INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE

Chapter 4

Geothermal Energy

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Length

Chapter 4 has been allocated a maximum of 34 (with a mean of 27) pages in the SRREN. The actual chapter length (excluding references & cover page) of the original version (prior to TSU commenting and formatting) was 38 pages, a total of 4 pages over the maximum (11 over the mean, respectively).

Expert reviewers are kindly asked to indicate where the Chapter could be shortened by 7-14 pages in terms of text and/or figures and tables to reach the mean length.

References

References of figures/tables are often missing. References from the text that are found missing in the reference list have been highlighted in yellow. In the same manner, references found in the reference list but missing from the text have also been highlighted.

Metrics

All monetary values provided in this document will be adjusted for inflation/deflation and then converted to US$ for the base year 2005.

Figures

Pictures and figures will be replaced by equivalents with higher resolution where necessary.

Chapter 4: Geothermal energy

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EXECUTIVE SUMMARY

Geothermal energy is literally the heat of the Earth's interior. This heat can be tapped mainly through wells in the form of naturally formed geothermal fluids (geothermal reservoirs) or fluids artificially introduced from the surface (EGS: Enhanced Geothermal Systems). Once at surface, both types of fluids can be indirectly used to generate electric energy in a power unit, or in a direct way in several applications requiring heat, as heating and cooling for buildings, district heating, fish ponds, balneology, greenhouses, industrial and agricultural production and mineral drying, as well as space heating and cooling with geothermal heat pumps (GHP).

Geothermal is a renewable energy (RE) source since the tapped heat is continuously renovated by natural processes of the Earth's interior, and the extracted geothermal fluids are replenished by natural recharge and by reinjection of the exhausted fluids, providing a sustainable development. Given its locations and conditions, it is not expected that geothermal resources can be impacted by climate change.

Geothermal technologies are mature with established markets around the world. Geothermal-electric generation accounts for one century of commercial experience with more than 10 gigawatts of installed capacity in 24 countries providing up to 15% of their electricity demand in some of them; in all those countries, geothermal resources are used for base-load generation with an average capacity factor of 77%. Geothermal direct applications can be traced since the Palaeolithic, and currently there are almost 30 thermal gigawatts operating in 70 countries. Nevertheless, the geothermal technical potential is estimated to be 1000 gigawatts for electricity and 50,000 thermal gigawatts for direct uses, with an economic deployment of 160 gigawatts (electrical) and 815 gigawatts (thermal) by 2050. This could provide around 3% of the worldwide demand of electricity by this year, with some countries obtaining almost 100% of their own electrical needs from geothermal energy.

Direct CO_2 emissions average 120 g/kWh_e for currently operating conventional geothermal-electric power plants and less than 1 g/kWh_e for binary cycle plants. Corresponding figures for direct use applications are even lower. The life-cycle assessment CO_2-equivalent is 25-80 g/kWh_e for binary plants and 4-60 g/kWh_{th} for district heating systems and GHP. This means geothermal resources are environmentally advantageous and the net energy supplied more than offsets the environmental impacts of human, energy and material inputs.

Even geothermal-electric projects have relatively high up-front capital costs, varying currently between 2,000 and 10,000 US$ (2005) per megawatt [TSU: given capital cost values are per kilowatt], the levelized costs (LCOE) of geothermal electricity are competitive in the electric markets, being calculated to be 49-75 US$ (2005) per megawatt-hour (MWh) and around 176 US$/MWh for future EGS projects. These costs are expected to lower to 44-63 US$/MWh (and 137 US$/MWh for EGS) by 2050. Costs of geothermal direct uses are also competitive (1,100 to 2,700 US$ per installed thermal kilowatt).

In despite of the present competitiveness of geothermal resources for electric and heating uses, policy support for research and development is required for all geothermal technologies, and especially for EGS, including subsidies, guarantees and tax write-off to cover the risks of initial deep drilling. Feed-in tariffs with confirmed geothermal prices, and direct subsidies for district and building heating can also be useful.

Geothermal energy is independent of the climate and has an inherent storage capacity that makes it especially suitable for supplying base-load power in an economical way, and can thus serve as a partner with energy sources which are only available intermittently, contributing to significantly mitigate climate change. This is the challenge. This is the opportunity. [TSU: language]

4.1 Introduction

Geothermal resources essentially consist of the thermal energy stored at depth within the earth in both rock and trapped steam or liquid water. Exploitable geothermal systems 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 mantle hot spot anomalies. Intermediate (100-180°C) to low temperature (<100°C) systems are also found in continental settings, formed by above-normal heat production through radioactive isotope decay; they include aquifers charged by water heated through circulation along deeply penetrating fault zones. However, there are several notable exceptions to these temperature-defined categories, and under appropriate conditions, high, intermediate and low temperature geothermal fields can be utilised for both power generation and the direct use of heat.

Geothermal systems can also be classified as convective, which includes liquid and vapour-dominated hydrothermal, as well as lower temperature aquifers or conductive, which includes hot rock and magma over a wide range of temperatures. Lower temperature aquifer systems contain deeply circulating fluids in porous media or fracture zones, but lack a specific heat source. They are further sub-divided into systems at hydrostatic pressure and systems at pressure higher than hydrostatic (geo-pressured). Currently, the most widely exploited geothermal systems for power generation are hydrothermal (of continental subtype). Table 4.1 summarizes all of these types.

Table 4.1. Type of geothermal resources, temperatures and uses. Temperature: 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.

Type	Natural fluids	Subtype	Temperature Range	Utilisation	
				Current	Potential
Hydrothermal	Yes	Continental	H, I & L	Power, direct uses	
		Submarine	H	None	Power, direct
Conductive	No	Shallow (<400 m)	L	GHP	
		Hot rock (EGS)	H, I	Direct	Power, direct
		Magma bodies	H	None	Power, direct
Lower temperature aquifers	Yes	Hydrostatic aquifers	I & L	Direct	Power, direct
		Geo-pressured		Direct	Power, direct

In areas of magmatic intrusions, temperatures above 1000°C can occur at less than 10 km depth. Magma typically ex-solve mineralised fluids and gases, which then mix with deeply penetrating groundwater. Heat energy is also transferred by conduction but in magmatic systems, convection is also important. Typically, a hydrothermal convective system is established whereby local surface heat-flow (through hot springs and steam vents) is significantly enhanced. Such shallow 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.

Subsurface temperatures increase with depth according to the local geothermal gradient, and if hot rocks within drillable depth can be stimulated to improve permeability, using hydraulic pressure, chemical or thermal stimulation methods, they form a potential Enhanced or Engineered Geothermal System (EGS) resource that can be used for power generation and/or direct applications. EGS resources (including Hot Dry Rock: HDR) occur in any geothermal environment, but are likely to be economic in the medium term in geological settings where the heat flow is high enough to permit exploitation at depths of less than 5 km. Experiments have investigated the potential of such continental EGS settings in large areas of Europe, North America, Asia and Australia. In the longer term, and given the average geothermal gradients (25-30°C/km), EGS resources at relatively high temperature (≥180°C) may be exploitable in geological settings at depths up to 7 km, which is well within the range of existing drilling technology for oil and gas (~10 km depth). Stacked geothermal sub-types (plays) are common. Naturally fractured and water-saturated hot rocks are EGS targets below high temperature (>180°C at >2.6 km) hot sedimentary aquifer targets in the Australian Cooper Basin (Goldstein, 2010).

Direct uses of geothermal energy started at least since the Middle Palaeolithic when hot springs were used for ritual or routine bath (Cataldi, 1999), but industrial utilisation begun in Italy by exploiting boric acid from the geothermal zone of Larderello, where in 1904 the first kilowatts of electric energy were generated and in 1913 the first 250-kWe commercial geothermal power unit was installed (Burgassi, 1999).

For the last 100 years, at many places geothermal energy has provided safe, reliable, environmentally sustainable, renewable energy in the form of electric power and direct heating services on both large and small scales. Geothermal typically provides base-load generation, but it can be dispatched and used for meeting peak demand. Today, geothermal represents a viable energy resource in many industrial and developing countries using a mature technology to access and extract naturally heated steam or hot water from natural hydrothermal reservoirs, and it has the potential to make a more significant contribution on a global scale through the development of advanced technology such as EGS that would enable energy recovery from a much larger fraction of the accessible stored thermal energy in the earth's crust. In addition, geothermal (ground-source) heat pumps that can be utilized anywhere in the world for heating and cooling, have had significant growth in the past 10 years and are expected to provide energy savings in most countries of the world.

Today's hydrothermal technologies have demonstrated very high average capacity factors (up to 90%) in electric power generation with low carbon emissions. Environmental and social impacts do exist with respect to land and water use and seismic risk, but these are site and technology specific and largely manageable. New opportunities exist to develop geothermal beyond power generation, particularly to use geothermal heat for district and process heating, along with geothermal heat pumps for space heating and cooling.

This chapter includes a brief description of the worldwide potential of geothermal resources (4.2), the current technology and applications (4.3) and the expected technological developments (4.6), the present market status (4.4) and its probable future evolution (4.8), the geothermal environmental and social impacts (4.5) and the cost trends (4.7) in using geothermal energy to contribute to reduce GHG emissions and mitigate climate change. As presented in this chapter, climate change has no major impacts on geothermal energy, but the widespread development of geothermal energy could considerably reduce the future emission of carbon dioxide into the atmosphere, and play a significant role in reducing anthropogenic effects on climate change.

4.2 Resource potential

4.2.1 Global technical resource potential

The global technical geothermal potential was estimated at 50 EJ according to Table 4.7, chapter 4 (Energy Supply) of the IPCC Fourth Assessment Report (AR4). This is now considered a conservative estimate. Also, in Table 4.2 of the same AR4, it was estimated an available energy resource for geothermal (including potential reserves) of 5000 EJ/year (Sims et al., 2007).

The total 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 and 2004). 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 0.065 W/m^2 on land and 0.1 W/m^2 through the ocean floor. The result is a global average temperature gradient of 25-30°C/km and a total terrestrial heat flow rate of 44 TWt (1400 EJ/year).

Within a 10 km depth under the continents (reachable with current drilling technology) the stored thermal energy is of the order of 40 x 10^7 EJ (EPRI, 1978). Within 5 km depth the energy was estimated to be 14 x 10^7 EJ (WEC, 1994). In addition to the stored energy, the average thermal energy recharge rate from below 5 km depth (ignoring volcanic eruptions) is about 315 EJ/year (Stefansson, 2005). Based on those considerations, the overall **theoretical potential** for geothermal resources can be estimated to be almost 42 x 10^6 EJ (EPRI, 1978; Table 4.2).

More recent assessments reinforce these expectations. In a MIT-led assessment, the US stored geothermal energy was estimated to be 14 x 10^6 EJ with a technically extractable capacity of about 1200 GWe to depths of 10 km (see Tables 3.2 and 3.3 in Tester et al., 2006).The US Geological Survey (2008) estimated mean electric power generation potential from identified and undiscovered EGS resources in the western US alone is 518 GWe. Also for Australia, Budd et al. (2008) estimated that recovery of just 1% of the geothermal energy stored from 150°C to 5 km in the Australian continental crust corresponds to 190,000 EJ. Based on these estimates, available resource is clearly not a limiting factor for geothermal deployment globally.

Recovery of geothermal energy utilises only a portion of the stored thermal energy due to limitations in rock permeability that permit heat extraction through fluid circulation, and to the minimum temperature limits for utilization at a given site. To calculate an effective technical potential it is necessary to exclude the heat which cannot be accessed at drillable depths or is insufficiently hot for practical use. Global utilisation has so far concentrated on areas in which geological conditions, such as natural fractures and porous formations, permit water or steam to transfer the heat nearer to the surface, thus giving rise to convecting hydrothermal resources where drilling at up to 4 km depth can access fluids at temperatures of 180°C to more than 350°C.

A statistical analysis (Goldstein, 2010) of stored geothermal energy to depths of 5 km (WEC, 1994) and 10 km (ESPRI, 1978) assumes 0.5% and 20% as the minimum and maximum recovery factors, respectively. This assessment concludes the global technical recoverable continental geothermal energy resource is in the order of 9 x 10^6 EJ to 5 km and 27 x 10^6 EJ to 10 km, with a 7% (statistical mean) recovery of stored heat. Both estimates are conservative in the context of sustainable level for development (42 x 10^6 EJ, EPRI, 1978; Table 4.2).

From the distribution of geothermal resources over different temperature regimes, Stefansson (2005) estimated the low temperature potential (for direct use or binary-cycle electricity) to be 153 EJ/year (5 TWt). The combined high and low temperature technical potential (about 800 EJ/year) is approximately the same order of magnitude as the natural heat recharge of the underground resources.

For hydrothermal submarine resources, an estimation of 130 GWe off-shore technical potential has been made (Hiriart et al., 2010). This is based on the 3900 km of ocean ridges already confirmed as having hydrothermal vents and with the assumption that only 1% could be developed for electricity production with a recovery factor of 4%.

Stefansson (2005) concluded that the most likely value for the technical potential of known, onshore, hydrothermal resources capable of use for electricity generation (T>130°C) is 209 (±27) GWe. This value is supported by a statistical correlation between the numbers of active land-based volcanoes (1322 in total) and identified geothermal resources in well-explored regions. However, theoretical considerations based on well-explored regions of the USA and Iceland reveal that the magnitude of hidden hydrothermal resources is expected to be 5-10 times larger than this estimate of identified resources (Bertani, 2009).

The global geothermal **technical potential** can be estimated to be almost 30 EJ/y for electricity generation and almost 631 EJ/y for direct utilisation (Bertani, 2009). Technical potential for geothermal-electricity, including EGS, is equivalent to 1000 GWe (1 TWe) of installed capacity assuming an average capacity factor of 0.95, and to 8,322 TWh/y of electric generation. The technical potential for geothermal direct uses is equivalent to 50,000 GWt (50 TWt) of installed capacity, assuming an average capacity factor of 0.40 (Table 4.2 and Fig. 4.1).

A comparison of estimates of global geothermal economic potential published by different authors (Bertani, 2003) reveals that the projections are very scattered, due to differences in assumptions and uncertainties in energy recovery factors, economic viability and assumed rates of learning in all areas (exploration, drilling, stimulation, and energy conversion) as deployment proceeds. Nevertheless, a thorough review concludes that geothermal electricity **economic potential** (by **2050**) from identified geothermal reservoirs is realistically estimated to range between a minimum of 35 GWe, a median of 70 GWe, and a maximum of 160 GWe (Figure 4.1), depending on assumptions regarding technology improvement, development incentives or constraints that may be in effect over the next 40 years (Bertani, 2009; Fridleifsson et al., 2009; Rybach, 2010; Mongillo, 2009; Mongillo et al., 2010). The median value represents an annual compounding growth rate of 5% over 40 years and is considered to be economically realisable using present day technology. The maximum value (more than twice the median) represents an annual growth rate of 7% and is also economically realisable, but includes the assessed benefits of future financial incentives, and enhanced technologies such as permeability stimulation and deeper drilling.

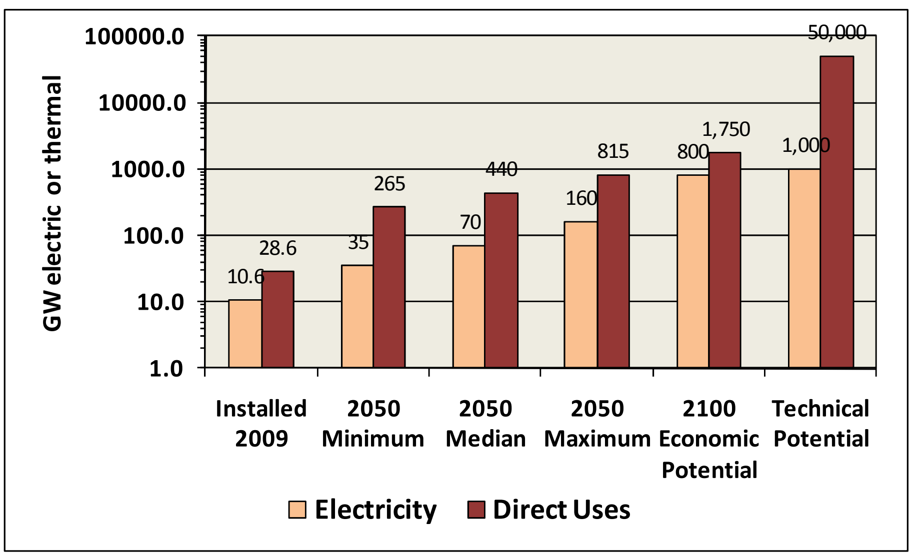

Figure 4.1. Estimated global geothermal electricity and direct use economic potentials by 2050 and beyond, with assumptions of status-quo growth rates (minimum), present technology (median) and technology improvement (maximum). Data for 2009 direct uses correspond to 2005 (to be updated [by AUTHORS]). Technical resource potentials (including inferred but unidentified resources) are also shown (Adapted from Fridleifsson et al., 2008, and Stefansson, 2005).

The geothermal-electric **economic potential** by **2100** was also estimated to be around 24 EJ/y, equivalent to 800 GWe of installed capacity using the same capacity factor of 0.95.

On the basis of the estimates shown in Figure 4.1, it is considered plausible to produce up to 8.3% of the total world electricity by 2100 with onshore geothermal resources (including EGS), serving ~17% of the world population (Bertani, 2009). More than thirty countries (located mostly in Africa, Central/South America, the Pacific and South-East Asia) could potentially obtain 100% of their electricity from a combination of base-load geothermal and variable-load hydro and wind resources.

The next issue is to consider the prospective contribution of EGS to the technical and economical potential more carefully. Recognizing that there is very limited operating experience with EGS at a commercial scale, any estimate is by nature speculative. Nonetheless, one should keep in mind that many characteristics and deployment requirements of EGS systems bear similarity to commercial hydrothermal systems. And, if geothermal is to have a large scale impact in off-setting global carbon dioxide emissions in the future, utilization of the EGS resource will be necessary.

A statistical analysis by Goldstein et al. (2009) yields a mean forecast for global EGS deployment of 444 GWe (worldwide) by 2050 without any consideration of commercial risks or technical uncertainties. Accounting for these factors, the authors give a more realistic range of 90 to 130 GWe by 2050, from which it was estimated that EGS could represent around the half of the maximum of 160 GWe projected by this year (Fig. 4.1). Industrial and governmental co-funding of EGS development aims to make financial investment more attractive based on an increased probability of EGS project success. With this co-funding and appropriate mitigation policy instruments, high grade, hot rock resources are expected to become competitive, as early as 2015.

Regarding geothermal **direct uses**, the **economic potential** by **2100** is estimated to be 22 EJ/y, equivalent to 1750 GWt of installed capacity with an average capacity factor of 0.40. The **economic potential** by **2050** is estimated to be between a minimum of 265 GWt, a median of 440 GWt, and a maximum of 815 GWt (Figure 4.1), depending on similar assumptions to those made for estimating the electric potential (Fridleifsson et al., 2008; Rybach, 2010; Mongillo, 2009; Mongillo et al., 2010).

Potential for increased direct use is very large. Recent likely-case scenario estimates of future direct use indicate that by 2050 the total use could increase to 815 GWt, with a GHP (Geothermal Heat Pumps) contribution of some 740 GWt (90%) (Table 4.9). The dominance and expected significant growth in GHP use arises from their ability to be used for heating, cooling and domestic hot-water applications anywhere on the earth's surface (Lund et al., 2003; Curtis et al., 2005; Rybach, 2008).

4.2.2 Regional resource potential

The assessed geothermal theoretical, technical and economic potentials (the latter by 2100), are presented on a regional basis in Table 4.2. The original regional assessment for the theoretical potential was conducted by EPRI in 1978 (EPRI, 1978), with a very detailed estimation of the heat stored inside the first 3 km under the continents, taking into account the average geothermal gradient and the presence of either a diffuse geothermal anomaly or an high enthalpy region, due to the location nearby the plate boundaries. Data from theoretical and technical potentials are taken and adapted from Bertani (2009), regrouping countries and regions into the 10 IEA regions. The economic potential by 2100 is an original estimation.

Table 4.2. Geothermal potentials for the IEA regions (Theoretical and technical potentials adapted from Bertani, 2009).

IEA REGION	Theoretical Potential	Technical Potential		Economic Potential (2100)	
		EJ/year		EJ/year	
	10^6 EJ	Direct uses	Electricity	Direct uses	Electricity
1. OECD North America	9.402	141.060	8.384	5.046	6.441
2. Latin America	5.509	81.409	6.896	0.631	0.749
3. OECD Europe	2.019	30.711	1.110	6.307	4.494
4. Africa	6.083	93.145	2.390	2.018	1.947
5. Transition Economies	6.930	106.732	1.710	0.631	0.599
6. Middle East	1.355	20.711	0.580	0.505	0.449
7. Developing Asia	3.732	55.379	4.300	1.261	4.494
8. India	0.938	14.528	0.100	0.631	0.899
9. China	3.288	48.842	3.720	2.523	2.397
10. OECD Pacific	2.487	38.203	0.770	2.523	1.498
TOTAL	**41.743**	**630.720**	**29.960**	**22.075**	**23.967**
Equivalent installed capacity (in GWt or GWe)*		**50,000**	**1,000**	**1,750**	**800**

*Equivalence considers 0.95 and 0.40 as average capacity factors for electricity and direct uses, respectively.

4.2.3 Sustainable development and the possible impact of climate change on resource potential

Geothermal energy is a renewable resource, yet it is clearly different from solar, wind, and biomass. As thermal energy is extracted from the active reservoir, it creates locally cooler regions. In more practical terms, commercial geothermal projects are operated at production rates that cause local declines in hydraulic pressure and/or in temperature over the economic lifetime of the installed facilities. These cooler and lower pressure zones lead to gradients that result in continuous recharge by conduction from hotter rock, and convection and advection of fluid from surrounding regions. The time scales for thermal and pressure recovery are similar to those required for energy removal (Stefansson, 2000). Detailed modelling studies (Pritchett, 1998) have shown that this type of resource exploitation can be economically feasible, and still be renewable on a timescale useful to society, when non-productive recovery periods are considered.

With proper well placement and reservoir management, geothermal energy can be sustainably developed. In hydrothermal reservoirs sustainable production can be achieved by adjusting production rates and injection strategies, taking into account the local resource characteristics (field size, natural recharge rate, etc.).

Time scales for re-establishing the pre-production state following the cessation of production have been determined using numerical model simulations for: 1) heat extraction by geothermal heat pumps, 2) the use of doublet systems on a hydrothermal aquifer for space heating, 3) the generation of electricity from a high enthalpy hydrothermal or EGS reservoir (for details see Rybach and Mongillo, 2006; Axelsson et al., 2005; O'Sullivan, 2008). After production stops, begins recharge driven by pressure and temperature gradients. The recovery typically shows an asymptotic behaviour, fastest at first then slowing down subsequently. Practical replenishment will generally occur on time scales of the same order as the lifetime of the geothermal production systems (Axelsson et al., 2005).

Good examples of sustainable uses of high- and low-temperature geothermal fields are given in recent international sustainability workshop proceedings (Axelsson and Bromley, 2008).

Since geothermal resources are located underground or undersea, they are not dependent on climate conditions. Therefore, climate change is not expected to have any relevant impact on the resource potential from a worldwide nor a regional perspective. However, the GHP efficiency could be affected by changes in surface temperature, and a future scarcity of water may force geothermal power plants to switch to air-cooled systems.

4.3 Technology and applications (electricity, heating, cooling)

4.3.1 Geothermal energy utilisation

Geothermal energy is used in two ways – as a heat supply for conversion to electricity and for direct heating or cooling without conversion. Geothermal resources can be divided into three main groups, depending on temperature and their relation to magmatic activity:

a) High-temperature (>180°C). These systems are mostly related to geologically recent volcanism and are mainly used for conventional power production. Some non-volcanic, high temperature areas are being appraised for power production from EGS.

b) Intermediate temperature (100°C-180°C). These are found all over the world in deep sedimentary basins, in hot rocks below sedimentary basins and in areas indirectly related to volcanism or tectonic fracturing and are often used for combined heat and power applications.

c) Low temperature (ambient to 100°C). These systems typically have little direct relation to volcanism, and are used mainly for direct heat and heat pump applications.

Energy is extracted from reservoir fluids by discharging various mixtures of hot water and steam through production wells. In high temperature reservoirs, as pressure drops, the water component boils or "flashes". Separated steam is piped to a turbine to generate electricity and the remaining hot water may be flashed again two or three times at progressively lower pressures (and temperatures) to obtain more steam. The remaining brine is usually sent back to the reservoir through injection wells. Some reservoirs produce "dry" steam, which 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 upflow in the well-bore is required to avoid gravity collapse of the water phase. In addition many reservoirs are utilised by extracting heat from thermal water of a producer well and generating power in a binary cycle. The cooled water is re-injected into the reservoir after passing the heat exchanger.

Geothermal technologies belong to category 1 (technologically mature with established markets in at least several countries) according to the 2004 Renewables Conference held in Bonn. Key technologies for exploration and drilling, reservoir management and stimulation and energy recovery and conversion are described below.

4.3.2 Exploration and drilling

Since geothermal resources are underground, some exploration activities (including geological, geochemical and geophysical surveys) have to be developed to locate and assess them. The objectives of geothermal exploration activities are to identify and rank prospective geothermal reservoirs prior to drilling, and to provide methods of characterising reservoirs that enable estimations of geothermal reservoir performance and lifetime. The major focus is the underground temperature distribution and the Earth's stress field in order to identify potential fluid bearing structures. Exploration of a prospective geothermal reservoir involves estimating its lateral extent and depth with geophysical methods, such as seismic, magneto-telluric and resistivity surveys, and drilling exploration wells. Thermograms recorded in available shallow water-wells (50-200 m) could be also useful to reveal geothermal anomalies and constructing terrestrial temperature maps (Zui, 2004, 2010).

Today, geothermal wells are drilled over a range of depths to about 5 km using conventional rotary drilling methods similar to those used for oil and gas. Advances in drilling technology enable high temperature operation and provide directional capability. Typically, wells are deviated from vertical to about 30-50° inclination from a "kick off point" at depths between 200 m and 2000 m. Many wells can be drilled from the same drilling-pad, heading in different directions to access large resource volumes, and target permeable structures. Current geothermal drilling methods are presented in more detail in the chapter 6 of Tester et al. (2006).

4.3.3 Reservoir engineering

The most sophisticated method of estimating reserves and sizing power plants is to apply reservoir simulation technology. Since it is not possible to gather all the data required to construct a comprehensive deterministic model, a conceptual model is built, using available data, then translated into a numerical representation, and calibrated to the unexploited, initial thermodynamic state of the reservoir. Future behaviour is forecast under selected load conditions using a heat and mass transfer algorithm (Pruess, 2009), and optimum plant size selected.

Injection management is an important aspect of geothermal development. Because most geothermal reservoirs are fracture-dominated, the system "plumbing" is poorly known at early times, and the placement of injection wells cannot be optimized until the field has been stressed by production, and flow paths and thermal responses identified. Cooling of production zones by injected water that has had insufficient contact with hot reservoir rock can result in severe production declines. Placement of wells should also aim to enhance deep hot recharge through production pressure drawdown, but suppress shallow inflows of peripheral cool water through injection pressure increase.

Given sufficient, accurate calibration with field measurements, geothermal reservoir evolution can be modelled and pro-actively managed. Hence, it is prudent to monitor and analyse the chemistry and thermodynamics of geothermal fluids, along with mapping their flow and movement. This information combined with other geophysical data are fed back to re-calibrate models for better predictions.

4.3.4 Surface equipment and power plants

Surface equipment generally has to handle steam, water and/or both (two) phases. Systems with direct use of steam consist of pipelines, water-steam separators, vaporisers, de-misters, and different types of turbines. Binary cycles require heat exchangers. Steam turbines are driven by convective flow to a low pressure exhaust or a vacuum. In a condensing turbine (Figure 4.2), vacuum conditions are usually maintained by direct condenser. Depending on humidity and temperature, a significant proportion of the steam condensate is thereby lost to the atmosphere as vapour. The unit sizes are commonly 20-110 MWe (DiPippo, 2009). Design optimisation requires knowledge of reservoir behaviour. Double or triple flash cycles make use of excess brine separated at high pressure. A "triple flash" steam turbine can have three different inlets, operating at pressures and temperatures as low as 1.4 bar_a and 110°C. Back-pressure turbines are also steam turbines that exhaust to the atmosphere, omitting the condenser and the cooling tower, and are frequently used as small plants supplied by isolated wells for distributed local (rural) power supplies. The efficiency is only about 50-60% of condensing turbines, but the cost is less. About 15 back-pressure units of 5 MWe have been successfully operating in Mexico since the 1980s.

Binary cycle plants of Organic Rankine Cycle (ORC) type (see Figure 4.3) typically utilise lower temperature geothermal fluids (about 70 to 170°C) than conventional flash and dry steam plants (from about 150°C to over 300°C). They are more complex since the geothermal fluid (water, steam or both) passes a heat exchanger heating another “working” fluid such as isopentane or isobutane with a low boiling point, which vaporizes and drives a turbine. The working fluid can then be air-cooled or condensed with water. Binary plants are often constructed as linked modular units of a few MWe in capacity.

Combined or hybrid plants comprise two or more of the above basic types to improve versatility, increase overall thermal efficiency, improve load-following capability, and efficiently cover a wide (200-260°C) resource temperature range.

Cogeneration (Co-gen) plants, or Combined or Cascaded Heat and Power plants (CHP), produce both electricity and hot water for district heating or direct use at significantly higher utilisation efficiency than can be achieved for just generating electricity or supplying heat. Relatively small industries and communities of a few thousand people provide sufficient markets for combined heat and power applications. Iceland has two geothermal cogeneration plants with a combined capacity of 300 MWt in operation; the distance of the plants to the towns ranges from 12 to 25 km, over which cooling losses using large insulated pipes and high flow-rates, are negligible. At the Oregon Institute of Technology (OIT) with 3000 students, faculty and staff a CHP provides most of the electricity needs and all the heat demand (Lund and Boyd, 2009). Combined heat and power using low temperature geothermal resources have also been developed in Germany and Austria.

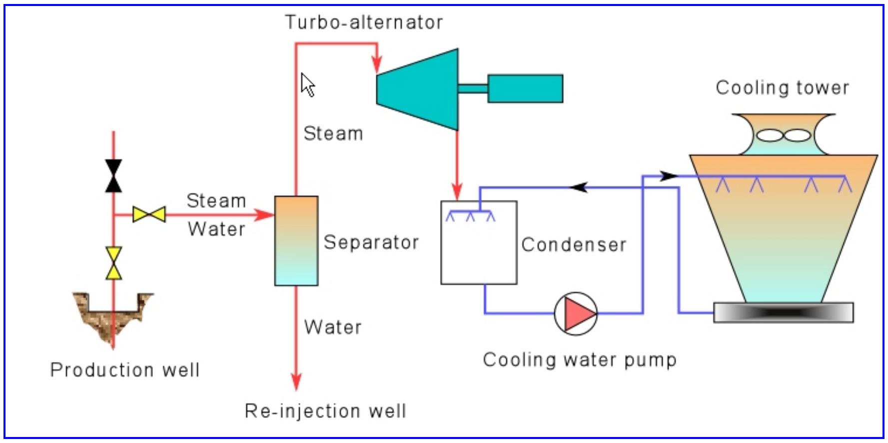

Figure 4.2. Schematic diagram of a geothermal condensing steam power plant. [TSU: Please add source.]

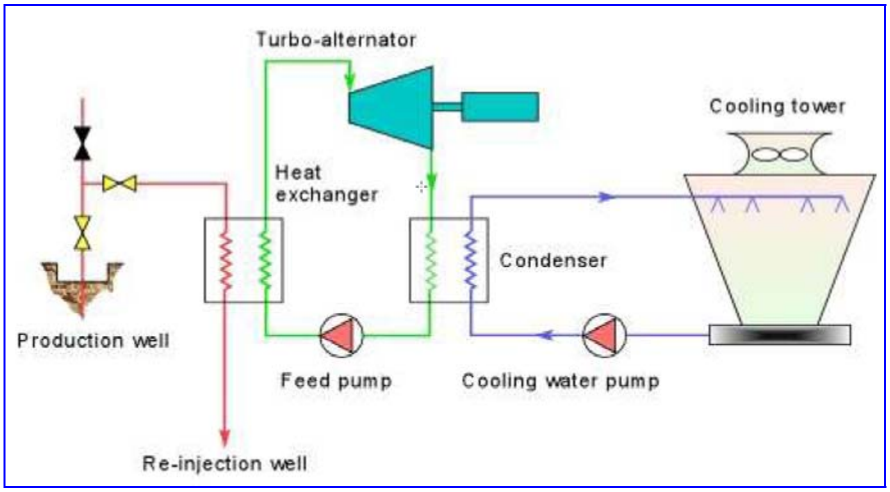

Figure 4.3. Schematic diagram of a geothermal binary cycle power plant. [TSU: Please add source.]

4.3.5 Technologies needed for EGS development

The principle of Enhanced Geothermal Systems (EGS) is as follows: in the subsurface where temperatures are high enough for effective utilisation, a fracture network is created or enlarged to act as new fluid pathways. Water is passed through this deep reservoir using injection and production wells, and heat is extracted from the circulating water at the surface. The extracted heat can be used for district heating and/or for power generation.

EGS projects are currently at a demonstration and experimental stage. The key technical and economic challenges for EGS over the next two decades will be to achieve efficient and reliable stimulation of multiple reservoirs with sufficient volumes to sustain long term production, with low flow impedance, limited short-circuiting fractures, and manageable water loss (Tester et al., 2006).

Conforming research priorities for EGS and magmatic resources as determined in Australia (DRET, 2008), the USA (DOE, 2008), the EU (ENGINE, 2008) and the International Partnership for Geothermal Technologies (IPGT, 2008) are summarised in Table 4.3. Successful deployment of the associated services and equipment will be also relevant to many conventional geothermal projects.

Table 4.3. Priorities for geothermal research –focusing on potential of magmatic and EGS resources. (Adapted from Goldstein et al., 2008). HTHP: high temperature and high pressure.

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

4.3.6 Technology for submarine geothermal generation

Offshore, there are some 67,000 km of mid-ocean ridges, of which 13,000 km have been studied, and more than 280 sites with submarine geothermal vents have been discovered (Hiriart et al., 2010). Some discharge thermal energy of up to 60 MWt (Lupton, 1995) but there is others, such as ‘Rainbow’, with an estimated output of 5 GWt (German et al., 1996). The abundance of submarine hydrothermal systems indicates that technology for their future exploitation should be investigated further, providing such projects could become economically feasible.

In theory, electric energy could be produced directly from a hydrothermal vent (without drilling) using an encapsulated plant, like a submarine, containing an ORC binary plant, as described by Hiriart and Espíndola (2005). An external coiled heat exchanger could be placed over the top of the hot water vent at one end, while at the other end another coiled heat exchanger with hyperbolic cooling tower could be installed in the cold water of the surrounding sea. The operation would be similar to other binary cycle power plants using evaporator and condenser heat exchangers. This cycle has an internal efficiency of the order of 80%, resulting from losses of the turbine, pumps and generator (Hiriart et al., 2010). Overall efficiency for a submarine vent of 4% (electrical power generated / thermal power) is a reasonable estimate for such an installation (Hernández, 2008). Other critical challenges for these resources include the distance from shore and off-to-onshore grid-connection costs and the potential impact on unique marine life around hydrothermal vents.

4.3.7 Direct use

Direct use provides heating and cooling for buildings including district heating, fish ponds, greenhouses and swimming pools, and industrial and process heat for agricultural products and mineral drying. In addition, ambient temperature shallow ground and groundwater are used for space heating and cooling with geothermal heat pumps.

For space heating, closed loop (double pipe) systems are commonly used. In this case, heat exchangers are utilised to transfer heat from the geothermal water to a closed loop that circulates heated freshwater through the radiators. This is often needed because of the chemical composition of the geothermal water. The spent water is disposed of into re-injection wells. Closed loop systems are more flexible than open loop systems, but in both cases a fossil fuel backup boiler (as shown in Figure 4.4) may be provided to meet peak demand, to reduce the overall investment, and to conserve the geothermal resource.

In Iceland, the geothermal water is piped up to 25 km from the geothermal fields to the towns. Transmission pipelines are 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.

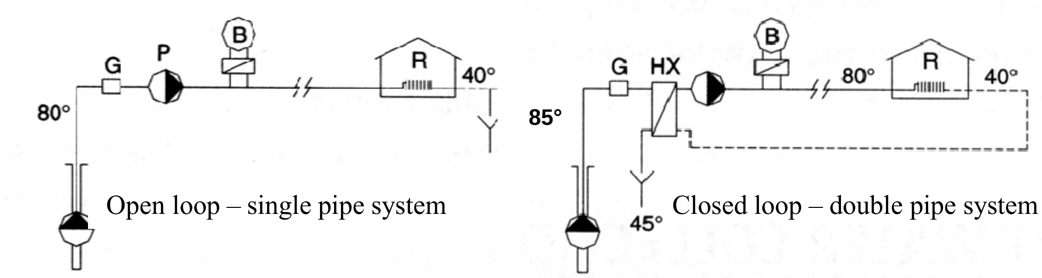

Figure 4.4. Two main types of district heating systems (Dickson and Fanelli, 2003). G=gas separator, P=pump, B=backup boiler, R=radiation heating, HX=heat exchanger.

4.3.8 Geothermal heat pumps

Geothermal Heat Pumps (GHP) are one of the fastest growing applications of renewable energy in the world today (Rybach, 2005). This form of direct use of geothermal energy is based on the relatively constant ground or groundwater temperature in the range of 4°C to 30°C available anywhere, to provide space heating, cooling and domestic hot water for all types of buildings. Extracting energy cools the ground, which creates temperature gradients, enhancing recharge.

There are two main types of geothermal heat pumps (Figure 4.5, modified from Lund et al., 2003). In ground-coupled systems a closed loop of plastic pipe is placed in the ground, either horizontally at 1-2 m depth or vertically in a borehole down to 50-250 m depth. A water-antifreeze solution is circulated through the pipe. Thus heat is collected from the ground in the winter and optionally heat is 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 to surface.

In essence heat pumps are nothing more than refrigeration units that are reversed. In the heating mode the efficiency is described by the coefficient of performance (COP) which is the heat output divided by the electrical energy input. Typically this value lies between 3 and 4 (Rybach, 2005).

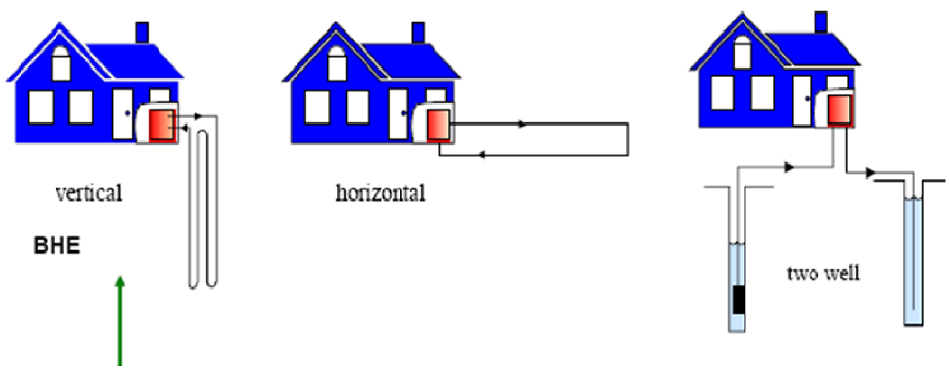

Figure 4.5. Closed loop and open loop heat pump systems. Green arrow indicates the most common system, with borehole heat exchangers (BHE). The heat pump is shown in red. [TSU: Please add source.]

4.4 Global and regional status of market and industry development

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. Current industrial participants can be found by searching the IGA, IEA-GIA, GEA, GRC, and other national websites featuring energy attributes [TSU: websites as footnotes?]. For convenience, the global geothermal market can be subdivided into conventional resource development for electricity, non-conventional development (EGS), and direct heat utilisation.

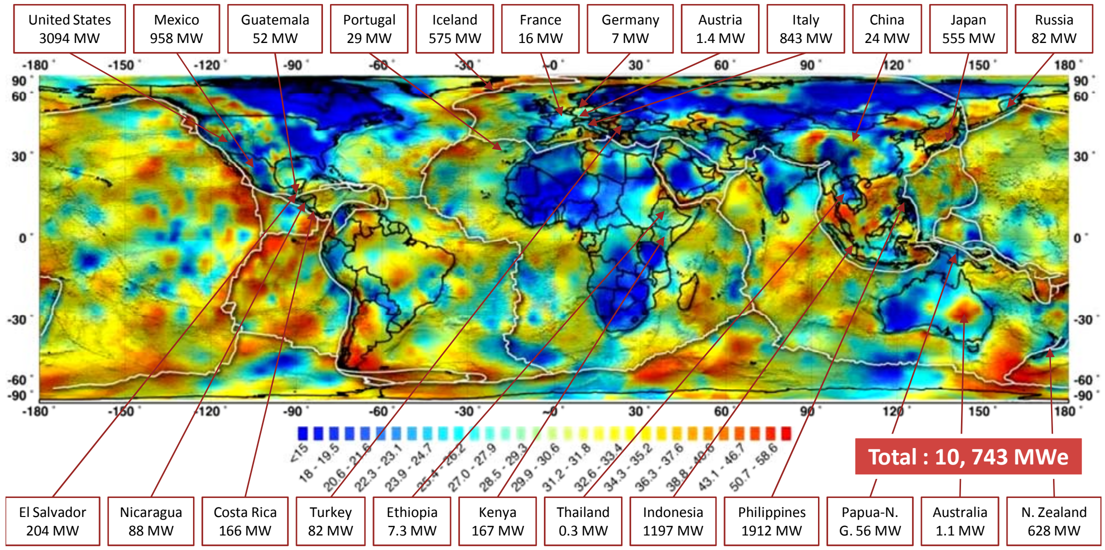

Figure 4.6. Geothermal-electric installed capacity by country in 2009 (Credits: [by AUTHORS]). Figure shows worldwide heat flow ranks in color (units? [by AUTHORS]) and tectonic plates boundaries (To be completed [by AUTHORS]). [TSU: Please add source.]

4.4.1 Status of geothermal electricity from conventional geothermal resources

In 2009, electricity was being produced from conventional high temperature geothermal resources in 24 countries (Fig. 4.6). Many developing countries are amongst the top 15 in geothermal electricity production, but many more have untapped resources inferred from their favourable locations with respect to active volcanism and fractured crustal rock, for example, Chile and Peru.

The worldwide use of geothermal energy for power generation (predominantly from conventional hydrothermal resources) was 67 TWh/year in 2008. The installed capacity by the middle of 2009 was 10.7 GWe (Fig. 4.6), and has been growing at 4.4% annually since 2004 (Gawell and Greenberg, 2007; Fridleifsson and Ragnarsson, 2007). This is higher than the 1999-2004 average annual growth rate of 3% (Bertani, 2005, 2009) (Fig. 4.7).

Evolution of geothermal installed capacity, annual generation and capacity factor since 1995 are provided in Table 4.4, along with projections to year 2100.

Table 4.4. World installed capacity, electricity production and capacity factor of geothermal power plants 1995-2005 and forecasts for 2010-2100 (with data from Fridleifsson et al., 2008, and Bertani, 2009).

Year	Installed Capacity (GWe) Actual or mean forecast	Electricity Production (GWh/yr) Actual or mean forecast	Capacity Factor (%)
1995	6.8	38,035	64
2000	8.0	49,261	71
2005	8.9	56,786	73
2010	11	74,669	77
2020	25	178,000	81
2030	50	372,000	85
2040	100	780,000	89
2050	160	1,261,000	90
2100	800	6,700,000	96

Conventional geothermal resources currently used to produce electricity are of high-temperature (>180°C), utilised through steam turbines (condensing or back-pressure, flash or dry-steam), and of low-intermediate temperature (<180°C) used by binary-cycle power plants. Electricity has been generated commercially by geothermal steam since 1904 (Figure 4.7).

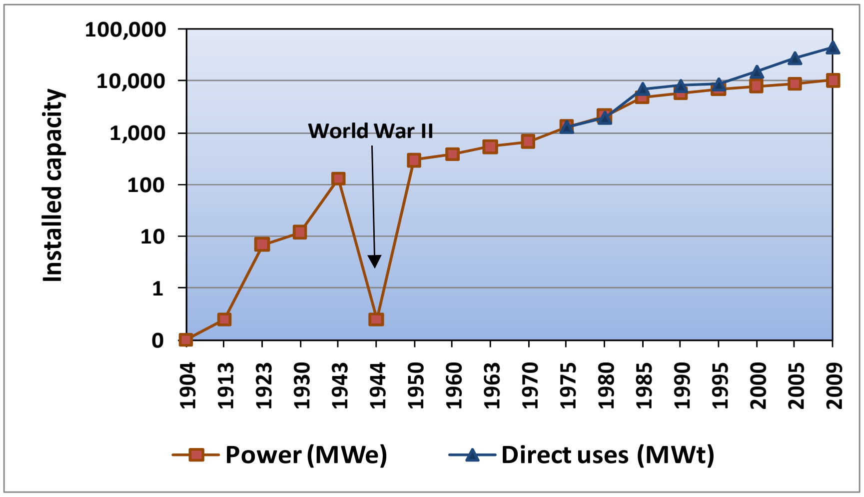

Figure 4.7. Historic development of geothermal installed capacity (power and direct uses) worldwide. For direct uses there are no reliable data before 1975. [TSU: Please add source.]

The US is currently the world's top geothermal market. The US geothermal resurgence is due to increased RE penetration in the US power generation market. State Renewable Portfolio Standards (RPS) demand and the Federal Production Tax Credit (PTC), increased natural gas price fluctuation, and a rapid acceleration of pushback against the permitting of new coal-fired power plants have all opened a clear market opportunity for geothermal growth (Stephure, 2009). US geothermal activity is concentrated in a few western states, which are home to vast reserves of US hydrothermal resources, particularly in California and Nevada, but only a small fraction of the geothermal potential has been developed so far. By September 2009, an industry advocacy group, the Geothermal Energy Association (GEA) had identified around 132 new geothermal-electric projects in different stages of development in the US. These projects represented between 4249 and 6443 MWe of new geothermal power plant capacity under development in 14 states of the country (Jennejohn, 2009).

Outside of the US, over 29% of the global installed geothermal capacity resides in the Philippines and Indonesia (Fig. 4.8). Indonesia is expected to evolve as the larger geothermal growth market in the longer term due to its better resource potential and growing power appetite (Stephure, 2009).

Outside of the US and Southeast Asia, the markets of Japan, Iceland, Italy, and Mexico account for over 65 percent of remaining [TSU: % of remaining unclear] global installed geothermal capacity. Although these markets have seen relatively limited growth over the past few years, greater urgency to advance low-carbon base-load power generation is helping re-start new capacity growth in these markets. Moreover, attention is turning to new markets like Chile, Germany, Australia, and East Africa, and other not so new as Turkey, Nicaragua and Russia (Fig. 4.8).

The majority of existing geothermal assets are owned by large incumbent state-owned utilities and large Independent Power Producers (IPP). Currently, more than 30 companies globally have an ownership stake in at least one geothermal deployed project. Altogether the top 20 owners of geothermal capacity control roughly 90% of the entire installed global market.

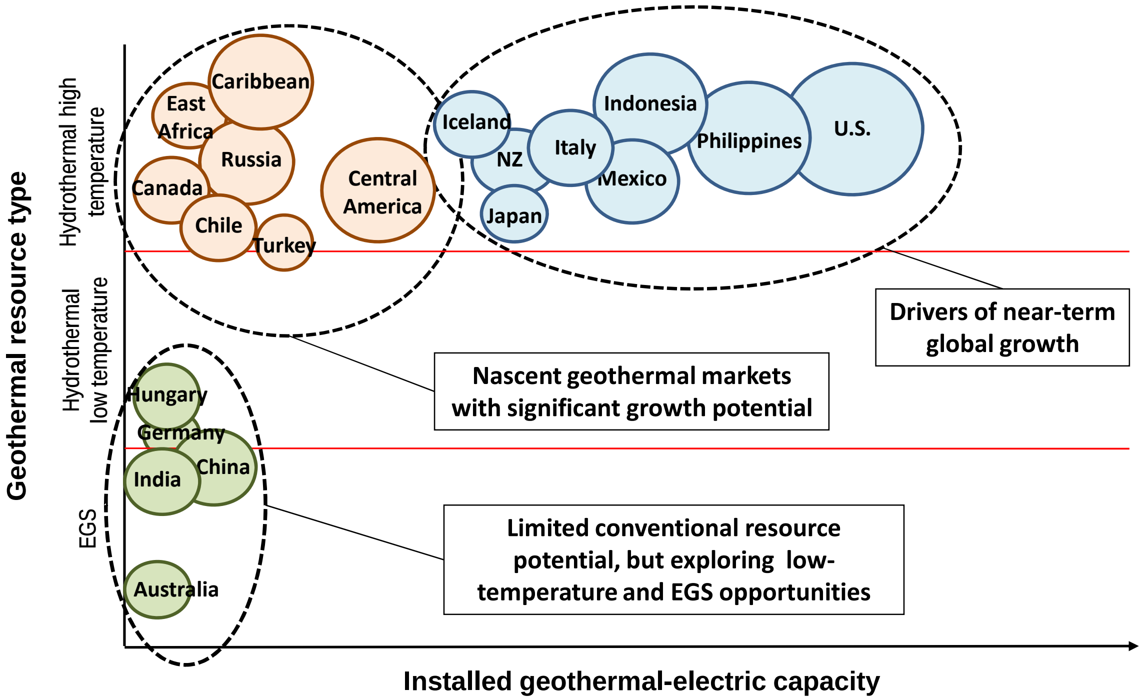

Figure 4.8. Global geothermal country rankings by installed capacity and resource type. (Bubble size approximately reflects MWe resource potential) (Emerging Energy Research, 2009.)

Today the geothermal-electric capacity represents only 0.22% of the total worldwide electric capacity (about 5,000 GWe [TSU: 5 GWe, consitency with table 4.4? (2005: 8.9 GWe, 2010: 11 GWe)]). However, taken separately, six of those 24 countries shown in Figure 4.6 (El Salvador, Kenya, Philippines, Iceland, Costa Rica and New Zealand) obtain more than 10% of their national electricity production from high temperature, conventional geothermal resources (Fridleifsson, 2007).

4.4.2 Status of Enhanced Geothermal Systems

There are several places where targeted EGS demonstration is underway. Australia can claim large-scale activity, since by 2010 eighteen stock market-registered enterprises held Australian geothermal licences. A real boom can be observed, with 48 companies in 391 leases (a total of 362,000 km^2 in six states), US$ 248 million invested to year-end 2008 and more than US$ 1000 million forecast to year-end 2014. This is underpinned with government grants to co-fund drilling, geophysical surveys and research totalling US$ 267 million (to year end 2009) (Goldstein et al., 2010). Project developers plan to establish the first power plants (with a few MWe capacity) in 2010 (Beardsmore, 2007).

The EU project “EGS Pilot Plant” in Soultz-sous-Forêts, France (started in 1987), has recently commissioned the first power plant (1.5 MWe) to utilise the enhanced fracture permeability at 200°C (low fracture permeability was enhanced). In Landau, Germany, the first EGS-plant with 2.5 to 2.9 MWe went into operation in fall 2007 (Baumgärtner et al., 2007). Another approach is made for deep sediments in the in situ geothermal laboratory in Groß Schönebeck using two research wells (Huenges et al., 2009). One of the main future demonstration goals in EGS will be to see whether and how the power plant size could be up-scaled to several tens of MWe by improved reservoir engineering measures.

The US in its recent clean energy initiatives has included significant EGS research, development, and demonstration components as part of a revived national geothermal program.

Although EGS power plants, once operational, can be expected to have great environmental benefits, their potential future impact and environmental benefits such as avoiding additional CO_2 emissions, cannot yet be satisfactorily quantified. [TSU: Relation to market and industry development?]

4.4.3 Status of direct uses of geothermal resources

Direct heat supply temperatures are typically close to actual process temperatures in district heating systems which range from approximately 60 to 120°C. As a result, only a small degradation of the thermodynamic quality of the geothermal heat occurs. The main types (and relative percentages) of direct applications are: space heating of buildings (52%, of which 32% [TSU: percentage points?] is from heat pumps), bathing and balneology (30%), horticulture (greenhouses and soil heating) (8%), industrial process heat (4%), aquaculture (fish farming) (4%) and snow melting (1%) (Lund et al., 2009 [TSU: list of references contains two publications of Lund et al., 2009]).

Heating of building spaces, including district heating schemes, is among the most important direct applications. When the resource temperature is too low for direct use, it is possible to use a geothermal heat pump (GHP). Also space cooling can be provided by geothermal resources, and GHP devices can heat and cool with the same equipment.

Bathing, swimming and balneology utilizing geothermal water have a long history and are globally wide-spread. In addition to the thermal energy the chemicals dissolved in the geothermal fluid are also important for treating various skin diseases.

Geothermally heated greenhouses allow cultivation of flowers and vegetables in colder climates where commercial greenhouses would not normally be economical. Heating soil in outdoor agricultural fields has also been applied at several places such as Iceland and Greece.

A variety of industrial processes utilise heat applications, including drying of forest products, food, and minerals industries as in the United States, Iceland and New Zealand. Other applications are process heating, evaporation, distillation, sterilisation, washing, CO_2 and salt extraction.

Aquaculture using geothermal heat allows better control of pond temperatures, which is of great importance for optimal growth. Tilapia, salmon and trout are the most common fish raised, but unusual species such as tropical fish, lobsters, shrimp or prawns, and alligators are also reported.

Snow melting or de-icing by using low temperature geothermal water is applied in some colder climate countries. City streets, sidewalks, and parking lots are equipped with buried piping systems carrying hot geothermal water. In some cases, this is return water from geothermal district heating systems as in Iceland, Japan and the United States.

The world installed capacity of geothermal direct use is currently estimated to be 28.6 GWt [by AUTHORS] (Fig. 4.1), with a total thermal energy usage of about 72.6 TWh/y (0.261 EJ/y) [by AUTHORS] (Lund et al., 2005). Out of that total, geothermal heat pumps (GHP) contributed more than half (15.7 GWt) [by AUTHORS], with approximately 1.6 million geothermal heat pumps (GHP) operating in more than 30 countries (IEA-GIA AP, 2008). GHP represents one of the more expanding markets of renewable energy in the world, and due to its rapidly growing development, statistical data can provide only snapshots of the current situation (Data for 2005; to be updated by 2009 later) [by AUTHORS].

4.4.4 Impact of policies

[TSU: cross-reference to chapters 1 and 11?]

Main present barriers in the geothermal market and industry, according to the taxonomy of barriers used in this report [TSU: replace by cross-reference to chapter 1.4 instead?], can be described as follows.

I1 (Clarity in concepts [knowledge, understanding]) [TSU: see above]. Support is needed for programmes to standardise geothermal technologies for a reliable and efficient use independent of site, to educate and enhance the public knowledge, understanding and acceptance of geothermal energy use, and to conduct research towards the avoidance or mitigation of potential induced hazards and adverse effects.

I2 (RE know-how systems) [TSU: see above]. The development of all geothermal technologies relies on the availability of skilled installation and service companies with trained personnel. For deep geothermal drilling and reservoir management, such services 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. For enhanced global development, such services need to be better distributed worldwide.

T3 (Transport and accessibility) [TSU: see above]. Distributions of potential geothermal resources vary from being nearly site-independent (for ground heat pump technologies and Enhanced Geothermal Systems) to site-specific (for hydrothermal sources). The distance between electricity markets or centres of heat demand and geothermal resources, as well as the availability of a transmission capacity, is sometimes a significant factor in the economics of power generation and direct use.

E2 (Cost structure and accounting) & E3 (Project appraisal and financing) [TSU: see above]. Reducing costs and increasing the efficiency of supplying geothermal energy will enhance its market competitiveness. Policies set to drive uptake of geothermal energy should take local demand factors into account. Small heat customers can be satisfied with the deployment of GHP technologies, with relatively small budgets. Hence, in many countries, the deployment of GHP technologies can be a suitable base-line for development targets. District heating systems can be operated with less auxiliary energy (for pumps) than GHPs, and have potential to provide greater mitigation of CO_2 emissions. However, district heating systems and industrial heat use applications require larger scale investments. Hence, production from hydrothermal resources to supply district heating systems and industrial heat uses can be sensibly and efficiently supported in some markets. Heat from deeper geothermal wells is better suited to larger heat and electricity demands. The development of geothermal energy from deeper resources requires yet larger scale investment in advance of deployment.

P3 (Energy subsidy, taxing, other support policies) [TSU: see above]. Policy support for research and development is required for all geothermal technologies, but especially for EGS –as the US Department of Energy currently does in the US. Public investment in geothermal research drilling programs should lead to a significant acceleration of EGS development. Specific incentives for geothermal development include subsidies, guarantees, and tax write-offs to cover the risks of initial deep drilling. Policies to attract energy-intensive industries to known geothermal resource areas can also be useful. Feed-in tariffs with confirmed geothermal prices have been very successful in attracting commercial investment in some countries (e.g. Germany). However, since feed-in tariffs for direct heating are difficult to arrange, direct subsidies for building heating and for district heating systems may be more successful. Subsidy support for refurbishment of existing buildings with GHP is also convenient.

P4 (Regulations and rules impeding RE) [TSU: see above]. The success of geothermal development in a country is linked to government policies and initiatives. It would be recommendable these policies take into account that geothermal energy is independent of weather conditions and has an inherent storage capability which makes it especially suitable for supplying base-load power in an economical way, and it can thus serve as a partner with energy sources which are only available intermittently. Another important policy consideration is the opportunity to subsidize the price of geothermal kWh (both power and direct heating and cooling) through the mechanism of direct or indirect CO_2 emission taxes. A funding mechanism that subsidizes the commercial upfront exploration costs, including the higher-risk initial drilling costs, would also be useful. In this regard, a tax write-off provision for unsuccessful exploration drilling costs can, and has been, a useful incentive. Government can also increase investors certainty for market access by moulding rules to foster fast and affordable connection of RE to power grids. Many countries are yet to reform market rules (public benefit tests) for electricity markets in alignment with mandated trajectories for increased use of renewable energy and emissions reductions. Government legislation, regulations, policies and programs that target increased use of RE and lower greenhouse gas emissions will generally provide support to the increased use of geothermal resources.

4.5 Environmental and social impacts

One of the strongest arguments for the development of geothermal resources worldwide is their positive attributes and limited environmental impacts. Sound practices protect and enhance natural thermal features that are valued by the community, minimise any adverse effects from disposal of geothermal fluids and gases, deal with possible induced seismicity and ground subsidence, optimize water and land use, and improve long-term sustainability of geothermal production for generations to come. The following sub-sections address these issues in more detail.

4.5.1 CO_2 and other gas and liquid emissions while operating geothermal plants

[TSU: references missing.]

Geothermal systems are natural phenomena, and typically discharge gases mixed with steam from surface features such as fumaroles, and minerals mixed with water from hot springs. Apart from CO_2, geothermal fluids can, depending on the site, contain a variety of other gases, such as hydrogen sulphide, nitrogen, and smaller proportions of ammonia, mercury, radon and boron. Sometimes very small amounts of methane are present, but in geothermal applications its effect is negligible relative to CO_2. The amounts depend on the geological and hydrological conditions of different geothermal fields.

Measured direct CO_2 emission from the operation of conventional power plants in **high-temperature** hydrothermal fields is widely variable, from 0 to 740 g/kWh$_e$, but averages about 120 g/kWh$_e$ (weighted average of 85% of the world power plant capacity, according to Bertani and Thain, 2002, and Bloomfield et al., 2003). 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). Of the remaining gases, hydrogen sulphide is usually not sufficiently concentrated to be harmful after venting to the atmosphere and dispersal. Despite this, removal of hydrogen sulphide released from geothermal power plants is a requirement in the US, Italy and Mexico. Elsewhere, H_2S monitoring is often used to provide assurance that concentrations after venting and atmospheric dispersal are not harmful.

Direct CO_2 emission from **low-temperature** (<100°C) geothermal fluid is negligible or in the order of 0-1 g/kWh$_e$ depending on the carbonate content of the water. When extracted geothermal fluid is passed through a heat exchanger and then completely re-injected (such as in a closed-loop pumped EGS system, among others), CO_2 emissions are nil to negligible. Geothermal heat pumps also reduce the direct CO_2 emission by at least 50% compared to other heating or cooling systems. Other gas emissions from low-temperature geothermal resources are normally much less than the emissions from the high-temperature fields conventionally used for electricity production.

Enhanced Geothermal Systems in the future are likely to be designed as closed-loop circulation systems, with zero direct emissions.

Direct emissions of CO_2 from geothermal **direct uses (heating)** are also negligible. In Reykjavik (Iceland), the CO_2 content of thermal groundwater used for district heating (0.05 mg/kWh) is lower than that of the cold groundwater. In China (Beijing, Tianjin and Xianyang) it is less than 1 g CO_2/kWh. In the Paris Basin (a sedimentary basin), the geothermal fluid is kept under pressure within a closed circuit (the geothermal 'doublet') and re-injected into the reservoir without any degassing taking place. Conventional geothermal district heating schemes (such as Klamath Falls, Oregon, US) commonly produce brines which are also re-injected into the reservoir and thus never release CO_2 into the environment. A similar closed loop arrangement with zero emissions generally applies to pumped EGS or hybrid projects.

Most of the chemicals in geothermal fluids are concentrated in the water phase. Boron and arsenic are the components most likely to be harmful to ecosystems if released in relatively large quantities to natural waterways. Therefore, the water is routinely re-injected into wells and thus not released into the environment. However, after separation and condensation, surplus steam condensate may be suitable for stock drinking water or irrigation purposes instead of injection. The most likely contaminates to be aware of will be boron, dissolved hydrogen sulphide, sulphuric acid, and added biocides (to treat the cooling tower) or sodium hydroxide (to raise the pH). In some situations (e.g. Wairakei, New Zealand) the steam condensate has been approved by environmental regulating agencies for irrigation purposes, but each case will be chemically different and must be judged on its merits.

4.5.2 Life-cycle assessment

As it is known, life-cycle assessment (LCA) analyses the whole life cycle of a product "from cradle to grave". For geothermal power plants all environmental impacts directly and indirectly related to the construction, operation and deconstruction of the plant need to be considered in LCA, especially referring to intermediate and low temperature geothermal plants due to the large effort to lock up the reservoir relative to the usable energy.

Even though published results vary depending on assumptions made, for most existing geothermal plants the global warming potential is small. Kaltschmitt et al. (2006) calculated CO_2-equivalent emissions of between 59 and 79 g/kWh for closed loop binary power plants. Pehnt (2006) calculated a LCA CO_2-equivalent of 41 g/kWh. Nill (2004) analysed the learning curve effects on the life cycle and predicts a reduction in CO_2-equivalent from binary plants from 80 g/kWh to 47 g/kWh between 2002 and 2020. Frick et al. (2009) compare two binary plants of the same capacity (1.75 MWe) with resources at different depths and temperatures, and calculated a CO_2-equivalent between 23 and 63 g/kWh. They also presented other LCA indicators, which are compared to those of the reference mix in Table 4.5, where it can be observed that the geothermal CO_2-equivalent is between 4 and 1% from the reference mix, such as for the finite energy resources. At a site with above-average geological conditions, CO_2-equivalent and the demand of finite energy resources can reach below 1% of the environmental impacts of the reference mix.

Table 4.5. Environmental impact indicators for a reference electricity mix and for typical geothermal binary power plants (Prepared with data from Frick et al., 2009).

LCA indicator	Reference electricity mix	Binary geothermal plants (1.75 MWe)
Finite energy resources	8.9 MJ/kWh	0.35-0.96 MJ/kWh
CO_2-equivalent	566 g/kWh	23-66 g/kWh
SO_2-equivalent	1.083 g/kWh	0.183-0.517 g/kWh
PO_4-equivalent	60 mg/kWh	24-70 mg/kWh

The breakdown of the reference mix is: 26% lignite coal, 26% nuclear power, 24% hard coal, 12% natural gas, 4% hydropower, 4% wind power, 1% crude oil, 3% other fuels. [TSU: SO2: sulphur dioxide, PO4: phosphate.]

For typical geothermal binary power plants, the power related SO_2-equivalent is between 17 to 54% and the power related PO_4-equivalent between 40 to 117% regarding the environmental impacts of the electricity mix. The lower values thereby refer to the plants providing power and heat. At a site with above-average geological conditions, SO_2- and PO_4-equivalent are at least reduced to below 22% of the electricity mix impacts. In general terms, geothermal power plants can be rated as environmentally benign based on that comparison.

Regarding geothermal direct uses, Kaltschmitt (2000) published figures of 4-16 tonnes CO_2-equivalent /TJ for low-temperature district heating systems, and data for heat pumps of 50-56 tonnes CO_2-equivalent/TJ based on life cycle assessments.

The life cycle of geothermal intermediate to low temperature developments is characterised by large initial material and energy inputs due to the construction of the wells, power plant, and pipelines, which need to be optimised to maximize net-energy output and minimize emissions. For hybrid electricity/district heating applications, the more heat can be used directly the better the environmental benefits.

The main conclusion of those LCA is that the use of geothermal energy for the provision of electricity and heat using intermediate and low temperature geothermal resources is environmentally advantageous. The net energy supplied more than offsets the environmental impacts of human, energy and material inputs.

4.5.3 Potential hazards of induced micro-seismicity and others

Local hazards arising from natural phenomena, such as micro-earthquakes, hydrothermal steam eruptions or ground subsidence may be influenced by the operation of a geothermal field, to the extent that pressure or temperature changes induced by stimulation, production or re-injection of fluids can lead to geo-mechanical stress changes and these can then affect the subsequent rate of occurrence of these natural phenomena. [TSU: length of sentence] A geological risk assessment is needed to help avoid or mitigate these hazards.

With respect to induced seismicity, detectable events by humans from felt ground vibrations or noise have been an environmental and social issue associated with some EGS demonstration projects, particularly in heavily populated areas (e.g. Soultz in France, Basel in Switzerland and Landau in Germany). The EU-project GEISER (Geothermal Engineering Integrating Mitigation of Induced Seismicity in Reservoirs) recently started in order to better understand and mitigate induced seismicity hazards in the development of geothermal reservoirs (GEISER, 2010). Such events have not lead to human injury or major property damage, but routine seismic monitoring is used as a diagnostic tool and management and protocols have been prepared to measure, monitor, and manage systems pro-actively as well as to inform the public of any hazards (Majer et al., 2008).

Best practice, risk-management protocols for induced seismicity implemented by regulators in South Australia are described in Malavazos and Morelli (2008).

Over its 100 year history, no commercially operating plant has been stopped due to induced seismicity. No buildings or structures within a geothermal operation or local community have been significantly damaged (more than superficial cracks) by shallow earthquakes originating from either geothermal production or injection activities. The process of high pressure injection of cold water into hot rock, which is the preferred EGS method of stimulating fractures to enhance fluid recirculation, generates local stress changes which usually trigger small seismic events through hydro-fracturing or thermal stress redistribution. Proper management of this issue will be an important step to facilitating significant expansion of future EGS projects.

There have been some hydrothermal steam eruptions triggered by shallow geothermal pressure changes (both increases and decreases). Such eruptions are generally caused by rapid boiling in a near-surface water body generating expansion forces that lift rock out of an expanding crater. These risks can be mitigated by prudent field design and operation.

Land subsidence has been an issue at a few high temperature geothermal fields, particularly in New Zealand. Pressure decline can affect some poorly consolidated formations (e.g. high porosity mudstones or clay deposits) causing them to compact anomalously and form local subsidence 'bowls'. Management by targeted injection to maintain pressures at crucial depths and locations has succeeded in preventing subsidence in the Imperial Valley (US) where maintaining levels to allow for irrigation drainage is important.

4.5.4 Benefits and impacts

Conventional high temperature geothermal power projects effectively contribute to mitigate GHG emissions. A recent, actual example of that is the Darajat III geothermal project, which was developed by a private company in Indonesia under prevailing international market conditions. This project started to operate in 2007 with 110 MWe and was registered by the United Nations' Clean Development Mechanism (CDM). The CDM provides a clear, market-driven valuation for the very low GHG emissions of geothermal power plants, and the revenue from certified emission reductions (CER) –carbon credits generated by CDM projects– can be used to reduce the price that would otherwise be charged to consumers of the electricity. The CERs, where each credit represents a reduction of one tonne of CO_2 or equivalent, are calculated by comparing the CO_2 emissions factor for the electricity generator, in tonnes per MWh, with that of the grid to which the electricity will be supplied. The Darajat III plant is currently producing about 650,000 CERs per year. After factoring in the uncertainties of the CER market and the risks of continued CER revenue in the post-Kyoto (post-2012) period, the CDM reduces the life-cycle cost of geothermal energy by about 2 to 4% (Newell and Mingst, 2009) (Chevron, 2007). [TSU: relevance in this context?]

One example of the environmental benefits of geothermal direct use is the city of Reykjavik, Iceland, which has eliminated heating with fossil fuels, significantly reducing air pollution, and avoided about 100 Mt of cumulative CO_2 emissions (i.e., around 2 Mt annually). Other good examples are at Galanta in Slovakia (Galantaterm, 2007), Pannonian Basin in Hungary (Lund et al., 2005; Arpasi, 2005), and Paris Basin in France (Laplaige et al., 2005).

In many cases, local deployment opportunities are created from geothermal development, which can be particularly helpful for poverty alleviation in developing countries. Geothermal developments, particularly in Asian, Central and South American and African developing nations, are often located in remote mountainous areas. These same regions may be populated by indigenous people with a relatively poor standard of living and limited land ownership rights. Because drilling and plant construction must be done at the site of a geothermal resource, local workforce development can lead to a permanent employment for many. Leading geothermal companies and government agencies have approached this social issue by improving local security, building roads, schools, medical facilities and other community assets, which are in some cases funded by contributions from profits obtained from operating the power plant. In some dry climate settings (e.g. Kenya) free water is provided, in others (e.g. Philippines) free electricity for local residents. Loan funds may be established to help small local businesses.

4.5.5 Land use

Environmental impact assessments for geothermal developments consider a range of 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).

Land use issues in many settings (e.g. Japan, the US and New Zealand) can be a serious impediment to further expansion of geothermal development. National Parks, for example, have often been established in remote volcanic tourist areas where new geothermal prospects also exist. This creates a conflict for obtaining permits to undertake drilling and development activities, and even for access to subsurface resources by directional drilling from outside such parks. Despite good examples of unobtrusive, scenically-landscaped developments (e.g. Matsukawa, Japan), and integrated tourism/energy developments (e.g. Wairakei, New Zealand and Blue Lagoon, Iceland), land use issues still seriously constrain new development options in some countries.

Another measure of optimum land use that is relevant in some settings is the ‘footprint’ occupied by geothermal installations. Taking into account surface installations (drilling pads, roads, pipelines, fluid separators and power-stations), the typical footprint for conventional geothermal is about 900 m^2/GWh/year (for 30 years), or 160 m^2/GWh/year excluding wells (Table 4.6). According to Kagel et al. (2005) and Tester et al. (2006), low-temperature geothermal plants are related to a land use between 1400 to 2300 m^2/MWe or a cumulative basis between 150 and 300 m^2/GWh per year (Table 4.6). The subsurface resource that is accessed by directional or vertical geothermal boreholes typically occupies an area equivalent to about 10 MWe/km^2 (Sanyal, 2005). Therefore, about 95% of the land above a typical geothermal resource is not needed for surface installations, and can be used for other purposes (e.g., farming and forestry at Mokai and Rotokawa in New Zealand, and a game reserve at Olkaria, Kenya).

Table 4.6. Comparison of land requirements for typical geothermal power generation options.

Type of power plant	Land Use	
	m^2/MWe	**m^2/GWh/year**
110-MWe geothermal flash plants (excluding wells)	1260	160
56-MWe geothermal flash plant (including wells (2), pipes, etc.)	7460	900
49-MWe geothermal FC-RC plant (1) (excluding wells)	2290	290
20-MWe geothermal binary plant (excluding wells)	1415	170

Reference? Notes (1) and (2)? [by AUTHORS] FC: Flash cycle, RC: Rankine cycle.

4.6 Prospects for technology improvement, innovation, and integration

4.6.1 Technological and process challenges

Successful development and deployment of geothermal technologies will mean significantly higher energy recovery, longer field lifetimes and much more widespread availability of geothermal energy. Achieving that success will require sustained support and investment into technology development from governments and private sectors for the next 10 to 20 years.

With time, better technical solutions are expected to improve power plant performance and reduce maintenance down-time. More advanced approaches for resource development, including advanced geophysical surveys, reinjection optimization, scaling/corrosion inhibition, and better reservoir simulation modelling, will help reduce the resource risks by better matching installed capacity to sustainable generation capacity.

While conventional, high-temperature, naturally-permeable geothermal reservoirs are profitably deployed today for power production and direct uses, the success of the EGS-concept would lead to widespread utilization of lower grade resources. EGS requires innovative methods for exploring, stimulating and exploiting geothermal resources at any commercially viable site. Most of these methods will also improve conventional geothermal technologies. The challenges facing EGS developers encompass several tracks (Tester et al., 2006):

1. Development of exploration technologies and strategies to reliably locate prospective EGS. Improvement and innovation in technologies and methods for the characterisation of deep geothermal reservoirs in ways that enable reliably predictive extrapolations from known to unexplored geothermal resources at specific sites.
2. Improvement and innovation in well drilling, casing, completion and production technologies for the exploration, appraisal and development of deep geothermal reservoirs (as generalised in Table 4.3).
3. Improvement of methods to hydraulically stimulate reservoir connectivity between injection and production wells to emulate sustained, commercial production rates.
4. 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.
5. Improvement of numerical simulators for production history matching and predicting coupled thermal-hydraulic-mechanical-chemical processes during developing and exploitation of reservoirs. Improvement in assessment methods to enable reliable predictions of chemical interaction between geo-fluids and geothermal reservoirs rocks, geothermal plant and geothermal equipment, enabling optimised, well-, plant- and field-lifetimes.
6. Performance improvement of thermodynamic conversion cycles for a more efficient utilisation of the thermal heat sources in district heating and power generation applications.

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).

4.6.2 Improvements in exploration technologies

In exploration, R&D is required for hidden geothermal systems and EGS prospects. Rapid reconnaissance geothermal tools will be essential to identify new prospects, especially those with no surface hot springs. Satellite-based hyper-spectral, thermal infra-red, high-resolution panchromatic and radar sensors are most valuable at this stage, since they can provide data inexpensively over large areas.

Once a regional focus area has been selected, success will depend upon the availability of cost-effective reconnaissance survey tools to detect as many geothermal indicators as possible. Airborne-based hyper-spectral, thermal infra-red, magnetic and electromagnetic sensors are valuable at this stage, providing rapid coverage of the geological environment being explored, at an elevation (and pixel size) appropriate to the features being imaged. Ground-based verification, soil sampling and heat flow measurements should follow. Recent advances in remote sensing and airborne electromagnetic methods have yet to be tested in the geothermal environment.

Research centres are now working towards an integrated approach for the comprehensive characterisation of EGS sites in a variety of geological settings. R&D will need to focus on achieving a better understanding of how cracks form and propagate in different stress regimes and rock types. New tools need to be developed that allow specific zones in a hot borehole to be isolated for both fracture creation and short-circuit repair. This will allow multiple fracture zones to be created from a single borehole, enhance the water circulation rate, and reduce the specific cost of development.

4.6.3 Accessing and engineering the reservoirs

[TSU: references missing.]

4.6.3.1 Drilling technologies

Special research is needed in large diameter drilling through plastic, creeping or swelling formations such as salt or shale. Abnormally high fluid pressure in such formations causes abnormal stresses that differ considerably from those found in hydrostatic pressure gradients. To provide long-life completion systems in plastic formations, new cementing technologies regarding the geo-mechanical behaviour of plastic rock need to be defined, especially for deviated wells.

Drilling must minimise 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. Damages can be reduced by using low mud pressures by means of near-balanced drilling (NBD). NBD and borehole stability under changing stress conditions must be well understood and need to be investigated by fracture mechanical experiments and simulations. Further research is required to understand salinity contrast effects, particle induced damage and filtrate induced damage.

The objective of a new-generation of geothermal drilling should be to reduce the cost of geothermal drilling through an integrated effort. Ultimately a larger portion the geothermal resource would be economically accessible, if drilling costs could be substantially reduced by introducing revolutionary methods that use different methods of drilling and completing wells, thermal, particle-assisted abrasive, and chemically-assisted techniques.

Production wells in high-grade fields are commonly 1.5-2.5 km deep with production temperatures of 250-340°C. Yet it is well known from research that much higher temperatures are found in the roots of high-temperature systems. The international Iceland Deep Drilling Project (IDDP) is a long-term program to improve the efficiency and economics of geothermal energy by harnessing deep unconventional geothermal resources (Fridleifsson et al., 2007). Its aim is to produce electricity from natural supercritical hydrous fluids from drillable depths. Producing supercritical fluids will require drilling wells and sampling fluids and rocks to depths of 3.5 to 5 km, and at temperatures of 450-600°C.

4.6.3.2 Reservoir engineering

All tasks related to the engineering of the reservoir require a sophisticated modelling of the reservoir processes and interactions being able to predict reservoir behaviour with time, to recommend management strategies for prolonged field operation and to minimize potential environmental impacts. In the case of EGS, reservoir stimulation procedures need to be refined to significantly enhance the hydraulic productivity, while reducing the risk of seismic hazard. Imaging fluid pathways induced by hydraulic stimulation treatments through innovative technology would constitute a major improvement of the EGS concept. New visualisation and measurement methodologies (imaging of borehole, permeability tomography, tracer technology, coiled tubing technology) should become available for the characterisation of the reservoir.

The relation between parameter uncertainty and the predictability of the geothermal reservoir evolution will be investigated with thermo-hydro-mechanical-chemical (THMC) effects included. The availability of fully coupled and efficient THMC codes provides a new basis for developing more reliable models with parameter identification at the reservoir scale based on inverse modelling techniques.

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

[TSU: references missing.]

Technical equipment needed to provide heat and/or electricity from geothermal wells is already available on the market. However, the efficiency of the different system components can still be improved, especially for low-enthalpy power plant cycles, cooling systems, heat exchangers and production pumps for the brine.

Thermodynamic cycles have to be improved, and thermal heat sources must be utilised more efficiently, both at the heat exchanger to a second cycle, in district heating and in conversion to electrical power. For power generation, a modular low-temperature cycle could be set up allowing for conventional and new working fluids to be examined.

New and cost-efficient materials are required for pipes, casing liners, pumps, heat exchangers and for other components to be used in geothermal cycles to reach higher efficiencies and develop cascade uses.

New inexpensive designs of small geothermal power plants using low-temperature reservoirs and able to generate distributed electricity, are likely to appear soon in the market. Those plants should be small, mass manufactured, easy to move from place to place, and easy to operate.

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, and in some cases, gold).

4.7 Cost trends

As other RE technologies, geothermal projects have high up-front costs (mainly due to the cost of drilling wells) and low operational costs. These operational costs vary from one project to another due to size, quality of the geothermal fluids, and so on, but are predictable in comparison with power plants of traditional energy sources which are usually subject to market fluctuations on fuel price. This section describes the capital costs of geothermal-electric projects, the levelized cost of geothermal electricity and the historic and probable future trends, and also presents some costs for direct uses of geothermal energy.

4.7.1 Costs of geothermal-electric projects and factors that affect it

The cost structure of a geothermal-electric project is composed of the following components: a) exploration and resource confirmation, b) drilling of production and injection wells, c) surface facilities and infrastructure, and d) power plant. Field expansion projects may cost 10-15% lesser than a new (greenfield) project, since investments have already been made in infrastructure and exploration and valuable resource information is available (Stefansson, 2002; Hance, 2005).

The first component (a) includes lease/acquisition, permitting, prospecting and drilling of exploration and test wells. Drilling of this type of wells has a success rate typically about 50-60% (Hance, 2005). Confirmation costs are affected by: well parameters (depth and diameter), rock properties, well productivity, rig availability, time delays in permitting or leasing land, and interest rates.

Drilling of production and injection wells (component b) has a success rate of 70 to 90% (Hance, 2005). Factors influencing the cost include: well productivity (permeability and temperature), well depths, rig availability, vertical or directional design, the use of air or special circulation fluids, the use of special drilling bits, number of wells and financial conditions in a drilling contract (Tester et al., 2006).

Surface facilities and infrastructure (component c) includes gathering steam and process brine, separators, pumps, pipelines and roads. Vapour-dominated fields have lower facilities 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).

Power plant (component d) includes turbines, generator, condenser, electric substation, grid hook-up, steam scrubbers, and pollution abatement systems. Power plant design and construction costs depend upon type (flash, back-pressure, binary, dry steam, or hybrid), as well as the type of cooling cycle used (water or air cooling). Other factors affecting power plant costs are: fluid enthalpy (resource temperature) and chemistry, location, cooling water availability, and the economies of scale (larger size is cheaper). Table 4.7 presents the breakdown of current capital costs (capex) for typical geothermal-electric projects in 2005 US$.

Table 4.7. Breakdown of current capital costs for typical turnkey (installed) geothermal-electric projects (2005 US$)

Type*	Concept	Component				Total
		(a) Exploration & confirmation	(b) Drilling (wells to 1.5-3 km depth)	(c) Surface facilities & infrastructure	(d) Power plant	
1	US$/kWe	475	1275	350	1225	3325
	% capex	14	38	11	37	100
2	US$/kWe	30	1275	350	1225	2880
	% capex	1	44	12	43	100
3	US$/kWe	25	1008	300	1175	2508
	% capex	1	40	12	47	100
4	US$/kWe	24	800	274	1782	2880
	% capex	1	28	10	61	100
5	US$/kWe	205-560	750-1500	205-750	1215-2240	2025-3750
	% capex	10-15	20-40	10-20	40-60	100
6	US$/kWe	275-425	750-1700	425-850	1500-2600	3400-4300
	% capex	8-12	20-40	10-20	40-60	100
7	US$/kWe	530	3350	1350	4720	9950
	% capex	5	34	14	47	100

*Type:

1) Greenfield project, 40-MWe single flash power plant, 200°C, wells to 2 km depth (data from Hance, 2005).

2) Expansion project, 40-MWe single flash power plant, 200°C, wells to 2 km depth. (data from Hance, 2005).

3) Expansion project, 4 x 25 MWe single flash power plant (100 MWe), wells to 2.2 km depth (From actual project installed in 2003).

4) Expansion project, 25-MWe single flash power plant, wells at 1.8 km depth in average (data from actual project currently in construction).

5) Greenfield project, 10-50 MWe condensing power plants (with data from Williamson et al. [TSU: "et al." added], 2001; Hance, 2005; Petty, 2005; Kagel, 2006; and Chevron, 2009).

6) Greenfield project, 10-20 MWe binary cycle power plants (estimations with data from Hance, 2005; Petty, 2005; Kagel, 2006; and Chevron, 2009).

7) Greenfield project, ~4MWe, binary cycle power plant, low temperature, wells to 2750 m depth (estimations with data from GEOFAR, 2009).

Labour and material costs are estimated to account for 40% each of total project construction costs. Labour costs can increase by 10% when a resource is remotely located. In addition to raw materials and labour, choice of power plant size is a key factor in determining the ultimate cost of a plant. For example using a single 50-MWe plant instead of multiple 10-MWe plants can decrease power plant costs per kilowatt by roughly 30-35% for binary systems. The installed cost per kilowatt for a 100-MWe flash steam plant can be 15-20% less than that of a 50-MWe plant (Dickson and Fanelli, 2003; Entingh and Mines, 2006).

4.7.2 Levelized cost of geothermal electricity

The levelized cost of geothermal power corresponds to the sum of two major components: levelized cost of capital investment and operation and maintenance costs. The levelized cost of capital investment (LCCI) corresponds to the cost of the initial capital investment (i.e. site exploration and development & power plant construction) and its related financial costs, divided by the total output of the facility throughout the entire payback period (typically 20-30 years). Operating and maintenance (O&M) costs consist of fixed and variable costs directly related to the electricity production phase. Operation and Maintenance costs include field operation (labour), well work-over, equipment, well operation, and facility maintenance, etc., and are currently ranged between 170 and 210 US$/kWh per year (equivalent to 152 and 187 US$/kWh per year at 2005 US dollar, respectively, according to the Current Consumer Price Index released by the US Bureau Labour Statistics) [TSU: consistent use of tools provided on TSU website to adjust for inflation/deflation?].

For geothermal plants, an additional factor must be added to these O&M costs, which is the cost of reposition or make-up wells, i.e. new wells to replace some of the older whose lifetime is over. Companies usually consider make-up drilling as a capital expense, but must be regarded as O&M costs since the purpose of make-up drilling is to maintain the full production capacity of the power plants (Hance, 2005). Costs of these wells are typically lower than those for the original wells, and their success rate is typically higher.

In most cases, the LCCI represents a major part (about 65%) of the levelized cost of energy (LCOE) of geothermal projects.

Current LCOE (i.e., including LCCI and O&M costs) in 2005 US$/kWh for some of the typical geothermal-electric plants described in Table 4.7 were calculated according to the methodology described in Chapter 1, using the version 6 of the calculator developed by Verbruggen and Nyboer (2009), and are presented in Figure 4.9. In all cases the project lifetime was calculated to be 30 years and the capacity factor (plant performance) was 77%. For greenfield projects it was estimated that the plant starts to operate between the beginning of the fourth and the sixth year since exploration starts, and for expansion projects the plant is commissioned by the third year.

There are important variations depending on the discount rate used, yet in general terms the LCOE for conventional plants in high temperature fields is lower than for binary cycle plants in low to intermediate temperature fields. LCOE for expansion projects is also lower than for new projects and the larger the project (in MWe) the lower LCOE, as clearly indicated by case 3, which is an actual project currently operating in Mexico. The LCOE for case 5, calculated with data from a low-temperature European project presented by GEOFAR (2009), is the highest and may be an appropriate estimate for the theoretical LCOE for EGS projects.

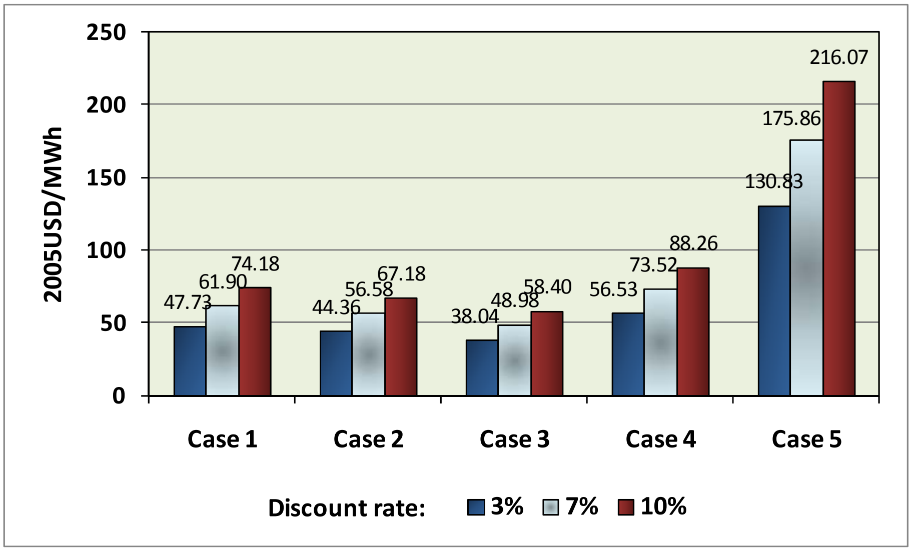

Figure 4.9. LCOE (LCCI plus O&M costs) in 2005 US$ per MWh for typical geothermal-electric plants using three different discount rates (3%, 7% and 10%).

Cases 1, 2 & 3 are the same for Table 4.7.

Case 4: Greenfield project, 20-MW binary cycle plant, wells at 1500 m depth. [TSU: Equivalent to case 6 in table 4.7?]

Case 5: Greenfield project, 4-MW binary cycle plant, well at 2750 m depth. [TSU: Equivalent to case 6 in table 4.7?]

[TSU: detailed data sources missing.]

4.7.3 Historical trends of geothermal electricity

From the 1980's until about 2004, project development costs remained flat or even decreased (Kagel, 2006; Mansure and Blankenship, 2008). However, in 2005-2008 project costs sharply increased due to increases in the cost of commodities such as steel and cement, drilling rig rates and engineering (Fig. 4.10). This cost trend was not unique to geothermal and was mirrored across most other power sectors. Capex costs have since started to decrease due to the current economic downturn and reduced demand.

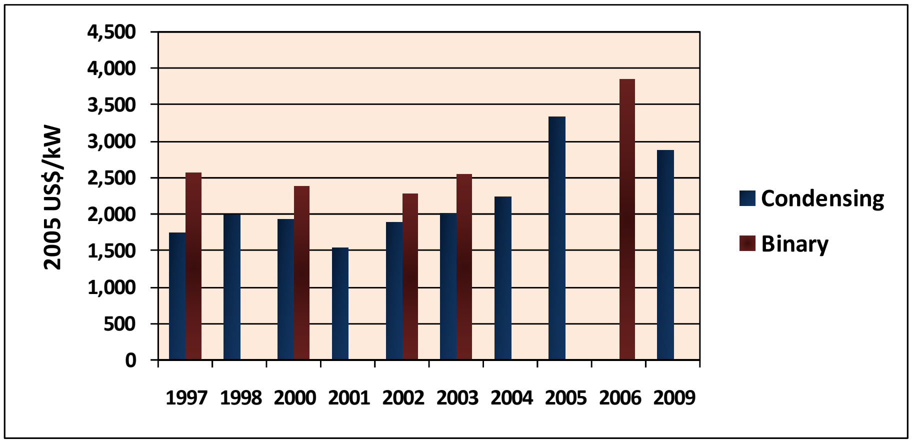

Figure 4.10. Variation in capex cost for condensing and binary geothermal-electric plants (To be completed with more data? [by AUTHORS]). [TSU: detailed data sources missing.]

Regarding the geothermal-electric plants performance, since 1995 the average capacity factor has been continuously increasing, and the average geothermal capacity factor based on 2008 global generation versus installed capacity is around 75%. However, in the past, this value incorporated a wide range of generation issues, including: grid connection failures (e.g. from storm damage), load following on smaller grids, turbine failures (some operating geothermal turbines have exceeded their economic lifetime, so require longer periods of shut-down for maintenance or replacement), and lack of make-up drilling to sustain long-term steam supply (usually due to financial constraints). For new developments, assuming no such grid or load constraints, long-term capacity factors above 95% can be expected (Fridleifsson et al., 2008; Fig. 4.11).

4.7.4 Future costs trends

The future costs for geothermal electricity are hard to predict. This is because future deployment will probably include an increasing percentage of unconventional development types (such as EGS, super-critical temperature and off-shore resources), which are still not commercially proven and presently only limited cost data about them are available. However, considering that the drilling cost represents between 20 and 40% of total capital costs (Table 4.7) and the projected plant performance shown in Fig. 4.11 by 2020, 2030 and 2050, future LCOE for the cases before mentioned were calculated using the same calculator developed by Verbruggen and Nyboer (2009), and are shown in Figure 4.12 considering only a discount rate of 7%, which is the rate decided to be used for all RE future costs trends in this report. [TSU: sentence structure and length]

Some assumptions remained the same: project lifetime is 30 years and the commissioning year for greenfield projects is between fourth and sixth year since exploration starts and for expansion projects is the third year. Figures for 2009 are those already presented in Figure 4.10. For 2020 it was assumed that the drilling cost does not vary since not many differences are expected in the oil industry, yet for 2030 this cost was estimated to be 7% lower and for 2050 15% lower than present costs, in all cases at 2005 US$. These decreasing costs are expected to occur due to better technological practices in the drilling industry and due to a probably higher availability of drilling rigs on that dates. Worldwide average capacity factors for 2020, 2030 and 2050 were assumed to be 81%, 85% and 90%, respectively, according to Figure 4.11. All the remaining aspects and costs were considered not variable, even though improvements in exploration, superficial [TSU: surface?] installations, materials and power plants are likely, which would lead to reduced costs.

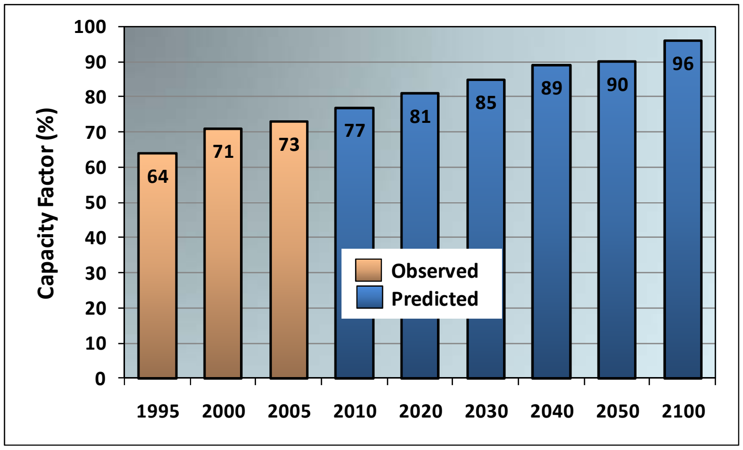

Figure 4.11. Historic and projected average worldwide capacity factor of geothermal plants (with data from Fridleifsson et al., 2008, and Bertani, 2009).

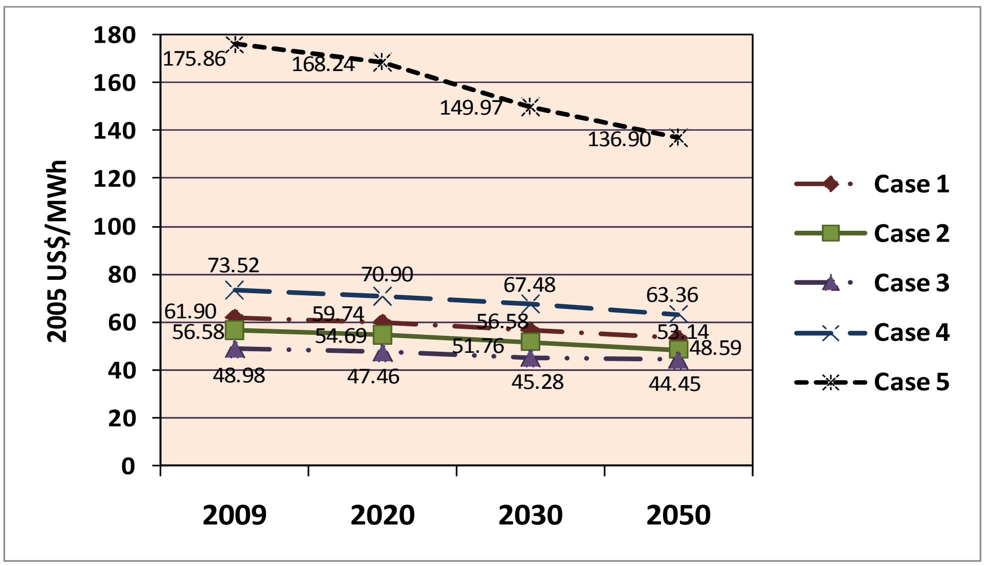

Figure 4.12. Present and projected LCOE in 2005 US$ for typical geothermal-electric plants at discount rate of 7%.

Cases 1, 2 & 3 are the same for Table 4.7.

Case 4: Greenfield project, 20-MW binary cycle plant, wells at 1500 m depth. [TSU: Equivalent to case 6 in table 4.7?]

Case 5: Greenfield project, 4-MW binary cycle plant, well at 2750 m depth. [TSU: Equivalent to case 6 in table 4.7?]

[TSU: Please add detailed data sources.]

4.7.5 Economics of direct uses and geothermal heat pumps

Direct-use projects costs have a wide range, depending upon the specific use, the temperature and flow rate required, the associate O&M and labor costs, and the income from the product produced. In addition, costs for new construction are usually less than cost for retrofitting older structures. The cost figures given below are based on a temperature climate typical of the northern half of the

United States or Europe, and obviously the heating loads would be higher for more northern climates such as Iceland, Scandinavia and Russia. Most figures are based on cost in the United States (expressed in 2005 US$), but would be similar in developed countries and lower in developing countries (Lund and Bertani, 2009).

Individual space heating for buildings, depending upon the well depth and temperature of the resource would vary from US$ 9,370 to 23,450 for a 200 m^2 building. With a load factor of 0.30, the capital cost would be 1,595 to 3,940 US$/kWt (Fig. 4.13).

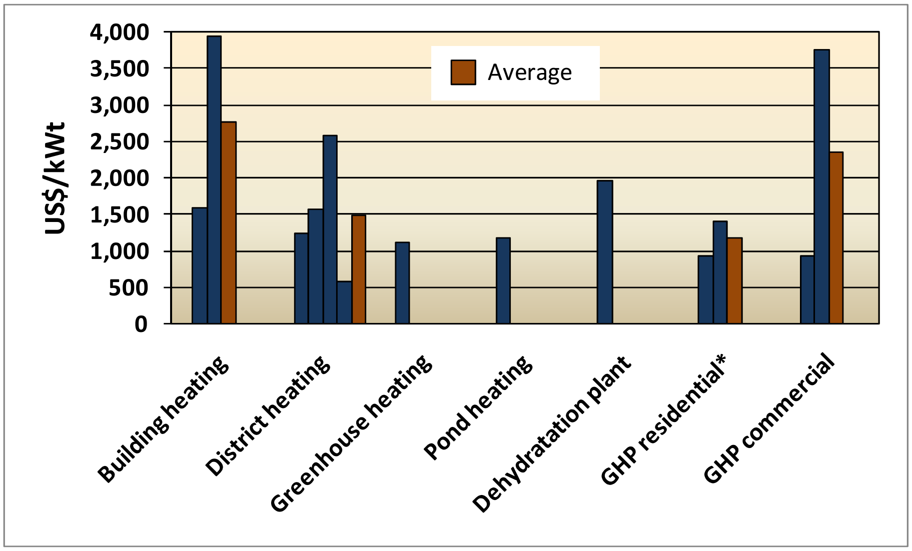

Figure 4.13. Current capital costs in 2005 US dollars per thermal kilowatt for several direct geothermal applications. [TSU: Please add source.]

*Costs for residential Geothermal Heat Pumps do not include the drilling cost.

[TSU: Use of level 4 subheadings for different direct use applications?]

District heating may be provided in the form of either steam or hot water and may be utilised to meet process, space or domestic hot water requirements. The heat is distributed through a network of insulated pipes consisting of delivery and return mains. Thermal load density (heating load per unit of land areas) 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 single family residential area. Generally a thermal load density about 1.2×10^9 J/hr/ha is recommended. Often fossil fuel peaking is used to meet the coldest period, rather than drilling additional wells or pumping more fluids, as geothermal can usually meet 50% of the load 80 to 90% of the time, thus improving the efficiency and economics of the system (Bloomquist et al., 1987).

A large district heating project in Germany (Reif, 2008), with a well drilled to 3,200 m to provide a capacity of 35 MWt and 66 GWh of heat to customers, costs 1,566 US$/kWt. This cost can be broken down into: 23% drilling, 2% pumps and accessories, 5% geothermal station and equipment, 2% peak-load heating plant (fossil fuel), 42% distribution network, 14% service connection, 12% heat-transfer stations, and 1% land [TSU: ordering by size]. A smaller example in Elko, Nevada, US, built in 1989 with a capacity of 3.8 MWt providing 6.5 GWh/year of heat to customers, costs 1,238 US$/kWt. The breakdown of costs was: 15% resource assessment, 15% drilling of production well (disposal is to a local river), 29% distribution system, 26% retrofitting customer heating systems, and 15% contract services and materials [TSU: ordering by size]. The geothermal station Mszczonow (1.2 MWt), Poland, for space heating, costs the equivalent of 2,578 US$/kWt (Balcer, 2000). Between 30 and 35% of natural gas consumption was saved when the geothermal installation was set in operation, and three conventional gas and coal boilers were stopped. The Klaipeda geothermal heating station (35 MWt), Lithuania, started to operate in 2005, with heat production of 598 x 10^9 J/yr [TSU: GJ] to produce warm water (70-80°C) for district heating. Total capital costs were equivalent to 571 US$/kWt (Radeckas and Lukosevicius, 2000). Based on these examples, total district heating installed costs average 1,488 US$/kWt (Fig. 4.13).

Greenhouses of 2.0 ha size (minimum for a commercial operation) would cost around US$ 281,000, which includes two production wells, one injection well, piping and heat exchanger in addition to the cost of the greenhouse itself of around US$ 2.81 million. With a load factor of 0.50 the annual heating load would be 88 x10^9 J [TSU: GJ]. Annual pumping cost and other O&M would be around 0.02 US$/kWh. The annual savings compared to conventional fuel would be approximately US$ 0.94 million.

Aquaculture ponds and tanks have similar costs, yet vary depending upon if the facilities are under cover, such as in a greenhouse, or outdoors. Typical pond constructs will cost 0.47 US$/$m^2$, thus a commercial operation of 10 to 15 ponds covering 2.0 ha would then cost approximately US$ 9,400. The capital costs of three production wells, two injection wells, piping and heat exchanger would be around US$ 375,000. With a load factor of 0.60, the annual heating requirement would be 263 x 109 J [TSU: 28.667 kJ]. Pumping costs and other O&M for the geothermal system would be around 0.03 US$/kWh. The annual savings in heating cost compared to conventional fuels would be approximately US$ 2.81 million less O&M, resulting in a simple payback of around a year. Covered ponds and tanks would have higher capital cost, but lower heating requirements.

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 (US and New Zealand) to pulp and paper plant (New Zealand). As an example, a large onion dehydration plant in the US (Nevada) uses 210 x 10^{12} J/year [TSU: TJ] to drying 4,500 kg/hour of wet onions over a 250 day period. This plant cost US$ 12.5 million with the geothermal system, including wells adding US$ 3.37 million. The annual operation cost is US$ 5.63 million and annual energy savings of US$ 1.5 million. With annual sales of US% 5.63 million, a positive cash flow is realised in about two years (Lund, 1995).

Geothermal (ground-source) heat pump project costs can vary between residential installation and commercial/institutional installations, as the larger the building to be heated and/or cooled, the lower the unit (US$/kWt) investment and operating costs. In addition, the type of installation, closed loop (horizontal or vertical) or open loop using ground water, have a large influence on the installed cost.

Closed loop systems would cost around 1,400 US$/kWt, whereas open loop systems would be around 938 US$/kWt (without the cost of the well). The highest cost for a vertical closed loop system is drilling the holes of 150 to 300 m deep, running 28 to 47 US$/m. Actual heat pumps unit will be around US$ 2,800.

Commercial and institutional buildings installations are more efficient and thus cost less. Installations of several hundred bore holes for vertical loops are not uncommon and can easily be placed under parking lots, or even under the building itself in piles or caissons as is done in Switzerland. The installed cost can vary over a wide range. Experience in the US for the total cost of the mechanical, electrical and geothermal system is as high as 3,751 US$/kWt, but can be as low as 938 US$/kWt. Operation cost, which is mainly due to the electricity input to the compressor, is around 0.02 to 0.03 US$/kWh. Energy use is around 60 kWh/m^2/year.

4.8 Potential deployment

Overall, the geothermal-electric market appears to be accelerating, as indicated by the trends in both the number of new countries developing geothermal energy and the total of new megawatts of power capacity under development. It is, however, difficult to predict future rates of deployment, because of the numerous variables involved. Using present technology to develop additional hydrothermal resources and given favourable economic drivers, an increase from the current value of 10.7 GWe of installed capacity, up to 70 or 80 GWe could be achievable by 2050. The gradual introduction of new technology improvements including EGS is expected to boost the growth rate exponentially after 10-20 years, reaching an expected global target of ~160 GWe by 2050 (Fig. 4.1). Some of the new technologies (for example, binary conversion plants, multilateral completions, etc.) have already been proven and are now rapidly deploying, whereas others are entering the field demonstration phases to prove commercial viability (EGS), or early investigation stages to test practicality (utilization of supercritical temperature and submarine hydrothermal vents or off-shore resources).

Low-temperature power generation with binary plants has opened up the possibilities of producing electricity in countries which do not have high-temperature resources or may have requirements for total re-injection. EGS technologies (deep drilling in lower grade regions, reservoir stimulation and pumping) are being developed to access resources in this setting. Supercritical and off-shore resources are also under investigation. If these technologies can be proven economical at commercial scales, the geothermal market potential could be limited only by demand and not by resource access.

Direct use of geothermal energy for heating is currently commercially competitive, using accessible, high grade hydrothermal resources. A moderate increase is expected in the future development of such hydrothermal resources for direct use, mainly because of dependence on resource proximity and therefore on local economic factors, along with the multiple uses of geothermal resources in combined heat and power plants. In contrast, an exponential increase is expected with the deployment of geothermal heat pumps (GHP) and direct use in lower grade regions, which can be used for heating and/or cooling in most parts of the world. Marketing the cost/benefit advantages of direct use, including the inclusion of GHPs in programs will support the uptake of RE and increase efficiencies of using existing electricity supplies by creating necessary infrastructure for widespread deployment.

4.8.1 Regional deployment

[TSU: references missing.]

4.8.1.1 Conventional hydrothermal resources

On a regional basis, the deployment potential for harnessing identified and prospective conventional hydrothermal resources varies significantly. In Europe and Central Asia, there are a few countries that have well-developed high temperature resources (e.g. Italy and Turkey, see Figure 4.1). In such countries, there are significant opportunities for future expansion, particularly if access and technical barriers can be overcome. Many other European and Asian countries have huge under-developed hot water resources, of lower temperature, located within sedimentary basins at various depths (e.g. Paris, Pannonian, and Beijing basins). These require pumped extraction, and are mostly suitable for direct heating, but could also be utilised to generate electricity using binary plant technology. In the African continent, Kenya was the first country to utilise its rich hydrothermal resources for both electricity generation and direct use, and several other countries along the East African Rift Valley may follow suit. In North America (US and Mexico) the existing installed capacity of almost 4 GWe, mostly from mature developments, is expected to double in the short term (5-7 years). By 2050, a significant proportion of the estimated unidentified resource base in the western US (30 GWe) and Alaska and co-production of energy from hot water discharged by oil wells (5 GWe) is also considered technically feasible now. In the Central American countries the geothermal potential for electricity generation has been estimated to be 4 GWe (Lippmann, 2002) of which 12% has been harnessed so far (~0.5 GWe). South American countries, particularly along the Andes mountain chain, also have significant untapped --and under-explored-- hydrothermal resource potentials (at least 2 GWe).

For island nations with mature histories of geothermal development, such as New Zealand, Iceland, Philippines, Japan and Hawaii, identified geothermal resources imply a future expansion potential of 2 to 5 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 conventional geothermal deployment to approximately twice the existing capacity over the next 40 years. Other volcanic islands in the Pacific Ocean (Papua-New Guinea, Solomon, Fiji, etc.) and the Atlantic Ocean (Azores, Caribbean, etc.), have significant potential for growth from known hydrothermal resources to replace fossil fuelled heating or power-plants, but are also grid 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 access to load. Parts of other South-East Asian nations (including India) contain numerous hot springs, inferring the possibility of potential, as yet unexplored, hydrothermal resources. Indonesia is one of the world's richest countries in geothermal resources and could, by 2050, replace a considerable part of its fossil fuelled electricity production by increasing its geothermal energy capacity by up to 20 times to 20 GWe.

Potential geothermal deployment for electricity (including EGS) and for direct use (including direct heating and cooling and GHP) by regions, are presented in Table 4.8.

Table 4.8. Expected deployment of geothermal energy by region.

REGION	Current (2009)		2020		2030		2050	
	Direct* (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)
1. OECD North America	8.443	4.052	50.0	9.5	120.0	15.0	230.0	42.0
2. Latin America	0.545	0.509	2.0	1.5	5.0	3.0	10.0	7.0
3. OECD Europe	10.959	1.551	62.0	3.0	150.0	5.5	300.0	28.0
4. Africa	1.520	0.174	4.0	0.5	11.0	1.5	18.0	9.5
5. Transition Economies	1.064	0.082	3.0	0.5	5.0	1.0	10.0	5.0
6. Middle East	0.422	0	1.0	0.0	4.0	0.5	7.0	3.5
7. Developing Asia	0.478	3.166	5.0	6.5	10.0	14.0	20.0	31.0
8. India	0.203	0	2.0	0.0	5.0	1.0	10.0	3.0
9. China	3.687	0.024	20.0	1.0	50.0	4.0	125.0	17.0
10. OECD Pacific	1.257	1.184	6.0	2.5	15.0	4.5	85.0	14.0
TOTAL	**28.578**	**10.743**	**155.0**	**25.0**	**375.0**	**50.0**	**815.0**	**160.0**
EJ Equivalent	0.279	0.256	1.589	0.639	3.843	1.34	8.353	4.541

* Data for 2005, which will be updated later. Direct includes direct heating and cooling and Geothermal Heat Pumps. Electric includes Enhanced Geothermal Systems. [TSU: Please add source.]

4.8.1.2 Enhanced Geothermal Systems

Resource grades for EGS vary substantially on a regional basis as well. This will have direct impact on the rate of deployment even after demonstrating EGS technology at commercial scale in the field. In addition, the availability of financing, water, transmission and distribution infrastructure and other factors will play major roles in regional deployment rates. In the US, 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, factors that would affect deployment are population density, electricity and heating and cooling demand.

Half of the total geothermal electric deployment by 2050 is expected to be contributed by EGS. This ~80 GWe projection depends not only on improvements gained by experience of using existing drilling, reservoir stimulation, and energy conversion technologies used both in hydrothermal and EGS projects, but also on the presence of suitable energy markets, favourable policies, and available attractive financing in all cases. At some level of deployment, given its modular and scalable characteristic, the rate of adoption of EGS is anticipated to accelerate and propagate globally.

4.8.1.3 Direct uses and geothermal heat pumps

The potential deployment in the geothermal direct use market is very large, as space heating and water heating are significant parts of the energy budget in large parts of the world. In industrialised countries, 35 to 40% of the total primary energy consumption is used in buildings. In Europe, 30% of energy use is for space and water heating alone, representing 75% of total building energy use. The high potential deployment is due in large part to the ability of geothermal ground-source heat pumps to utilise groundwater or ground-coupled heat exchangers anywhere in the world. This use has huge potential for saving energy in buildings which represent over 30% of our primary demand.

Estimation for future development of the worldwide geothermal utilisation market was presented in Table 4.8 on a regional basis, for 2020, 2030 and 2050. Projections were estimated considering a different annual growth for GHP installations and for other direct uses, as shown in Table 4.9.

Table 4.9. Estimation of future deployment of geothermal direct uses, distinguishing Geothermal Heat Pumps (GHP) up to 2100 (Modified from Fridleifsson et al., 2008)

Year	Average annual growth rate from 2005		Installed capacity (GWt)		
	Other direct uses (%)	GHP (%)	Direct Uses	GHP	Total
2005	--	--	12.87	15.72	28.59
2010	~7.0	~20.0	18.00	37.00	55.00
2020	~6.0	~15.0	31.00	124.00	155.00
2030	~5.0	~13.0	45.00	330.00	375.00
2040	~4.4	~11.0	60.00	595.00	655.00
2050	~4.0	~9.0	75.00	740.00	815.00
2100	~2.5	~5.0	150.00	1,600.00	1,750.00

As shown in Table 4.9, estimations show that while only a moderate increase is expected in direct use applications, an exponential increase is foreseen in the heat pump sector. The combined GHP plus other uses deployment expected for 2020, 2030 and 2050 are the same than in Table 4.8, while the total for 2100 corresponds to the economic potential reported in Table 4.2 for geothermal direct uses.

4.8.2 Technological factors influencing deployment

Direct heating technologies using GHP, district heating and EGS methods are available, with different degrees of maturity. GHP systems have the widest market penetration, and an increased deployment will 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 associated with accessing and engineering fractures in the geothermal reservoirs. The latter requires a better knowledge and measurement of the subsurface stress field. For EGS, additional remaining challenges are: drilling costs for deep wells, reservoir stimulation, management of induced seismicity, demonstration of sustainable production at commercial scale.

Geothermal power generation technologies also have different degrees of maturity. Reducing sub-surface exploration risks will contribute to more efficient and sustainable development. Drilling of high temperature reservoirs requires advanced technologies to prevent reservoir damage by drilling mud. An example is the use of balanced drilling procedures. Improved utilisation efficiency requires better auxiliary energy use and improved performance of surface installations. Better reservoir management, with improved simulation models, will optimize reinjection strategy, avoid excessive depletion, and plan future make-up well requirements, to achieve sustainable production.

Improvement in energy utilisation efficiency from cascaded use of geothermal heat is an important deployment strategy. Evaluating the performance of geothermal plants, including heat and power EGS installations, will consider heat quality of the fluid by differentiating between the energy and the exergy or availability content (that part of the energy that can be converted to electric power).

4.8.3 Long-term deployment in the context of carbon mitigation

The expected long-term deployment (2020, 2030 and 2050) based on the before mentioned assumptions, was presented in Table 4.8. The worldwide expected installed capacity by 2020 is 25 GWe for geothermal electric plants and 155 GWt for geothermal direct uses. These figures are equivalent to 0.639 EJ and 1.589 EJ, respectively, for a total primary energy supply (TPES) of 2.228 EJ. Corresponding figures for 2030 are 1.340 EJ and 3.843 EJ, for a geothermal TPES of 5.183 EJ, and for 2050 are 4.541 EJ and 8.353 EJ for a TPES of 12.894 EJ.

All those figures are independent of the rate of carbon mitigation that could be achieved by 2020, 2030 and 2050, since geothermal deployment is not technically affected by that effect – as mentioned earlier in this chapter. However, it is likely that the more restricted the CO_2 emissions will be in the future the higher geothermal deployment will be. A number of different scenarios have been modelled from the integrated assessment models presented in Chapter 10, taking into account the stabilization categories of CO_2 emissions regarded by the IPCC AR4 and grouping them into three: categories I+II (<440 ppm), III+IV (440-600 ppm) and V+VI (>600 ppm).

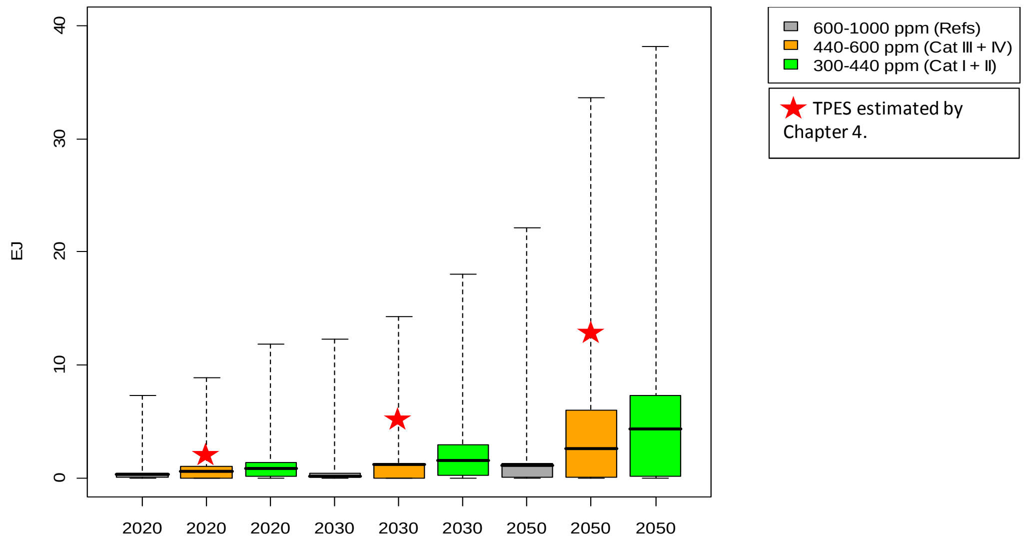

Figure 4.14. Total Primary Energy Supply (TPES) from geothermal resources in the context of carbon mitigation for 2020, 2030 and 2050. Thick black line is the median, the coloured box corresponds to interquantile range 25th-75th percentile, and whiskers correspond to the total range across all scenarios. [TSU: Please add reference to chapter 10.]

Geothermal deployment for each of those category groups are presented in Figure 4.14, where also are plotted the projected deployment estimated in this chapter. [TSU: language] It can be seen that estimations from chapter 4 are within the range of all considered scenarios, yet are higher than the median and are located in the 75%-100% quartile. For instance, by 2020 the median of the scenarios goes from 0.4 EJ for categories V+VI, to 0.61 EJ for categories III+IV and up to 0.81 EJ for categories I+II, while the projected deployment obtained in this Chapter 4 is 2.228 EJ, which is in the last 25% percentile (75-100%) in all cases. A similar condition occurs for 2030 and 2050 (Figure 4.14).

So, it seems to be clear [TSU: language] that the global and regional availability of geothermal resources is enough to meet the results of the modelled scenarios, and also the projected market penetration seems to be reasonable. As a matter of fact, the modelled scenarios would seem to be conservative [TSU: language] compared to the potential deployment estimated in this chapter.

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