricity generation GHG emissions (see Section 9.3.4.1). A key factor contributing to higher reported emissions for EGS/binary systems versus steam-driven geothermal systems is higher energy and materials requirements for EGS' well-field development. Additional LCA studies to increase the number of estimates for all geothermal energy technologies are needed.

Frick et al. (2010) compared LCA environmental indicators to those of European and German reference power mixes, the latter being composed of lignite coal (26%), nuclear power (26%), hard coal (24%), natural gas (12%), hydropower (4%), wind power (4%), crude oil (1%) and other fuels (3%), and observed that geothermal GHG emissions fall in a range between 8 and 12% of these reference mixes. At sites with above-average geological conditions, low-end GHG emissions from closed loop geothermal power systems can be less than 1% of corresponding emissions for coal technologies.

For lifecycle GHG emissions of geothermal energy, Kaltschmitt (2000) published figures of 14.3 to 57.6 g CO_2eq/kWh_{th} for low-temperature district heating systems, and 180 to 202 g CO_2eq/kWh_{th} for GHP, although the latter values depend significantly on the mix of electricity sources that power them.

The LCA of intermediate- to low-temperature geothermal developments is dominated by larger initial material and energy inputs during the construction of the wells, power plant and pipelines. For hybrid electricity/ district heating applications, greater direct use of the heat generally provides greater environmental benefits.

In conclusion, the LCA assessments show that geothermal is similar to other RE and nuclear energy in total lifecycle GHG emissions (see 9.3.4.1), and it has significant environmental advantages relative to a reference electricity mix dominated by fossil fuel sources.

4.5.3 Local environmental impacts

Environmental impact assessments for geothermal developments involve consideration of a range of local land and water use impacts during both construction and operation phases that are common to most energy projects (e.g., noise, vibration, dust, visual impacts, surface and ground water impacts, ecosystems, biodiversity) as well as specific geothermal impacts (e.g., effects on outstanding natural features such as springs, geysers and fumaroles).

4.5.3.1 Other gas and liquid emissions during operation

Geothermal systems involve natural phenomena, and typically discharge gases mixed with steam from surface features, and minerals dissolved in water from hot springs. Apart from CO_2, geothermal fluids can, depending on the site, contain a variety of other minor gases, such as hydrogen sulphide (H_2S), hydrogen (H_2), methane (CH_4), ammonia (NH_3) and nitrogen (N_2). Mercury, arsenic, radon and boron may be present. The amounts depend on the geological, hydrological and thermodynamic conditions of the geothermal field, and the type of fluid collection/ injection system and power plant utilized.

Of the minor gases, H_2S is toxic, but rarely of sufficient concentration to be harmful after venting to the atmosphere and dispersal. Removal of H_2S released from geothermal power plants is practised in parts of the USA and Italy. Elsewhere, H_2S monitoring is a standard practice to provide assurance that concentrations after venting and atmospheric dispersal are not harmful. CH_4, which has warming potential, is present in small concentrations (typically a few percent of the CO_2 concentration).

Most hazardous chemicals in geothermal fluids are in aqueous phase. If present, boron and arsenic are likely to be harmful to ecosystems if released at the surface. In the past, surface disposal of separated water has occurred at a few fields. Today, this happens only in exceptional circumstances, and geothermal brine is usually injected back into the reservoir to support reservoir pressures, as well as avoid adverse environmental effects. Surface disposal, if significantly in excess of natural hot spring flow rates, and if not strongly diluted, can have adverse effects on the ecology of rivers, lakes or marine environments. Shallow groundwater aquifers of potable quality are protected from contamination by injected fluids by using cemented casings, and impermeable linings provide protection from temporary fluid disposal ponds.

Such practices are typically mandated by environmental regulations. Geochemical monitoring is commonly undertaken by the field operators to investigate, and if necessary mitigate, such adverse effects (Bromley et al., 2006).

4.5.3.2 Potential hazards of seismicity and other phenomena

Local hazards arising from natural phenomena, such as micro-earthquakes, hydrothermal steam eruptions and ground subsidence may be influenced by the operation of a geothermal field (see also Section 9.3.4.7). As with other (non-geothermal) deep drilling projects, pressure or temperature changes induced by stimulation, production or injection of fluids can lead to geo-mechanical stress changes and these can affect the subsequent rate of occurrence of these phenomena (Majer et al., 2008). A geological risk assessment may help to avoid or mitigate these hazards.

Routine seismic monitoring is used as a diagnostic tool and management and protocols have been prepared to measure, monitor and manage systems proactively, as well as to inform the public of any hazards (Majer et al., 2008). In the future, discrete-element models would be able to predict the spatial location of energy releases due to injection and withdrawal of underground fluids. During 100 years of development, although turbines have been tripped offline for short periods, no buildings or structures within a geothermal operation or local community have been significantly damaged by shallow earthquakes originating from geothermal production or injection activities.

With respect to induced seismicity, ground vibrations or noise have been a social issue associated with some EGS demonstration projects, particularly in populated areas of Europe. The process of high-pressure injection of cold water into hot rock generates small seismic events. Induced seismic events have not been large enough to lead to human injury or significant property damage, but proper management of this issue will be an important step to facilitating significant expansion of future EGS projects. Collaborative research initiated by the IEA-GIA (Bromley and Mongillo, 2008), the USA and Australia (International Partnership for Geothermal Technology: IPGT)[12] and in Europe (GEISER)[13], is aimed at better understanding and mitigating induced seismicity hazards, and providing risk management protocols.

Hydrothermal steam eruptions have been triggered at a few locations by shallow geothermal pressure changes (both increases and decreases). These risks can be mitigated by prudent field design and operation.

Land subsidence has been an issue at a few high-temperature geothermal fields where pressure decline has affected some highly compressible formations causing them to compact anomalously and form local subsidence 'bowls'. Management by targeted injection to maintain pressures at crucial depths and locations can minimize subsidence effects. Some minor subsidence may also be related to thermal contraction and minor tumescence (inflation) can overlie areas of injection and rising pressure.

4.5.3.3 Land use

Good examples exist of unobtrusive, scenically landscaped developments (e.g., Matsukawa, Japan), and integrated tourism/energy developments (e.g., Wairakei, New Zealand and Blue Lagoon, Iceland). Nonetheless, land use issues still seriously constrain new development options in some countries (e.g., Indonesia, Japan, the USA and New Zealand) where new projects are often located within or adjacent to national parks or tourist areas. Spa resort owners are very sensitive to the possibility of depleted hot water resources. Potential pressure and temperature interference between adjacent geothermal developers or users can be another issue that affects all types of heat and fluid extraction, including heat pumps and EGS power projects (Bromley et al., 2006). Good planning should take this into account by applying predictive simulation models when allocating permits for energy extraction.

Table 4.5 presents the typical operational footprint for conventional geothermal power plants, taking into account surface installations (drilling pads, roads, pipelines, fluid separators and power-stations). Due to directional drilling techniques, and appropriate design of pipeline corridors, the land area above geothermal resources that is not covered by surface installations can still be used for other purposes such as farming, horticulture and forestry, as occurs, for example, at Mokai and Rotokawa in New Zealand (Koorey and Fernando, 2010), and a national park at Olkaria, Kenya.

Table 4.5 | Land requirements for typical geothermal power generation options expressed in terms of square meter per generation capacity and per annual energy output.

Type of power plant	Land Use	
	m^2/MW_e	m^2/GWh/yr
110-MW_e geothermal flash plants (excluding wells)	1,260	160
56-MW_e geothermal flash plant (including wells, pipes, etc.)	7,460	900
49-MW_e geothermal FC-RC plant (excluding wells)	2,290	290
20-MW_e geothermal binary plant (excluding wells)	1,415	170

Notes: FC: Flash cycle. RC: Rankine cycle (data from Tester et al. (2006) taken from DiPippo (1991); the CFs originally used to calculate land use vary between 90 and 95% depending on the plant type).

4.5.4 Local social impacts

The successful realization of geothermal projects often depends on the level of acceptance by local people. Prevention or minimization of detrimental impacts on the environment, and on land occupiers, as well as

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[12] A description of the project IPGT is available at: internationalgeothermal.org/IPGT.html.

[13] A description of the GEISER project is available at: www.gfz-potsdam.de.

the creation of benefits for local communities, is indispensable to obtain social acceptance. Public education and awareness of the probability and severity of detrimental impacts are also important. The necessary prerequisites to secure agreement of local people are: (a) prevention of adverse effects on people's health; (b) minimization of environmental impacts; and (c) creation of direct and ongoing benefits for the resident communities (Rybach, 2010). Geothermal development creates local job opportunities during the exploration, drilling and construction period (typically four years minimum for a greenfield project). It also creates permanent and full-time jobs when the power plant starts to operate (Kagel, 2006) since the geothermal field from which the fluids are extracted must be operated locally. This can alleviate rural poverty in developing countries, particularly in Asia, Central and South America, and Africa, where geothermal resources are often located in remote mountainous areas. Some geothermal companies and government agencies have approached social issues by improving local security, building roads, schools, medical facilities and other community assets, which may be funded by contributions from profits obtained from operating the power plant (De Jesus, 2005).

Multiple land use arrangements that promote employment by integrating subsurface geothermal energy extraction with labour-intensive agricultural activities are also useful. In many developing countries, geothermal energy is also an appropriate energy source for small-scale distributed generation, helping accelerate development through access to energy in remote areas. This has occurred, for example, in Maguarichi, Mexico (Sánchez-Velasco et al., 2003).

4.6 Prospects for technology improvement, innovation and integration[14]

Geothermal resources can be integrated into all types of electrical power supply systems, from large, interconnected continental transmission grids to onsite use in small, isolated villages or autonomous buildings. They can be utilized in a variety of sustainable power generating modes, including continuous low power rates, long-term (decades long) cycles of high power rates separated by recovery periods and long-term, uninterrupted high power rates sustained with effective fluid reinjection (Bromley et al., 2006). Since geothermal typically provides base-load electric generation, integration of new power plants into existing power systems does not present a major challenge. Indeed, in some configurations, geothermal energy can provide valuable flexibility, such as the ability to increase or decrease production or start up/shut down as required. In some cases, however, the location dependence of geothermal resources requires new transmission infrastructure investments in order to deliver geothermal electricity to load centres.

For geothermal direct uses, no integration problems have been observed. For heating and cooling, geothermal (including GHP) is already widespread at the domestic, community and district scales. District heating networks usually offer flexibility with regard to the primary energy source and can therefore use low-temperature geothermal resources or cascaded geothermal heat (Lund et al., 2010b).

For technology improvement and innovation, several prospects can reduce the cost of producing geothermal energy and lead to higher energy recovery, longer field lifetimes, and better reliability. With time, better technical solutions are expected to improve power plant performance and reduce maintenance down time. The main technological challenges and prospects are described below.

4.6.1 Improvements in exploration, drilling and assessment technologies

In exploration, R&D is required to locate hidden geothermal systems (i.e., with no surface manifestations such as hot springs and fumaroles) and for EGS prospects. Refinement and wider usage of rapid reconnaissance geothermal tools such as satellite-based hyper-spectral, thermal infrared, high-resolution panchromatic and radar sensors could make exploration efforts more effective. Once a regional focus area has been selected, availability of improved cost-effective reconnaissance survey tools to detect as many geothermal indicators as possible is critical in providing rapid coverage of the geological environment being explored at an appropriate resolution.

Special research is needed to improve the rate of penetration when drilling hard rock and to develop advanced slim-hole technologies, and also in large-diameter drilling through ductile, creeping or swelling formations. Drilling must minimize formation damage that occurs as a result of a complex interaction of the drilling fluid (chemical, filtrate and particulate) with the reservoir fluid and formation. The objectives of new-generation geothermal drilling and well construction technologies are to reduce the cost and increase the useful life of geothermal production facilities through an integrated effort (see Table 4.6).

Improvements and innovations in deep drilling are expected as a result of the international Iceland Deep Drilling Project. The aim of this project is to penetrate into supercritical geothermal fluids, which can be a potential source of high-grade geothermal energy. The concept behind it is to flow supercritical fluid to the surface in such a way that it changes directly to superheated (>450°C) hot steam at sub-critical pressures. This would provide up to ten-fold energy output of approximately 50 $\mathrm{MW_e}$ as compared to average high enthalpy geothermal wells (Fridleifsson et al., 2010).

All tasks related to the engineering of the reservoir require a more sophisticated modelling of the reservoir processes and interactions to be

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[14] Chapter 10.5 offers a complementary perspective on drivers of and trends in technological progress across RE technologies. Chapter 8 deals with other integration issues more widely.

Table 4.6 | Priorities for advanced geothermal research (HTHF: high temperature and high flow rate).

Complementary research & share knowledge	Education / training
Standard geothermal resource & reserve definitions	Improved HTHF hard rock drill equipment
Predictive reservoir performance modelling	Improved HTHF multiple zone isolation
Predictive stress field characterization	Reliable HTHF slim-hole submersible pumps
Mitigate induced seismicity / subsidence	Improve resilience of casings to HTHF corrosion
Condensers for high ambient surface temperatures	Optimum HTHF fracture stimulation methods
Use of CO_2 as a circulating fluid for heat exchangers	HTHF logging tools and monitoring sensors
Improve power plant design	HTHF flow survey tools
Technologies & methods to minimize water use	HTHF fluid flow tracers
Predict heat flow and reservoirs ahead of the bit	Mitigation of formation damage, scale and corrosion

able to predict reservoir behaviour with time, to recommend management strategies for prolonged field operation and to minimize potential environmental impacts.

4.6.2 Efficient production of geothermal power, heat and/or cooling

Equipment needed to provide heating/cooling and/or electricity from geothermal wells is already available on the market. However, the efficiency of the different system components can still be improved, and it is even more important to develop conversion systems that more efficiently utilize energy in the produced geothermal fluid at competitive costs. It is basically inevitable that more efficient plants (and components) will have higher investment costs, but the objective would be to ensure that the increased performance justifies these costs. Combined heat and power (CHP) or cogeneration applications provide a means for significantly improving utilization efficiency and economics of geothermal projects, but one of the largest technical barriers is the inability in some cases to fully utilize the thermal energy produced (Bloomquist et al., 2001).

New and cost-effective materials for pipes, casing liners, pumps, heat exchangers and other components for geothermal plants is considered a prerequisite for reaching higher efficiencies.

Another possibility for an efficient type of geothermal energy production is the use of suitable oil fields. There are three types of oil and gas wells potentially capable of supplying geothermal energy for power generation: medium- to high-temperature (>120°C or so) producing wells with a sufficient water cut; abandoned wells due to a high water cut; and geo-pressured brine with dissolved gas. All of these types have been assessed and could be developed depending on the energy market evolution (Sanyal and Butler, 2010). The primary benefit from such a possibility is that the drilling is already in place and can greatly reduce the first costs associated with geothermal project development. However, these savings may be somewhat offset by the need to handle (separate and clean up) multi-phase co-produced fluids, consisting of water, hydrocarbons and other gases.

The potential development of valuable by-products may improve the economics of geothermal development, such as recovery of the condensate for industrial applications after an appropriate treatment, and in some cases recovery of valuable minerals from geothermal brines (such as lithium, zinc, high grade silica and in some cases, gold).

4.6.3 Technological and process challenges in enhanced geothermal systems

EGS require innovative methods, some of which are also applicable to power plants and direct-use projects based on hydrothermal resources. Among these are (Tester et al., 2006):

- Improvement and innovation in well drilling, casing, completion and production technologies for the exploration, appraisal and development of deep geothermal reservoirs (as generalized in Table 4.6).
- Improvement of methods to hydraulically stimulate reservoir connectivity between injection and production wells to attain sustained, commercial production rates. Reservoir stimulation procedures need to be refined to significantly enhance the productivity, while reducing the risk of seismic hazard. Imaging fluid pathways induced by hydraulic stimulation treatments through innovative technology would facilitate this. Technology development to create functional EGS reservoirs independent of local subsurface conditions will be essential.
- Development/adaptation of data management systems for interdisciplinary exploration, development and production of geothermal

reservoirs, and associated teaching tools to foster competence and capacity amongst the people who will work in the geothermal sector.

- Improvement of numerical simulators for production history matching and predicting coupled thermal-hydraulic-mechanical-chemical processes during development and exploitation of reservoirs. In order to accurately simulate EGS reservoirs, computer codes must fully couple flow, chemistry, poro-elasticity and temperature. Development of suitable fully coupled reservoir simulators, including nonlinear deformability of fractures, is a necessity. Modern laboratory facilities capable of testing rock specimens under simulated down-hole conditions of pressure and temperature are also needed.

- Improvement in assessment methods to enable reliable predictions of chemical interactions between geo-fluids and geothermal reservoir rocks, geothermal plants and equipment, enabling optimized, well, plant and field lifetimes.

- Performance improvement of thermodynamic conversion cycles for a more efficient utilization of the thermal heat sources in district heating and power generation applications.

Conforming research priorities for EGS and magmatic resources as determined in Australia (DRET, 2008), the USA, the EU ((ENGINE, 2008), the Joint Programme on Geothermal Energy of the European Energy Research Alliance)[15] and the already-mentioned IPGT (see footnote in Section 4.5.3.2) are summarized in Table 4.6. Successful deployment of the associated services and equipment is also relevant to many conventional geothermal projects.

The required technology development would clearly reflect assessment of environmental impacts including land use and induced micro-seismicity hazards or subsidence risks (see Section 4.5).

The possibility of using CO_2 as a working fluid in geothermal reservoirs, particularly in EGS, has been under investigation. Recent modelling studies show that CO_2 would achieve heat extraction at higher rates than aqueous fluids, and that in fractured reservoirs CO_2 arrival at production wells would occur a few weeks after starting CO_2 injection. A two-phase water-CO_2 mixture could be produced for a few years followed by production of a single phase of supercritical CO_2 (Pruess and Spycher, 2010). In addition, it could provide a means for enhancing the effect of geothermal energy deployment for lowering CO_2 emissions beyond just generating electricity with a carbon-free renewable resource: a 5 to 10% loss rate of CO_2 from the system ('sequestered'), which is equivalent to the water loss rate observed at the Fenton Hill test in the USA, leads to 'sequestration' of 3 MW of coal burning per 1 MW of EGS electricity (Pruess, 2006). As of 2010, much remains to be done before such an approach is technically proven.

4.6.4 Technology of submarine geothermal generation

Currently no technologies are in use to tap submarine geothermal resources. However, in theory, electric energy could be produced directly from a hydrothermal vent using an encapsulated plant, like a submarine, containing an organic Rankine cycle (ORC) binary plant, as described by Hiriart and Espíndola (2005). The operation would be similar to other binary-cycle power plants using evaporator and condenser heat exchangers, with internal efficiency of the order of 80%. The overall efficiency for a submarine vent at 250°C of 4% (electrical power generated/ thermal power) is a reasonable estimate for such an installation (Hiriart et al., 2010). Critical challenges for these resources include the distance from shore, water depth, grid connection costs, the current cable technology that limits ocean depths, and the potential impact on unique marine life around hydrothermal vents.

4.7 Cost trends[16]

Geothermal projects typically have high upfront investment costs due to the need to drill wells and construct power plants and relatively low operational costs. Operational costs vary depending on plant capacity, make-up and/or injection well requirements, and the chemical composition of the geothermal fluids. Without fuel costs, operating costs for geothermal plants are predictable in comparison to combustion-based power plants that are subject to market fluctuations in fuel prices. This section describes the fundamental factors affecting the levelized cost of electricity (LCOE) from geothermal power plants: upfront investment costs; financing costs (debt interest and equity rates); taxes; operation and maintenance (O&M) costs; decommissioning costs; capacity factor and the economic lifetime of the investment. This section also includes some historic and probable future trends, and presents investment and levelized costs of heat (LCOH) for direct uses of geothermal energy in addition to electric production.

Cost estimates for geothermal installations may vary widely (up to 20 to 25% not including subsidies and incentives) between countries (e.g., between Indonesia, the USA and Japan). EGS projects are expected to be more capital intensive than high-grade hydrothermal projects. Because there are no commercial EGS plants in operation, estimated costs are subject to higher uncertainties.

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[15] The Joint Programme on Geothermal Energy (JPGE) is described at: www.eera-set.eu/index.php?index=36.

[16] Discussion of costs in this section is largely limited to the perspective of private investors. Chapters 1 and 8 to 11 offer complementary perspectives on cost issues covering, for example, costs of integration, external costs and benefits, economy-wide costs and costs of policies. All values are expressed in USD_{2005}.

4.7.1 Investment costs of geothermal-electric projects and factors that affect them

Investment costs of a geothermal-electric project are composed of the following components: (a) exploration and resource confirmation; (b) drilling of production and injection wells; (c) surface facilities and infrastructure; and (d) the power plant. Component costs and factors influencing them are usually independent from each other, and each component is described in the text that follows, including its impact on total investment costs.

The first component (a) includes lease acquisition, permitting, prospecting (geology and geophysics) and drilling of exploration and test wells. Drilling of exploration wells in greenfield areas is reported to have a success rate of typically about 50 to 60%, and the first exploration well of 25% (Hance, 2005), although other sources (GTP, 2008) reduce the percentage success to 20 to 25%. Confirmation costs are affected by well parameters (mainly depth and diameter), rock properties, well productivity, rig availability, time delays in permitting or leasing land, and interest rates. This first component represents between 10 and 15% of the total investment cost (Bromley et al., 2010) but for expansion projects may be as low as 1 to 3%.

Drilling of production and injection wells (component b) has a success rate of 60 to 90% (Hance, 2005; GTP, 2008). Factors influencing the cost include well productivity (permeability and temperature), well depths, rig availability, vertical or directional design, special circulation fluids, special drilling bits, number of wells and financial conditions in a drilling contract (Hance, 2005; Tester et al., 2006). This component (b) represents 20 to 35% of the total investment (Bromley et al., 2010).

The surface facilities and infrastructure component (c) includes facilities for gathering steam and processing brine: separators, pumps, pipelines and roads. Vapour-dominated fields have lower facility costs since brine handling is not required. Factors affecting this component are reservoir fluid chemistry, commodity prices (steel, cement), topography, accessibility, slope stability, average well productivity and distribution (pipeline diameter and length), and fluid parameters (pressure, temperature, chemistry) (Hance, 2005). Surface facilities and infrastructure costs represent 10 to 20% of the investment (Bromley et al., 2010) although in some cases these costs could be <10%, depending upon plant size and location.

Power plant components (d) include the turbines, generator, condenser, electric substation, grid hook-up, steam scrubbers and pollution abatement systems. Power plant design and construction costs depend upon type (flash, dry steam, binary, or hybrid), location, size (a larger unit and plant size is cheaper per unit of production (Dickson and Fanelli, 2003; Entingh and Mines, 2006), fluid enthalpy (resource temperature) and chemistry, type of cooling cycle used (water or air cooling) and cooling water availability if using water. This component varies between 40 and 81% of the investment (Hance, 2005; Bromley et al., 2010).

Some historic and current investment costs for typical geothermal-electric projects are shown in Figure 4.7. For condensing flash power plants, the current (2009) worldwide range is estimated to be USD$_{2005}$ 1,780 to 3,560/kW$_e$, and for binary cycle plants USD$_{2005}$ 2,130 to 5,200/kW$_e$ (Bromley et al., 2010).

One additional factor affecting the investment cost of a geothermal-electric project is the type of project: field expansion projects may cost 10 to 15% less than a greenfield project, since investments have already been made in infrastructure and exploration and valuable resource information has been learned from drilling and producing start-up wells (Stefansson, 2002; Hance, 2005).

Most geothermal projects are financed with two different kinds of capital with different rates of return: equity and debt interest. Equity rates can be up to 20% while debt interest rates are lower (6 to 8%). The capital structure of geothermal-electric projects is commonly composed of 55 to 70% debt and 30 to 45% equity, but in the USA, debt lenders usually require 25% of the resource capacity to be proven before lending money. Thus, the early phases of the project often have to be financed by equity due to the higher risk of failure in these phases (Hance, 2005). Real and perceived risks play major roles in setting equity rates and in determining the availability of debt interest financing.

From the 1980s until about 2003-2004, investment costs remained flat or even decreased (Kagel, 2006; Mansure and Blankenship, 2008). Since then project costs have increased (Figure 4.7) due to increases in the cost of engineering, commodities such as steel and cement, and particularly drilling rig rates. This cost trend was not unique to geothermal and was mirrored across most other power sectors.

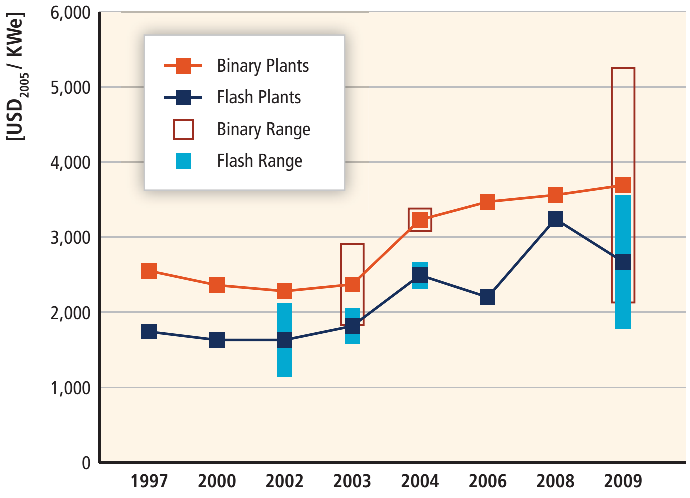

Figure 4.7 | Historic and current investment costs for typical turnkey (installed) geothermal-electric projects (rounded values taken from Kutscher, 2000; Owens, 2002; Stefansson, 2002; Hance, 2005; GTP, 2008; Cross and Freeman, 2009; Bromley et al., 2010; Hjartarson and Einarsson, 2010).

4.7.2 Geothermal-electric operation and maintenance costs

O&M costs consist of fixed and variable costs directly related to the electricity production phase. O&M per annum costs include field operation (labour and equipment), well operation and work-over and facility maintenance. For geothermal plants, an additional factor is the cost of make-up wells, that is, new wells to replace failed wells and restore lost production or injection capacity. Costs of these wells are typically lower than those for the original wells, and their success rate is higher.

Each geothermal power plant has specific O&M costs that depend on the quality and design of the plant, the characteristics of the resource, environmental regulations and the efficiency of the operator. The major factor affecting these costs is the extent of work-over and make-up well requirements, which can vary widely from field to field and typically increase with time (Hance, 2005). For the USA, O&M costs including make-up wells have been calculated to be between US cents$_{2005}$ 1.9 and 2.3/kWh (Lovekin, 2000; Owens, 2002), and Hance (2005) proposed an average cost of US cents$_{2005}$ 2.5/kWh. In terms of installed capacity, current O&M costs range between USD$_{2005}$ 152 and 187/kW per year, depending of the size of the power plant. In New Zealand, O&M costs range from US cents$_{2005}$ 1.0 to 1.4/kWh for 20 to 50 MW$_e$ plant capacity (Barnett and Quinlivan, 2009), which are equivalent to USD$_{2005}$ 83 to 117/kW per year.

4.7.3 Geothermal-electric performance parameters

One important performance parameter is the economic lifetime of the power plant. Twenty-five to thirty years is the common planned lifetime of geothermal power plants worldwide, although some of them have been in operation for more than 30 years, such as Units 1 and 2 in Cerro Prieto, Mexico (since 1973; Gutiérrez-Negrín et al., 2010), Eagle Rock and Cobb Creek in The Geysers, USA (since 1975 and 1979, respectively), and Mak-Ban A and Tiwi A, the Philippines (since 1979) (Bertani, 2010). This payback period allows for refurbishment or replacement of aging surface plants at the end of the plant lifetime, but is not equivalent to the economic lifetime of the geothermal reservoir, which is typically longer, for example, Larderello, The Geysers, Wairakei, Olkaria and Cerro Prieto, among others. In some reservoirs, however, the possibility of resource degradation over time is one of several factors that affect the economics of continuing plant operation.

Another performance parameter is the capacity factor (CF). The evolution of the worldwide average CF of geothermal power plants since 1995 is provided in Table 4.7, calculated from the installed capacity and the average annual generation as reported in different country updates gathered by Bertani (2010). For 2008, the installed capacity worldwide was 10,310 MW$_e$ (10,715 MW$_e$ as of the end of 2009, reduced by the 405 MW$_e$ added in 2009, according to Table X in Bertani (2010)), with an average CF of 74.5%. This worldwide average varies significantly by country and field. For instance, the annual average gross CF in 2008 for Mexico was 84% (data from Gutiérrez-Negrín et al., 2010), while for the USA it was 62% (Lund et al., 2010b) and in Indonesia it was 78% (Darma et al., 2010; data from their Table 1).

Table 4.7 | World installed capacity, electricity production and capacity factor of geothermal power plants from 1995 to 2009 (adapted from data from Bertani (2010).

Year	Installed Capacity (GW$_e$)	Electricity Production (GWh/yr)	Capacity Factor (%)
1995	6.8	38,035	63.5
2000	8.0	49,261	70.5
2005	8.9	55,709	71.2
2008-2009[1]	10.7	67,246	74.5

Note: 1. Installed capacity as of December 2009, and electricity production as of December 2008. Installed capacity in 2008 was 10.3 GW$_e$ and was used to estimate the capacity factor of 74.5% shown here.

The geothermal CF worldwide average increased significantly between 1995 and 2000, with a lower increase in the last decade. This lower increase can be partially explained by the degradation in resource productivity (temperature, flow, enthalpy or combination of these) in geothermal fields operated for decades, although make-up drilling can offset this effect. The complementary explanation is that in the last decade some operating geothermal turbines have exceeded their economic lifetime, and thus require longer periods of shut-down for maintenance or replacement. For instance, out of the 48 geothermal-electric power units of >55 MW$_e$ operating in the world in 2009, 13 (27%) had been in operation for 27 years or more (Bertani, 2010, Table IX). Moreover, 15 new power plants, with a combined capacity of 456 MW$_e$, started to operate during 2008, but their generation contributed for only part of the year (Bertani, 2010, Table X). Typical CFs for new geothermal power plants are over 90% (Hance, 2005; DiPippo, 2008; Bertani, 2010).

4.7.4 Levelized costs of geothermal electricity

The current LCOE for geothermal installations (including investment cost for exploration, drilling and power plant and O&M costs) are shown in Figure 4.8.

The LCOE is presented as a function of CF, investment cost and discount rates (3, 7 and 10%), assuming a 27.5-year lifetime and using the values for worldwide investment and O&M costs shown in Figure 4.7 for 2009 and as presented in Section 4.7.2 (Bromley et al., 2010). As can be expected, the main conclusions from the figure are that the LCOE is proportional to investment cost and discount rate, and inversely proportional to CF, assuming the same average O&M costs. When lower O&M costs can be achieved, as is currently the case in New Zealand (Barnett and Quinlivan, 2009), the resulting LCOE would be proportionally lower. For greenfield projects, the LCOE for condensing flash plants currently ranges from US cents$_{2005}$ 4.9 to 7.2/kWh and, for binary-cycle plants, the LCOE ranges from US cents$_{2005}$ 5.3 to 9.2/kWh, at a CF of 74.5%, a 27.5-year economic design lifetime, and a discount rate of 7% and using the

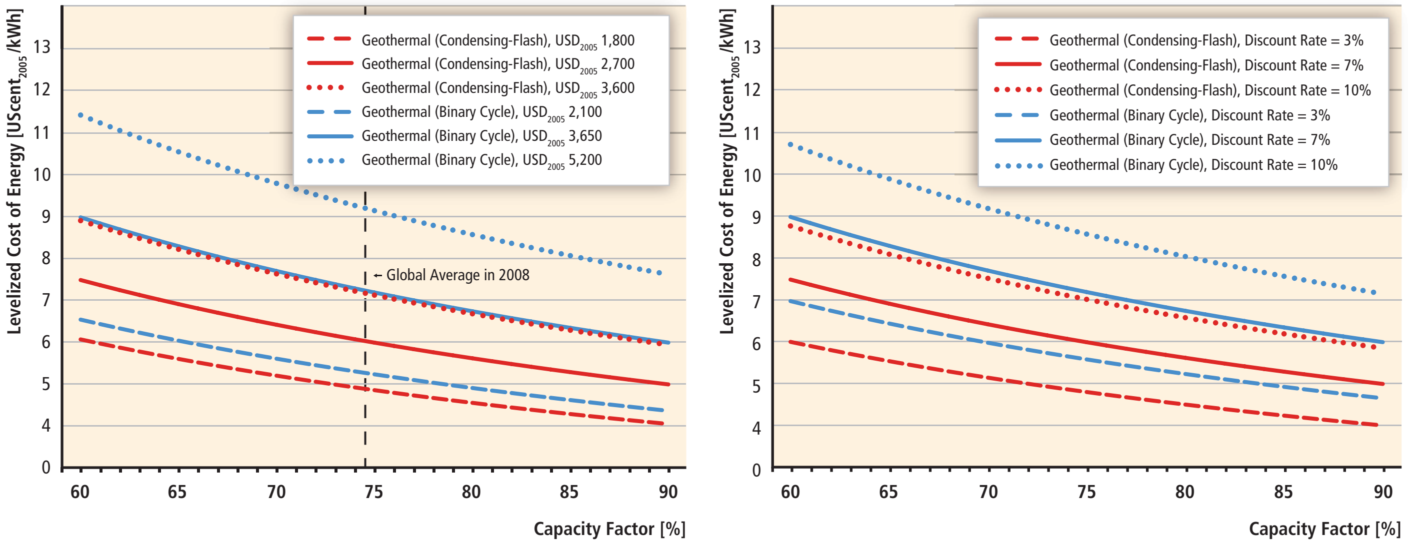

Figure 4.8 | Current LCOE for geothermal power generation as a function of (left panel) capacity factor and investment cost (discount rate at 7%, mid-value of the O&M cost range, and mid-value of the lifetime range), and (right panel) capacity factor and discount rate (mid-value of the investment cost range, mid-value of the O&M cost range, and mid-value of the lifetime range) (see also Annex III).

lowest and highest investment cost, respectively. Achieving a 90% lifetime average CF in new power plants can lead to a roughly 17% lower LCOE (Figure 4.8). The complete range of LCOE estimates, considering variations in plant lifetime, O&M costs, investment costs, discount rates and CFs, can vary from US cents$_{2005}$ 3.1 to 13/kWh for condensing flash plants and from US cents$_{2005}$ 3.3 to 17/kWh for binary plants (see also Annex III and Chapters 1 and 10).

No actual LCOE data exist for EGS, but some projections have been made using different models for several cases with diverse temperatures and depths (Table 9.5 in Tester et al., 2006). These projections do not include projected cost reductions due to future learning and technology improvements, and all estimates for EGS carry higher uncertainties than for conventional hydrothermal resources. The obtained LCOE values for the Massachusetts Institute of Technology EGS model range from US cents$_{2005}$ 10 to 17.5/kWh for relatively high-grade EGS resources (250°C to 330°C, 5-km depth wells) assuming a base case present-day productivity of 20 kg/s per well. Another model for a hypothetical EGS project in Europe considers two wells at 4 km depth, 125°C to 165°C reservoir temperature, 33 to 69 kg/s flow rate and a binary power unit of 1.6 MW$_e$ running with an annual capacity factor of 86%, and obtains LCOE values of US cents$_{2005}$ 30 to 37/kWh (Huenges and Frick, 2010).[17]

4.7.5 Prospects for future cost trends

The prospects for technical improvements outlined in Section 4.6 indicate that there is potential for cost reductions in the near and longer term for both conventional geothermal technology and EGS. Additionally, the future costs for geothermal electricity are likely to vary widely because future deployment will include an increasing percentage of unconventional development types, such as EGS, as mentioned in Section 4.8.

The following estimates are based on possible cost reductions from design changes and technical advancements, relying solely on expert knowledge of the geothermal process value chain. Published learning curve studies for geothermal are limited, so the other major approach to forecasting future costs, extrapolating from historical learning rates, is not pursued here. See Section 10.5 for a more complete discussion of learning curves, including their advantages and limitations.

Foreseeable technological advances were presented in Section 4.6. Those potentially having the greatest impact on LCOEs in the near term are: (a) engineering improvements in design and stimulation of geothermal reservoirs; and (b) improvements in materials, operation and maintenance mentioned in Section 4.6.3 as well as some from Section 4.6.1. These changes will increase energy extraction rates and lead to a better plant performance, and less frequent and shorter maintenance periods, all of which will result in better CFs. With time, more efficient plants (with CFs of 90 and 95%) are expected to replace the older ones still in operation, increasing the average CF to between 80 and 95% (Fridleifsson et al., 2008). Accordingly, the worldwide average CF for 2020 is projected to be 80%, and could be 85% in 2030 and as high as 90% in 2050.

Important improvements in drilling techniques described in Section 4.6.2 are expected to reduce drilling costs. Drilling cost reductions due to increasing experience are also based on historic learning curves for deep oil and gas drilling (Tester et al., 2006). Since drilling costs represent at least between 20 and 35% of total investment cost (Section 4.7.1), and also impact the O&M cost due to the cost of make-up wells, a lower LCOE can be expected as drilling cost decreases. Additionally, an increased success rate for exploration, development and make-up

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[17] Further assumptions, for example, about O&M costs, lifetime, CFs and the discount rate may be available from the references.

wells is also foreseeable. Nevertheless, these reductions are unlikely to be achieved in the near term, and were not included in projections for LCOE reductions by 2020. Other improvements in exploration, surface installations, materials and power plants mentioned in Sections 4.6.2 and 4.6.3 are likely, and should lead to reduced costs.

Based on those premises, future potential LCOEs were calculated for 2020. For greenfield projects the worldwide average projected LCOE for condensing flash plants with a distribution of investment costs ranges from US cents$_{2005}$ 4.5 to 6.6/kWh and for binary-cycle plants ranges from US cents$_{2005}$ 4.9 to 8.6/kWh, at a CF of 80%, 27.5-year lifetime and discount rate of 7%. Therefore, a global average LCOE reduction of about 7% is expected for geothermal flash and binary plants by 2020.

For projected future costs for EGS, a sensitivity analysis of model variables carried out in Australia obtained near-term LCOE estimates of between AU$ 92 and AU$ 110 per MWh, equivalent to US cents$_{2005}$ 6.3 and 7.5/kWh, which are slightly higher than comparable estimates from Credit Suisse (Cooper et al., 2010). Another model (Sanyal et al., 2007) suggested that the LCOE for EGS will decline with increasing stimulated volume and replication of EGS units, with increasing the maximum practicable pumping rate from a well, and with the reduced rate of cooling of the produced fluid (LCOE increases approximately US cents$_{2005}$ 0.45/kWh per additional degree Celsius of cooling per year), which in turn can be achieved by improving the effectiveness of stimulation by closely spaced fractures (Sanyal, 2010). Tester et al. (2006) suggested that a four-fold improvement in productivity to 80 kg/s per well by 2030 would be possible and that the projected LCOE values would range from US cents$_{2005}$ 3.6 to 5.2/kWh for high-grade EGS resources, and for low-grade geologic settings (180°C to 220°C, 5- to 7-km depth wells) LCOE would also become more economically viable at about US cents$_{2005}$ 5.9 to 9.2/kWh.[18]

4.7.6 Costs of direct uses and geothermal heat pumps

Direct-use project costs have a wide range, depending upon specific use, temperature and flow rate required, associated O&M and labour costs, and output of the produced product. In addition, costs for new construction are usually less than costs for retrofitting older structures. The cost figures given in Table 4.8 are based on a climate typical of the northern half of the USA or Europe. Heating loads would be higher for more northerly climates such as Iceland, Scandinavia and Russia. Most figures are based on cost in the USA (in USD$_{2005}$), but would be similar in developed countries and lower in developing countries (Lund and Boyd, 2009).

Some assumptions for the levelized cost of heat (LCOH) estimates presented in Table 4.8 are mentioned in Annex III. For building heating, assumptions included a load factor of 25 to 30%, investment cost of USD$_{2005}$ 1,600 to 3,900/kW$_{th}$ and a lifetime of 20 years, and for district heating, the same load factor, USD$_{2005}$ 600 to 1,600/kW$_{th}$ and a lifetime of 25 years. Thermal load density (heating load per unit of land area) is critical to the feasibility of district heating because it is one of the major determinants of the distribution network capital and operating costs. Thus, downtown high-rise buildings are better candidates than a single family residential area (Bloomquist et al., 2001). Generally, a thermal load density of about 1.2 x 10^9 J/hr/ha (120,000 J/hr/m^2) is recommended.

Table 4.8 | Investment costs and calculated levelized cost of heat (LCOH) for several geothermal direct applications (investment costs are rounded and taken from Lund, 1995; Balcer, 2000; Radeckas and Lukosevicius, 2000; Reif, 2008; Lund and Boyd, 2009).

Heat application	Investment cost USD$_{2005}$/kW$_{th}$	LCOH in USD$_{2005}$/GJ at discount rates of		
		3%	7%	10%
Space heating (buildings)	1,600–3,940	20–50	24–65	28–77
Space heating (districts)	570–1,570	12–24	14–31	15–38
Greenhouses	500–1,000	7.7–13	8.6–14	9.3–16
Uncovered aquaculture ponds	50–100	8.5–11	8.6–12	8.6–12
GHP (residential and commercial)	940–3,750	14–42	17–56	19–68

The LCOH calculation for greenhouses assumed a load factor of 0.50, and 0.60 for uncovered aquaculture ponds and tanks, with a lifespan of 20 years. Covered ponds and tanks have higher investment costs than uncovered ones, but lower heating requirements.

GHP project costs vary between residential installations and commercial/institutional installations. Heating and/or cooling large buildings lowers the investment cost and LCOH. In addition, the type of installation, closed loop (horizontal or vertical) or open loop using groundwater,

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[18] Further assumptions, for example, about future O&M costs, lifetime, CFs and the discount rate may be available from the references.

has a large influence on the installed cost (Lund and Boyd, 2009). The LCOH reported in Table 4.8 assumed 25 to 30% as the load factor and 20 years as the operational lifetime. It is worth taking into account that actual LCOH are influenced by electricity market prices, as operation of GHPs requires auxiliary power input. In the USA, recent trends in lower natural gas prices have resulted in poor GHP project economics compared to alternative options for heat supply, and drilling costs continue to be the largest barrier to GHP deployment.

Industrial applications are more difficult to quantify, as they vary widely depending upon the energy requirements and the product to be produced. These plants normally require higher temperatures and often compete with power plant use; however, they do have a high load factor of 0.40 to 0.70, which improves the economics. Industrial applications vary from large food, timber and mineral drying plants (USA and New Zealand) to pulp and paper plants (New Zealand).

4.8 Potential deployment[19]

Geothermal energy can contribute to near- and long-term carbon emissions reductions. In 2008, the worldwide geothermal-electric generation was 67.2 TWh_e (Sections 4.4.1 and 4.7.3) and the heat generation from geothermal direct uses was 121.7 TWh_{th} (Section 4.4.3). These amounts of energy are equivalent to 0.24 EJ/yr and 0.44 EJ/yr, respectively, for a total of 0.68 EJ/yr (direct equivalent method). The IEA (2010) reports only 0.41 EJ/yr (direct equivalent method) as the total primary energy supply from geothermal resources in 2008 (see Chapter 1); the reason for this difference is unclear. Regardless, geothermal resources provided only about 0.1% of the worldwide primary energy supply in 2008. By 2050, however, geothermal could meet roughly 3% of global electricity demand and 5% of the global demand for heating and cooling, as shown in Section 4.8.2.

This section starts by presenting near-term (2015) global and regional deployments expected for geothermal energy (electricity and heat) based on current geothermal-electric projects under construction or planned, observed historic growth rates, as well as the forecast generation of electricity and heat. Subsequently, this section presents the middle- and long-term (2020, 2030, 2050) global and regional deployments, compared to the IPCC AR4 estimate, displays results from scenarios reviewed in Chapter 10 of this report, and discusses their feasibility in terms of technical potential, regional conditions, supply chain aspects, technological-economic conditions, integration-transmission issues, and environmental and social concerns. Finally, the section presents a short conclusion regarding potential deployment.

4.8.1 Near-term forecasts

Reliable sources for near-term geothermal power deployment forecasts are the country updates recently presented at the *World Geothermal Congress 2010.* This congress is held every five years, and experts on geothermal development in several countries are asked to prepare and present a paper on the national status and perspectives. According to projections included in those papers, which are based on the capacity of geothermal-electric projects stated as under construction or planned, the geothermal-electric installed capacity in the world is expected to reach 18.5 GW_e by 2015 (Bertani, 2010). This represents an annual average growth of 11.5% between 2010 and 2015, based on the present conditions and expectations of geothermal markets. This annual growth rate is larger than the historic rates observed between 1970 and 2010 (7%, Table 4.4), and reflects increased activity in several countries, as mentioned in Section 4.4.

Assuming the countries' projections of geothermal-electric deployment are fulfilled in the next five years, which is uncertain, the regional deployments by 2015 are shown in Table 4.9. Note that each region has its own growth rate but the average global rate is 11.5%. Practically all the new power plants expected to be on line by 2015 will be conventional (flash and binary) utilizing hydrothermal resources, with a small contribution from EGS projects. The worldwide development of EGS is forecasted to be slow in the near term and then accelerate, as expected technological improvements lower risks and costs (see Section 4.6).

The country updates did not include projections for geothermal direct uses (heat applications, including GHP). Projecting the historic annual growth rate in the period 1975 to 2010 (Table 4.4) for the following five years results in a global projection of 85.2 GW_{th} of geothermal direct uses by 2015. The expected deployments and thermal generation by region are also presented in Table 4.9. By 2015, total electric generation could reach 121.6 TWh/yr (0.44 EJ/yr) while direct generation of heat, including GHP, could attain 224 TWh_{th}/yr (0.8 EJ/yr).

On a regional basis, the forecast deployment for harnessing identified and hidden hydrothermal resources varies significantly in the near term. In Europe, Africa and Central Asia, large deployment is expected in both electric and direct uses of geothermal, while in India and the Middle East, only a growing deployment in direct uses is projected with no electric uses projected over this time frame.

The existing installed capacity in North America (USA and Mexico) of 4 GW_e, mostly from mature developments, is expected to increase almost 60% by 2015, mainly in the USA (from 3,094 to 5,400 MW_e, according to Lund et al. (2010b) and Bertani (2010). In Central America, the future geothermal-electric deployment has been estimated at 4 GW_e (Lippmann, 2002), of which 12% has been harnessed so far (~0.5 GW_e). South American countries, particularly along the

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[19] Complementary perspectives on potential deployment based on a comprehensive assessment of numerous model-based scenarios of the energy system are presented in Chapter 10 and Sections 10.2 and 10.3 of this report.

Table 4.9 | Regional current and forecast installed capacity for geothermal power and direct uses (heat, including GHP) and forecast generation of electricity and heat by 2015.

REGION*	Current capacity (2010)		Forecast capacity (2015)		Forecast generation (2015)	
	Direct (GW_{th})	Electric (GW_e)	Direct (GW_{th})	Electric (GW_e)	Direct (TW_{th}/yr)	Electric (TWh_e/yr)
OECD North America	13.9	4.1	27.5	6.5	72.3	43.1
Latin America	0.8	0.5	1.1	1.1	2.9	7.2
OECD Europe	20.4	1.6	32.8	2.1	86.1	13.9
Africa	0.1	0.2	2.2	0.6	5.8	3.8
Transition Economies	1.1	0.08	1.6	0.2	4.3	1.3
Middle East	2.4	0	2.8	0	7.3	0
Developing Asia	9.2	3.2	14.0	6.1	36.7	40.4
OECD Pacific	2.8	1.2	3.3	1.8	8.7	11.9
TOTAL	**50.6**	**10.7**	**85.2**	**18.5**	**224.0**	**121.6**

Notes: * For regional definitions and country groupings see Annex II.

Current and forecast data for electricity taken from Bertani (2010), and for direct uses from Lund et al. (2010a), both as of December 2009. Estimated average annual growth rate in 2010 to 2015 is 11.5% for power and 11% for direct uses. Average worldwide capacity factors of 75% (for electric) and 30% (for direct use) were assumed by 2015.

Andes mountain chain, also have significant untapped—and under-explored—hydrothermal resources (Bertani, 2010).

For island nations with mature histories of geothermal development, such as New Zealand, Iceland, the Philippines and Japan, identified geothermal resources could allow for a future expansion potential of two to five times existing installed capacity, although constraints such as limited grid capacity, existing or planned generation (from other renewable energy sources) and environmental factors (such as national park status of some resource areas) may limit the hydrothermal geothermal deployment. Indonesia is thought to be one of the world's richest countries in geothermal resources and, along with other volcanic islands in the Pacific Ocean (Papua-New Guinea, Solomon, Fiji, etc.) and the Atlantic Ocean (Azores, Caribbean, etc.) has significant potential for growth from known hydrothermal resources, but is market-constrained in growth potential.

Remote parts of Russia (Kamchatka) and China (Tibet) contain identified high-temperature hydrothermal resources, the use of which could be significantly expanded given the right incentives and grid access to load centres. Parts of other South-East Asian nations and India contain numerous hot springs, inferring the possibility of potential, as yet unexplored, hydrothermal resources.

Additionally, small-scale distributed geothermal developments could be an important base-load power source for isolated population centres in close proximity to geothermal resources, particularly in areas of Indonesia, the Philippines and Central and South America.

4.8.2 Long-term deployment in the context of carbon mitigation

The IPCC Fourth Assessment Report (AR4) estimated a potential contribution of geothermal to world electricity supply by 2030 of 633 TWh/yr (2.28 EJ/yr), equivalent to about 2% of the total (Sims et al., 2007). Other forecasts for the same year range from 173 TWh/yr (0.62 EJ/yr) (IEA, 2009) to 1,275 TWh/yr (4.59 EJ/yr) (Teske et al., 2010).

A summary of the literature on the possible future contribution of RE supplies in meeting global energy needs under a range of GHG concentration stabilization scenarios is provided in Chapter 10. Focusing specifically on geothermal energy, Figure 4.9 (left) presents modelling results for the global supply of geothermal energy in EJ/yr. About 120 different long-term scenarios underlie Figure 4.9 that derive from a diversity of modelling teams, and span a wide range of assumptions for—among other variables—energy demand growth, the cost and availability of competing low-carbon technologies, and the cost and availability of RE technologies (including geothermal energy).

Chapter 10 discusses how changes to some of these variables impact RE deployment outcomes, with Section 10.2.2 providing a description of the literature from which the scenarios have been taken. In Figure 4.9 (left) the geothermal energy deployment results under these scenarios for 2020, 2030 and 2050 are presented for three GHG concentration stabilization ranges, based on the AR4: Baselines (>600 ppm CO_2), Categories III and IV (440 to 600 ppm) and Categories I and II (<440 ppm), all by 2100. Results are presented for the median scenario, the 25th to 75th percentile range among the scenarios, and the minimum and maximum scenario results. Primary energy is provided as direct equivalent, that is, each unit of heat or electricity is accounted for as one unit at the primary energy level.[20]

The long-term projections presented in Figure 4.9 (left) span a broad range. The 25th to 75th percentile ranges of all three scenarios are 0.07

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[20] In scenario ensemble analyses such as the review underlying Figure 4.9, there is a constant tension between the fact that the scenarios are not truly a random sample and the sense that the variation in the scenarios does still provide real and often clear insights into collective knowledge or lack of knowledge about the future (see Section 10.2.1.2 for a more detailed discussion).

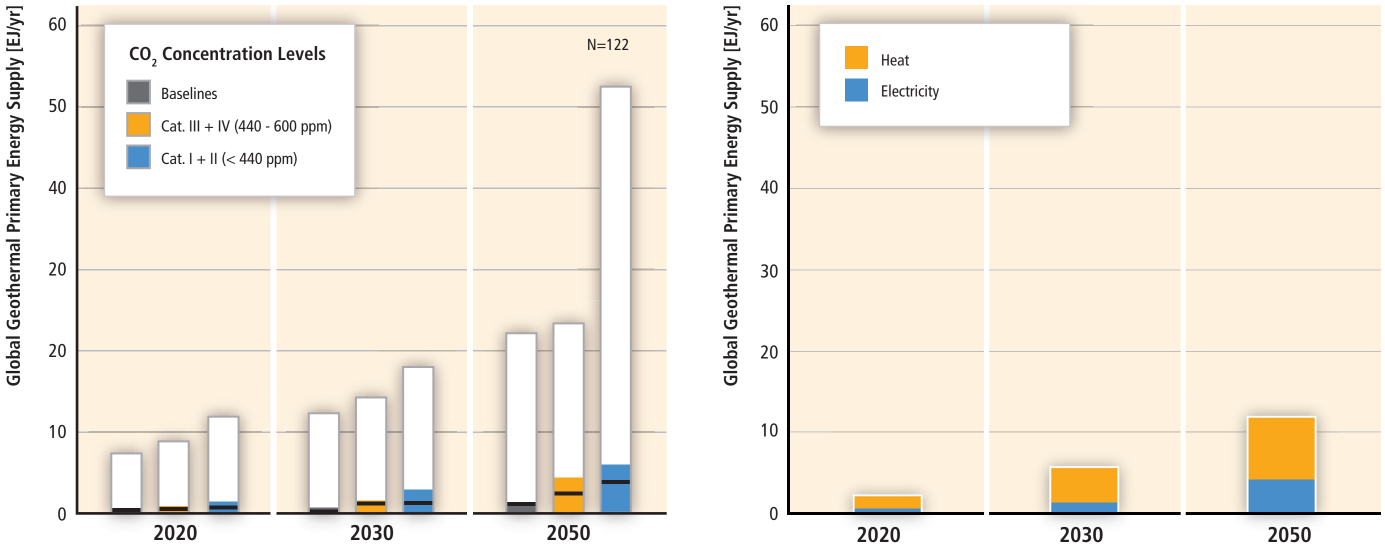

Figure 4.9 | Global primary energy supply of geothermal energy. Left panel: In long-term scenarios (median, 25th to 75th percentile range, and full range of scenario results; colour coding is based on categories of atmospheric CO$_2$ concentration level in 2100; the specific number of scenarios underlying the figure is indicated in the right upper corner) (adapted from Krey and Clarke, 2011; see also Chapter 10). Right panel: Estimated in Section 4.8.2 as potential geothermal deployments for electricity and heat applications.

Table 4.10 | Potential geothermal deployments for electricity and direct uses in 2020 through 2050.

Year	Use	Capacity[1] (GW)	Generation (TWh/yr)	Generation (EJ/yr)	Total (EJ/yr)
2020	Electricity	25.9	181.8	0.65	2.01
	Direct	143.6	377.5	1.36	
2030	Electricity	51.0	380.0	1.37	5.23
	Direct	407.8	1,071.7	3.86	
2050	Electricity	150.0	1,182.8	4.26	11.83
	Direct	800.0	2,102.3	7.57	

Note: 1. Installed capacities for 2020 and 2030 are extrapolated from 2015 estimates at 7% annual growth rate for electricity and 11% for direct uses, and for 2050 are the middle value between projections from Bertani (2010) and Goldstein et al. (2011). Generation was estimated with an average worldwide CF of 80% (2020), 85% (2030) and 90% (2050) for electricity and of 30% for direct uses.

to 1.38 EJ/yr by 2020, 0.10 to 2.85 EJ/yr by 2030 and 0.11 to 5.94 EJ/yr by 2050. The scenario medians range from 0.39 to 0.71 EJ/yr for 2020, 0.22 to 1.28 EJ/yr for 2030 and 1.16 to 3.85 EJ/yr for 2050. The medians for 2030 are lower than the IPCC AR4 estimate of 2.28 EJ/yr, which is for electric generation only, although the latter lies in the 25th to 75th percentile range of the most ambitious GHG concentration stabilization scenarios presented in Figure 4.9 (left). Figure 4.9 (left) shows that geothermal deployment is sensitive to the GHG concentration level, with greater deployment correlated with lower GHG concentration stabilization levels.

Based on geothermal technical potentials and market activity discussed in Sections 4.2 and 4.4, and on the expected geothermal deployment by 2015, the projected medians for geothermal energy supply and the 75th percentile amounts of all the modelled scenarios are technically reachable for 2020, 2030 and 2050.

As indicated above, climate policy is likely to be one of the main driving factors of future geothermal development, and under the most favourable policy of CO$_2$ emissions (<440 ppm) geothermal deployment by 2020, 2030 and 2050 could be higher than the 75th percentile estimates of Figure 4.9, as a simple extrapolation exercise shows. By projecting the historic average annual growth rates of geothermal power plants (7%) and direct uses (11%) from the estimates for 2015 (Table 4.9), the geothermal deployment in 2020 and 2030 would reach the figures shown in Table 4.10 (see also Figure 4.9, right).

By 2050 the projected installed capacity of geothermal power plants would be between 140 GW$_e$ (Bertani, 2010) and 160 GW$_e$ (Goldstein et al., 2011), with one-half of them being of EGS type, while the potential installed capacity for direct uses could reach 800 GW$_{th}$ (Bertani, 2010). Potential deployment and generation for 2050 are also shown in Table 4.10 and Figure 4.9 (right).

The total contribution (thermal and electric) of geothermal energy would be 2 EJ/yr by 2020, 5.2 EJ/yr by 2030 and 11.8 EJ/yr by 2050 (Table 4.10), where each unit of heat or electricity is accounted for as one unit at the primary energy level. These estimates practically double the estimates for the 75th percentile of Figure 4.9, because many of the approximately 120 reviewed scenarios have not included the potential for EGS development in the long term.

Future geothermal deployment may not follow its historic growth rate between 2015 and 2030. In fact, it could be higher (e.g., Krewitt et al., (2009) adopted an annual growth rate of 10.4% for electric deployment between 2005 and 2030), or lower. Yet the results from this extrapolation exercise indicate that future geothermal deployment may reach levels in the 75 to 100% range of Figure 4.9 rather than in the 25 to 75% range.

Note that for 2030, the extrapolated geothermal electric generation of 380 TWh/yr (1.37 EJ/yr) is lower than the IPCC AR4 estimate (633 TWh/yr or 2.28 EJ/yr).

Teske et al. (2010) estimate the electricity demand to be 25,851 to 27,248 TWh/yr by 2020, 30,133 to 34,307 TWh/yr in 2030 and 37,993 to 46,542 TWh/yr in 2050. The geothermal share would be around 0.7% of global electric demand by 2020, 1.1 to 1.3% by 2030 and 2.5 to 3.1% by 2050.

Teske et al. (2010) project the global demand for heating and cooling by 2020 to be 156.8 EJ/yr, 162.4 EJ/yr in 2030 and 161.7 EJ/yr in 2050. Geothermal would then supply about 0.9% of the total demand by 2020, 2.4% by 2030 and 4.7% by 2050.

The high levels of deployment shown in Figure 4.9 could not be achieved without economic incentive policies to reduce GHG emissions and increase RE. Policy support for research and development (subsidies, guarantees and tax write-offs for initial deep drilling) would assist in the demonstration and commercialization of some geothermal technologies such as EGS and other non-conventional geothermal resource development. Feed-in tariffs with confirmed geothermal prices, and direct subsidies for district and building heating would also help to accelerate deployment. The deployment of geothermal energy can also be fostered with drilling subsidies, targeted grants for pre-competitive research and demonstration to reduce exploration risk and the cost of EGS development. In addition, the following issues are worth noting.

Resource potential: Even the highest estimates for the long-term contribution of geothermal energy to the global primary energy supply (52.5 EJ/yr by 2050, Figure 4.9, left) are well within the technical potentials described in Section 4.2 (118 to 1,109 EJ/yr for electricity and 10 to 312 EJ/yr for heat, see Figure 4.2) and even within the upper range of hydrothermal resources (28.4 to 56.8 EJ/yr). Thus, technical potential is not likely to be a barrier in reaching more ambitious levels of geothermal deployment (electricity and direct uses), at least on a global basis.

Regional deployment: Future deployment of geothermal power plants and direct uses are not the same for every region. Availability of financing, water, transmission and distribution infrastructure and other factors will play major roles in regional deployment rates, as will local geothermal resource conditions. For instance, in the USA, Australia and Europe, EGS concepts are already being field tested and deployed, providing advantages for accelerated deployment in those regions as risks and uncertainties are reduced. In other rapidly developing regions in Asia, Africa and South America, as well as in remote and island settings where distributed power supplies are needed, factors that would affect deployment include market power prices, population density, market distance, electricity and heating and cooling demand.

Supply chain issues: No mid- or long-term constraints to materials supply, labour availability or manufacturing capacity are foreseen from a global perspective.

Technology and economics: GHP, district heating, hydrothermal and EGS methods are available, with different degrees of maturity. GHP systems have the widest market penetration, and an increased deployment can be supported by improving the coefficient of performance and installation efficiency. The direct use of thermal fluids from deep aquifers, and heat extraction using EGS, can be increased by further technical advances in accessing and fracturing geothermal reservoirs. Combined heat and power applications may also be particularly attractive for EGS and low-temperature hydrothermal resource deployment. To achieve a more efficient and sustainable geothermal energy supply, subsurface exploration risks need to be reduced and reservoir management needs to be improved by optimizing injection strategies and avoiding excessive depletion. Improvement in energy utilization efficiency from cascaded use of geothermal heat is an effective deployment strategy when markets permit. Evaluation of geothermal plants performance, including heat and power EGS installations, needs to take into account heat quality of the fluid by considering the useful energy that can be converted to electric power. These technological improvements will influence the economics of geothermal energy.

Integration and transmission: The site-specific geographic location of conventional hydrothermal resources results in transmission constraints for future deployment. However, no integration problems have been observed once transmission issues are solved, due to the base-load characteristic of geothermal electricity. In the long term, fewer transmission constraints are foreseen since EGS developments are less geography-dependent, even though EGS' resource grades can vary substantially on a regional basis.

Social and environmental concerns: Concerns expressed about geothermal energy development include the possibility of induced local seismicity for EGS, water usage by geothermal power plants in arid regions, land subsidence in some circumstances, concerns about water and soil contamination and potential impacts of facilities on scenic quality and use of natural areas and features (such as geysers) that might otherwise be used for tourism. Sustainable practices will help protect natural thermal features valued by the community, optimize water and land use and minimize adverse effects from disposal of geothermal fluids and gases, induced seismicity and ground subsidence.

4.8.3 Conclusions regarding deployment

Overall, the geothermal-electric market appears to be accelerating compared to previous years, as indicated by the increase in installed and planned power capacity. The gradual introduction of new technology improvements, including EGS, is expected to boost the deployment, which could reach 140 to 160 GW_e by 2050 if certain conditions are met. Some new technologies are entering the field demonstration phase to evaluate commercial viability (e.g., EGS), or the early investigation stage to test practicality (e.g., utilization of supercritical temperature and submarine hydrothermal vents). Power generation with binary plants permits the possibility of producing electricity in countries that have no high-temperature resources, though overall costs are higher than for high-temperature resources.

Direct use of geothermal energy for heating and cooling is competitive in certain areas, using accessible, hydrothermal resources. A moderate increase can be expected in the future development of such resources for direct use, but a sustained compound annual growth is expected with the deployment of GHP. Direct use in lower-grade regions for heating and/or cooling in most parts of the world could reach 800 GW_{th} by 2050 (Section 4.8.2). Cogeneration and hybridization with other thermal sources may provide additional opportunities.

Evidence suggests that geothermal supply could meet the upper range of projections derived from a review of about 120 energy and GHG-reduction scenarios. With its natural thermal storage capacity, geothermal is especially suitable for supplying base-load power. Considering its technical potential and possible deployment, geothermal energy could meet roughly 3% of global electricity demand by 2050, and also has the potential to provide roughly 5% of the global demand for heating and cooling by 2050.

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