MSc Program
Renewable Energy in Central and Eastern Europe

Deep Geothermal Energy – The Risk of non-discovery of the Hydrothermal Resource

A Master's Thesis submitted for the degree of
"Master of Science"

supervised by
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November 2017, Vienna

Affidavit

I, **Walter Saurer**, hereby declare

1. that I am the sole author of the present Master Thesis, "Deep Geothermal Energy – the risk of non-discovery of the hydrothermal resource", 122 pages, bound, and that I have not used any source or tool other than those referenced or any other illicit aid or tool, and
2. that I have not prior to this date submitted this Master Thesis as an examination paper in any form in Austria or abroad.

Vienna, _____ _____

Date Signature

To my parents

Abstract

The non-discovery of the hydrothermal resource is the main investment risk for deep geothermal. The core question of this master thesis is how to depict the risk of non-discovery at the investigated site at Baden in an investment decision calculation. Thus I have chosen Percentiles of flow of water and temperature of the hydrothermal resource to calculate expected distributions of installable capacities and respective distributions of generation costs. For P50 (120 l/s), P40 (62 l/s) and P20 (12 l/s) flow rate of water expected generation costs range from 5-15 € / MWh_{th} for P50 (120 l/s = 50% probability), 8-29 € / MWh_{th} for P40 (62 l/s = 60% probability) and 44-131 € / MWh_{th} for P20 (12 l/s = 80% probability). Distributions of generation costs are calculated with Percentiles P10-P90 for temperature gradient and with net present value method. Limit of the method of approach and derived conclusions is the question whether the *Geological Model* correctly reflects expected depth, flow rate and temperature of the hydrothermal resource. Since the Geological Model derived from GeoHeat.at is best available data, it is assumed for this work that indicated depth of rock layers and Percentiles for temperature and flow rate of the hydrothermal resource are correct.

Prospective market sales price is assumed with 36 € / MWh_{th} and thus the site of Baden may be profitable for geothermal heat production. In order to depict the risk of non-discovery in an investment decision calculation it can be either used a higher discount rate (reflecting the risk of non-discovery) or if a risk insurance against non-discovery is possible, this is shown in investment costs (premium for risk insurance). To solve the risk of non-discovery from an economic point of view the investment risk needs to be spread across a given portfolio as it is done in the oil and gas industry *(Portfolio Approach)* which would make it possible to insure individual geothermal drilling project against the risk of non-discovery. Given the geological risk whether the hydrothermal resource is found in sufficient quantity (l/s) and quality (°C) the establishment of an international or *European Geothermal Risk Insurance Fund (EGRIF)* may be able to solve the investment risk of non-discovery. This can facilitate market deployment of deep geothermal energy especially in low and medium enthalpy areas.

Table of content

1 Introduction

1.1 Motivation

I had been part of the Austrian research project GeoHEAT.at (AIT, Austrian Geological Survey, TU Vienna in cooperation with two energy utility companies and an energy intensive company in the food industry). In this project deep geothermal energy production in Vienna and in Baden was investigated. In the Vienna Basin huge potentials of hydrothermal resources exist, yet the main barrier for market deployment is the risk of non-discovery of the hydrothermal resource. Thus I have chosen this topic for my master thesis. Since the risk of non-discovery is similar to exploration risk in the oil and gas industry and the same drilling technologies are used, the exploration of deep geothermal energy resources may become a solution for oil and gas companies to replace step by step fossil fuels with geothermal energy.

1.2 What is the core objective / the core question?

The core objective of this master thesis is to investigate the risk of non-discovery of the hydrothermal resource from an economic point of view. The core question is how to depict geological risk of non-discovery in an investment decision calculation. The goal is to depict the risk of non-discovery in a distribution of expected generation costs for investment decision calculation.

1.3 Citation of main literature

The core of this master thesis is based on results of the Austrian research project GeoHeat.at (reports not publicly available). I have taken the results of GeoHeat.at as basis for my calculations in order to depict the risk of non-discovery. For the risk of non-discovery for deep geothermal heat plants in low and medium enthalpy areas only limited literature exists. Thus I have given a general overview on deep geothermal in this work.

1.4 Structure of work and method of approach

Structure of work

First I will give a general overview: what is geothermal energy, worldwide potentials, market deployment globally, in Europe and in Austria. It is structured in heat applications and electricity generation from deep geothermal. Then I have described the risk of non-discovery of the hydrothermal resource and its implication for deep geothermal deployment as described in the literature. In the core part of my master thesis I have chosen the site of Baden (Vienna Basin) to investigate the risk of non-discovery from an economic point of view. This case study is based on the results of the research project GeoHeat.at.

Method of approach

I have taken given values from GeoHeat.at for transmissivity of the rock layer “Hauptdolomit” at Baden and calculated expected distribution of flow of water (l/s). With flow of water and given temperature distribution (from GeoHeat.at) I have calculated expected distribution of installable capacities (MWth). For flow of water I have chosen P50 (120 l/s = 50% probability), P40 (62 l/s = 60% probability) and P20 (12 l/s = 80% probability) and with given temperature Percentiles (P10 to P90) I have calculated three possible distributions of installed capacities. Then I have calculated the respective distributions of generation costs (EUR/MWh_{th}) and compared the results. Given the Percentiles for flow of water and temperature the distributions of generation costs show the risk of uncertainty (non-discovery of hydrothermal resources) from an investor’s point of view. Generation costs are calculated with the net present value method and a discount rate that reflects normal market risks.

1.5 Austrian research project GeoHeat.at as basis of this Master Thesis

This master thesis is based on the Austrian research project GeoHeat.at of which I was part of. The main part of the research project was to investigate prospective

sites for deep geothermal heat production in the Vienna Basin. Selected and investigated sites were in Vienna and Baden. It comprised geological, technical and economic aspects.

The team was led by **Edith Haslinger** (AIT, Austrian Institute of Technology) and **Gregor Götzl**, head of shallow and deep geothermal at Geological Survey of Austria (www.geologie.ac.at).

The project was done in cooperation with experts from two large Austrian energy utilities and an energy intensive industrial company.

Team members:

Lead: Edith Haslinger (AIT), Gregor Götzl (Geological Survey of Austria)

Prof. Karl Ponweiser (Vienna University of Technology) Energy Systems and Thermodynamics

Richard Niederbrucker (Geohydrotherm) engineering consultancy

Julia Weilbold
Gerhard Heiss
Stefan Hoyer
Martin Jung
Daniel Lange
Alain Strauss
Walter Saurer

My part was to support in calculating generation costs, net present value method, investment decision calculation, integration of risk of non-discovery and research and preparation of scientific papers.

Please note: results and papers from GeoHeat.at are not publicly available
All parts I have used are quoted and referred to “GeoHEAT”

2 What is geothermal energy?

2.1 Overview

Geothermal energy is **heat from the Earth** that can be used for **direct use applications** (i.e. heating) or **electricity** production. It can be differentiated between shallow and deep geothermal technologies. **Shallow geothermal** technologies use the heat stored at low depths (some meters to 400 meters below surface) for heat production with lower temperatures, e.g. heat pumps. **Deep geothermal** uses the heat stored at greater depths, usually at several 1000 meters. It represents a completely different technology than shallow geothermal: with deep drilling technologies – similar to those used for oil extraction – the hot fluid is brought to the surface and used for heat or electricity production. In **low-to-medium enthalpy areas** like Austria, fluids (i.e. hot water) with temperatures up to 200°C can be found in a depth of several 1000 meters. In **high enthalpy areas** like Iceland fluids with temperatures of even more than 350° C can be found at lower depths.

Shallow geothermal is not part of this work since it represents a completely different technology.

In deep geothermal two different types of ressources can be differentiated:

- **Hydrothermal resources:**
  In regions where hot fluids (hot water) occur at certain depths this is called deep geothermal from *hydrothermal* ressources. This is often referred to *conventional* deep geothermal since allmost all of the existing deep geothermal drillings use hydrothermal resources.
- **Hot rock resources[1]:**
  In all other areas where no hydrothermal ressources occur the heat stored in rocks at a certain depth can be extracted by injecting an artificial fluid by which the heat can be brought to the surface. This technology is called *EGS (Enhanced Geothermal Systems)* or HDR (Hot Dry Rock). This is often referred to *unconventional* deep geothermal since this technology is still in experimental status and the plants build so far are pilot plants.

[1] In other publications the term *Hot Rock resources* is also referred to *Petrothermal resources* which is used synonymously.

For both – hydrothermal and hot dry rock resources – deep drilling technologies are used.

Unconventional deep geothermal (i.e. EGS technologies for hot dry rock resources) is still in experimental status. However this might be a promising future technology because no hydrothermal ressources are required and thus this technology could be applied almost everywhere in the world.

Conventional deep geothermal (i.e. from hydrothermal resources) represents most of the deep geothermal drillings worldwide and has been existing for a long time. Yet it can be only applied in regions where hot fluids occur within rock layers and there is always the risk of non-discovery of the hydrothermal resource. Even in areas where geologic models suggest the occurrence of large hydrothermal reservoirs the existence of the resource is eventually proven only after drilling the wells. This is a major obstacle for a broader use of the huge geothermal potential since drilling is very expensive and represents the main cost factor for deep geothermal. If the hydrothermal resource is not found, drilling costs are completely lost which constitutes a major investment risk.

This work investigates the risk of non-discovery of the hydrothermal resource for deep geothermal drillings. **Thus in this work the term *deep geothermal* refers to deep geothermal from hydrothermal resources if not otherwise specified.**

2.2 The Earth – an almost infinite source of thermal energy

99% of the Earth's volume is hotter than 1000°C which constitutes virtually an indefinite source of energy. Geothermal energy can be considered as renewable energy source because the heat is continously flowing from the Earth's interior outwards and is exptected to remain so for billions of years to come, thus ensuring an inexhaustible supply of energy. Inside the Earth the core has a temperature of about 5,000°C surrounded by the mantle of the Earth with temperatures over 1200°C (see figure below). This creates a countinous upstream heat flow that can be used by geothermal technologies for heat and electricity production. Practically

only a small fraction of the heat inside the earth can be used: deep drilling technologies usually reach thermal energy reservoirs in a depth up to several kilometres below surface (today's drilling technologies usually have depths of 3000-5000 m and can reach depths up to 10 km from a technical point of view). Within the crust of the earth, which has a thickness of about 30 km, the average[2] temperature gradient is 3°C/100 m, which means that temperature increases by 30°C per 1000 m depth. Therefore at a depth of 1 km temperatures of 30°C can be expected, in 2 km depth 60°C and in 5 km depth a temperature of 150°C is to expect (Bundesverband Geothermie 2015a; Geothermal Energy Association 2015; Goldstein, Hill et al. 2009; Barbier 2002).

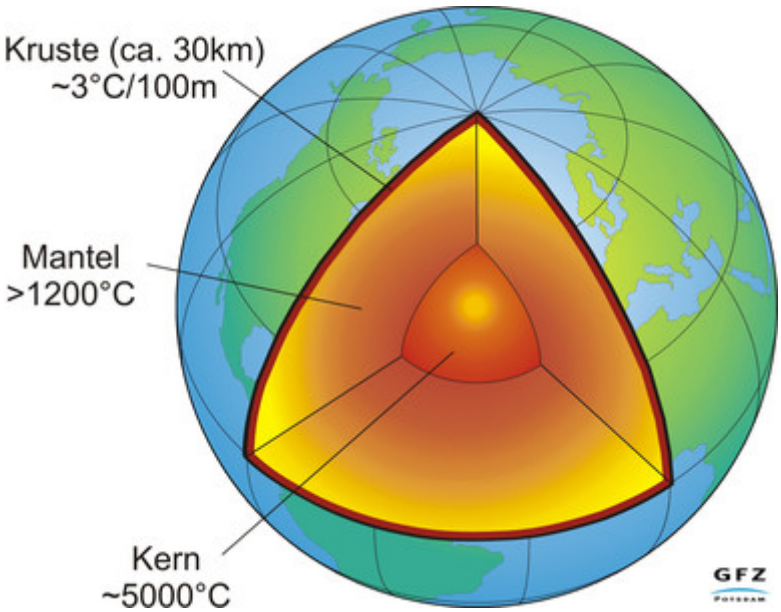

Figure 1: Crust, mantle and core of the Earth (Source: Bundesverband Geothermie 2015a)

Geothermal energy can be defined as *heat from the earth* (Geothermal Energy Association 2015). Geothermal resources consist of thermal energy from the interior of the earth stored either in hot rocks or hot thermal waters that circulate within rock layers, which is called a hydrothermal system (Goldstein, Hiriart et al. 2011, p. 406).

[2] This value (3°C/100 m) is the worldwide average and may differ significantly depending on local geological settings.

The term *geothermal resources*[3] refer in its broadest sense to the thermal energy (i.e. heat) stored in the Earth. Within the first 5,000 meters of the Earth crust the energy stored is estimated at 140,000,000 EJ. This constitutes an enormous theoretical potential compared to current world energy consumption of 500 EJ/year (Bertani 2010, p. 26; WEC 1994; WEC 1998). Total thermal energy contained in the Earth is estimated at 12,000,000,000,000 EJ of which 5,000,000,000 EJ are stored within 50 km below surface (Dickson and Fanelli 2003).

The heat stored under the Earth's surface stems mainly from heat flows from the Earth's mantle and core having temperatures of 1200°C and 5000 °C and from decay of radioactive isotopes in the crust of the Earth. This heat flow from the interior to the surface of the Earth (65 mW/m^2 on continents and 101 mW/m^2 through the ocean floor) results in a global terrestrial heat flow rate of 1,400 EJ/year. The heat flow rate of continents, which cover a third of the Earth's surface, is estimated at 300 EJ/year (Stefansson 2005).

The stored thermal energy down to 3 km depth on continents is estimated at 42,000,000 EJ of which 80% (34,000,000 EJ) is stored in hot dry rocks (HDR, extractable with EGS-technology) and 20% (8,000,000 EJ) is stored in hydrothermal systems. EGS is currently still under development. At present deep geothermal energy uses primarily hydrothermal resources. In very favorable areas the temperature of the thermal fluids can reach 180°C to more than 350°C in depths below 4 km (Goldstein, Hiriart et al. 2011, p. 408). The high temperature regions cover about 10% of the earth's surface Bertani 2010, p. 26).

Hydrothermal systems can be categorized according to its temperature levels (Tester and Drake 2005):

- **High-temperature hydrothermal fluids (>180°C)**
  (They are often found in areas with recent volcanic activities or near tectonic plate boundaries or at crustal hot spot anomalies. In very favorable areas temperatures may reach more than 350°C at depths below 4 km.[4])
- **Medium-temperature hydrothermal fluids (100°C-180°C)**
- **Low-temperature hydrothermal fluids (<100°C)**

[3] Please note: normally in this work the term *geothermal resources* refers to hydrothermal resources (i.e. hot thermal waters in a certain depth).
[4] (Goldstein, Hiriart et al. 2011, p. 408)

2.3 Types of geothermal resources

On continents about 80% of the thermal energy stored within a depth of 3 km is stored in hot rocks and 20% in hydrothermal resources. Today deep geothermal energy production stems mainly from hydrothermal resources and is thus called *conventional* deep geothermal energy. In the following two subchapters hydrothermal resources will be explained (which is the topic of this work) and then energy production from hot rock resources (*EGS, Hot Dry Rock, unconventional deep geothermal energy*) will be briefly explained for reasons of understanding deep geothermal in general. Yet, EGS and Hot Dry Rock are not part of this work.

2.3.1 Hydrothermal resources – conventional deep geothermal

Main characteristic of geothermal from hydrothermal resources is the existence of hot water stored and circulating in rock layers in a certain depth below the Earth's surface. Since hydrothermal resources do not exist everywhere it is only possible to produce geothermal energy in those regions where sufficient amounts of water at sufficient temperature levels occur.

Rainwater from the surface gets trough permeable rock layers into a certain depth where impermeable rock layers prevent the water from further flowing downwards. This forms a geothermal reservoir where the water is trapped in porous rocks. The reservoir cannot be imagined as a lake or sea beneath the surface, it constitutes rather a huge porous rock formation containing a lot of smaller amounts of water dispersed within the respective rock layer. The water there is continuously heated by the heat flowing outwards from the Earth's core:

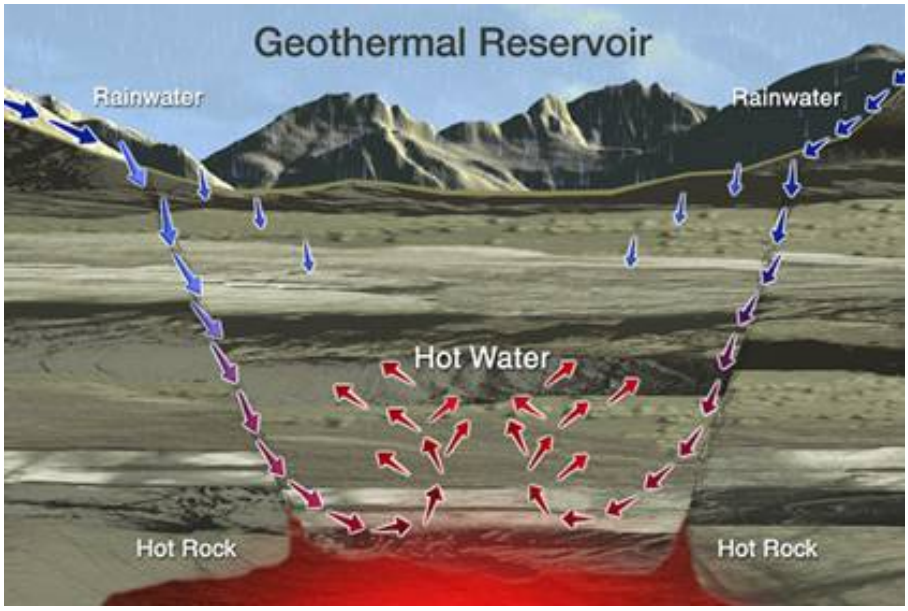

Figure 2: Deep geothermal from hydrothermal resources – geothermal reservoir.
(Source: Geothermal Energy Association 2015)

In some areas the heat, as magma, flows upwards as lava and reaches the surface or the heated water streams upwards as geysers or hot springs. Yet usually the hot water stays within the porous rock formation in between impermeable rock layers that prevents the water from flowing up- or downwards:

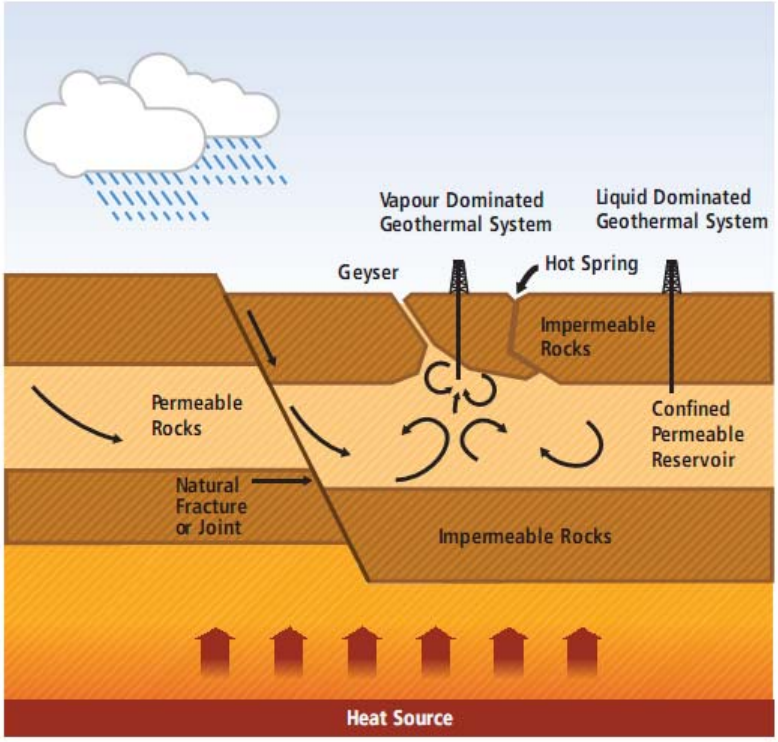

Figure 3: Schematic depiction of a hydrothermal reservoir.
(Source: Goldstein, Hiriart et al. 2011, p. 406)

The hot water trapped in a geothermal reservoir can be brought to the surface by deep geothermal drillings. In high temperature reservoirs the water is vaporized by the heat (vapour dominated geothermal system) whereas in liquid dominated geothermal systems temperatures are lower. The hot fluid can then be used for electricity production or heating. Currently, deep geothermal energy production is usually from hydrothermal resources, since non conventional (non-hydrothermal, EGS) is in experimental status (Goldstein, Hiriart et al. 2011, p. 406).

For the risk of non-discovery of the hydrothermal resource it is essential to understand that a hydrothermal reservoir is not a huge lake underneath the surface. Thus, even if it the existence of huge hydrothermal resources is known for a certain area (like in the Vienna Basin), the resources may not be found in sufficient amounts or at sufficient temperature levels if the wells are not drilled at the right location.

2.3.2 Hot rock resources – unconventional deep geothermal (EGS, HDR)

Currently only a small fraction of deep geothermal drillings are *unconventional deep geothermal drillings* since this technology is still in experimental status and plants build so far are pilot plants.

Subsurface temperatures increase with depth and the rock formations heated by the Earth's core can be used for energy production with *Enhanced Geothermal Systems (EGS).* This makes it possible to produce energy from deep geothermal also in regions where no hydrothermal resources exist.

EGS resources occur in all areas worldwide but are likely to be economic in regions where sufficient rock temperatures are found in a depth of less than 5 km. Given average geothermal gradients of 30°C/km, EGS resources (hot rocks) with temperatures above 180°C provide favorable conditions for heat and electricity production. Existing drilling technologies are currently capable of reaching depths up to 10 km. If EGS technology further improves it might be possible to exploit those high temperature resources in many areas of the world (Goldstein, Hill et al. 2009). EGS technologies are still in development status. If EGS proves to be technically and economically viable the development potential of deep geothermal energy will be enormous in many countries of the world (Bertani 2010, p. 25).

Economics of EGS – electricity

Since EGS is in development status and actual cost data are only available from pilot plants where economics are relatively unimportant, costs cannot be assessed accurately yet (IEA 2011a, p. 16). Thus for EGS no actual data for levelized costs of electricity (LCOE) exist, though different models for cost estimations indicate potential cost ranges. For example the model developed by the Massachusetts Institute of Technology indicates a cost range (LCOE) from US cents 10 to 17/kWh_{el} for high temperature EGS resources (250-330°C in a depth of 5 km) assuming a flow rate of 20 kg/sec. Another model for a hypothetical EGS plant in Europe estimates costs (LCOE) between US cents 30 to 37/kWh_{el} assuming temperatures of 125-165°C of the EGS resource in a depth of 4 km with a flow rate of 33-69 kg/sec. A projection of future cost trends for EGS suggested that a significant decrease in costs might be possible by 2030 with LCOE of US cents 3.6 to

5.2/kWh_{el} for high-temperature EGS resources and US cents 5.9 to 9.2/ kWh_{el} for medium-temperature EGS resources with 180-220°C in a depth of 5-7 km (Tester and Anderson et al. 2006; Huenges and Frick 2010; Goldstein and Hiriart et al. 2011, p. 426-427).

2.4 Utilization of geothermal resources: electricity and direct use (heat)

Geothermal resources can be used in two forms: either for electricity production or for direct use (which is used synonymously for heat applications). In CHP plants (combined heat and power) electricity and heat is produced simultaneously. Heat can be produced from geothermal resources with lower and higher temperatures, whereas electricity production requires a certain temperature level.

The classical Lindal diagram from 1973 (see figure below) is still valid and shows different types of utilization of geothermal resources (International Geothermal Association 2004). On top of the diagram the temperature levels of geothermal resources is indicated ranging from 0-350°C. The diagram itself shows different forms of utilization suitable within a given temperature range and indicating the required minimum temperature. For example, for Spa treatment or heating of swimming pools temperature levels from 30-50°C are sufficient. The diagram lists a variety of possible geothermal applications from hot domestic water to agricultural or industrial uses and their respective required temperature ranges:[5]

[5] Please note: examples shown in the diagram are illustrative and do not include all possible applications. For example industrial process heat applications requiring over 150°C are not included. The diagram covers applications from deep and shallow geothermal resources.

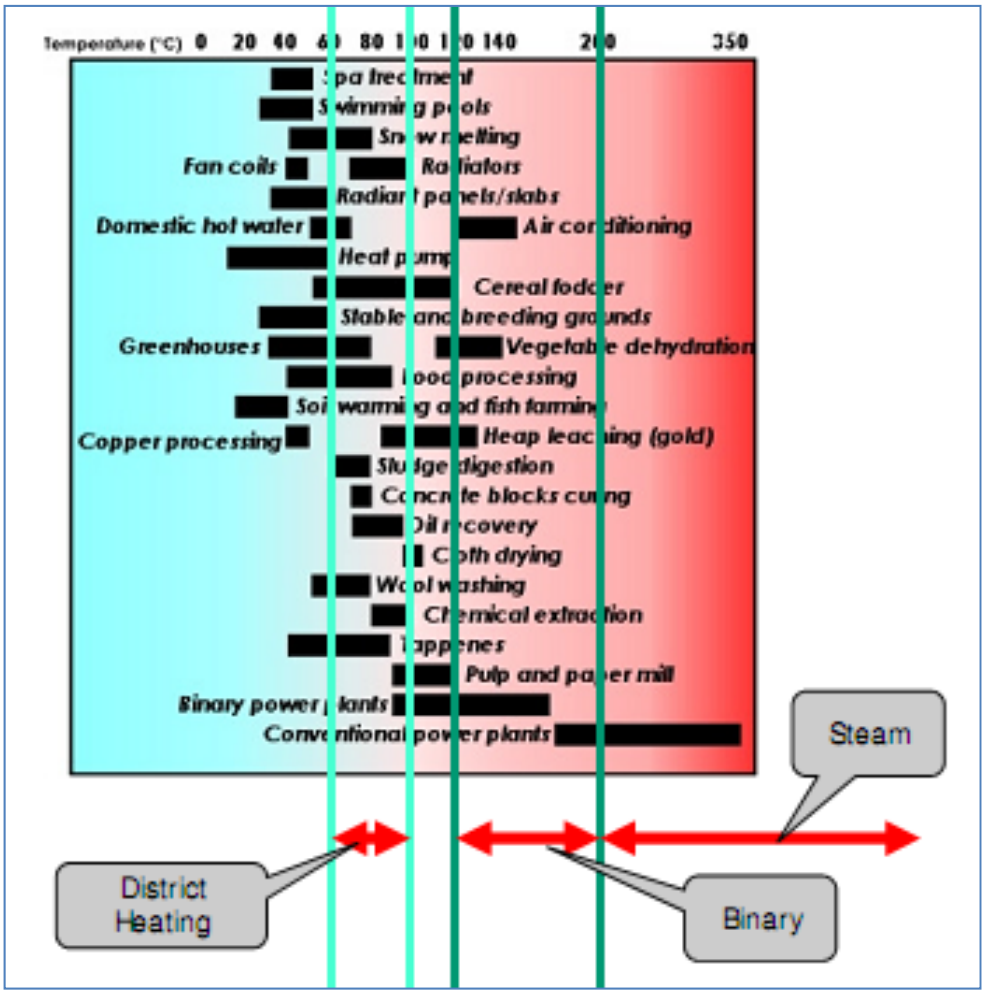

Figure 4: Lindal diagram.

(Source: taken from Valdimarsson 2012, p. 79, derived from Lindal, 1973.)

All of the listed examples are heat applications (direct use) except *Binary power plants* and *Conventional power plants* shown with necessary temperature ranges for electricity production. Electricity production requires minimum temperatures of above 90-120°C. In areas with low to medium temperature resources electricity can be produced by *Binary power plants* whereas in very favorable areas with high temperature resources (steam) electricity is produced by *Conventional power plants*. District heating usually requires minimum temperatures of 60-100°C.

Economics and efficiency of a geothermal plant can be increased with cascading and combined use of different applications according to needed temperature levels (International Geothermal Association 2004). For example if the outlet temperature of a district heating system can be used for heating greenhouses. In general the resource temperature limits possible uses.

For the risk of non-discovery of the hydrothermal resource it does not matter whether the deep geothermal drilling is intended for electricity or heat applications. In both cases the hydrothermal resource needs to be found in sufficient quantity (l/sec) and at sufficient temperature levels (depending on the required minimum temperature for the intended use).

2.5 Geothermal resource potential worldwide

The term *geothermal resources* refers to the thermal energy (i.e. heat) that is contained inside the earth. Deep drilling technologies have certain limits from a technical and economic point of view. Today deep geothermal drillings usually have a depth up to 3,000 to 5,000 meters. Total thermal energy stored in the earth up to 3,000 meters is estimated at 42,000,000 EJ. The thermal energy recharge rate (i.e. rate at which the heat is continuously replenished from the higher temperature regimes below 5,000 meters depth) is estimated at about 315 EJ/year. Compared to current world energy demand (500 EJ) this represents a huge theoretical potential. From theoretical potential (42,000,000 EJ) to technical potential only those geothermal resources are included that might be accessed with current technologies: estimates for the technical potential amount some 700 EJ/year. For the economic potential that part of the technical potential is taken that can be extracted under competitive market settings. The economic potential is estimated up to 2050 at 10 EJ/year for direct utilization and 65 EJ/year for electricity production. Direct utilization (10 EJ/year or a calculated equivalent capacity of 800 GW_{th}) comprises deep and shallow geothermal resources. Electricity production comprises hydrothermal and EGS resources. Equivalent capacity for electricity production from hydrothermal resources is 70 GW_{el} (Bertani 2010, p. 25-27; WEC 1994; WEC 1998; Stefansson 2005).

To assess the potential of geothermal it is important to estimate the amount of resources stored in the earth. Generally studies provide estimates based on today's knowledge and current state of technology. Indicated figures depend on a variety of factors that have to be estimated and can therefore be seen as a rough approximation. Furthermore technical potentials tend to increase with time as technology progresses and overcomes some of the technical constraints of

accessing theoretically available resources (Goldstein and Hiriart et al. 2011, p. 408-411).

In the *IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation (2011)* existing studies on the potential of geothermal resources are analyzed. Figures comprise the potential of deep and shallow resources as well as geothermal potential exploitable by EGS technology which is still under development. A summary of the outcome of existing studies on geothermal potential is shown in the table below:

Table 1: Geothermal Technical Potential on Continents worldwide (Source: Goldstein and Hiriart et al. 2011, p. 411, in: IPCC Special Report on Renewable Energy Sources and Climate Change Mitigation)

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

Firstly, the table shows the technical potential of geothermal resources on continents worldwide. Secondly, it is differentiated between potentials for electricity production and direct use applications. This differentiation is somehow arbitrary since direct use application could be produced also from resources indicated for electricity production. Different figures for the resource potential are indicated according to drilling depth: estimates are given for the technical potential for 3 km and 5 km depth, which represents average drilling depths of existing deep geothermal plants, and for a depth of 10 km which could be reached with current drilling technologies. Thirdly, lower and upper values characterize the range of indicated potentials in different studies. Figures for electric technical potential comprise hydrothermal and EGS resources (Goldstein and Hiriart et al. 2011, p. 408-411). For the technical potential for direct use applications a depth range is not explicitly indicated. Estimates on the global technical potential on continents can be summarized as following:

Current technical potential for electricity production (hydrothermal and EGS resources):

- depth up to 3 km: 117-145 EJ/year
- depth up to 5 km: 174-421 EJ/year
- depth up to 10 km: 317-1108 EJ/year

Current technical potential for direct use applications (shallow and deep geothermal technologies):

- 9 – 312 EJ/year (no depth range indicated)

3 Deep Geothermal in the World

3.1 Overview

In 2010 worldwide installed capacities for electricity production from deep geothermal were about 10,700 MW_{el}. Installed capacities for direct use (heat) were 50,000 MW_{th} (including all forms of geothermal, mainly shallow geothermal technologies, e.g. heat pumps. Heat provided from deep geothermal is estimated to represent only a fraction of the indicated 50,000 MW_{th} heat capacities).

Statistics for global use of geothermal is collected only every five years. Thus the most currently available figures date from 2010[6]. Global statistics are prepared by the *World Geothermal Congress (WGC)* which takes places every five years. The last WGC took place in 2010 – data presented in the chapters below are mainly based on proceedings and outcomes of WGC 2010. The next World Geothermal Congress (WGC 2015)[7] will take place in April 2015 in Australia. Therefore most recent data for global geothermal energy use shall be available by the end of 2015, including worldwide statistics indicating the current figures for installed capacities for electricity and direct use / heat for 2015 and most important developments for the period from 2010 to 2015 (Bundesverband Geothermie 2015b).

Direct use from geothermal comprises all applications for heating, e.g. heating of individual houses, district heating, industrial process heat, heated water for balneology and spa use and any other heating purpose. The terms *direct use* and *heat* are used synonymously. In geothermal context energy production is usually divided into:

- Heat or direct use
- Electricity

In the following subchapters the world status of heat and electricity from geothermal will be presented.

[6] Presented figures represent data from the end of 2009.
[7] http://wgc2015.com.au/

3.2 Direct use (heat) from shallow and deep geothermal resources – World

3.2.1 Why figures for deep and shallow geothermal resources are aggregated in statistics for direct use (heat)

In the literature separate figures for the world status of deep geothermal for direct use are hardly available. Usually aggregated figures are presented for all types of geothermal technologies that produce heat – and no distinction is made between deep and shallow geothermal technologies. Thus in this chapter an overview is given on worldwide status of geothermal for direct use from *deep AND shallow*[8] geothermal technologies. Eventually a rough estimation on the share of deep geothermal in worldwide direct use/heat applications is undertaken. It is to assume that deep geothermal stems almost exclusively from hydrothermal resources since other forms of deep geothermal (unconventional deep geothermal technologies, EGS, HDR) are still in development status.

3.2.2 Installed capacities by type of application for direct use

In 2010[9] worldwide installed capacity of geothermal for direct use (heat) was 50,583 MW_{th}. This figure comprises not only deep geothermal but also shallow geothermal technologies which account for the major part of installed capacities (Lund, Freeston and Boyd 2010, p. 1-3):

[8] If not otherwise specified for all other parts of this work shallow geothermal is not dealt with since deep geothermal – or to be precise deep geothermal drilling technologies – constitute a completely different technology and in order to assess the risk of non-discovery of the resource there is no relation to shallow geothermal applications.
[9] Presented figures represent data from the end of 2009.

Table 2: Installed capacities worldwide from deep and shallow geothermal for direct use in 2010 – by type of application in MWth (Source: Lund, Freeston and Boyd 2010, p. 3)

	2010
Geothermal Heat Pumps	35,236
Space Heating	5,391
Greenhouse Heating	1,544
Aquaculture Pond Heating	653
Agricultural Drying	127
Industrial Uses	533
Bathing and Swimming	6,689
Cooling / Snow Melting	368
Others	41
Total	**50,583**

Out of the 50,583 MW_{th} total installed capacity heat pumps represent by far the largest part (35,236 MW_{th} or 69.7% of total installed capacities). Followed by bathing and swimming (6,689 MW_{th} or 13.2%) and space heating (5,391 MW_{th} or 10.7%). All other forms of direct use represent less than 10%:

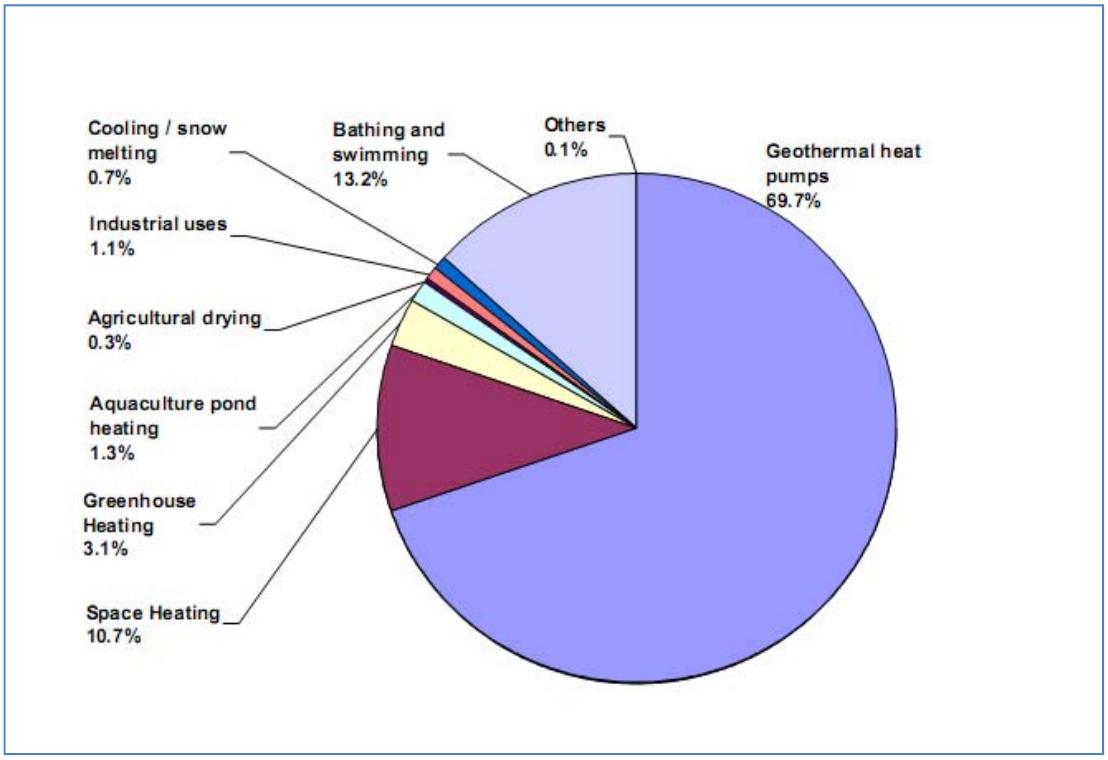

Figure 5: Installed capacities worldwide from deep and shallow geothermal for direct use in 2010 – by type of application (distribution by percentage of total installed capacity); Source: Lund, Freeston and Boyd 2010, p. 3

3.2.3 Estimate on installed capacities of deep geothermal for direct use

Global statistics for direct use applications are prepared by the *World Geothermal Congress* and are taken from the *Worldwide Review for Direct Utilization of Geothermal Energy* (published by Lund, Freeston and Boyd 2010). Yet no separate figures for deep geothermal are given. From logical reasoning deep geothermal accounts only for a minor part of worldwide installed capacities for direct use (50,583 MW_{th}). Heat pumps (69.7%) represent a shallow geothermal technology. Bathing and swimming (13.2%) is probably provided for the overwhelming part by shallow geothermal like hot springs and shallow drillings. Yet in some locations, e.g. in Austria[10], balneologic applications (thermal spa) is provided by deep geothermal drillings. Industrial uses (1.1%) might be largely provided be deep geothermal since required temperature levels are usually higher than shallow geothermal technologies may provide. Greenhouse heating (3.1%) may be provided by shallow or deep geothermal technologies. Finally the most important application that may be largely provided by deep geothermal is *Space Heating* (10.7%): space heating comprises individual space heating and district heating. According to (Lund, Freeston and Boyd 2010, p. 3) individual space heating accounts for 15% and district heating for 85% of *Space Heating*. Whereas the heating of single houses is normally provided by shallow geothermal – district heating is probably mainly provided by deep geothermal technologies.

Thus deep geothermal for direct use might be around or lower than 10% (some 5,000 MW_{th}) of worldwide installed capacities (50,583 MW_{th}). Given the fact that installed deep geothermal capacities for district heating in Europe is about 4,300 MW_{th} (EGEC 2013b)[11] it might be concluded that **worldwide installed capacities for direct use from deep geothermal comprises mainly the before mentioned 4,300 MW_{th} district heating capacity in Europe.**

[10] see: chapter 5
[11] See also chapter 4.2

3.2.4 Growth rate of installed capacities for direct use from deep and shallow geothermal

With a worldwide installed geothermal capacity of 50,583 MW_{th} for direct use an amount of 121,696 GWh/yr[12] of thermal energy was produced in 2010. In 78 countries direct use applications of geothermal exist. The five countries with the largest installed capacities account for about 60% of world capacity (50,583 MW_{th}): USA, China, Sweden, Norway and Germany (Lund, Freston and Boyd 2010, p. 1-2). The figure below shows the increase in installed capacities and produced thermal energy output since 1995:

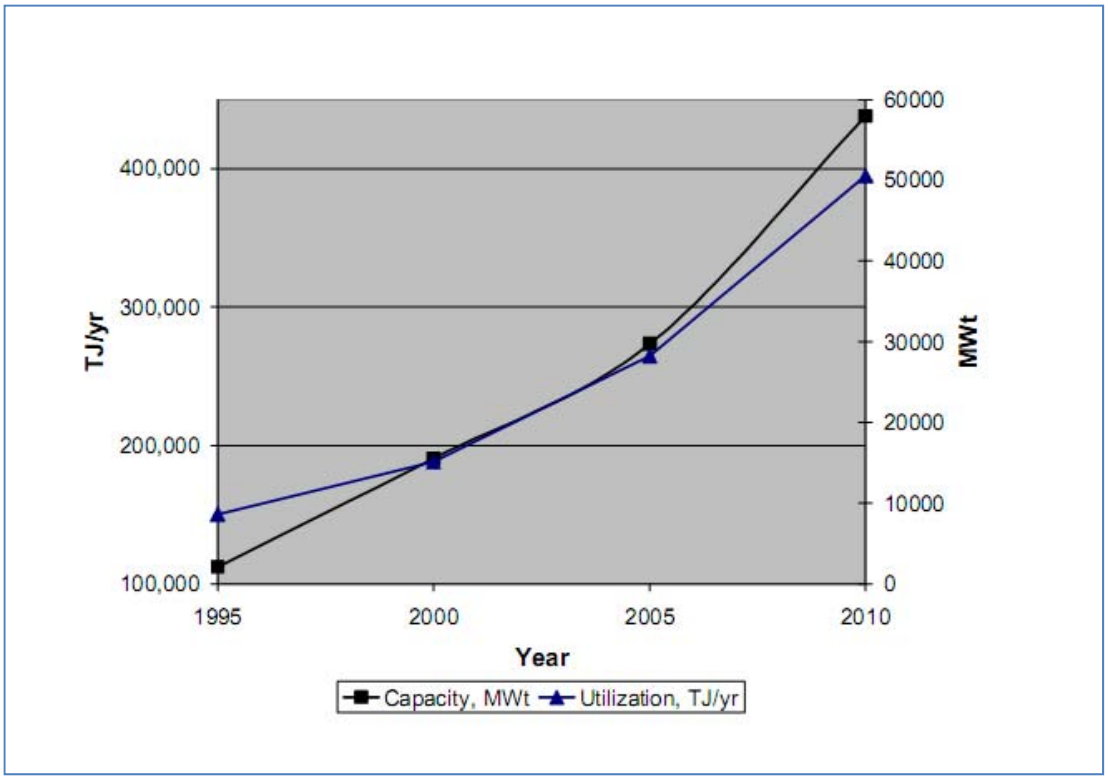

Figure 6: Growth rate of worldwide installed capacity and thermal energy output for direct use of shallow and deep geothermal technologies from 1995-2010 (Source: Lund, Freeston and Boyd 2010, p. 2)

Installed capacities increased from 8,664 MW_{th} in 1995 to 50,583 MW_{th} in 2010. This significant growth was mainly due to the high growth rate of heat pumps (from 1,854 MW_{th} in 1995 to 35,236 MW_{th} in 2010). Average worldwide capacity factor for all direct use applications is 0.27 (equivalent to 2,365 full load operating hours per

[12] that is 438,071 TJ/yr

year) which is mainly due to the predominance of heat pumps[13] in worldwide installed capacity. Capacity factors vary a lot within and in between applications of direct use. For example the average worldwide capacity factor for space heating is 0.37 (Lund, Freeston and Boyd 2010, p. 1-5).

3.2.5 Economics and costs for district heating and greenhouse heating

Since district heating and partially greenhouse heating represent the main applications of direct use from deep geothermal resources cost ranges for those two applications shall be provided.

Geothermal heat used for district heating can be competitive when the temperature level of the hydrothermal resource is sufficiently high and a district heating system is already in place. Geothermal heat may be also competitive when a continuous demand of heat is required, e.g. for greenhouse heating (IEA 2011a, p. 16). According to calculations of the *International Energy Agency* geothermal energy for district heating can have a wide range of costs and lay between 45-85 USD/MWh$_{th}$. Costs of heating greenhouses range between 40-50 USD/MWh$_{th}$:

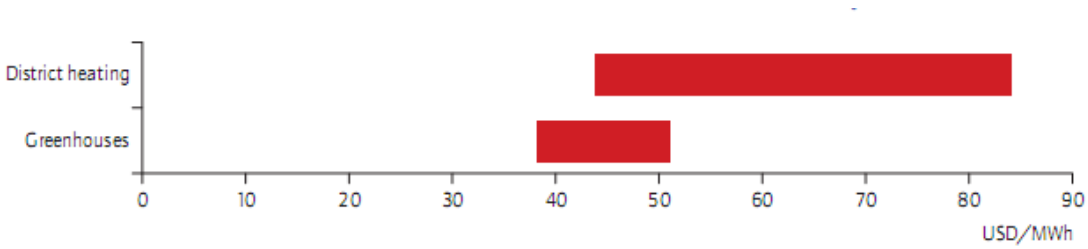

Figure 7: Generation costs of geothermal heat use (USD/MWh$_{th}$). Source: IEA 2011a, p. 18

It is to note that costs of deep geothermal heat depend on a variety of factors. The above shown cost ranges provided by the *International Energy Agency* indicate average values under specific assumptions and may thus differ from cost ranges indicated in other studies. The *European Geothermal Energy Council (EGEC)* for instance indicates a much lower cost range for district heating systems in Europe. According to the EGEC production costs of district heating systems in Europe vary

[13] Worldwide average capacity factor of heat pumps is only 0.19 since in some regions like the United States heat pumps are mainly sized for peak cooling load and are therefore oversized for heating. Thus full load hours are only some 2,000 hours per year whereas in Europe heat pumps are usually sized for base load heat and run up to 6,000 full load hours a year (capacity factor of 0.68).

within a range of 20-80 €/MWh_{th} (EGEC 2013b, p. 26). This for example seems to be in line with current data for a recently planned geothermal heat plant in Vienna/Aspern where costs of only around 20 EUR/MWh_{th} were expected (Kontrollamt der Stadt Wien 2012, p. 19). In general it can be said that cost ranges provide a useful overview but actual costs for individual plants may differ from these cost ranges since they strongly depend on local geothermal conditions.

The assumptions used by the *International Energy Agency* for calculating the cost ranges shown in the figure above are given in the following table[14]:

Table 3: Assumptions for production cost calculations (Source: IEA 2011a, p. 42)

	Flash plants	*Binary plants*	*District heating*	*Greenhouses*
Investment costs (USD)	2000-4000/kW_e	2400-5900/kW_e	571-1566/kW_t	500-1000/kW_t
Capacity factor	85%	85%	50%	50%
Interest rate	10%	10%	10%	10%
Lifetime	35	35	25	20
O&M	2.5% of investment	2.5% of investment	2.0% of investment	2.0% of investment

For *District heating* average investment costs of 571-1566 USD/kW_{th} were taken and a plant lifetime of 25 years was assumed. For *Greenhouses* average investment costs of 500-1000 USD/kW_{th} were taken with an assumed lifetime of 20 years. For both applications a capacity factor of 50% was assumed, operation and maintenance cost were estimated at 2% of investment costs and an interest rate of 10% was taken.

3.3 Electricity from deep geothermal – World

3.3.1 Installed capacities

In 2010[15] worldwide installed capacity of deep geothermal for electricity production was 10,715 MW_{el}. With an average capacity factor of 0.71 (6,275 full load hours)

[14] Please note: the columns *Flash plants* and *Binary plants* refer to cost calculations for deep geothermal electricity production which are not shown in this chapter.
[15] Presented figures represent data from the end of 2009.

67,246 GWh_{el} of electricity was produced which accounted for 0.3% of worldwide electricity production (Bertani 2010, p. 1 and p. 32-33; IEA 2011b, p. 546). This is roughly the equivalent of total electricity demand in Austria.

Since the early 1950s (200 MW_{el} total installed capacity) deep geothermal experienced moderate growth rates until the 1970s (reaching 1,000 MW_{el} total installed capacity) followed by a period of stronger growth rates between the late 1970s and early 1990s (to 6,000 MW_{el} total installed capacity). Since then the average newly installed capacity was about 300 MW_{el}/year reaching a total capacity of 10,715 MW_{el} in 2010 (Bertani 2010, p. 1 and p. 32-33; IEA 2011b, p. 546):

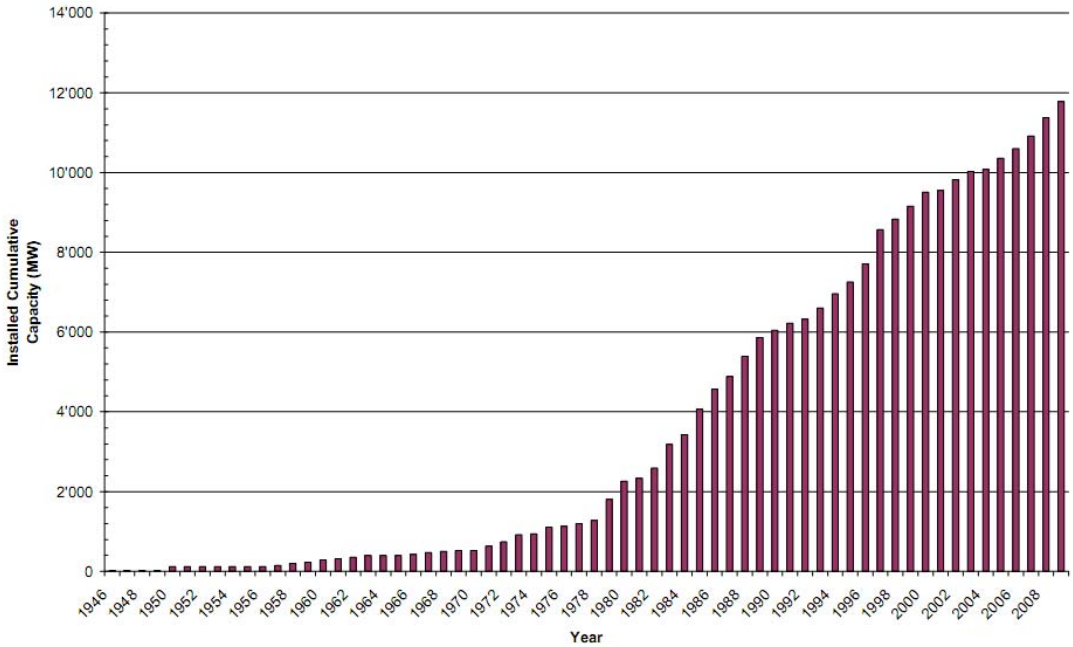

Figure 8: Worldwide installed capacity of deep geothermal for electricity production (1946-2010); Source: Bertani 2010, p. 33

In 24 countries worldwide electricity was produced from deep geothermal in 2010. The map below shows all these 24 countries (with a total capacity of 10,715 MW_{el}):

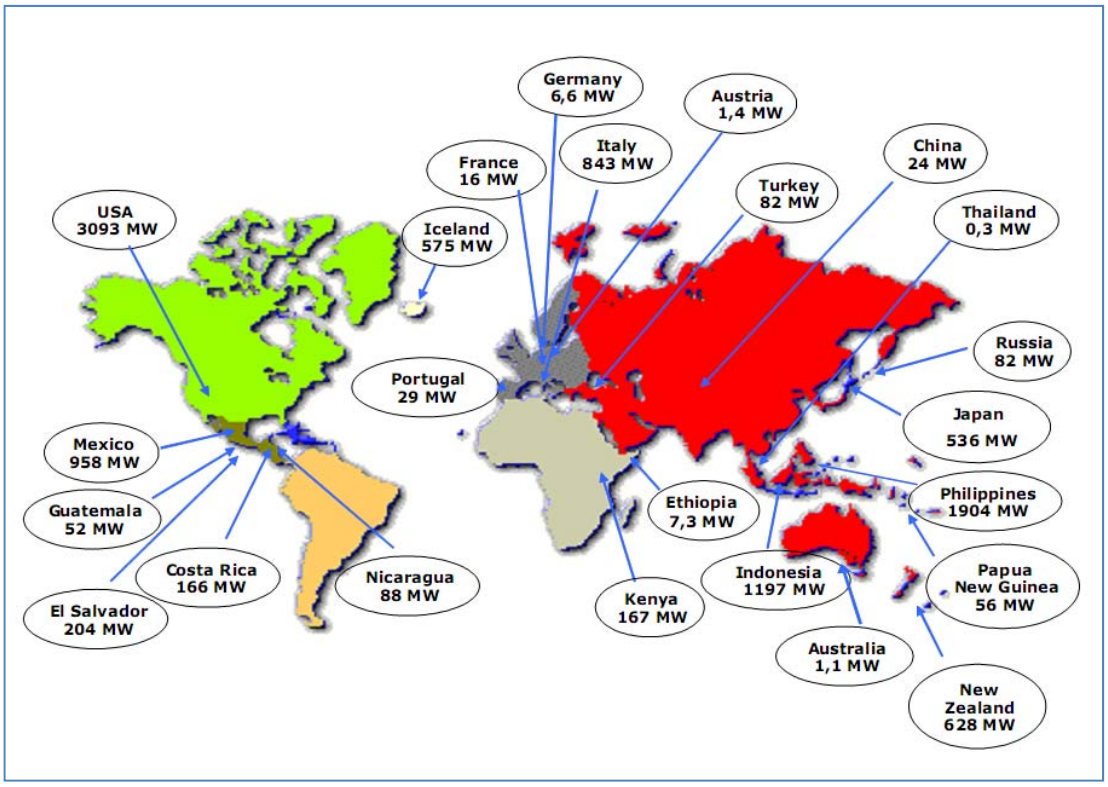

Figure 9: World map with all 24 countries with deep geothermal electricity production in 2010 and installed capacity per country (Source: Bertani 2010, p. 2)

From 10,715 MW_{el} globally installed capacities 8,000 MW_{el} (i.e. 75%) are installed in five countries (Bertani 2010):

1. USA: 3,093 MW_{el}
2. Philippines: 1,904 MW_{el}
3. Indonesia: 1,197 MW_{el}
4. Mexico: 958 MW_{el}
5. Italy: 843 MW_{el}

In contrast to deep geothermal heat – where often only one or a few production wells are used for heat production – a major part of deep geothermal electricity is produced in *geothermal fields* comprising a large number of production wells (10-50 wells or more). This is relevant for the risk of non-discovery of the hydrothermal resource: in geothermal fields with many exploration wells the risk of non-discovery is easier to estimate than in greenfield projects with only one single exploration/production well.

The 12 largest fields in the world represent a capacity of 5,982 MW_{el}. That is 55% of worldwide installed capacities (10,715 MW_{el}) – which illustrates that for the time being geothermal electricity production is highly concentrated in those areas of the world that provide highly favorable geological conditions. E.g. half of the 3,000 MW_{el} installed capacity in the United States is concentrated in one geothermal field: *The Geysers*/*California* with 1,500 MW_{el} – which is the largest geothermal field in the world (Bertani 2010).

This concentration is due to geological reasons. Highly favorable conditions for electricity production from deep geothermal exist especially in high-enthalpy regions where hydrothermal resources with high temperatures occur in low depth. It is therefore not surprising that most of the worldwide installed capacities are located in those areas of the world. The bar chart below shows again those 24 countries worldwide that produce electricity from deep geothermal and indicate their respective installed capacities. The world map in the figure illustrates those areas with especially favorable geothermal resources (heat flow in mW/m^2):

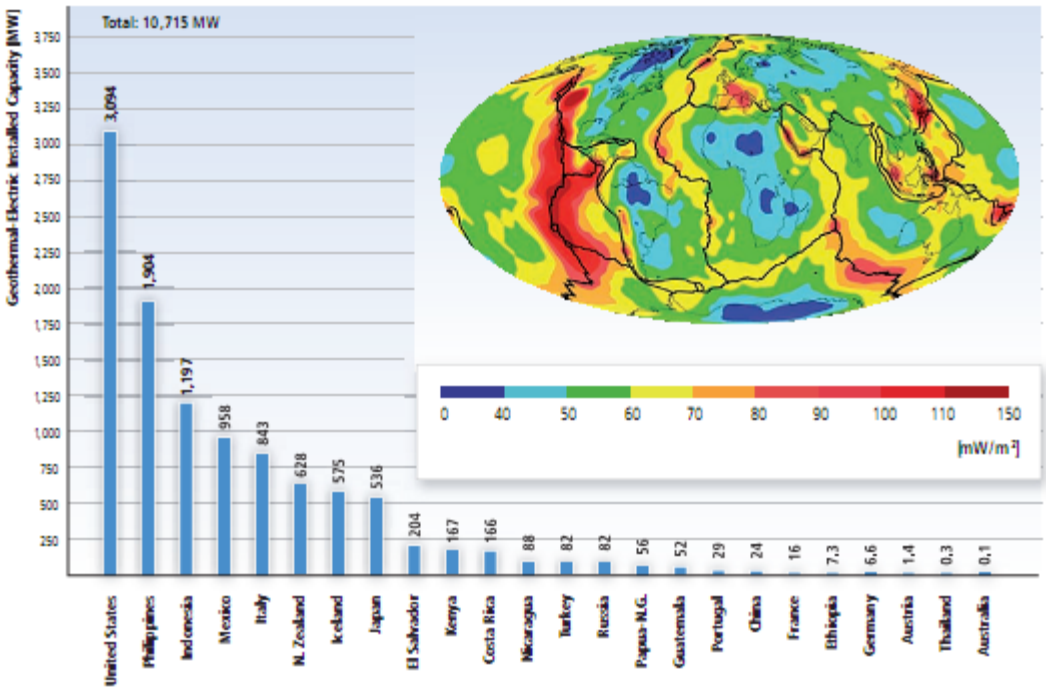

Figure 10: Geothermal-electric installed capacity by country in 2010. Inset figure shows worldwide average heat flow in mW/m^2 and tectonic plate boundaries (Source: Goldstein and Hiriart et al. 2011, p. 415)

Comparing the world map in the figure above with the geographic location of the largest geothermal fields (see figure below) it can be seen that deep geothermal electricity production is concentrated in highly favorable geological areas with high temperatures of hydrothermal resources. This is mainly around tectonic plate boundaries with very favorable heat flow rates (red area in the above inset figure in mW/m^2). The figure below shows the largest geothermal fields of the world in terms of installed capacities. (Dots are proportional to field size. Besides the indicated top 12 fields other fields of the world are illustrated by red dots):

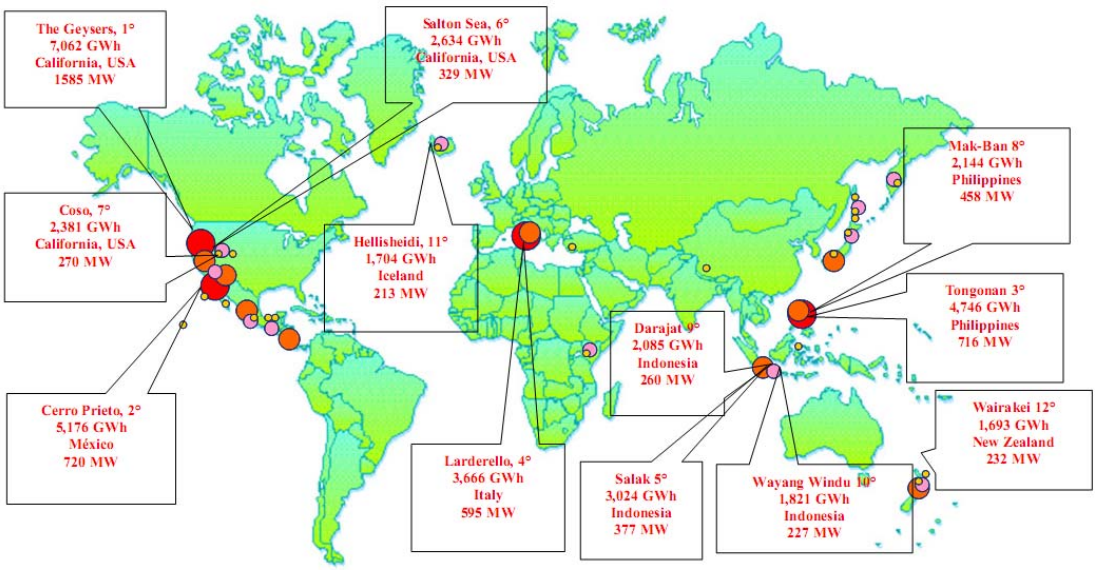

Figure 11: World map of top 12 geothermal fields for electricity production. (Dots are proportional to the field size). Source: Bertani 2010, p. 38

The field with the largest installed capacities worldwide is located in California/USA (*The Geysers*) with 1,585 MW_{el} followed by *Cerro Prieto* in Mexico with 720 MW_{el}. The largest field in Europe is located in Italy (*Lardarello*) and has a capacity of 595 MW_{el}. 55% of worldwide installed capacities (10,715 MW_{el}) are installed in the top 12 fields.

Geothermal capacities (10,715 MW_{el}) accounted in 2009 for 0.2% of worldwide installed electrical capacities (4,957,000 MW_{el}):

Table 4: Worldwide installed capacities for electricity production and IEA scenario by 2035 (Source: IEA 2011b, p. 546)

	Electrical capacity (GW)						Shares (%)		CAAGR (%)
	2009	2015	2020	2025	2030	2035	2009	2035	2009-2035
Total capacity	**4 957**	**6 196**	**6 941**	**7 594**	**8 293**	**9 038**	**100**	**100**	**2.3**
Coal	1 581	1 975	2 133	2 211	2 289	2 353	32	26	1.5
Oil	431	430	356	303	266	255	9	3	-2.0
Gas	1 298	1 602	1 749	1 868	2 016	2 185	26	24	2.0
Nuclear	393	431	495	546	591	633	8	7	1.8
Hydro	1 007	1 152	1 297	1 439	1 548	1 629	20	18	1.9
Biomass and waste	53	75	109	148	193	244	1	3	6.0
Wind	159	397	582	752	921	1 102	3	12	7.7
Geothermal	11	15	20	27	33	41	0	0	5.0
Solar PV	22	112	184	272	385	499	0	6	12.7
CSP	1	7	14	25	45	81	0	1	20.9
Marine	0	0	1	2	6	17	0	0	17.3

With an installed capacity of 10,715 MW_{el} from deep geothermal 67,246 GWh_{el} electricity was produced. That is 0.3% of worldwide electricity production:

Table 5: Worldwide annual electricity production and IEA scenario by 2035 (Source: IEA 2011b, p. 546)

	Electricity generation (TWh)							Shares (%)		CAAGR (%)
	1990	2009	2015	2020	2025	2030	2035	2009	2035	2009-2035
Total generation	**11 819**	**20 043**	**24 674**	**27 881**	**30 640**	**33 417**	**36 250**	**100**	**100**	**2.3**
Coal	4 425	8 118	10 104	10 860	11 253	11 616	12 035	41	33	1.5
Oil	1 337	1 027	833	713	620	547	533	5	1	-2.5
Gas	1 727	4 299	5 280	6 020	6 676	7 376	7 923	21	22	2.4
Nuclear	2 013	2 697	3 062	3 576	3 984	4 337	4 658	13	13	2.1
Hydro	2 144	3 252	3 887	4 380	4 861	5 231	5 518	16	15	2.1
Biomass and waste	131	288	425	635	879	1 165	1 497	1	4	6.5
Wind	4	273	835	1 282	1 724	2 182	2 703	1	7	9.2
Geothermal	36	67	96	131	174	221	271	0	1	5.5
Solar PV	0	20	126	230	369	551	741	0	2	14.9
CSP	1	1	24	52	92	167	307	0	1	25.5
Marine	1	1	1	2	9	23	63	0	0	20.2

3.3.2 Potential future development

The economic potential for geothermal electricity production from hydrothermal resources is estimated at 70 GW_{el} by 2050. In contrast to the theoretical potential

(stored heat in the earth crust up to a depth of 5,000 meters) and technical potential (extractable heat with current technology) the economic potential indicates that part of the technical potential that can be extracted economically in a competitive market setting. Given an actual installed capacity of 10,715 MW_{el} (i.e. 10 GW_{el}) which is shown in the figure below in red, with existing technology the estimated economic potential of 70 GW_{el} from hydrothermal resources could be realized by 2050 (blue). If *Enhanced Geothermal Systems (EGS)* – which is currently in experimental status – proves economically and technically viable the economic potential of geothermal electricity might reach 140 MW_{el} by 2050 which is illustrated below by the green bar. If the 140 MW_{el} target is reached about 8% of world electricity production could be provided by geothermal thus leading to savings of some 1,000 million tons of CO2 per year (Bertani 2010; IPCC 2000; IPCC 2007):

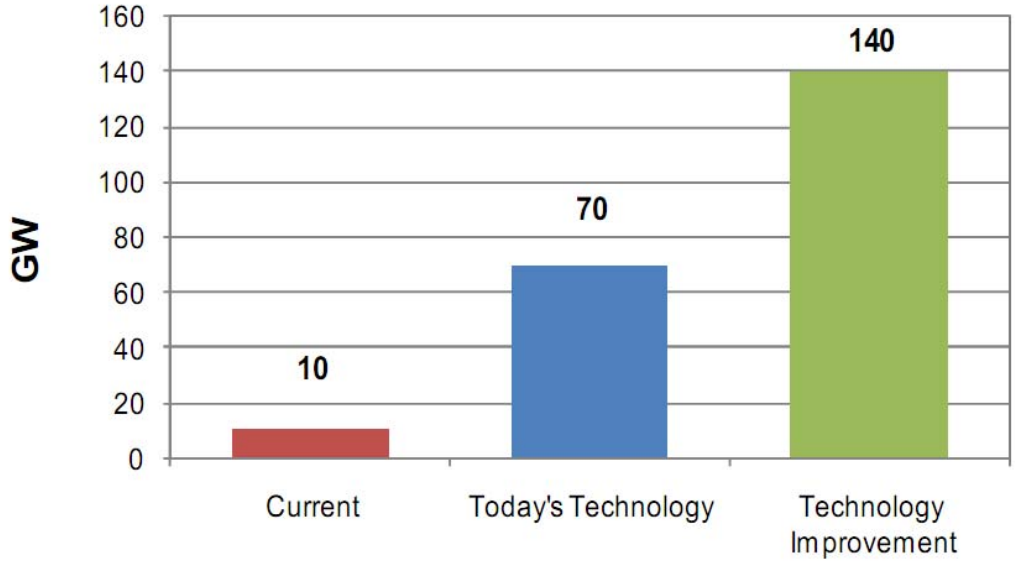

Figure 12: World geothermal electricity – actual installed capacity in 2010 (red) and estimated potential with current technology (blue) and with EGS (green). Source: Bertani 2010, p. 27

If the economic potential of 70 GW_{el} from hydrothermal resources is realized by 2050 the trajectories for geothermal electricity production are illustrated in the following figure:

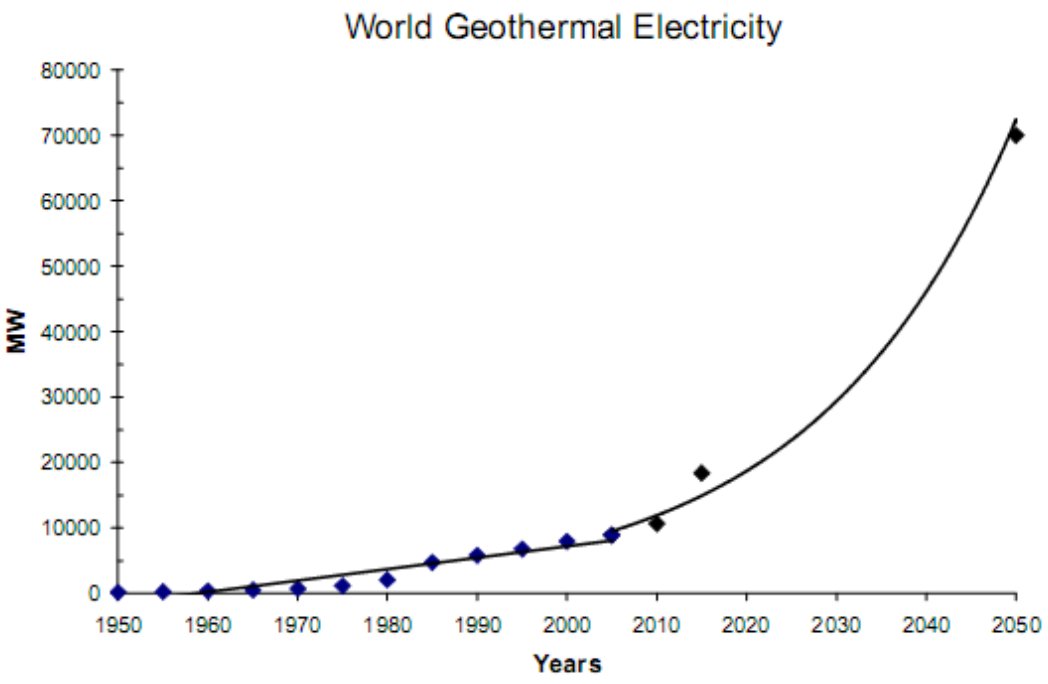

Figure 13: World geothermal electricity – forecasting scenario up to 2050 (Source: Bertani 2010, p. 39)

Interestingly the IEA scenario for 2035 expects 41 GW_{el} geothermal capacity for 2035 (see Table 4) and is thus almost in line with the above scenario from Bertani 2010.

3.3.3 Typical plant sizes

The worldwide installed capacity of 10,715 MW_{el} is provided by **526 deep geothermal plants** with an **average capacity of some 20 MW_{el}**. Plant sizes vary a lot, generally plants can be classified as **small (5 MW_{el})**, **medium (around 30 MW_{el})** and **large (45 MW_{el})** with largest plants having over 100 MW_{el}. *Flash steam plants* account for two third of installed capacity and are used for high-temperature reservoirs over 180°C. The liquid water component boils, or "flashes", as pressure drops. The separated steam is then piped to a turbine to generate electricity. *Dry steam plants* make up about a quarter of installed capacity. The dry steam is here directly piped from the well to the turbine. *Binary plants* typically operate with temperatures from 73°C to 180°C by using an organic ranking cycle (ORC) or Kalina cycle. The heat from the geothermal resource is extracted by a heat exchanger and then an organic fluid with a low boiling point is used to drive the turbine. This type of technology constitutes the smallest number of geothermal power plants (11% of

installed capacity), yet numbers of plants are growing since binary plants have enabled electricity production in low and medium enthalpy areas (Bertani 2010, p. 25-30; IEA 2011a, p. 14-15).

3.3.4 Economics and costs

In areas with high-temperature hydrothermal resources geothermal electricity is in many cases competitive with conventional newly built power plants. In areas with lower temperatures of the hydrothermal resource geothermal electricity may be competitive in some cases. In general costs vary considerably depending on many factors like geological conditions or plant size (IEA 2011a, p. 16). According to calculations of the *International Energy Agency* generation costs[16] of geothermal electricity from hydrothermal resources lay between **50-110 USD/MWh$_{el}$**: for hydrothermal resources with lower temperatures (usually *binary plant technology*) production costs range between 60-110 USD/MWh$_{el}$ and for high temperature hydrothermal resources (usually *flash plant technology*) costs are between 50-80 USD/MWh$_{el}$. Costs for non-hydrothermal plants which are still in experimental status (hot rock resources, EGS-technology) are estimated at 100-300 USD/MWh$_{el}$:

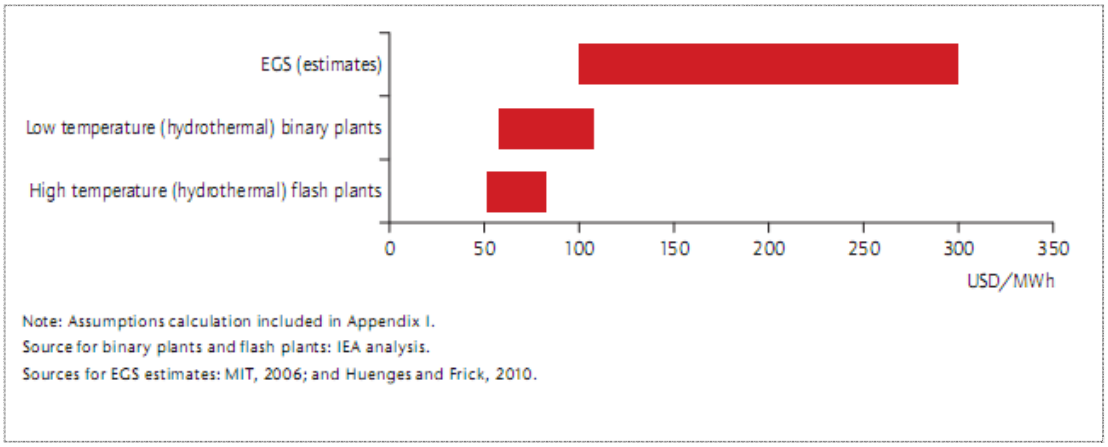

Figure 14: Production costs (LCOE – Levelized Costs of Electricity) of geothermal in USD/MWh$_{el}$ (Source: IEA 2011a, p. 18)

It is to note that these figures represent average values for given assumptions. Actual generation costs for individual plants may differ from the above indicated cost ranges. E.g. for greenfield projects in areas with lower temperatures of the hydrothermal resource and smaller plant sizes generation costs for low temperature

[16] on LCOE basis (Levelized Costs of Electricity).

(hydrothermal) binary plants can be as high as 200 USD/MWh_{el} (IEA 2011a, p. 17). For high temperature hydrothermal resources (flash plants) other studies suggest even lower generation costs than the above indicated lower end of 50 USD/MWh_{el}: for example in (Goldstein, Hiriart et al. 2011, p. 424-426) cheapest generation costs are indicated with 31 USD/MWh_{el}.

The *International Energy Agency* has used for its cost calculations for the indicated cost ranges of geothermal electricity production shown in the figure above the following assumptions:

Table 6: Assumptions of the IEA for electricity generation cost calculations for flash and binary plants (Source: IEA 2011a, p. 42)

	Flash plants	*Binary plants*
Investment costs (USD)	2000-4000/kW_e	2400-5900/kW_e
Capacity factor	85%	85%
Interest rate	10%	10%
Lifetime	35	35
O&M	2.5% of investment	2.5% of investment

For geothermal electricity production from high temperature hydrothermal resources *(flash plants)* lower investment costs were taken (2000-4000 USD/kW_{el}) whereas electricity production from hydrothermal resources with lower temperatures *(binary plants)* usually require higher investment costs (2400-5900 USD/kW_{el}). For all other factors the same assumptions were taken for high and lower temperature hydrothermal resources: it was assumed a capacity factor of 85% for a plant lifetime of 35 years and an interest rate of 10%. Operation and maintenance costs (O&M) were assumed with 2.5% of the investment costs (IEA 2011a, p. 42).

Deep geothermal has high upfront investment costs (drilling of wells and construction of power plant) and low operating costs. Yet cost estimates vary widely depending on a variety of factors. In contrast to combustion based power plants operating costs for geothermal electricity production are much more predictable since they do not depend on fluctuating fossil fuel prices. In order to assess the economics of geothermal power plants production costs per kWh have to be

calculated over the economic life, i.e. levelized costs of electricity (LCOE). The most important factors for calculating levelized costs of electricity are (Goldstein, Hiriart et al. 2011, p. 423-426):

- upfront investment costs
- financing costs (interest rates for debt and equity finance)
- operation and maintenance (O&M)
- taxes
- decommissioning costs
- capacity factor
- economic lifetime of the investment

Equity rates can be up to 20% (depending e.g. on the risk of non-discovery of the hydrothermal resource) whereas debt interest rates can be expected around 6-8%. The planned economic lifetime of a deep geothermal power plant is usually around 25-30 years. Yet experience has shown that the actual economic lifetime of plant installation can be even longer. In contrast to the economic lifetime of plant installations (time span until surface plant installation reaches the end of its lifetime and needs to be refurbished or replaced) the economic lifetime of the geothermal reservoir is typically longer. The economic lifetime of the geothermal reservoir indicates the period of time in which heat can be extracted from the hydrothermal resource (Goldstein, Hiriart et al. 2011, p. 423-426).

Cost calculations for geothermal electricity from (Goldstein, Hiriart et al. 2011) indicate similar cost ranges as the above described calculations from the *International Energy Agency* yet the complexity of calculating the costs is better illustrated. Current levelized costs of energy (LCOE) for geothermal power generation are shown in the figure below. As already mentioned cost calculations depend on a variety of factors. An average discount rate of 7% was assumed, the average plant lifetime design was estimated at 27.5 years and for investment and operation costs the worldwide average for 2009 was taken. Average LCOEs are presented for *Condensing-Flash plants* (which are normally used for high-temperature hydrothermal resources) and *Binary Cycle plants* (which are normally used for hydrothermal resources with lower temperatures). Average turnkey investment costs for *Flash Plants* range form 1,800-3,600 USD / kW_{el} and *Binary Plants* range from 2,100-5,200 USD:

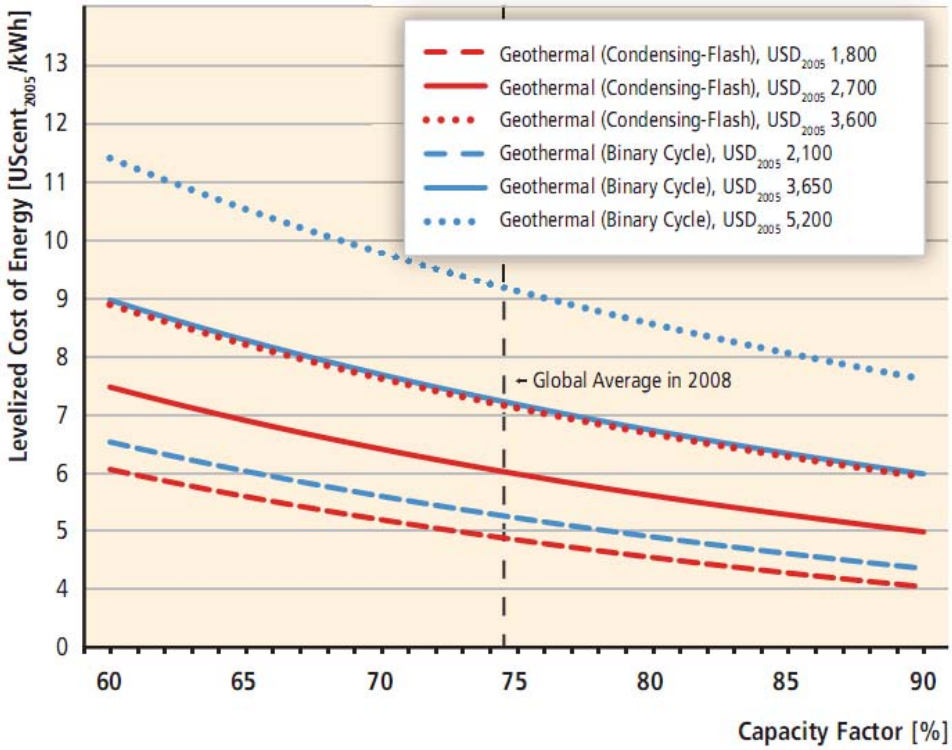

Figure 15: Current levelized costs of electricity (LCOE) for geothermal power generation, worldwide average (Source: Goldstein, Hiriart et al. 2011, p. 426)

Worldwide average capacity factor in 2008 was 74.5%. As depicted in the figure above average generation costs (calculated as levelized costs of energy) range between US cents 4.9 to 9.2 / kWh. If a capacity factor of 90% is achieved for the whole plant lifetime, generation costs can be as low as US cents 4 / kWh for plants using high-temperature hydrothermal resources. Figures are estimations for new build plants based on cost data for 2008. Further variations of cost factors (not shown in the figure above) indicate generation costs ranging from US cents 3.1 to 17 / kWh. Presented figures indicate average values for different assumptions of the most important cost factors. Thus generation costs for individual plants may actually lie even below or above these mean values (Goldstein, Hiriart et al. 2011, p. 424-426).

3.3.5 Prospects for future cost trends

Since published learning curve studies for deep geothermal are limited, future potential LCOEs based on expert knowledge were calculated for 2020 (Goldstein, Hiriart et al. 2011). For 2020 a worldwide cost decrease of 7% for new build plants is

expected. Mean values for worldwide generation costs (LCOE) therefore might range between US cents 4.5 to 8.6 / kWh. A capacity factor of 80%, a 27.5-year life time and a discount rate of 7% was assumed. Main factors for expected cost reductions are: technological advances (improvements in design and stimulation of the reservoir leading to higher energy extraction rates) and higher capacity factors due to more efficient plants with capacity factors of above 90% replacing older ones still in operation. Improvements in drilling techniques with lower drilling costs and increased success rates for exploration wells (i.e. discovery of the hydrothermal resource) were not taken into account. Though this might be foreseeable it is unlikely to be achieved in the near term (Goldstein, Hiriart et al. 2011, p. 426-427).

4 Deep Geothermal in Europe

In Europe heat and power production from deep geothermal is for the time being **mainly concentrated in high-enthalpy areas in Italy, Iceland and Turkey**. Yet huge geological resources for geothermal energy production exist all over Europe. In low to medium regions especially heat and to some extent electricity production from deep geothermal might become a future alternative.

In 2013 **68 power plants** with a total installed capacity of **1850 MW_{el}** were in operation which accounted for almost a quarter of worldwide installed electrical capacities. Heat from deep geothermal is mainly used for district heating. 237 **geothermal district heating plants** were in operation in 2013 with an installed capacity of **4,300 MW_{th}**.

In the following three subchapters in chapter 4.1 an overview on deep geothermal resources in Europe will be given, in 4.2 district heating from deep geothermal will be presented and in 4.3 an overview on electricity from deep geothermal will be given.

4.1 Deep Geothermal Resources in Europe

Hydrothermal resources can be classified into low, medium and high temperature (enthalpy) resources. In areas with very high temperatures (>180°C) the conditions for energy production from deep geothermal are generally much more favorable, especially for electricity production since higher temperatures are needed for operating power plants economically. Areas with lower enthalpy are suitable for heat production. In Europe there are three countries with high enthalpy areas, i.e. Iceland, Italy and Turkey – therefore it is not surprising that most of the deep geothermal plants installed in Europe are located in those three countries (see chapters below). The following figure provides an overview about the regions in Europe that are suitable for deep geothermal energy production. Dark areas show the regions suitable for deep geothermal energy production. *"High enthalpy"* and *"High temperature basins"* are suitable for electrical power and heat production, *"Medium temperature basins"* are mainly suitable for heat production:

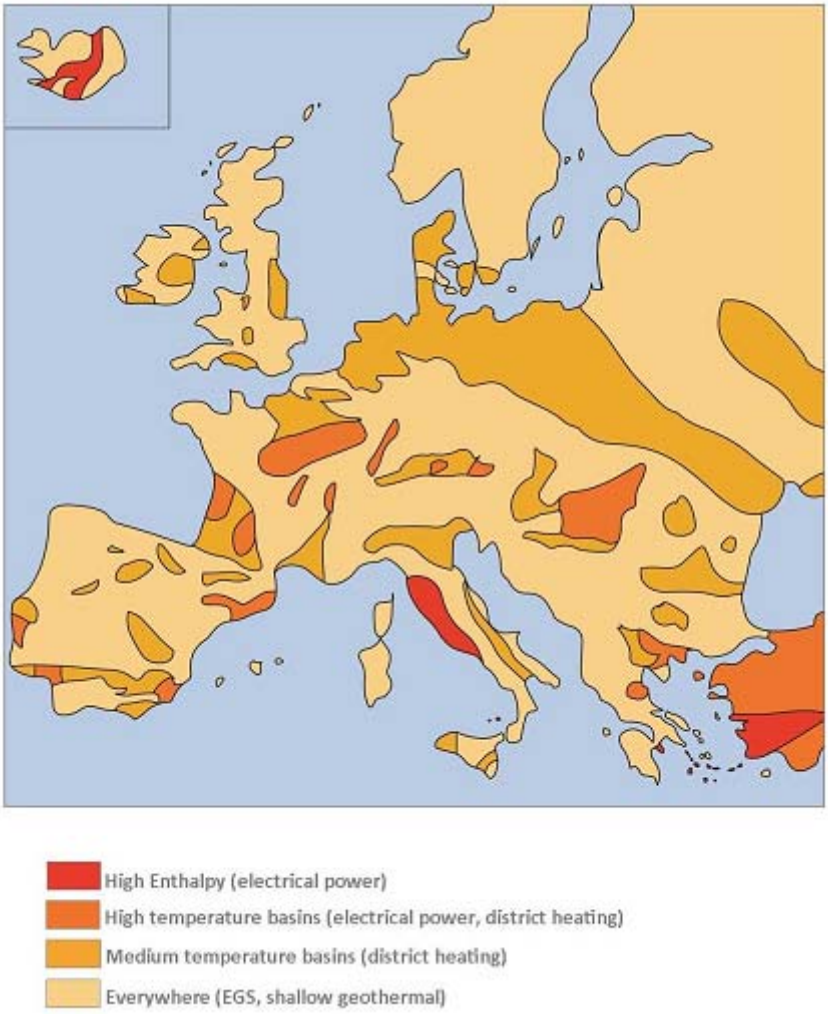

Figure 16: Geothermal resources in Europe (Source: EGEC 2013a, p. 8)

The very light areas (EGS, shallow geothermal) are not suitable for deep geothermal energy production from hydrothermal resources. Deep geothermal energy may be gained there by EGS, which is still in experimental status and does not use hydrothermal but hot dry rock resources and is thus not subject of this work. As well as shallow geothermal technology, e.g. heat pumps. Shallow geothermal technologies can be applied everywhere. Since this is not a deep geothermal technology this is not subject of this work either.

To summarize, the potential for exploration and use of *conventional* deep geothermal exists in Europe in those areas where three factors are given:

1. hydrothermal resources exist (in sufficient amounts in l/sec)
2. with a sufficient temperature level of the hydrothermal resource
3. at a depth lower than 5000 meters economically accessible by trilling

The relevant factor for depth is drilling costs to access the hydrothermal resource (e.g. 1000 m or 5000 m). The deeper the resource is located the more difficult and costly it is to explore the resource.

Areas with deep geothermal energy reservoirs from hydrothermal resources can therefore be found in the figure above in the dark areas *("High enthalpy", "High temperature basins"* and *"Medium temperature basins")*. Those are the potential areas in Europe for the use and erection of deep geothermal plants for power or heat production.

Deep geothermal heavily depends on local settings, especially local geological conditions. Europe exhibits a variety of geological settings which can be grouped into different categories: (1) Volcano-magmatic, which can be found in parts of Italy and Iceland; (2) Back-arc marginal basin, e.g. Pannonian Basin; (3) Cristalline massif, e.g. Bohemian Massif; (4) Foredeep basin, e.g. Alpine Fore Foredeep, Po Basin, Carpathian Foredeep; (5) Intracratonic basin, e.g. Paris Basin, Münsterland Basin; (6) Activ pull-apart / horst-graben structures, in large parts of Turkey; (7) Active subduction zones, in Mediterranean Sea; (8) Orogenic belt, in parts of Europe; (9) Volcanic island arc, between Turkey and Greece. The here mentioned categories are shown in the figure below and shall provide an overview of the complexity of geological settings in Europe and thus the difficulty to compare results from different sites for estimations of the discovery of the hydrothermal resource:

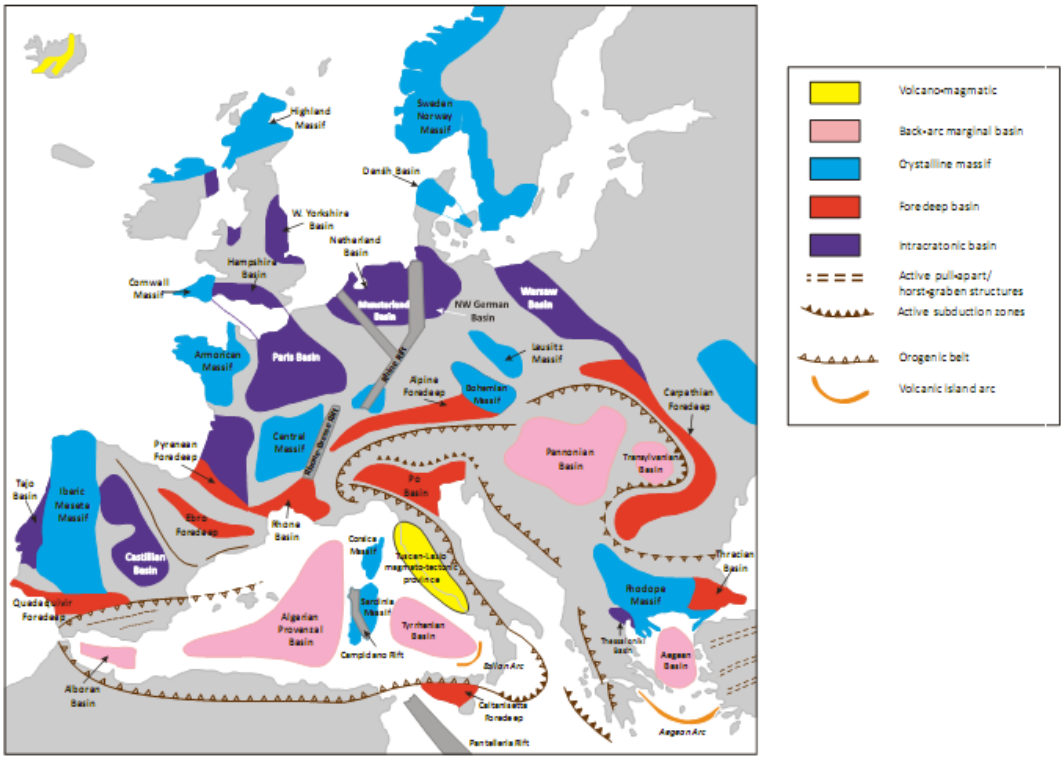

Figure 17: European geodynamic settings (Source: Ungemach & Sommaruga, figure taken from European Technology Platform on Renewable Heating and Cooling 2012, p. 48)

Geological settings can also be grouped in a different way into the following categories: (a) Large sedimentary units, subdivided into: intracratonic, orogenic belt foredeep, marginal/back arc basins; (b) Tertiary-quaternary continental rifts, e.g. Rhine Graben; (c) Orogenic fold-belts and foreland platforms; (d) Crystalline massifs; (e) Recent “in plate” Pliocene/Quaternary volcanism; (f) Active subduction zones; Volcanic island arcs; Active magmatic; Recent or active extensional horst and graben structures; in those areas excellent high-enthalpy geothermal resources can be found (European Technology Platform on Renewable Heating and Cooling 2012, p. 47).

4.2 District Heating from deep geothermal in Europe

Geothermal District Heating (GeoDH) is a mature and well established technology which is already in use for 50 years. By 2013 the total installed capacity in Europe amounts about **4,300 MW_{th}** (including CHP systems) with an annual heat production of **12,884 GWh_{th}**. Since 2009 the GeoDH market in general showed a renewed momentum, in 2013 eight new systems became operational with a newly installed capacity of 122 MW_{th} (EGEC 2013b, p. 21-26). The figure below shows the installed

capacity per country. Most of the capacity has been built in two countries, namely Iceland and Turkey. Both are located in high enthalpy zones where high temperatures of the hydrothermal reservoirs can be found in lower depths:

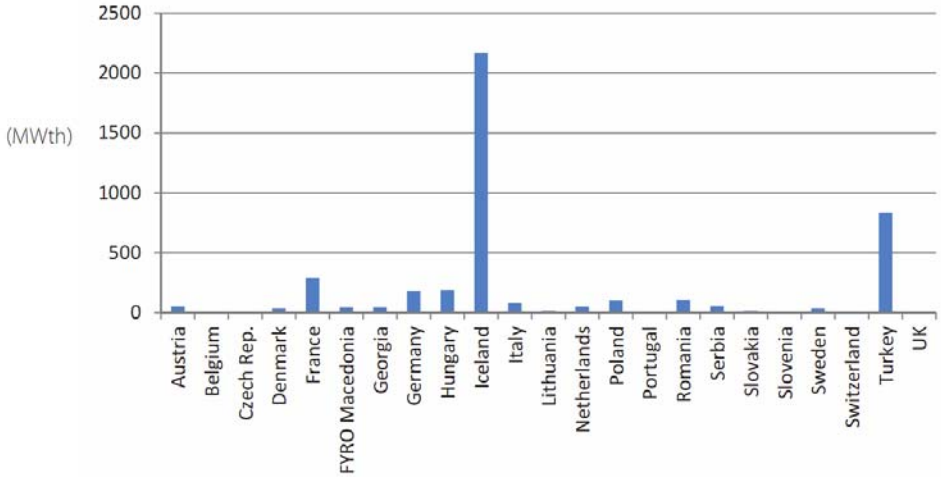

Figure 18: Geothermal District Heating – installed capacity in Europe, per country in 2013 (MWth) Source: EGEC 2013b, p. 22

In total 26 countries in Europe show deep geothermal activity. 75% of the capacities are installed in Iceland and Turkey with some 3,000 MW_{th}, 25% are installed in all other countries – mainly in the EU-28 with around 1,100 MW_{th} producing 4250 GWh thermal power. According to the *European Geothermal Energy Council (EGEC)* **geothermal heat could be available for 26% of the population in the EU through future district heating systems** – referring to the fact that about 20% of the population is located in regions where the temperature at 2000 m depth is higher than 60°C and thus suitable for geothermal heating (EGEC 2013b, p. 22-25).

EGEC classifies geothermal heat plants into **small systems (from 0.5 to 2 MW_{th})** and **large systems** with a capacity of **50 MW_{th}**. In Iceland – where 90% of the homes are heated by geothermal energy – three huge CHP systems exist with a combined thermal capacity of 800 MWth (EGEC 2013b, p. 17-18). It is to note that system sizes vary a lot and countries with lower installed capacities tend to have smaller systems and thus a higher number of systems installed (compared to Iceland and Turkey) – the following figure shows the number of geothermal district heating systems per country in 2013 and forecast for 2016:

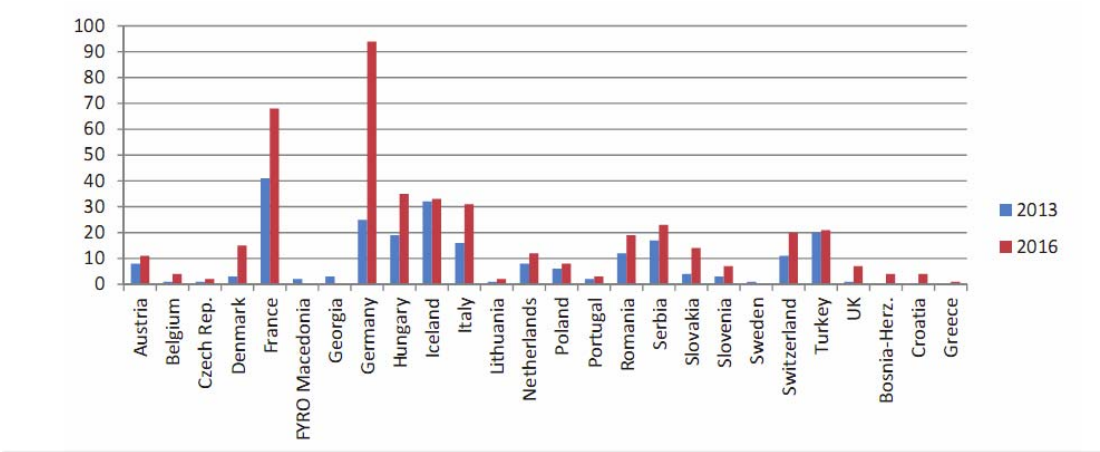

Figure 19: Geothermal District Heating – number of systems in Europe, per country 2013 and forecast 2016 (Source: EGEC 2013b, p. 23)

In 2013 were **237 geothermal heating plants** in operation (including CHP systems) which are indicated by the blue columns in the figure above. With **201 projects currently being developed** (new systems and the upgrading of existing plants) the EGEC expects not only a sharp increase in the number of systems (red columns) but also a sharp increase in installed capacity to 6,500 MWth in 2016. This would represent a growth of 50% (+2,200 MWth) compared to 2013 (4,300 MWth total installed capacity). Interestingly **most of the projects are planned in Germany (69 new systems being developed or upgraded) followed by France (27) Hungary and Denmark** (EGEC 2013b, p. 22).

Generating costs (production costs) in Europe vary within a range of **20-80 €/MWh$_{th}$** and are usually around 60 €/MWh$_{th}$ (EGEC 2013b, p. 26). It is to note that generation costs are highly dependent on local conditions such as depth of the hydrothermal resource (drilling costs) and temperature of the resource.

Given the data for 2013 (4,300 MWth total installed capacity in Europe producing 12,884 GWh heat), the European average for full load hours and capacity factor can be calculated: 12,884 GWh / 4,300 MWth = 3000 full load hours, that is an **average capacity factor of 43%** (3000 full load hours divided by 8760 hours of a full year). The EGEC market report does not indicate typical figures for individual heat plants. Yet, the European industry average (3000 full load hours, 43% capacity factor) may not necessarily apply to individual plants. For the calculation of the economics of a new heat plant these figures may thus serve only as a very rough first approximation. From a technical point of view heat plants are able to produce base load energy all over the year (with a 70-100% capacity factor similar to power

plants). Since heat demand is primarily given in winter, heat plant operators can increase the number of full load hours and the capacity factor (and thus the economics) if they are able to sell heat all over the year (e.g. to energy intensive industries or other facilities with a continuous high demand of base load heat all over the year, e.g hospitals).

The sector *heat* accounts for about 50% of final energy demand in the EU of which almost 80% is produced by fossils (gas, coal, petroleum) while renewable energy sources accounted only for 16.5% (mainly biomass). Geothermal district heating has a share of **about 1% in the sector *heat* in Europe** and produced a thermal energy output of 365.9 ktoe in 2012 (EGEC 2013b, p. 28).

Typical temperatures for geothermal district heating range between 60-120°C (Goldstein, Hiriart et al. 2011, p. 416) – for large district heating systems like Vienna for example temperatures up to 150°C are needed to operate economically.

4.3 Electricity from deep geothermal in Europe

Deep geothermal electricity is – as well as deep geothermal heat – a well established and mature technology. Whereas geothermal heat is already in existence for 50 years, geothermal electricity has even 100 years of experience: the first power plant was build in 1913 in Larderello (Italy) and is in use ever since. In 2013 there were **68 power plants** in operation in Europe with a total installed capacity of **1850 MW_{el}** (1.8 GW_{el}) producing **11.7 TWh_{el}** electric power. The leading countries in terms of installed capacity are **Italy, Iceland and Turkey** (EGEC 2013b, p. 7-9):

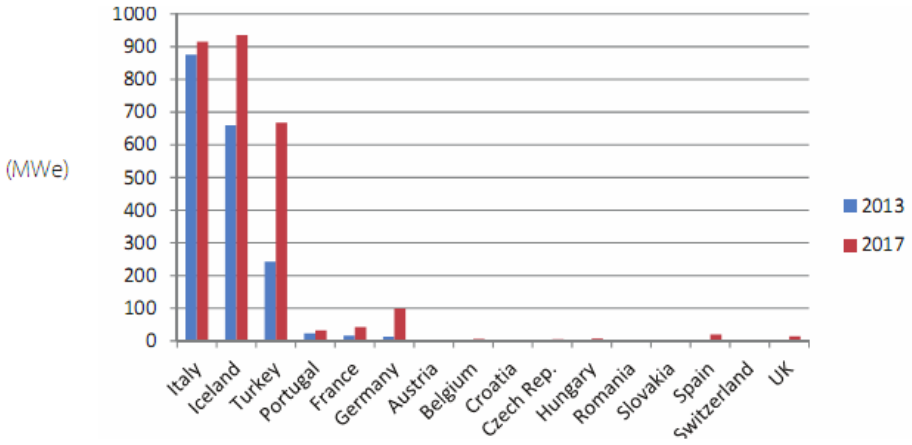

Figure 20: Geothermal Electricity – installed capacity in Europe, per country in 2013 (MWel) and forecast 2017 (Source: EGEC 2013b, p. 9)

In 2013 (blue columns) almost 900 MWel installed capacity were in operation in Italy, followed by Iceland with about 650 MWel and Turkey with over 200 MWel. Again – like in deep geothermal heat – geothermal power plants are mainly built in countries with high enthalpy regions that provide very favorable geological conditions for deep geothermal energy production. The forecasts for 2017 (red columns) indicate in general a strong growth within the next years. In addition to the high enthalpy countries Italy, Iceland and Turkey it is interesting to note that Germany is also planning to built deep geothermal power plants.

Installed capacities are **expected to increase by 50% (+900 MW_{el})** within the next four years: from 1850 MW_{el} in 2013 to 2750 MW_{el} in 2017 (sum of the red columns in the figure above). **Most of the capacities will be installed in Turkey**, followed by Iceland and Germany. Given the fact that a large number of additional projects are already under investigation and are supposed to become operational by 2020 this trend might continue (EGEC 2013b, p. 8-9). The following figure shows the development of deep geothermal power in Europe in its historical context:

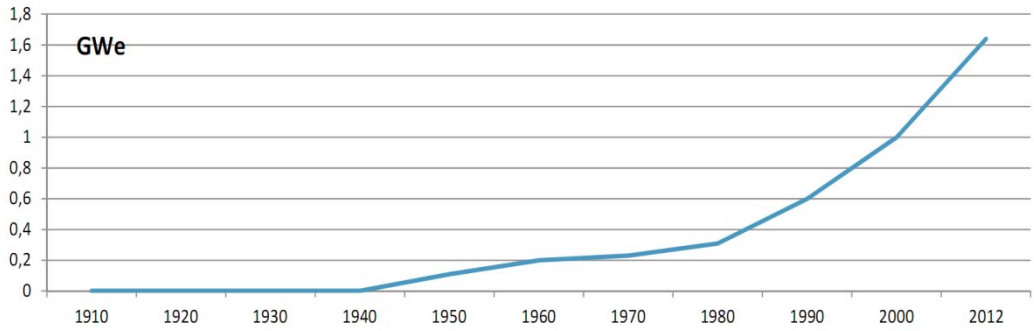

Figure 21: Geothermal Electricity – development of installed capacity in Europe from 1913-2012 (GWel); Source: EGEC 2012, p. 7

After the first plant was built in Larderello in 1913, only a few more plants were installed in Italy and Iceland until 1970 (0.23 GWel = 230 MWel). Following the energy crisis in the 70s, more countries (for example France and Portugal) installed geothermal plants resulting in a total installed capacity of 1.8 GW_{el} (1850 MW_{el}) in 2013. As described above, over 80% of the capacities are concentrated in Italy and Iceland. Yet, one trend seems to be worth to highlight: **Turkey, the third country with high enthalpy regions in Europe, has started to explore its hydrothermal resources for electricity production** since 2009, and – given the potential and planned projects – is expected to join Italy and Iceland as the leading countries in Europe in the use of deep geothermal energy (EGEC 2012, p. 7; EGEC 2013b, p. 8-11).

A second trend to highlight is the currently expected market growth: with 68 power plants being in operation, 74 additional projects are under development and expected to become operational by 2017 (= 142 plants in total: 2750 MWel, new installations mainly in Turkey, Iceland and to a lower extent in Germany). Further 144 projects are currently under investigation or already being explored – if all of them will be successfully realized the number of plants would rise to 286 by 2020 (EGEC 2013b, p. 8-9):

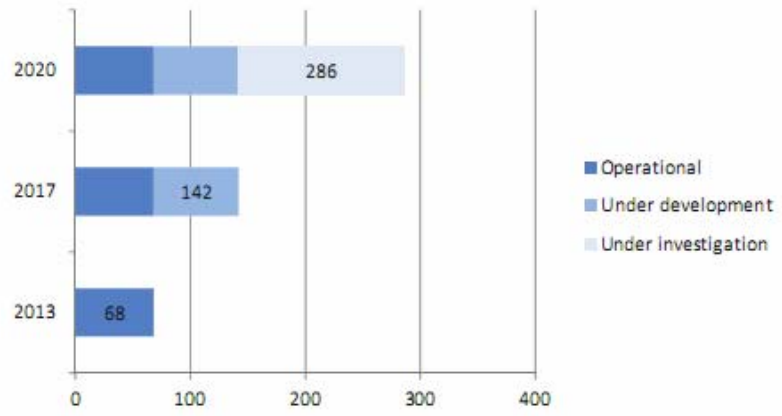

Figure 22: Geothermal Electricity – number of power plants in Europe in 2013 and forecasts for 2017 and 2020 (Source: EGEC 2013b, p. 9)

Deep geothermal power is a base load technology which is able to provide electricity all over the year in stable amounts. In Europe the **capacity factor of a plant is typically over 80%** with some plants operating at almost 100% a year (24h x 365 days = 8760h full load hours). If we take the figures for 2013 the average capacity factor and full load hours can be calculated for all plants that are in operation in Europe: with an installed capacity of 1.85 GW_{el} about 11,700 GWh_{el} of electrical power is produced, that is 6324 full load hours on average (11,700 GWh_{el} divided by 1.85 GW_{el} = 6324 h). The **average net capacity factor of all European plants in 2013 is therefore 72%** (6324 h divided by 8760h of a full year = 72%). The fact that European average is lower than for individual plants (typically 80%) is probably due to two factors: on the one hand there are statistical distortions in measurement on a year-by-year basis (e.g. new plants that are commissioned in the later part of the year reduce the industry average of the capacity factor) and on the other hand the capacity factor of CHP plants are partly lower since production in these cases is mainly driven by heat demand (based on data given in: EGEC 2012, 15; EGEC 2013b, 8–9).

For the investment decision calculation of a new power plant the assumption of a capacity factor of typically 80% (some 7000 h full load hours) seems to be an adequate estimation.

According to the *EGEC* geothermal power plants in high enthalpy areas (temperature of the hydrothermal resource over 180°C) can be fully commercial today with generation costs of about **7 €ct/kWh_{el}**, whereas power plants in medium

and low temperature/enthalpy areas (<180°C) have been developing for some years with generation costs between **12-18 €ct/kWh** (EGEC 2013b, p. 17).

Sizes of the 68 existing power plants vary a lot: the largest plant has a capacity of 303 MW_{el} (Hellisheidi in Iceland) whereas small plants have a capacity of 5 MW_{el} or below. Other **typical plant sizes are 5-10 MW_{el}, 20 MW_{el}, 40 MW_{el} and 60 MW_{el}** (EGEC 2012, p. 9; EGEC 2013b, p. 46-48).

The *EGEC* assumes a huge potential for deep geothermal electricity referring to the GeoElec project (www.geoelec.eu): the assumed geological potential (heat in place) is translated to an economic potential using a Levelised Cost of Energy (LCoE) value for its scenarios. In 2030 LCoE of less than 150 €/MWh_{el} is assumed and expected to decrease to less than 100 €/MWh_{el} in 2050. Both values are considered to be the grid parity at the respective times. According to the scenarios in 2030 deep geothermal may provide 34 TWh_{el} in the EU-28 (2013: 6 TWh_{el}) and 174 TWh_{el} in total Europe. **For 2050 an economic potential of 2570 TWh_{el} for EU-28 and 4000 TWh_{el} for total Europe is assumed** under the assumptions that non-hydrothermal EGS technology from hot dry rock resources will become competitive (EGEC 2013b, p.10 and p.15-17).

Especially for the period after 2030 a breakthrough in the EGS technology is expected which is currently still in experimental status. Yet, the EGEC criticizes that the geothermal power market is not developing as quickly as expected and finds three reasons for that (EGEC 2013b, p. 15-17):

1.) **The vast geothermal potential is still underestimated by decision-makers and investors.**

2.) **Financial support is needed to allow the technology to progress along its learning curve.**

3.) **Geothermal projects are threatened by the geological risk (non-discovery of the hydrothermal resource) – therefore the establishment of a Geothermal Risk Insurance Fund is needed for the development of the deep geothermal sector in Europe.**

5 Deep Geothermal in Austria

5.1 Overview

Austria exhibits in general moderate to favorable conditions for deep hydrothermal use of energy. Hydrothermal resources are characterized by low to medium enthalpy (60-200°C) and are used mainly for heat production, namely **district heating (52 MW_{th})**. Electricity production plays only a very limited role (**2 MW_{el})**. In total there are **8 deep geothermal plants** in operation, all of which are district heating plants. Three of these plants also produce electricity (Goldbrunner and Götzl 2013, p.1 and p. 5-6).

A **main barrier** for further exploration of the hydrothermal potential in Austria is seen by Goldbrunner and Götzl in the **need for public funding schemes**, e.g. feed-in tariffs (Goldbrunner and Götzl 2013, p. 1). Another barrier is the **risk of non-discovery of the hydrothermal resource**: from a financial point of view the drilling phase is highly capital intensive and constitutes financially the high risk phase of a geothermal project since the existence of the hydrothermal resource normally can be proven only after drilling. (This will be discussed in detail later in this work.) If drilling is successful and the resource is found in sufficient quantity and quality (l/sec and sufficient temperature level) heat may be produced at competitive costs. For example, according to the business plan of the geothermal project in the Vienna Basin at Airfield Aspern, **cost of heat production was estimated at 22 EUR/MWh_{th}** (Kontrollamt der Stadt Wien 2012, p. 19).

5.2 Context and history of deep geothermal energy production

Geothermal utilization of hydrothermal resources and the use of natural thermal water have a long-term tradition in Austria. Whereas the first balneologic applications can be traced back to Roman times (e.g. Warmbad Villach in Carinthia or Therme Baden near Vienna), deep geothermal drilling technologies emerged in the 20th century. Today, in Austria still a considerable part of deep geothermal drilling projects was intended for balneological purposes, mainly spa and wellness (Goldbrunner and Götzl 2013, p. 1).

Balneologic applications are not part of this work. The hydrothermal resource is thereby not used for energetic use (i.e. energy production of heat or electricity). Yet, balneologic use and energy production can be done at the same site using the same deep drilling well. In general the same deep geothermal drilling technology is used for both balneologic and energy production systems. According to (Goldbrunner 2013, p. 13) a total **of 73 deep geothermal wells** had been drilled in Austria so far, of which the majority (55 wells) were intended for balneologic use whereas 18 wells were intended for energetic use for geothermal heat or electricity production Therefore the **development of deep geothermal energy in Austria can be seen in the context of balneologic geothermal utilization**. Although balneologic applications and energy production plants can use the same drilling technology, needed temperature levels of the hydrothermal resource are much lower for balneologic applications.

According to *Kotschan* the **oil price shock in 1973 was the reason for the start of developing deep geothermal for energetic use** (Kotschan 2012, p. 5). This was followed by a first concept for geothermal development in Austria presented by the Austrian government in 1976. The second oil price shock in 1979 has further enhanced efforts to develop deep geothermal energy (Goldbrunner 2013, p. 4).

The **exploration of hydrothermal resources for heat production has started in the late 1970s** with the erection of the first two systems in Bad Waltersdorf (Styrian Basin) and Geinberg (Upper Austrian Molasse Basin). From 1986 to 2005 a remarkable number of deep drilling projects was realized (in total over 50 deep geothermal drillings – comprising balneological projects and projects for energetic use – including failed projects, i.e. non-successful drillings where the hydrothermal resource was not found in sufficient quantity or quality). One reason for the increasing number of deep geothermal exploration activities was the access to EU funding after Austria has joined the European Union in 1995. In the time period from 2005 to 2010 drilling activities slowed down (Goldbrunner and Götzl 2013, p.1).

5.3 Potentials and regions with deep hydrothermal resources

5.3.1 Regions with deep hydrothermal resources in Austria

According to (Goldbrunner 2010, p.2-7) there are mainly three regions in Austria where deep hydrothermal resources for energy production occur in sufficient quantity (flow volume: l/sec of hot water) and quality (sufficiently high temperature of water):

1. Vienna Basin
2. Upper Austrian Molasse Basin
3. Styrian Basin

The figure below indicates the potential of deep hydrothermal resources (in GWh_{th} per year) and illustrates the main areas suitable for deep geothermal energy production:

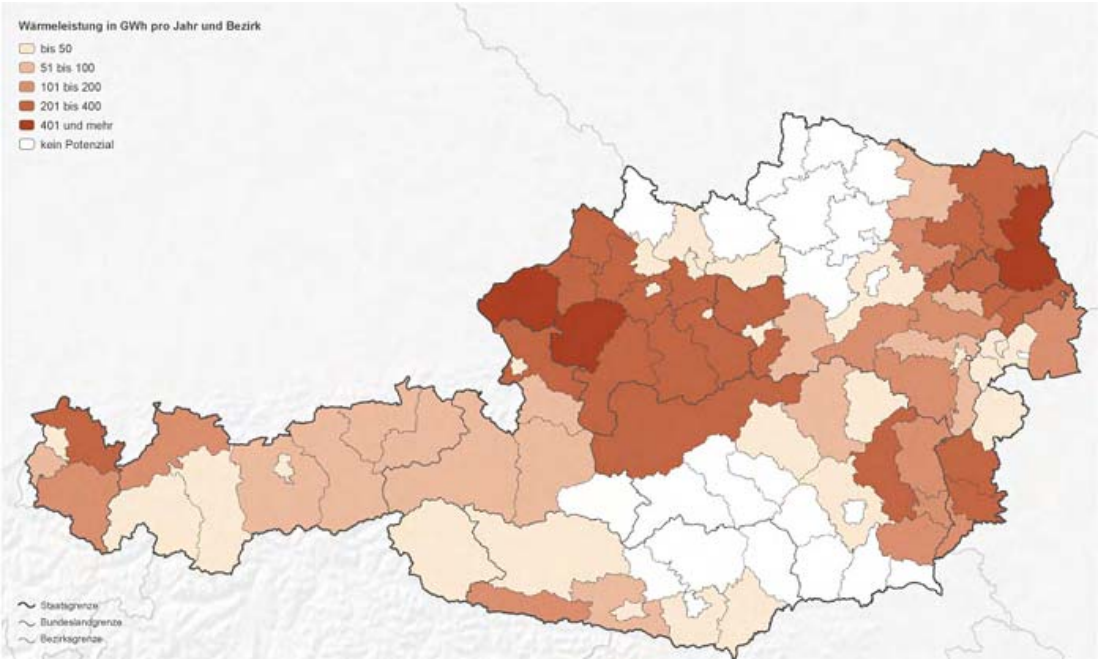

Figure 23: Potential of deep hydrothermal resources in Austria; (Source: figure taken from Kotschan 2012, p.8)

The later in this work discussed geothermal project at Baden is located in the Vienna Basin. Thus I provide here a short description of the Vienna Basin:

5.3.2 Vienna Basin

The Vienna Basin might be regarded as one of the future main targets for heat and power generation since temperature levels of the hydrothermal resources of more than **200 °C can be expected** (up to a depth of 8,000 meters). The basin is 200 km long and 50 km wide. The gross part is in Austria, the rest lies in the Czech Republic and Slovakia. The structure of the basin is a result of tectonic movements since the lower Mioscene. The basin filling has a maximum thickness of about 5,500 m and comprises different sediments: permeable horizons with sand and sandstones, conglomerates and carbonate rocks that contain oil and gas fields. Especially in layers with oil and gas fields the exploration for geothermal purposes is questionable due to possible conflicts with hydrocarbon drillings (oil and gas drillings). The main targets for geothermal exploration can be seen in the pre-Neogene basin floor where thick carbonate rock units offer promising conditions for the production of high flow volumes, i.e. l/sec of the hydrothermal resource (Goldbrunner 2010, p.1-2). The down-thrown block of the permeable carbonate rocks (mainly Hauptdolomit and Wettersteindolomit of the Göller Nappe) is lowered to 3,000 to 6,000 m and the bottom is expected in a depth of more than 8,000 m. Temperature levels of the hydrothermal resource are expected in a **range between 100 °C and 215° C** (Wessely 2006, p. 307-310).

The **structure and geological knowledge of the Vienna Basin is mainly based on more than 3,500 oil and gas exploration drillings** that had been undertaken in the last decades and are essential to understand geological structures apart from theoretical geological modeling (Hamilton, Wagner and Wessely 1999). In addition, seismic surveys including 3-D-seismic had been conducted for a better understanding of the geological structures (Goldbrunner 2010, p.2).

5.4 Deep geothermal heat and electricity production in Austria

In 2012 (Goldbrunner and Götzl 2013, p.5–6) there were **8 plants in operation** in Austria with a total installed capacity of **52 MW_{th} for district heating** and **2 MW_{el} for power production**. All plants are located in the **Upper Austrian Molasse Basin** and the **Styrian Basin**. The third area with large hydrothermal resources, the Vienna Basin, is not developed yet:[17]

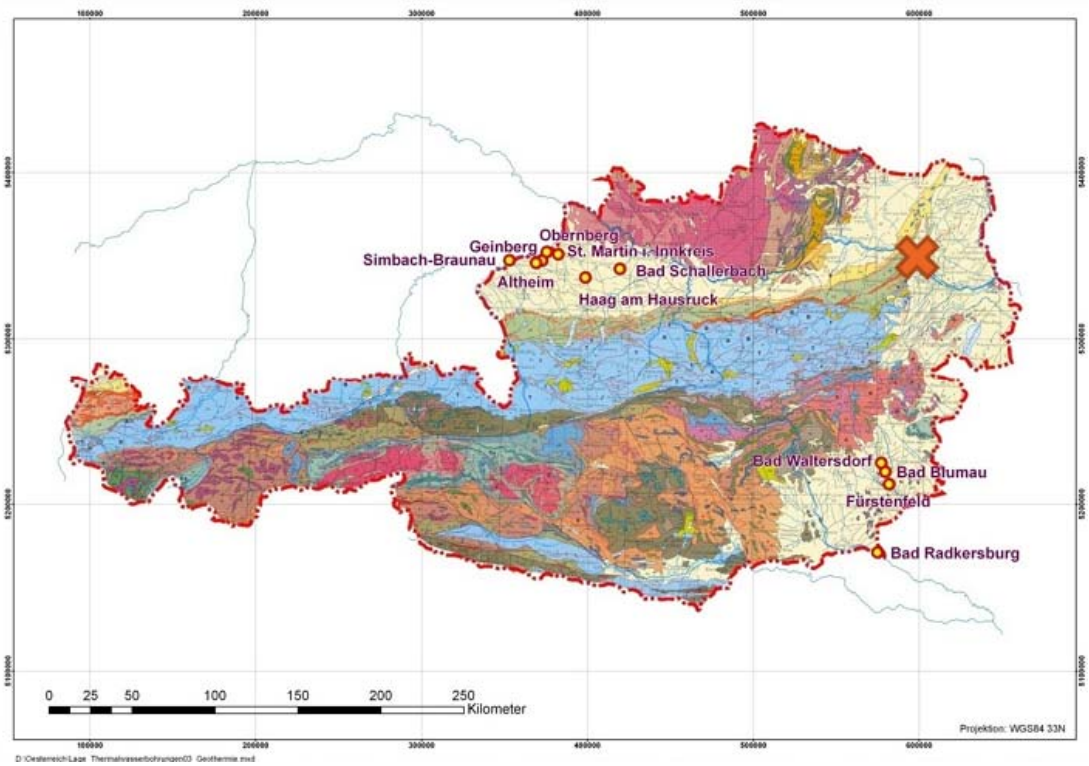

Figure 24: Deep geothermal plants in Austria (Source: figure taken from Rapottnig 2012, p.9)

5.4.1 Electricity from deep geothermal – installed capacities

Electricity production from deep geothermal plays only a very limited role in Austria so far. By the end of 2012 there were **two geothermal power plants** in operation with a total installed capacity of **2 MW_{el}** producing **2.2 GWh_{el}** of electricity per year. Given the total amount of electricity that is produced in Austria (81,400 GWh_{el} per

[17] Please note: in addition to the 8 plants in operation the figure shows three more sites which were not in operation in 2012(Bad Schallerbach, Fürstenfeld, Bad Radkersburg).

year) only 0.003 % is provided by deep geothermal. The two deep geothermal power plants in operation are located in **Altheim** (Upper Austrian Molasse Basin) and **Bad Blumau** (Styrian Basin). The third **existing power plant (Simbach-Braunau)** was not in operation in that point of time (Goldbrunner and Götzl 2013, p.5). All of **these three plants produce also heat for district heating** and are included in the following chapter:

5.4.2 Heat from deep geothermal – installed capacities

Deep geothermal energy in Austria is mainly used for heat production, especially for district heating. **51.5 MW_{th}** is the total installed capacity for **district heating**, provided by **8 plants** currently in operation. In addition, **2 MW_{th}** installed capacity provide **heat for agriculture or industry** and another **2.4 MW_{th}** are used for **balneologic** purposes:

Table 7: Geothermal district heating (DH) plants and other forms of direct use in Austria (Source: Goldbrunner and Götzl 2013, p. 6)

	Geothermal DH Plants		Geothermal heat in agriculture and industry		Geothermal heat in balneology and other	
	Capacity (MW_{th})	Production (GWh_{th}/yr)	Capacity (MW_{th})	Production (GWh_{th}/yr)	Capacity (MW_{th})	Production (GWh_{th}/yr)
In operation end of 2012	51.5	158.8	2	4.6	2.4	20.6

With 51.5 MW_{th} installed capacities district heating is by far the most important application of deep geothermal in Austria in terms of produced energy. 8 geothermal district heating plants produce annually 158.8 GWh_{th} which is a minimal share of the total district heating supply in Austria.

At the end of 2012 there were 8 geothermal district plants in operation: 6 plants are located in the Upper Austrian Molasse Basin **(Altheim, Geinberg, Simbach-Braunau, Obernberg, St. Martin, Haag)** and 2 plants are located in the Styrian Basin (**Bad Blumau and Bad Waltersdorf**). Most of the plants were commissioned between 1996 and 2003 whereas Bad Waltersdorf (1979) was one of the first plants that were build in Austria and is the plant that has been in operation for the longest time. The largest installed capacities are in **Altheim (12 MW_{th})** followed by

Simbach-Braunau (9.3 MW_{th}). The total installed capacity of all 8 plants amounts 51.5 MW_{th} producing 158.9 MWh_{th} for deep geothermal district heating:[18]

Table 8: Existing geothermal district heating (DH) plants in Austria – individual sites (Source: Goldbrunner and Götzl 2013, p.6)

Locality	Plant Name	Year commis s.	Is the heat from geo-thermal CHP?	Is cooling provided from geo-thermal?	Installed geotherm. capacity (MW_{th})	Total installed capacity (MW_{th})	2012 geo-thermal heat prod. (GWh_{th}/y)	Geother. share in total prod. (%)
Altheim	Doublet Altheim	2000	yes	No	12	18	28.6	100
Geinberg	Doublet Geinberg	2000	No	No	5.1	7.1	24	100
Simbach a. Inn / Braunau a. Inn	Doublet Simbach-Braunau	2003	No	No	9.3	40.7	46.1	77
Obernberg	Doublet Obernberg	2000	No	No	5.3	5.3	11.8	100
St. Martin im Innkreis	Doublet St. Martin	2002	No	No	5	29	18.9	60
Haag am Hausruck	Doublet Haag	1996	No	No	5	5	6	100
Bad Blumau	Bad Blumau	2001	Yes	No	7.5	7.5	18	100
Bad Waltersdorf	Bad Walters-dorf	1979	No	No	2.3	5	5.5	70
Total					**51,5**	**117.6**	**158.9**	

Two plants – Altheim and Bad Blumau – are CHP plants (combined heat & power): i.e. heat and electricity is produced simultaneously. (The third existing CHP plant – Simbach-Braunau – was not producing electricity in that point of time.)

At three sites (Geinberg, Bad Blumau, Bad Waltersdorf) the hydrothermal resource is also used for balneology (bathing and swimming). In Geinberg and Bad Waltersdorf it is also used for greenhouse heating. In addition, Geinberg is the only plant where deep geothermal is used for industrial process heat (Goldbrunner 2010, p.13).

[18] Please note: the 117.6 MW_{th} total installed capacities indicated in the table comprises total installed capacity from deep geothermal (i.e. 51.5 MW_{th}) and installed capacities from other sources (e.g. gas) that are used for producing district heat at the individual plants.

The flow rate of the hydrothermal resources at the individual sites ranges between **17 kg/s** (Bad Waltersdorf) and **100 kg/s** in Altheim which is the plant with the highest flow volume. The inlet temperatures of the hydrothermal resource are between **63°C** (Bad Waltersdorf) and **110°C** (Bad Blumau). At most sites the temperature of the hydrothermal resource is higher than 80°C (Goldbrunner 2010, p.13). The length of the district heating (DH) grids varies from 1.5 km – e.g. in Bad Blumau and in Bad Waltersdorf – to 40 km in Simbach-Braunau (Goldbrunner 2013, 15, p.38).

5.4.3 New deep geothermal projects under development

Three deep geothermal projects were under development over the past years:

- Ried im Innkreis in Upper Austria – district heating
  (under development)
- Fürstenfeld in Styria – agricultural use (greenhouse heating)
- Vienna/Aspern – district heating
  (project was stopped due to non-discovery of hydrothermal resource)

5.4.3.1 Ried im Innkreis (district heating)

The geothermal district heating plant project was started in 2011 and supposed to become operational by the end of 2013. First pumping tests showed a production temperature of 105°C and a flow rate of 64 l/s (Goldbrunner and Götzl 2013, p.3). Expected flow rate was higher (150 l/s) whereas the expected temperature (100°C) could have been proven successfully. Planned installed capacity was thus calculated with 25 MW_{th}. Drilling depth was 2700 m with an expected temperature gradient of 3.4 – 3.8 °C per 100 m depth: hence temperature of the hydrothermal resource at a depth of 2700 m was expected at around 100°C (Könighofer 2013, p.33).

In a second step it is planned to increase installed capacity from 25 MW_{th} to 50 MW_{th} providing district heat for 1200 customers (90,000 MWh_{th}). Planned length of the district heating grid is 35 km. Total investment costs are estimated at 35-40 million Euro (Könighofer 2013, p.34).

5.4.3.2 Fürstenfeld (greenhouse heating)

In 2012 a deep geothermal drilling project was launched in Fürstenfeld (Styria) for the heat supply of 27 ha greenhouses. The hydrothermal resource is expected to be found in a depth of 3600 m with an expected temperature of over 130°C. Drillings were supposed to start by the end of 2013 (Goldbrunner and Götzl 2013, p.3).

5.4.3.3 Aspern / Vienna

In Aspern (Vienna) a deep geothermal drilling for generation district heat was planned. Yet, drillings had been stopped due to non-discovery of the hydrothermal resource.[19]

5.5 Deep geothermal drillings in Austria and the risk of non–discovery of the hydrothermal resource

From 1977 to 2012 in total 73 deep geothermal wells had been drilled in Austria. The following map shows the sites of the drillings:

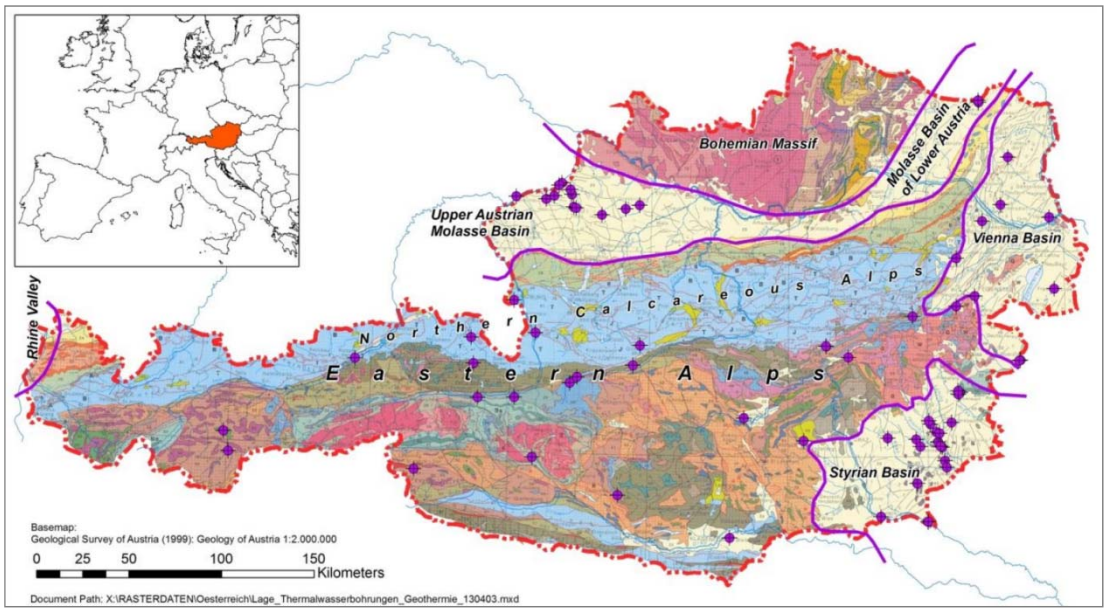

Figure 25: Deep geothermal drillings in Austria from 1977-2012, overview of geographical locations; (Source: Goldbrunner 2013, p.12)

[19] http://derstandard.at/1353209116668/Wiener-Geothermie-Plan-in-Aspern-muss-begraben-werden [accessed 26.11. 2017]

Wells were not only drilled in regions especially suitable for deep geothermal energy production (Upper Austrian Molasse Basin, Vienna Basin, Styrian Basin) but also in other areas like the Alpine region, where they were mainly intended for balneologic purposes in skiing resorts for thermal Spa (Goldbrunner and Götzl 2013, p.1).

Out of these 73 deep geothermal wells that had been drilled in Austria, 18 were intended for geothermal energy production (heat or electricity) and 55 wells were intended for balneology:

Table 9: Deep geothermal drillings in Austria from 1977-2012, key data; (Source: Goldbrunner 2013, p.13)

Einheit	Anzahl Bohrungen	durchschn. Teufe [m]	Teufe gesamt [m]	Geothermie	Balneologie
Steirisches Becken	26	1.597	41.522	6	20
Oberösterreichisches Molassebecken	13	2.172	28.236	11	2
Wiener Becken und Niederösterreichische Molassezone	8	1.576	12.605	1	7
Pannonisches Becken	1	860	860	0	1
Nördliche Kalkalpen und Karbonate des OOA	7	2.115	14.802	0	7
UOA, MOA (vorwiegend Kristallin) und OOA	18	1.368	24.618	0	18
Gesamt:	**73**	**1.680**	**122.643**	**18**	**55**

The 73 wells have a cumulative depth of 122,643 m. That is an average drilling depth of 1,680 m per well. A graphic depiction of all of the 73 drillings is given in the next figure which shows the depth of each single well. Yellow wells were intended for balnelogic purposes, violet ones for energy production and grey wells were unsuccessful drillings where the hydrothermal resource was not discovered:

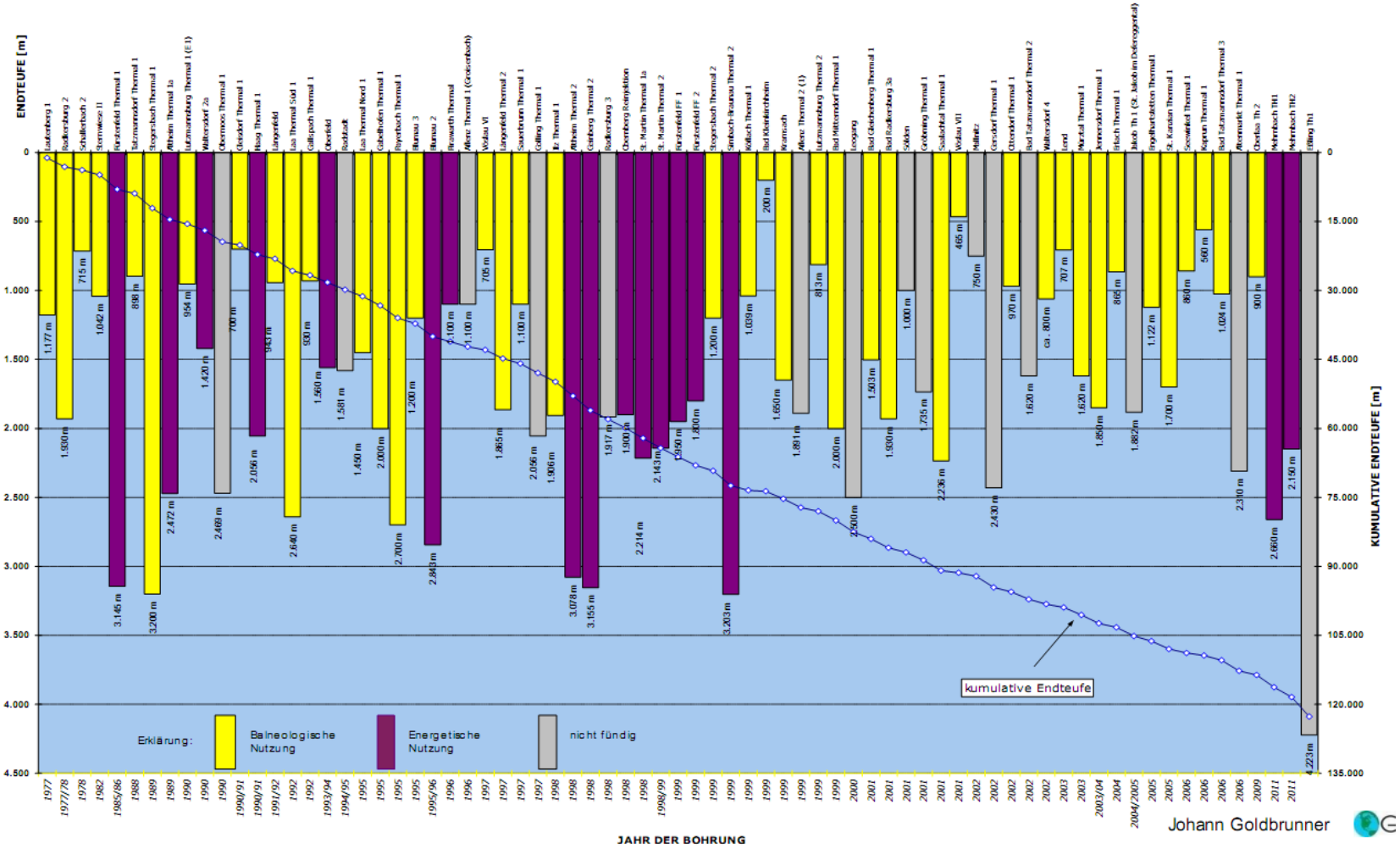

Figure 26: Deep geothermal drillings in Austria from 1977-2012: Name, depth and intended use of each single well (73 wells in total); Source: Goldbrunner 2013, p.7

The figure above indicates the name of each well (on top) and the year of drilling (at the bottom) starting in 1977 up to 2012. The first well – *Lautenberg 1* – was drilled in 1977 and had a depth of 1,177 m. The most recent well – *Eßling Thermal* [20]– was drilled in 2011/2012 with a depth of 4,223 m and represents the deepest drilling project until now.

Out of the 73 deep geothermal wells in Austria 15 drillings failed (Goldbrunner 2013, p.7), i.e. the hydrothermal resource was not discovered (red area in figure below). Successful wells are shown according to its type of use – the blue area denotes projects for energetic use (heating or electricity production) and the green area shows projects for balneologic purposes (Thermal Spa) which accounts for the majority of deep geothermal drilling projects:

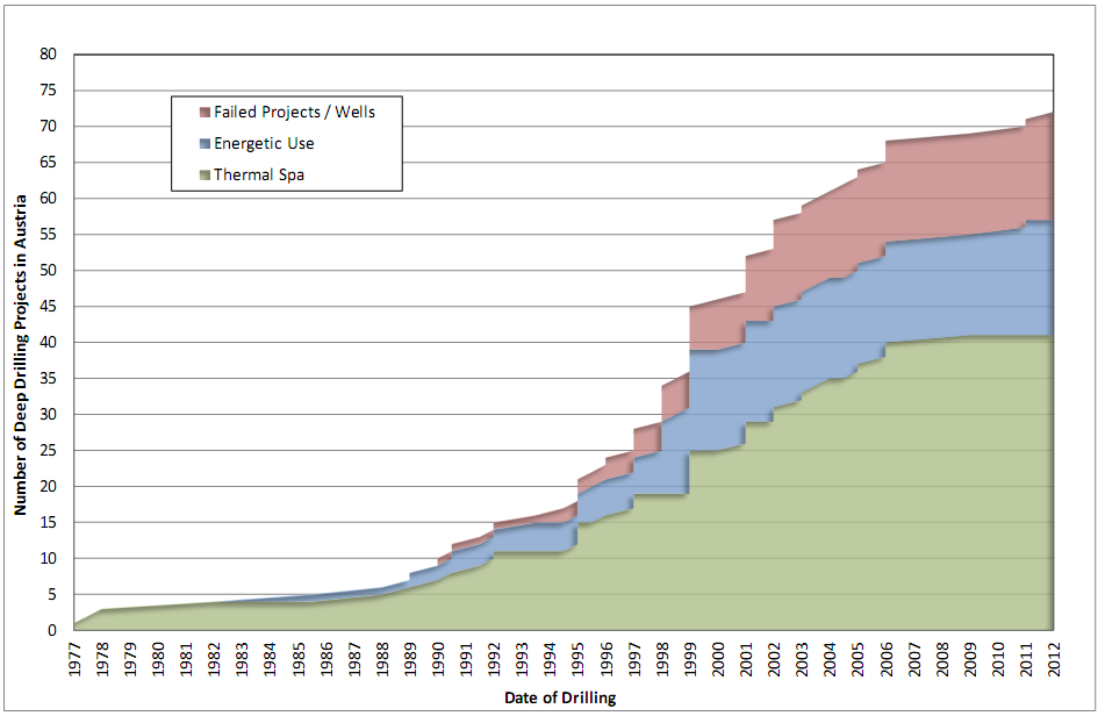

Figure 27: Deep geothermal drillings in Austria from 1977-2012: Failed projects / Enegetic Use / Thermal Spa; Source: Goldbrunner and Götzl 2013, p. 1

[20] Eßling Thermal 1 is the name of the well of the district heating project at Aspern near Vienna that was stopped in 2012 due to non-discovery of the hydrothermal resource.

6 Risk of non-discovery of the hydrothermal resource

6.1 What is the risk of non-discovery of the hydrothermal resource?

The hydrothermal resource has to be found in sufficient quantity[21] (l/sec) and at a sufficiently high temperature level (e.g. >150°C). Drillings are only successful when both parameters are found at a certain minimum level ensuring that the plant will be able to operate economically. Besides drilling costs, which account for the major part of investment costs and depend on well depth, flow rate and temperature are important factors for the economics of a plant (Piatti, Piemonte and Szegö 1992). Temperature and flow rate determine the extractable energy and thus the installed capacity of a plant. For a geothermal heating plant the thermal power Q can be calculated as following (Knaut et al. 2012, p.4):

$$Q = V \cdot \rho \cdot c_p \, (T_{out} - T_{in}),$$

V…..flow rate [in m^3 / sec]
ρ.....density of the fluid [in kg / m^3]
c_p…..thermal capacity of the fluid [in J kg^{-1} K^{-1}]
T_{out}…well extraction temperature [in K]
T_{in}….well re-injection temperature [in K]

The average temperature gradient worldwide is 30°C per km depth. Yet temperature gradients vary a lot depending on geological conditions (Barbier 2002). The figure below shows temperature gradients from different sites in Europe:

[21] The terms *productivity* and *flow rate* are used synonymously.

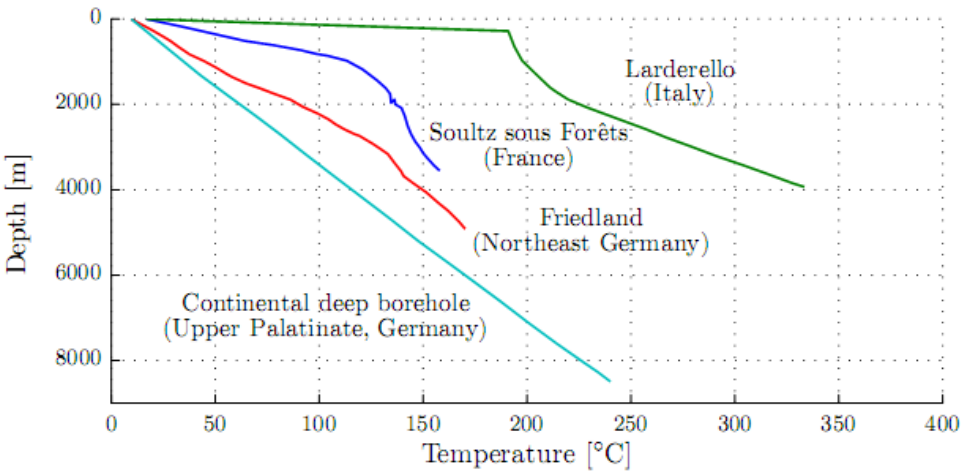

Figure 28: Temperature gradients in different European boreholes for geothermal energy use; (Source: Kaltschmitt et al. 2001)

The temperature gradient for the *Continental deep borehole* in Upper Palatinate, Germany, for example is in line with the worldwide average of 30°C per km depth. As it can be seen in the figure above at a depth of 5000 m a temperature of approximately 150°C was found. The region in *Soultz sous Forêts*, France, shows a higher enthalpy: temperatures of 150°C were found in only 3000 m depth. In the high-enthalpy region *Lardarello* in Italy temperatures of even 200°C exist in very low depths close to the surface. In about 3500 m depth temperatures higher than 300°C were found.

Temperature gradients depend on rock properties such as thermal conductivity (Knaut et al. 2012, p.3). Apart from sufficiently high temperature gradients – hot rocks heated by the heat flow from the Earth's core exist everywhere – areas with the occurrence of hydrothermal resources have to be identified. In Austria for instance three regions exist with known large hydrothermal resources suitable for energy production (Vienna Basin, Upper Austrian Molasse Basin, Styrian Basin):

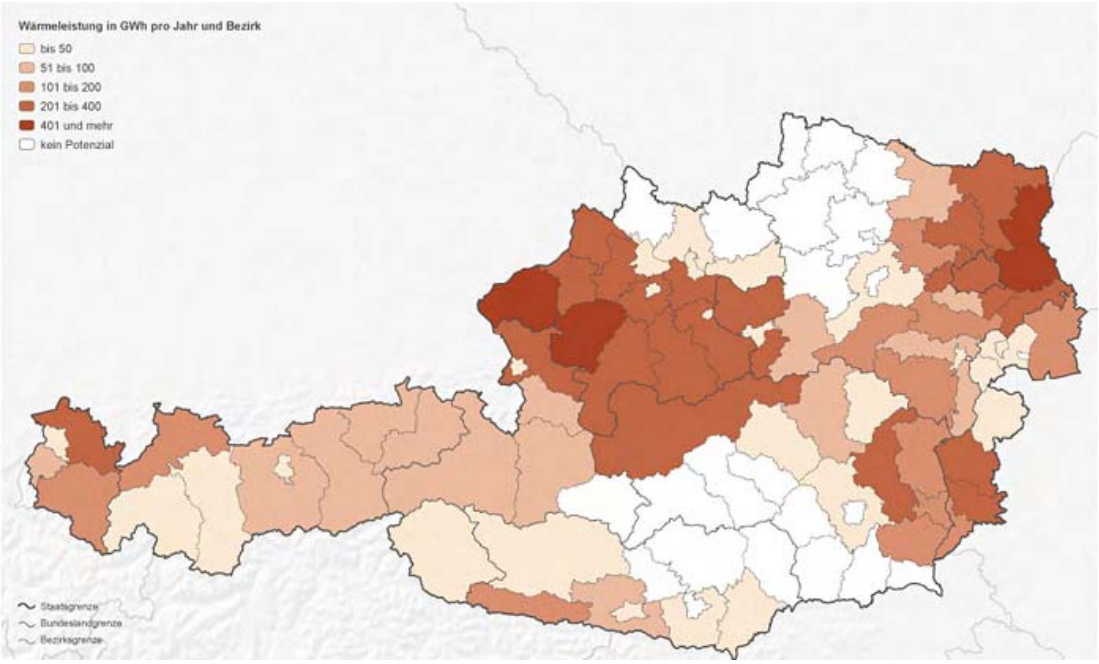

Figure 29: Potential of deep hydrothermal resources in Austria; (Source: figure taken from Kotschan 2012, p.8)

In the Vienna Basin for example temperatures of up to 200°C and high flow volumes in l/sec of the hydrothermal resource are expected (Goldbrunner 2010, p.1-2). With only 10 wells with a capacity of 40 MW_{th} and a total capacity of 400 MW_{th} over 25% of the heat supply for the Viennese district heating system could be provided (derived from presentation Rapottnig 2012, p.13). Yet, depths and exact locations of the hydrothermal reservoirs have to be identified within the 200 km long and 50 km wide Vienna Basin.

Hydrothermal resources cannot be imagined as a huge lake or sea as it is shown in the following figure:

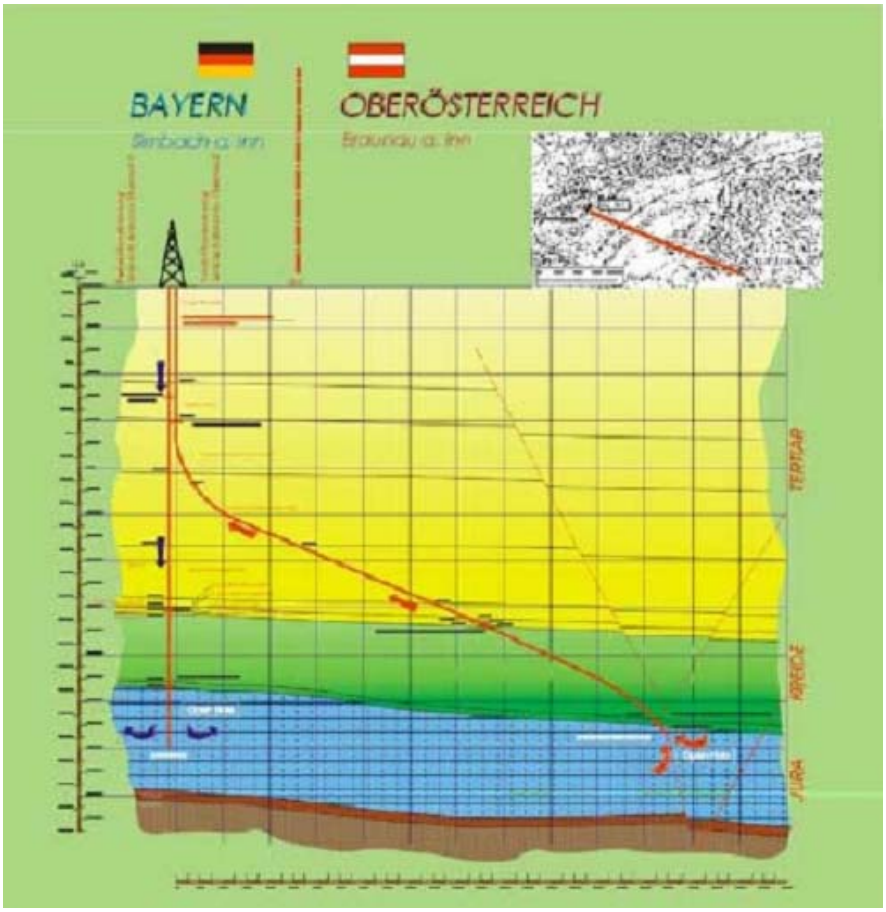

Figure 30: Schematic depiction of a geothermal district heating plant in Simbach/Braunau at the Austrian-German border (Source: Bucar et al 2006, p.69)

The schematic depiction of the hydrothermal reservoir (blue area) is misleading. The figure below gives a better understanding of hydrothermal reservoirs:

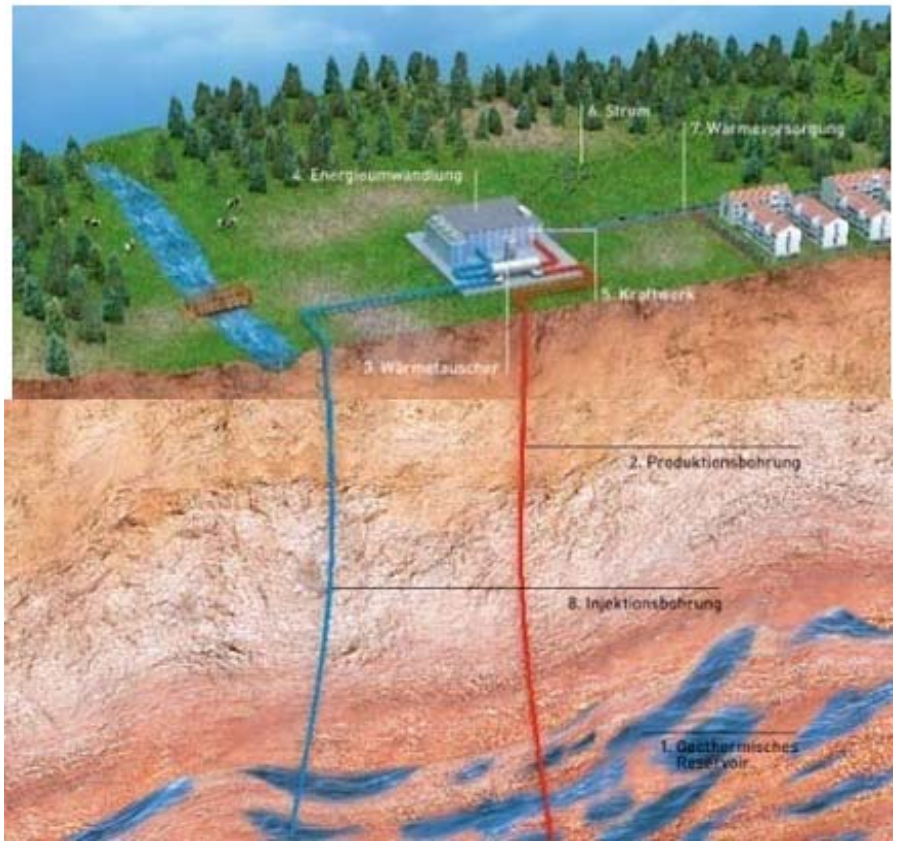

Figure 31: Schematic depiction of a geohtermal plant and hydrothermal reservoirs; Source: figure taken from Götzl 2010, p. 22

Even in the above figure the illustration of hydrothermal reservoirs is simplified. In fact, reservoirs are porous rock formations containing a lot of smaller amounts of water dispersed within the respective rock layer. This is better displayed in the figure below, which is taken from the geothermal district heating project at Airfield Aspern in the Vienna Basin:

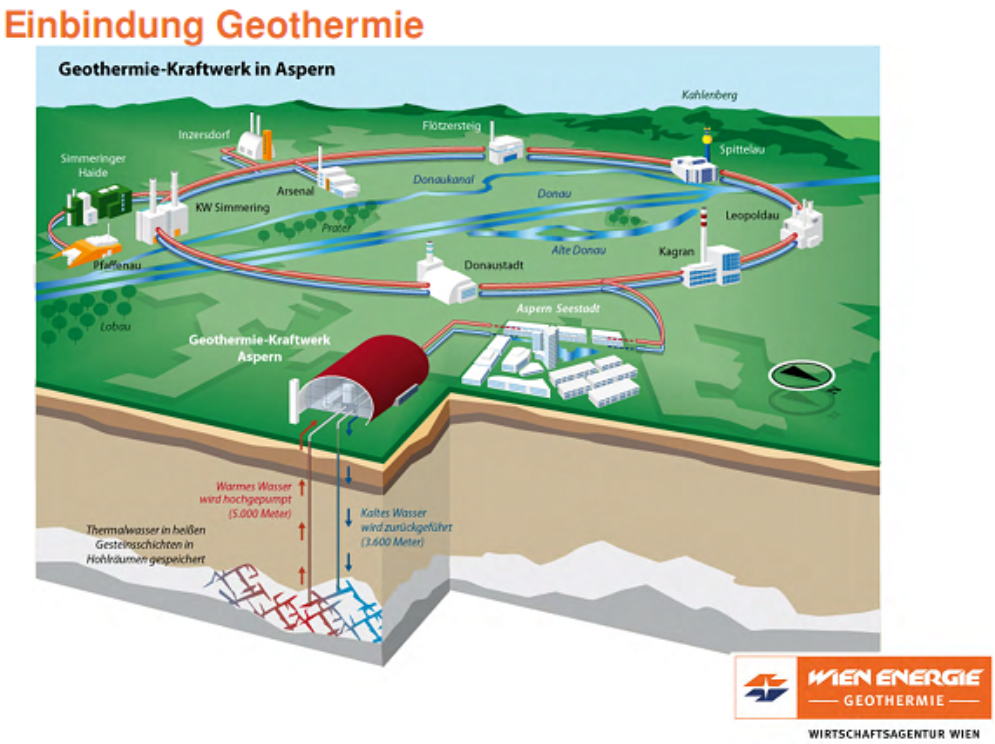

Figure 32: Schematic depiction of the planned district heating project at Airfield Aspern in the Vienna Basin (Source: Kotschan 2012, p.25)

In the figure above the hydrothermal resource is illustrated and shows rock layers with smaller amounts of hot waters stored within porous rocks. The occurrence of hot waters was estimated at this site in a depth of 5000 m at a temperature level of 150°C. Yet, geological models proved to be wrong at this site and no hot waters in sufficient amounts and at sufficient temperature levels were found after drilling the first well. The project was thus stopped due to non-discovery of the hydrothermal resource.

The structure and geological knowledge of the Vienna Basin is mainly based on more than 3,500 oil and gas exploration drillings that had been drilled in the last decades and are useful to understand geological structures apart from theoretical geological modeling (Hamilton, Wagner and Wessely 1999). In addition, seismic surveys including 3-D-seismic had been conducted for a better understanding of the geological structures (Goldbrunner 2010, p. 2). Based on this knowledge models had been developed that indicate geological structures, temperature estimations and estimations on locations where hydrothermal reservoirs might be found in sufficient quantity. Although the existence of large hydrothermal reservoirs in the Vienna Basin is known, temperatures and exact locations of hydrothermal reservoirs

may differ from what is modeled in geological models. Since geologic models are based on available geological knowledge, they might be wrong. The existence of a hydrothermal reservoir at a certain location with a certain temperature level can eventually be proven only after drilling. Thus even if a profound knowledge of geological structures is available a certain risk of non-discovery remains before drilling.

6.2 How to assess the risk of non-discovery economically?

The non-discovery of the hydrothermal resource is the main investment risk for deep geothermal (ESMAP 2012, p.3).

The figure below illustrates the risk of non-discovery of the hydrothermal resource. It constitutes the major risk for geothermal deployment. Please note: the illustration below is for a whole geothermal field with potentially dozens of geothermal wells for electricity production. Yet, the principle is the same for a deep geothermal heat plant with two wells:

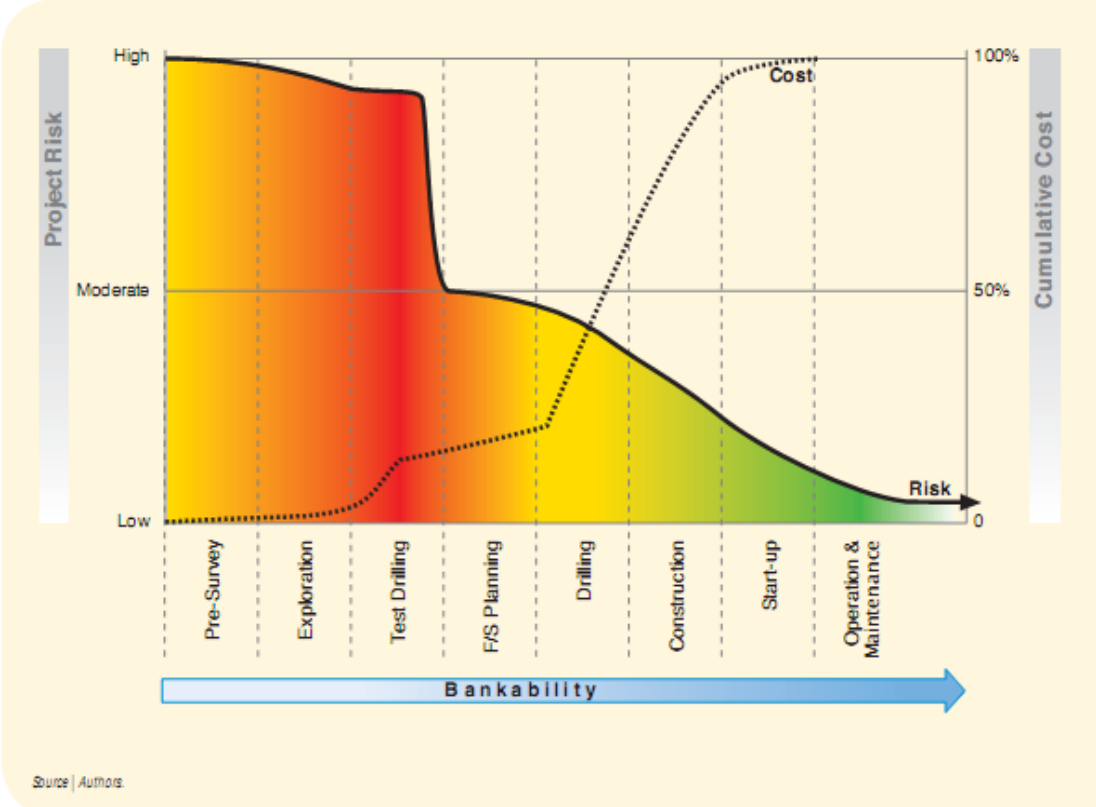

Figure 33: Risk of non-discovery compared with cumulative investment costs for a geothermal field; (Source: ESMAP 2012, p.69)

In the *Prey-Survey* and *Exploration* phase costs are comparatively low since only studies are undertaken to examine the exact location and potential of the hydrothermal resource. At this stage uncertainty about discovery of the hydrothermal resource is very high. If *Prey-Survey* and *Exploration* phase show promising results the first drillings are undertaken in the *Test Drilling* phase (for a whole geothermal field e.g. five test drillings). Since drilling costs constitute the major cost factor costs increase sharply at this stage. At the same time the risk of non-discovery can be reduced by the findings of the test drillings and falls sharply from high to medium if test drillings prove to be successful (i.e. quantity and quality of hydrothermal resource shows promising results). Then in the *Drilling* phase production and reinjection wells are drilled (e.g. 20-50 wells for a whole geothermal field) and the power plant for electricity production is built. For the phase before the hydrothermal resource is found bankability is low, that means that private equity is needed to take the risk of non-discovery (capital for investment risk). After the hydrothermal resource is found overall risk is comparably low and thus bankability is high and from that point of time it is possible to finance the geothermal project with bank loans.

In general the risk of non-discovery for whole geothermal fields (e.g. 20-50 wells) as well as for geothermal projects with two wells (dublet) can be displayed as following:

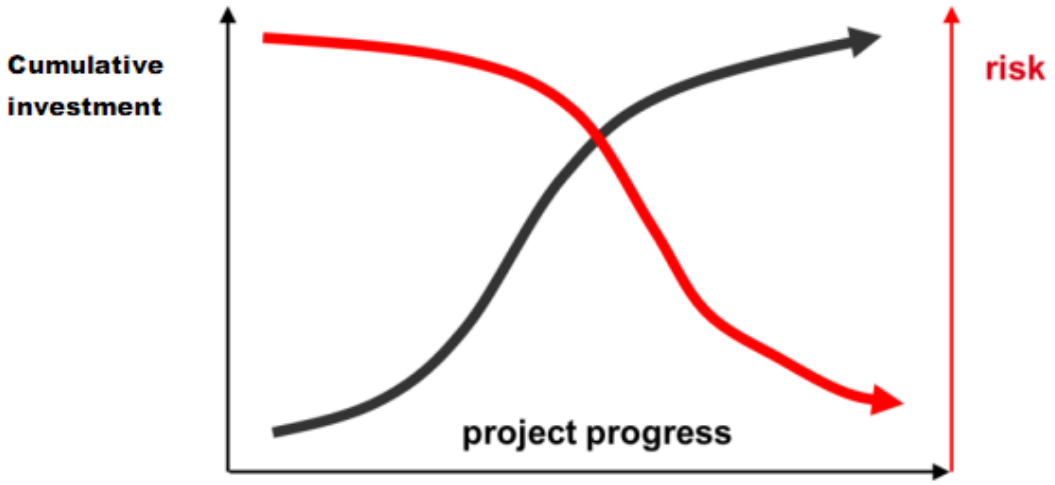

Figure 34: Risk and cumulative investment during project progress; (Source: GEOELEC 2013a, p. 22)

Most of the investment (i.e. drilling of wells) falls into the high-risk phase of the geothermal project before the resource is proved. For a geothermal field this is the drilling of the exploration wells. For a dublet – which consists of a production well and a reinjection well – this is the drilling of the first well (production well).

Within the GeoHEAT research project the following illustration for a geothermal heat plant (deep drilling with two wells) was developed:

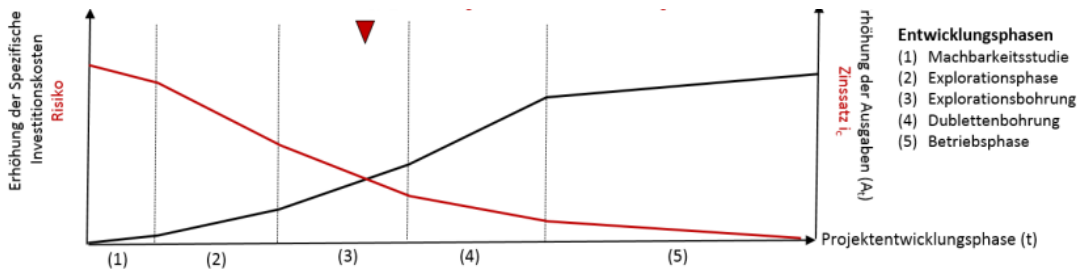

Figure 35: Risk of non-discovery and cumulative investment costs for a deep geothermal heat plant with two wells (dublet); Source: GeoHEAT 2014, Götzl, Saurer and Niederbrucker, p. 18)

The black curve shows cumulative investment costs during project progress. In the pre-drilling phases (1) feasibility study (Machbarkeitsstudie) and (2) exploration

phase investments are comparatively low and the risk of non-discovery is high (red curve). In phase (3) when the production well is drilled (Explorationsbohrung) it turns out if the drilling is successful and whether the hydrothermal resource is found and to what extent, i.e. if flow rate (l/s) and temperature level will have expected levels (e.g. 50 l/s with a temperature of 130°C). Then in phase (4) the reinjection well is drilled and the dublet is completed. In the operating phase (5) the geothermal drillings are expected to produce energy for at least 30 years. In this phase there remains only a very low risk that produced energy output is lowered by a depletion of the hydrothermal resource. If plant engineering is designed correctly this risk is almost zero.

In addition GeoHEAT has developed an approach to show how additional measures can help to reduce the investment risk:

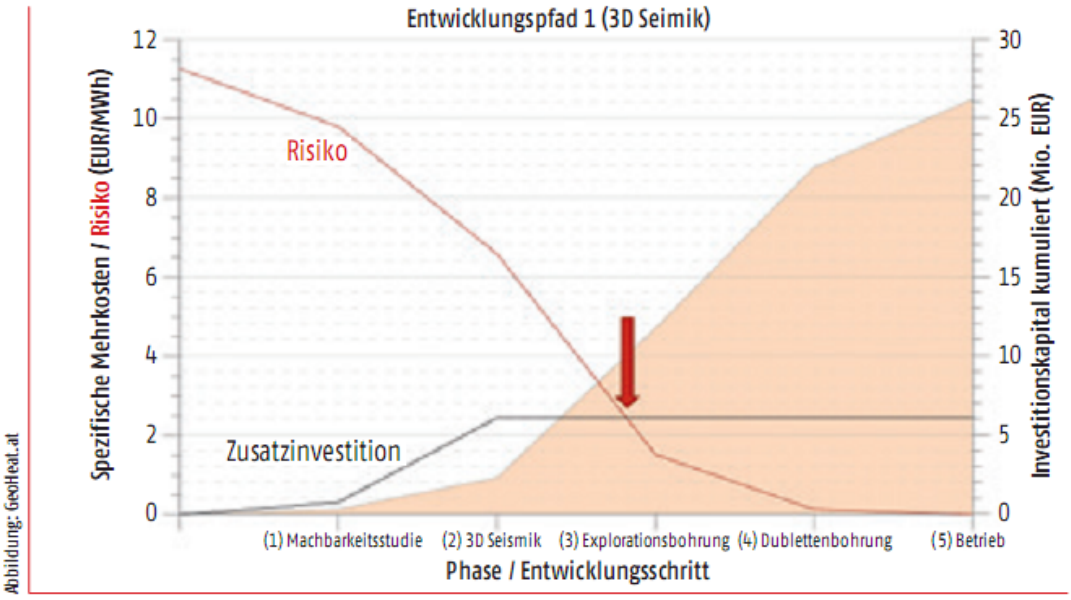

Figure 36: Risk and cumulative investment costs of a geothermal heat plant (dublet) compared with costs for additional measures to reduce the risk of non-discovery; (Source: GeoHEAT, Gregor Götzl, published in bbr 2014, S.110)

This concept was developed for the site of Baden (southern Vienna Basin) and shows in an exemplary way how additional measures before drilling can help to reduce the risk of non-discovery. Geological structures in the Vienna Basin are roughly known from former oil and gas drillings. At the specific drilling site at Baden additional investments in geological surveys like a 3D Seismic makes sense to gain more exact knowledge of geological structures at the prospective point of drilling. This reduces the risk of non-discovery when the capital intensive drilling of a well is

actually realized. The question is how much money shall be invested in pre-drilling activities: money invested in reducing uncertainty versus money invested in drilling which actually shows if the hydrothermal resource exists in expected quantity and quality.

In the figure above pre-drilling activities are projected with costs of 2 million Euro for phase (1) feasibility study and phase (2) 3D seismic. In phase (3) the first well is drilled with projected costs of 10 million Euro. In phase (4) the second well is drilled with costs of another 10 million Euro. For phase (5) costs of 4 million Euro are projected to finalize the heat plant (construction of the building and pipes). In total investment costs are projected with 26 million Euro.

Before drilling the first well it might make sense to invest more money in a profound 3D Seismic (up to 2.5 million Euro as shown in the figure above: “Zusatzinvestition”). This improves decision making if drilling makes sense and it helps to identify the exact location of the hydrothermal resource. Risk capital is primarily needed for the pre-drilling phase and the drilling of the first well. In the above shown case this amounts 10 million Euro for drilling the first well and 2 million Euro for feasibility study and 3D seismic (plus additional investments in a more comprehensive 3D seismic). In total 12 million Euro risk capital is needed for a total investment of 26 million Euro for the whole geothermal heat plant.

After drilling the first well (production well) it turns out whether the hydrothermal resource is found. Two extreme cases may arise: the hydrothermal resource is not found and the whole investment is lost or the resource is found and meets or even exceeds predicted estimations from geological surveys. It may also occur that the hydrothermal resource is found but with a lower flow (l/s) or lower temperature than expected. This leads to higher generation costs, yet the heat plant may still be profitable. The same is true if the hydrothermal resource is located in greater depth (e.g. 500m deeper than expected), this increases drilling costs and thus result in higher generation costs (bbr 2014, p. 110).

6.3 Risk insurance and portfolio approach as instrument to solve the risk of non-discovery

A solution to overcome the risk of non-discovery might be the establishing of an international geothermal risk insurance fund. The main idea is to build a portfolio of projects where from the cash flow of successful drillings non-successful projects are financed. This enables to provide risk capital for new projects and to insure the risk of non-discovery.

In principle the idea is the same as in the oil and gas industry. The risk is spread amongst a large number of drilling projects and thus drillings where no oil and gas is found are financed be successful oil and gas drilling projects. The exploration risk in the oil and gas industry is very similar to the risk of non-discovery in the geothermal industry. One major difference is that the number of oil and gas drillings is much higher and thus it is much easier to build portfolios whereas considerably less deep geothermal drilling projects exist so far. To bundle geothermal drillings on a global or at European level might enable to build a portfolio of geothermal projects with the necessary number of drillings needed to cover the risks of failed projects:

Risk insurance Funds for the geological risk already exist in some European countries (France, Germany, Iceland, The Netherlands and Switzerland). The geological risk is a common issue all over Europe. Collaboration between Member States to remove it will allow them to save money. For this reason the establishment of a Geothermal Risk Insurance Fund at the EU level could insure deep geothermal projects all over Europe (EGEC 2013a, p.17).

6.3.1 European Geothermal Risk Insurance Fund (EGRIF)

GEOELEC (www.geoelec.eu) promotes geothermal electricity generation in the EU and aims at removing notably financial barriers. Thus it has put forward a report that outlines a scheme for an EU fund that facilitates market deployment of deep geothermal by insuring the risk of non-discovery of the hydrothermal resource: *European Geothermal Risk Insurance Fund (EGRIF).* The idea is the pooling of the resource risk among geothermal electricity projects in the EU. Its scope comprehends deep geothermal and all types of geothermal technology including Enhanced Geothermal Systems (EGS). In a first step it is proposed to use public

funds for the deployment of deep geothermal by catalyzing an initial round of investment and stimulating private investments. In a second step it is proposed to phase out public finance and replace it with private funding. A strategy from a publically funded program such as the EGRIF toward a public-private partnership or a fully private insurance has to be envisaged. The seed capital shall be at least 50 – 100 Mio EUR (GEOELEC 2013b).

In the USA, which is one of the largest consumer and producer of geothermal energy in the world, there have been a number of government-sponsored financial schemes to boost geothermal industry. Of significance regarding the resource risk was the User Coupled Confirmation Drilling Program which promoted geothermal heat production. The Department of Energy paid between 20% (success) and 90% (failure) of the project costs. (GEOELEC, 2013b, p.62)

If for example the probability of discovery for deep geothermal projects is assumed with 80% that means that in a portfolio approach four out of five drillings are successful. To be economically viable four successful drillings need to bear the costs of the non-successful drilling project:

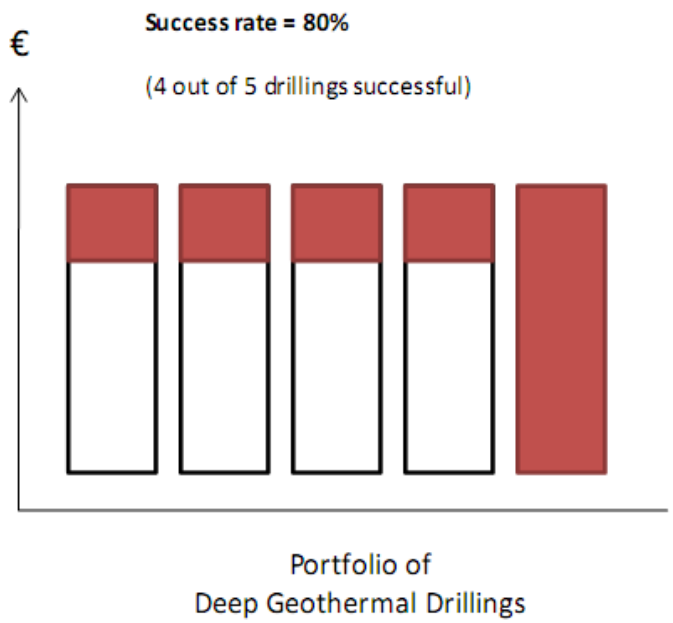

Figure 37: Schematic depiction of a portfolio approach to solve the risk of non-discovery
(source: Walter Saurer, own depiction)

If a non-successful drilling costs for example 10 million Euro and the cash flow of four successful drillings bear those costs (marked in red) the risk is spread successfully. To establish a risk insurance fund for deep geothermal a sufficient number of drilling projects is needed, for two reasons: firstly to assess the probability of discovery on a statistical profound basis (e.g. n = 100) and secondly a certain number of insurable projects is needed to effectively build an insurable portfolio.

6.3.2 Depiction of the risk of non-discovery in an investment decision calculation

In contrast to a risk insurance fund as described above or an investment fund the risk of non-discovery for a single deep geothermal drilling project can be depicted in the investment decision calculation in two ways: either by a risk insurance premium for the specific project or by a higher discount rate that reflects the risk of non-discovery.

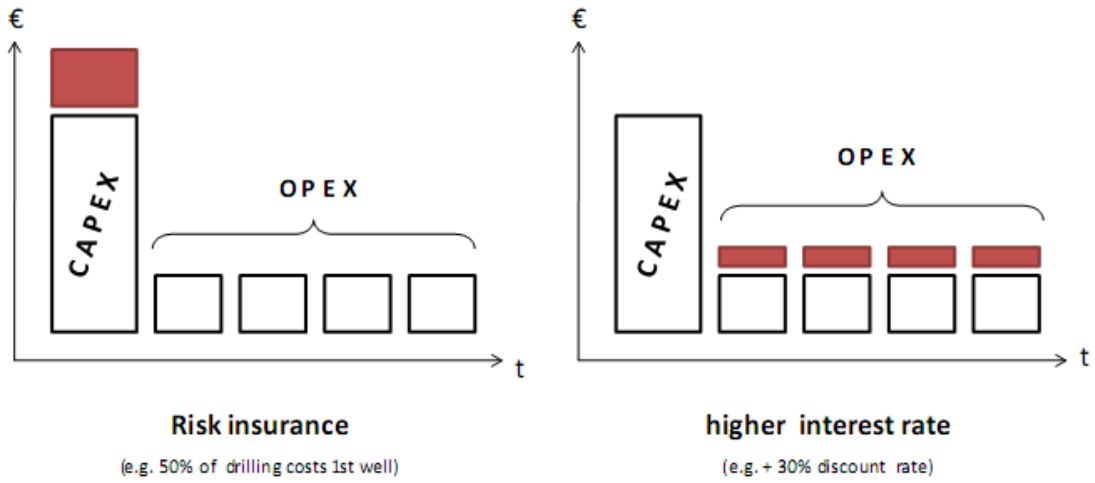

Figure 38: Depiction of the risk of non-discovery in an investment decision calculation for a single deep geothermal drilling project (source: Walter Saurer, own depiction)

Risk insurance covers the costs if the hydrothermal resource is not found after drilling the first well. Thus the investment risk is shifted from the investor to the insurance company. The investor has to pay an insurance premium that depends on the estimated risk of non-discovery (e.g. 50% of drilling cost for the first well). In case of non-discovery the insurer has to pay the drilling costs. The second possibility to depict investment risk of non-discovery is a higher interest rate that reflects the risk of non-discovery, e.g. 30% discount rate for equity capital.

7 Case Study: The risk of non-discovery and economic assessment of a prospective deep geothermal heating plant at the site of Baden

For the energetic use of hydrothermal reservoirs the existence of the reservoir (hot thermal waters) needs to be proved and in order to assess the potential for energetic use the productivity (l/sec) and the temperature level (°C) of the thermal water has to be estimated. This is highly dependent on local factors of the specific site (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.3). In chapter 7.1 an overview of the local conditions for deep geothermal energy use at the site of Baden is given:

7.1 Description of the site of Baden

The Vienna Basin is located between the Alps and Carpathian Mountains and contains hydrothermal reservoirs (hot thermal waters) as well as hydrocarbon reservoirs (oil and gas). As depicted in the figure below the Vienna Basin contains huge subsoil geological structures with rock layers that contain huge amounts of hot thermal waters (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.14):

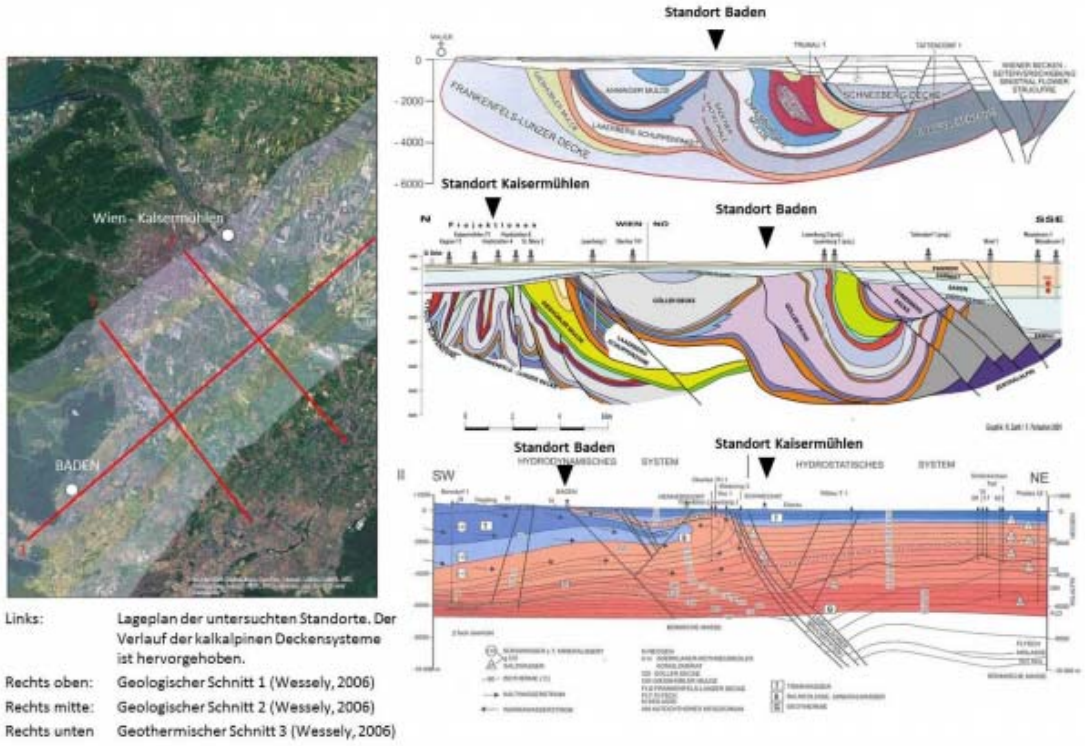

Figure 39: „Kalkalpines Deckensystem“ in the Vienna Bassin – figures on the right hand side: geological and geothermal cross-sections around the site of Baden (Source: GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.4)

Baden is a city in the south of Vienna and is located in the southern part of the Vienna Basin. Whereas in the central and northern part of the Vienna Basin the knowledge about geothermal reservoirs as well as expected temperature levels and productivity (l/sec) of the geothermal fluids is much better known, in the southern part around Baden much less valid data about geological structures exist. This is due to oil and gas drillings in the central and northern Vienna Basin which provides data about geothermal fluids. Since there were no oil and gas drillings in the southern Vienna Basin close to the investigated site, no such data exist for the site around Baden (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p. 4).

What is known for the southern part of the Vienna Basin is that there exists an actively circulating system of thermal waters where water enters the hydrodynamic system at the eastern part of the Limestone Alps and is heated underneath the earth in the Basin and leaks as hot water in thermal springs which is used for thermal spa in Bad Vöslau and Baden (Wessely 1983, 2006). Yet, this hydrodynamic system produces local temperature anomalies of the geothermal fluids (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.14). This means that in contrast to the expected geothermal gradient (e.g. 30°C temperature rise per km depth),

temperatures can reach higher levels close to the surface whereas lower temperature levels of the thermal waters in greater depth may occur due to cold water streams. This is shown in the figure above on the right hand side (bottom figure: Geothermischer Schnitt 3, Wessely 2006).

In the figure below the site of Baden is shown. The red area indicates the water protection zone where drillings are forbidden. The green lines mark the area where subsurface rock formations were investigated for potential geothermal energy use. At the prospective drilling point ("Standort Dublette") a geological cross-section of the subsurface structures were modeled. The geological cross-section ("Lage des Schnitts") was done across the white line and is inserted in the figure below:

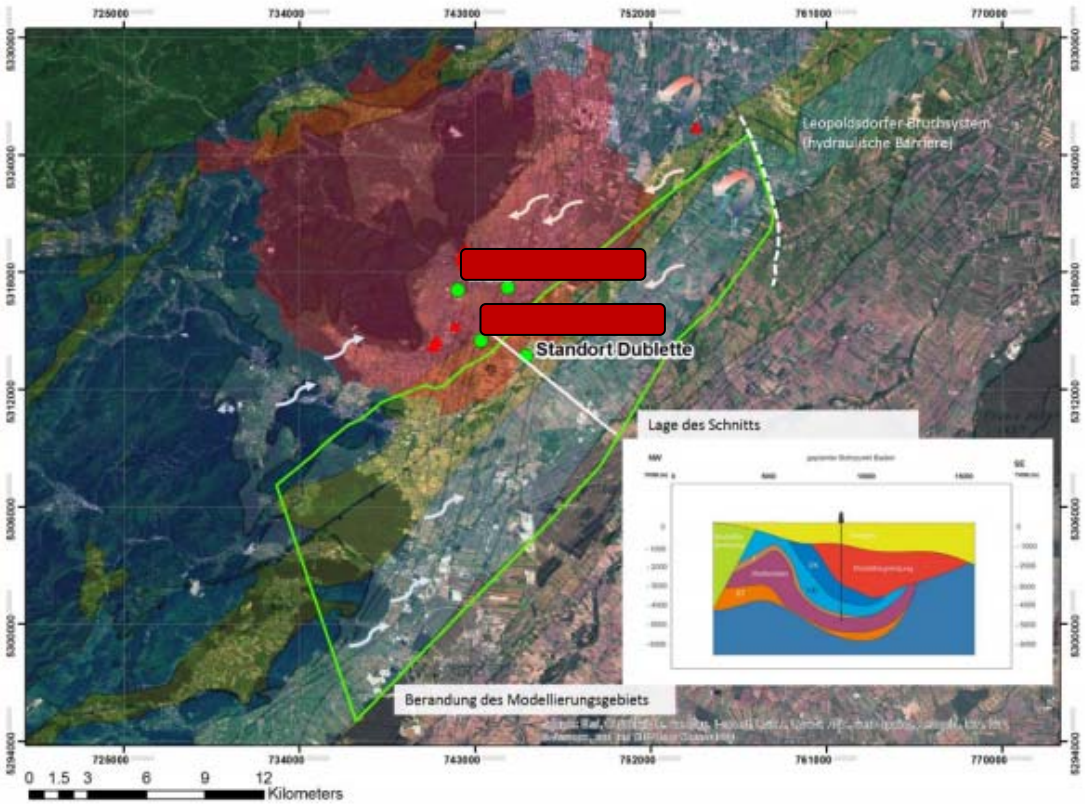

Figure 40: Overview of the selected site at Baden and geological cross-section of subsurface structures (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.15)

In the figure above the selected site of a potential deep geothermal heat plant is indicated ("Standort Dublette", green dot). Potential demand for a deep geothermal heat plant is local district heating and energy supply for industrial companies, e.g. for process heat. The green lines mark the area that was selected for geological modeling in the GeoHEAT research project: subsurface rock formations were modeled based on available data in order to estimate temperature levels and

productivity (l/sec) of the geothermal fluids according to depth. The white arrows indicate expected streams of the circulating thermal waters. The red marked area shows the protection zone for thermal spa usage which cannot be used for geothermal energy production in order to avoid negative impacts on the hot thermal waters used in Balneology in Baden and Bad Vöslau. The white line represents the geological cross-section which is depicted in the figure and shows the rock layers at the selected site for the deep geothermal heat plant. This geological cross-section was taken from the 3D model developed during the GeoHEAT research project (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.15).

Due to expected subsurface temperature anomalies in the area of Baden and the lack of proven knowledge about temperature levels, e.g. by data of former oil and gas drillings which exists in the central and northern Vienna Basin but not in the southern part around Baden, a prediction of rock temperatures and thus an estimation of temperatures levels of the geothermal fluids is possible, yet with a high degree of uncertainty (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.14-15).

An explicit consideration of local temperature anomalies would reduce the degree of uncertainty in the prediction of the temperature levels of geothermal fluids and thus decrease the risk of non-discovery of the hydrothermal resource. This does not exist so far and further geological research of the subsurface rock structures in the area of Baden would be needed, which might be a useful follow-up research project in order to get a better understanding of temperature levels of the geothermal fluids (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.15).

7.2 Geological cross-section at the site of Baden

The geological cross-section from Figure 40 which shows the rock layers at the site of Baden is depicted in the figure below. The prospective deep geothermal drilling at the site of Baden is indicated by the red arrow and has a maximum drilling depth of about 5,000m:

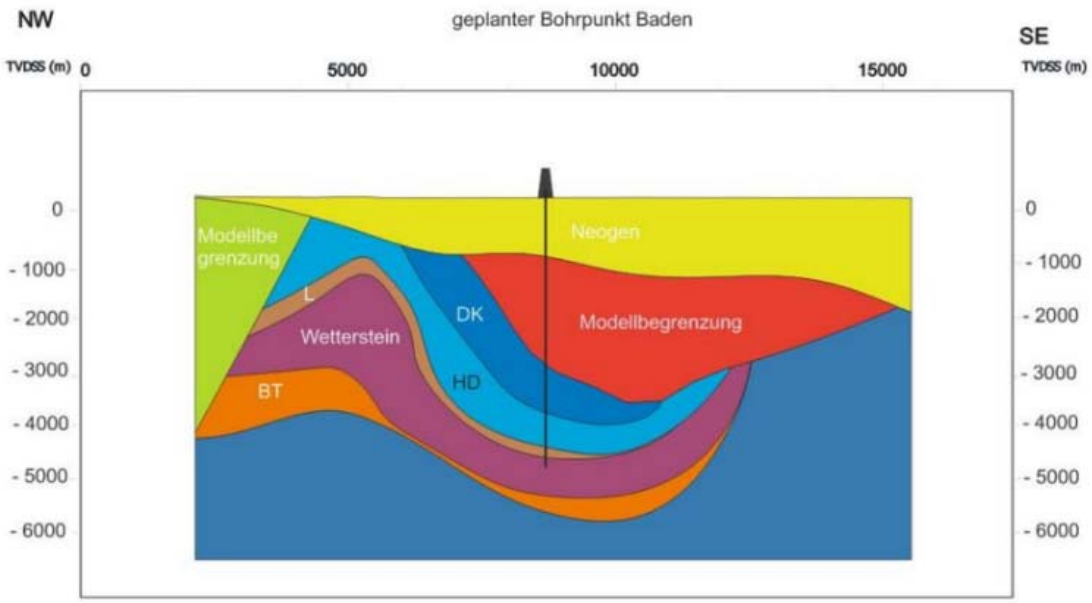

Figure 41: Geological cross-section at the site of Baden (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.17)

According to the geological model three rock layers potentially contain hydrothermal resources (hot thermal waters):

1. "Dachsteinkalk" (DK): depicted in dark blue in the figure above
2. "Hauptdolomit" (HD): depicted in light blue
3. "Wettersteindolomit" (WD): depicted in purple

"Neogen" (yellow area) indicates sediments up to a depth of 1,000m that might contain hydrothermal resources, yet expected productivity (l/sec) is too low to be considered for a geothermal heat plant.

"Lunzer Schichten" (L) depicted in brown colour in the figure above is a non/low-water permeable rock layer that separates the potentially water containing "Dachsteinkalk" (DK) and "Hauptdolomit" (HD) from "Wettersteindolomit" (WD) which is also a potentially water containing rock layer (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.16-17).

The geological cross-section of Baden is depicted again in the figure below, from a perspective where the depths of the potentially water containing layers (Dachsteinkalk, Hauptdolomit, Wettersteindolomit) is shown in a better way:

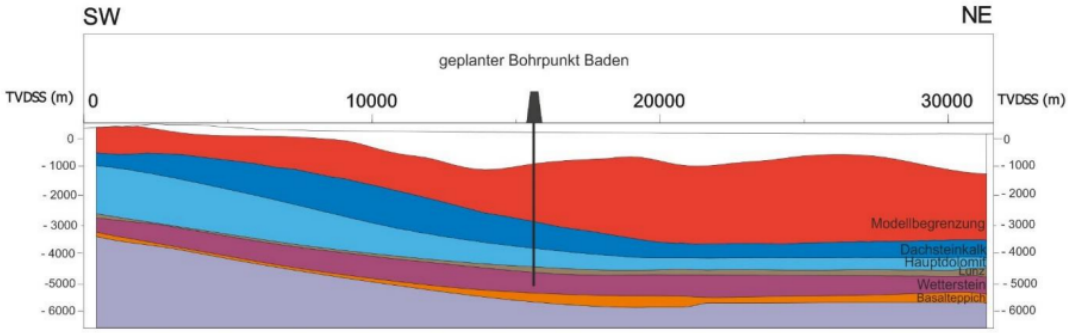

Figure 42: Geological cross-section at the site of Baden (AP3_Detailbericht1 p.18) (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.18)

At the prospective point of drilling (black arrow in the figure above) the three water containing rock layers are expected at following depths (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.18):

- Dachsteinkalk (dark blue): 3,091 – 4,011 m
- Hauptdolomit (light blue): 4,011 – 4,663 m
- Wettersteindolomit (purple): 4,843 – 5,548 m

Limits of the model: the geological cross-section (Figure 41 and Figure 42) is based on available geological data. It cannot be said if the geological cross-section depicts correctly the subsurface structures until actual drillings prove the model to be correct. It may turn out that depths and structures of the rock layers "Dachsteinkalk", "Hauptdolomit" and "Wetterstein" are completely different than modeled in the cross-section above. It is not possible to give any serious scientific guess about the prognostic validity of the geological cross-section: this means that it cannot be said whether the cross-section depicts subsurface rock layers with a probability of 10%, 50% or 90% (Source: expert interview with Gregor Götzl 2017).

Since not enough available geological data exist, geological models may be wrong. The 3D model was made on the basis of available geological data and thus this is the best method to predict depth, productivity and temperature of the geological resource. Yet geological models based on available data may differ from actual rock structures and thus the prediction of depth, quantity and temperature of the fluid is based on estimations depending on available geological data (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.20).

Since it is not possible to quantify the uncertainty to what extent the geological cross-section correctly depicts subsurface structures, quantitative estimates of non-discovery of the hydrothermal resource derived from the geological modeling do have a degree of uncertainty that cannot be measured. Thus it is difficult to determine a valid interest rate for the investment decision calculation that properly reflects the risk of non-discovery. Any outcome of the investment decision calculation (e.g. prospective generation costs) is therefore speculative. The same is true for calculating the premium for a risk insurance against the risk of non-discovery for a specific site.

For this work the assumption is that the geological model (cross-section) correctly depicts subsurface structures at the site of Baden.

7.3 Geological estimation of expected temperature and flow rate of the hydrothermal resource and the risk of non-discovery at the site of Baden

Based on the assumption that geological modeling correctly depicts subsurface structures at Baden (see chapter above: *7.2 Geological cross-section at the site of Baden*) a statistical analysis of estimates on expected temperatures and flow rates of the geothermal fluid is given in this chapter.

This implies the 3 core questions for the risk of non-discovery of the hydrothermal resource:

1. Depth: at what depths is hot thermal water expected?
2. Flow rate: is the quantity of the water (l/sec) sufficient?
3. Temperature: does the water actually have the expected temperature?

For successfully operating a geothermal heat plant all these three factors need to be proved, e.g.: hot thermal water is found at a depth of 4,000 m, with a flow rate of 50 l/sec and a temperature level of at least 120°C. Drillings are successful when hot water is found with the needed flow rate and temperature level at the expected depth.

7.3.1 Depth: at what depth is hot thermal water expected?

According to geological modeling (see chapter *7.2 Geological cross-section at the site of Baden*) the potentially water containing rock layers shall be found at following depths:

- "Dachsteinkalk" is expected at the prospective point of drilling at a depth of 3,091 – 4,011 m and has thus a thickness of 920 m
- "Hauptdolomit" is expected at a depth of 4,011 – 4,663 m with a thickness of 650 m
- "Wettersteindolomit" is expected at a depth of 4,843 – 5,548 m with a thickness of 720 m

According to geological modeling it is assumed that the thickness of the rock layers may differ in reality by a maximum of 100 meter. Actual depth of rock layers is supposed to differ from modeled depth by a maximum of 300 meter (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.20).

In the figure below the three potentially water containing rock layers "Dachsteinkalk", "Hauptdolomit" and "Wettersteindolomit" are modeled and the aggregated thickness is shown:

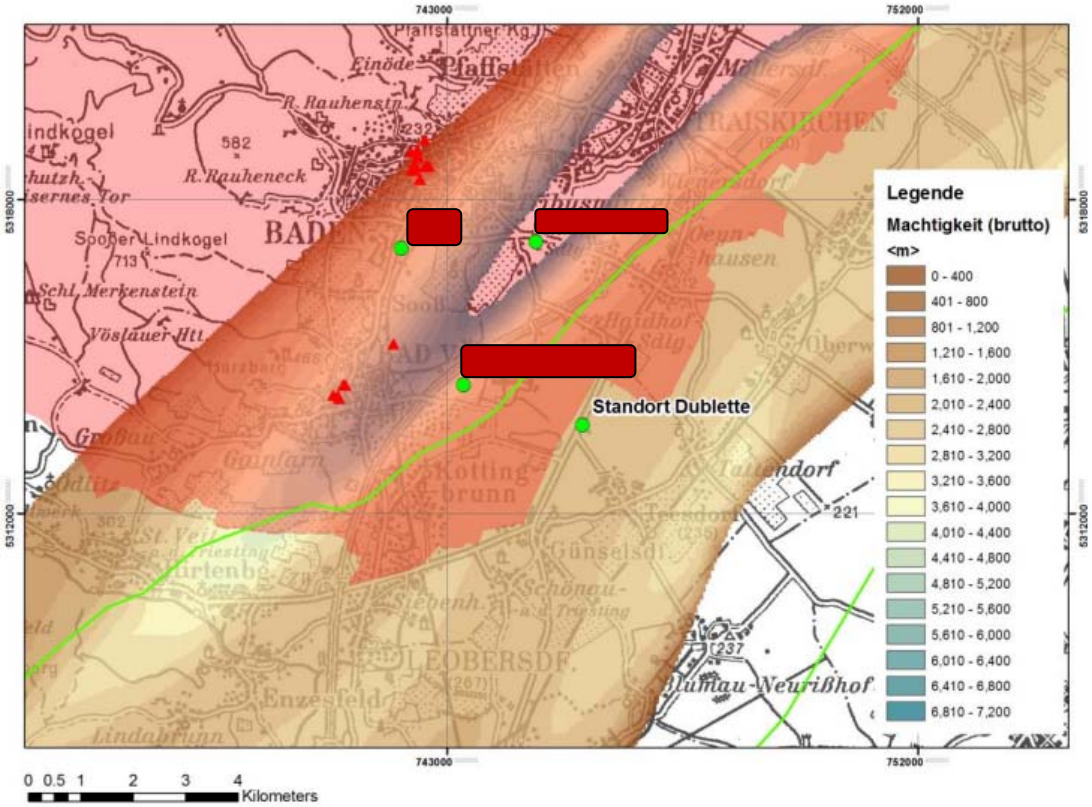

Figure 43: Aggregated thickness of "Dachsteinkalk", "Hauptdolomit" and "Wettersteindolomit" at the site of Baden; Please note: "Mächtigkeit" indicates thickness of rock layers (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.20)

The red area indicates the water protection zone where no geothermal drillings are allowed in order to insure no interference with existing geothermal water use for thermal spa at Baden. The prospective drilling site for a deep geothermal heat plant (green dot "Standort Dublette") is located close to prospective commercial heat consumers: sites of a district heat providing energy utility company and a prospective industrial heat consumer.

At the point of drilling ("Standort Dublette") the aggregated thickness of the potentially water containing rock layers ("Dachsteinkalk", "Hauptdolomit", "Wettersteindolomit") is expected in the range of 2,010 – 2,400 m and marked in light brown in the figure above.

The expected flow rate (l/sec) of a geothermal reservoir depends to a great degree on the thickness of the water containing rock layers. At the prospective drilling site (green dot "Standort Dublette" in the figure above) the aggregated thickness of the potentially water containing rock layers is supposed to provide sufficient productivity of the geothermal fluid, i.e. l/sec flow of thermal water in a specified depth below

surface. The prospective drilling site was chosen since it is located near prospective heat consumers and the estimated productivity of the geothermal resource is supposed to be sufficient at the selected site. Alternatively other prospective drilling sites in the area may provide as well sufficient productivity, yet the distance to prospective heat consumers is longer which would imply additional costs for pipes carrying the geothermal fluid to the point needed (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.20).

To summarize it is expected that the three potentially water containing rock layers ("Dachsteinkalk", "Hauptdolomit", "Wettersteindolomit") are located in a depth of 3,091 – 5,548 m with an estimated aggregated thickness of 2,010 – 2,400 m. Thickness of the rock layers is a key parameter to assess the flow rate of the hydrothermal reservoir which is discussed in the following chapter:

7.3.2 Flow rate: is the quantity of the water (l/sec) sufficient?

In order to estimate the flow rate of a hydrothermal reservoir (l/sec upstream of hot thermal waters) the hydraulic conductivity and thickness of potentially water containing rock layers need to be estimated. Then the transmissivity (m^2/sec flow of water) can be calculated (hydraulic conductivity x thickness of the reservoir). Hydraulic conductivity depends on the hydraulic permeability of the rock formation (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.25).

7.3.3 Temperature: does the water actually have the expected temperature?

In order to predict the temperature of the geothermal fluid three questions are essential (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.21):

- For which rock formations do actual temperature data exist? (which means that the temperature level of certain rock formations are known for sure due to measurement results of existing drillings)
- For which rock formations temperature estimations need to be derived on the basis of existing data? (which means that on the basis of existing drillings temperatures need to be modeled for rock formations where no drillings

exist. Whether modeled temperatures of rock formations are correct can only be known for sure if drillings are undertaken at that specific site)

- Prognostic validity: how is it possible to quantify the probability that modeled temperatures of rock formations are correct?

Proven rock temperatures (i.e. temperatures measurements at existing drillings) in the area of Baden lay around 100°C. Yet, available data are mainly from existing drillings that are located in a distance of 15-20 km from the prospective drilling site of the geothermal heat plant. In a radius of 5 km from the prospective drilling site only a very limited number of actual temperature measurements exist. Thus the modeling of temperature levels of the various rock formations implies a certain degree of uncertainty (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.21). Existing data of temperature measurements in the area of Baden are depicted in the figure below:

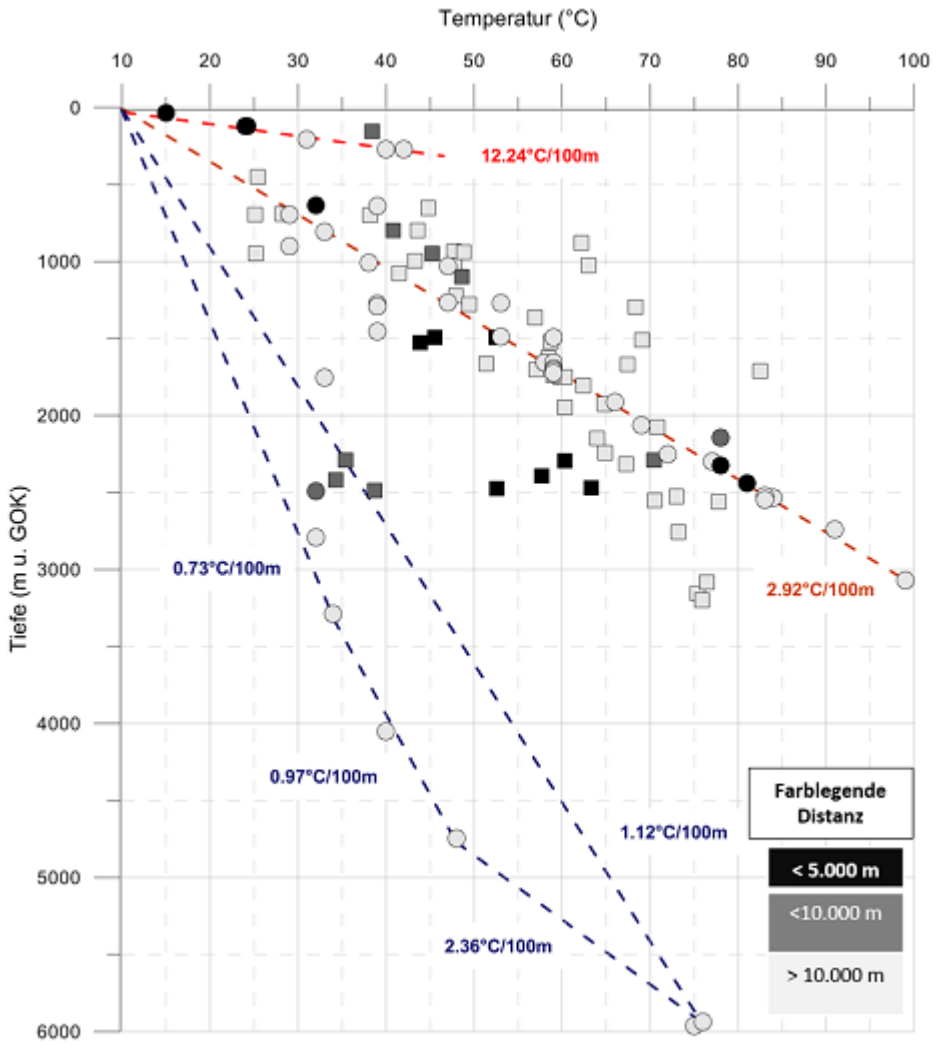

Figure 44: Existing temperature measurements of rock formations in the surroundings of the prospective drilling site at Baden (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p. 22)

Black dots indicate temperature measurements in a distance of < 5,000 m to the specific drilling site, dark gray dots indicate temperature measurements in a distance of < 10,000 m and light gray dots > 10,000 m. Actual measured temperatures range from very shallow depths to 6 km below surface. The highest proven temperature is 100°C at a depth of 3 km (light gray dot at the right hand side of the figure above).

As shown in the figure above three different geothermal conditions are calculated on the basis of available data (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.22-23):

a) Geothermal gradient of 1.12°C/100m:
   This very low geothermal gradient is due to an inflow of cold waters.

b) Geothermal gradient of 2.92°C/100m:
   No inflow of cold waters. This geothermal gradient is close the worldwide average of 3°C/100m.

c) Geothermal gradient of 12.24°C/100m: upstream of thermal waters in shallow depths only. It can be said with certainty that such a high geothermal gradient can be found in the area of Baden only in very shallow depths of 0-300 m below surface with a maximum temperature of < 50°C. This temperature level is far too low to be considered for a deep geothermal heat plant.

In general it can be said that it is to assume that temperature levels of the various rock formations vary a lot at the area of Baden. On the basis of available data the temperature levels were calculated with a numeric model which is based on the geological 3D model that considers regional geological anomalies and the inflow of cold waters as described above. Since too few actual temperature measurements exist in the closer distance to the prospective drilling site the validity of the estimated temperature levels is unclear. It is estimated that temperatures of the geothermal reservoirs at the prospective drilling site may range between 100°C to a maximum of 170°C. According to the geological model the following temperatures are to expect for the three main reservoirs (GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.23):

- Dachsteinkalk: 100°C –129°C
- Hauptdolomit: 129°C – 146°C
- Wettersteindolomit: 151°C – 172°C

Figures below show the modelled temperatures for the rock layers “Dachsteinkalk”, „Hauptdolomit“ and „Wettersteindolomit“:

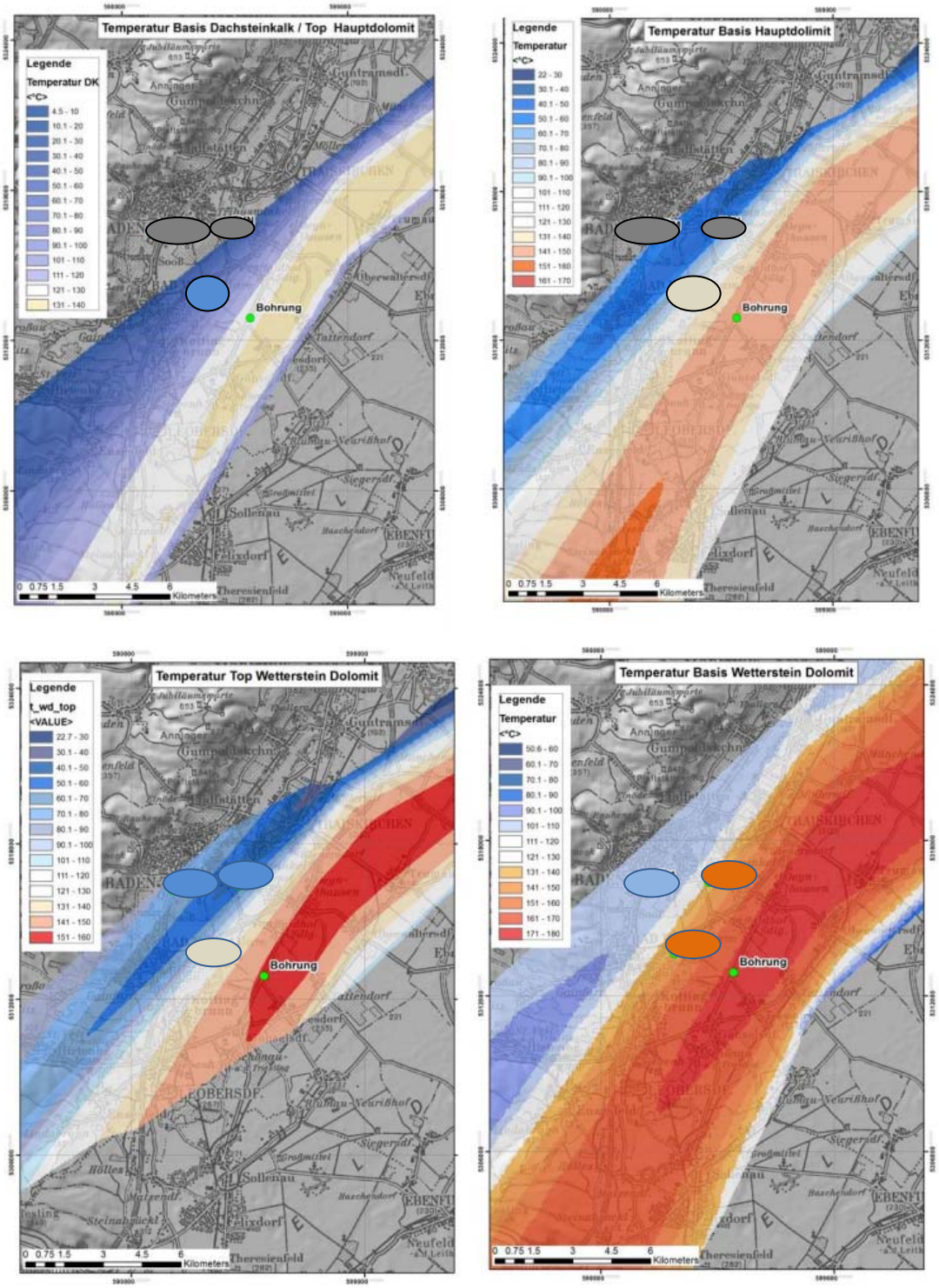

Figure 45: Modeled temperatures for rock layers "Dachsteinkalk", „Hauptdolomit" and „Wettersteindolomit" at Baden with a temperature gradient of 2.9°C/100m (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p. 24)

7.3.4 Summary of the valuation of geothermal reservoirs at the site of Baden

At the prospective drilling site at Baden three rock layers were identified that potentially contain hot thermal waters (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.31): "Dachsteinkalk", "Hauptdolomit "and "Wetterstein Dolomit". The summary of the valuation of these three geothermal reservoirs at Baden is shown in the table below:

Table 10: Summary of the valuation of the three reservoirs at Baden (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p. 31)

Reservoir	Depth	Expected temperature range	Productivity
Dachsteinkalk	**medium drilling costs** **3,091 - 4,011 m**	**not sufficient** **100°C - 129°C**	**probability of success: 30%**
Hauptdolomit	**medium drilling costs** **4,011 - 4,663 m**	**probability of success: 45%** **129°C - 146°C**	**probability of success: 60%**
Wetterstein Dolomit	**high drilling costs** **4,843 - 5,548 m**	**probability of success: 69%** **151°C - 172°C**	**probability of success: 70%**

Rock layer "Hauptdolomit" is seen as the primary target for deep geothermal exploration because it is expected that the three critical parameters for deep geothermal energy production are more promising than in the other two rock layers:

1.) Expected depth is 4,011 – 4,664 m and thus drilling costs are lower than for "Wetterstein Dolomit" which is located in greater depth
2.) Temperature of hot thermal waters is estimated in the range of 129°C – 146°C and thus sufficient for energy production. Yet, probability that the temperature range is correct is only estimated with 45%.
3.) The quantity of hot thermal waters is estimated to be sufficient with a probability of 60%.

Temperature level (°C of hot thermal waters) and quantity (flow of water in l/sec) determine the amount of extractable energy and thus the amount of energy (MWh_{th}) that can be produced. Drilling costs increase overproportionally per km depth and are thus a limiting factor: even if high productivity reservoirs with high thermal water temperatures exist in a certain depth (e.g. 5,000 m) drilling costs might be too high to extract the energy economically.

“Wetterstein Dolomit” is expected to have higher temperature and productivity, yet it is located in greater depth (4,843 – 5,548 m) and thus drilling costs might be too high. If drillings are undertaken to find hot thermal waters in the rock layer “Hauptdolomit” (4,011 – 4,664 m) and no hot thermal waters will be found, it might be an option to continue drillings and to search for the hot thermal waters at the underneath located rock layer “Wetterstein Dolomit”.

7.4 Cost calculation for a geothermal heat plant

7.4.1 Schematic depiction of main parameters of a geothermal heat plant

A schematic depiction including main parameters used for cost calculation of a prospective heat plant at the site of Baden is shown in the figure below:

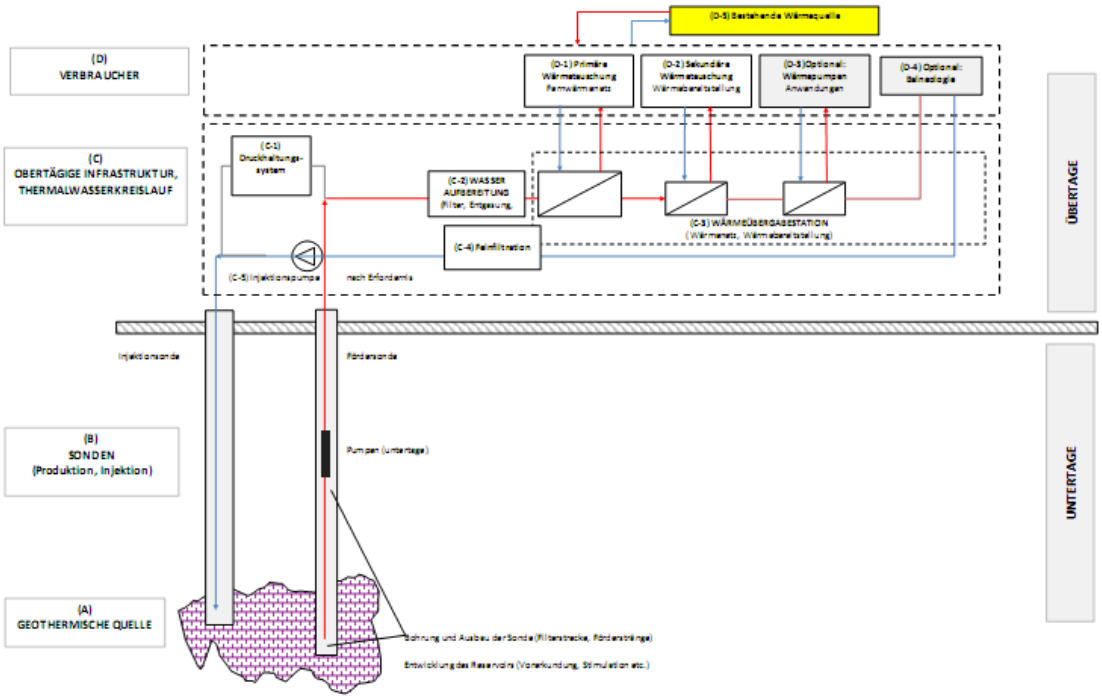

Figure 46: Depiction of main parameters of a deep geothermal heat plant at Baden (Source: GeoHEAT 2013, Götzl and Niederbrucker, p. 6)

Derived from the main parameters of the geothermal heat plant prospective costs were assessed:

7.4.2 Investment costs and capital expenditure (CAPEX) and operational costs (OPEX)

Based on the results of GeoHEAT and the schematic depiction of the main parameters of a geothermal heat plant as shown above I have calculated the cost parameters for this master thesis. The relevant cost parameters for capital expenditure (CAPEX) and operational expenditures (OPEX) for a deep geothermal plant at the specific site of Baden are summarized in the table below:

Table 11: CAPEX for a prospective geothermal heat plant at Baden (Source: figures taken from GeoHEAT with modified drilling costs)

CAPEX (EUR)

			Lifetime
17'676'000	Drillings (Dublet)		30 years
700'000	Project costs, testing		
205'000	Pump		8 years
120'000	Control system pump		15 years
185'000	Filter		25 years
150'000	Building		50 years
1'121'000	Heat transfer station:		
	345'000	Auskoppeleinheiten	Unknown
	376'000	Heat exchanger	15 years
	100'000	Hydraulic connection, Bad Vöslau	15 years
	100'000	Hydraulic connection, Baden	15 years
	200'000	Connection devices	20 years
	1'121'000		
1'488'000	Pipe 1		40 years
1'019'000	Pipe 2		40 years
22'664'000			

Table 12: OPEX for a prospective geothermal heat plant at Baden (Source: figures taken from GeoHEAT with modified drilling costs)

OPEX (EUR)

		Assumptions:
88'380	Maintenance drillings	(0.5% of drilling costs p.a.)
149'000	Electricity for pump	
	Maintenance:	
2'775	Filter	(1.5% of investment costs p.a.)
37'600	Heat exchanger	(10% of investment costs p.a.)
10'000	Hydraulic connection B.Vöslau	(10% of investment costs p.a.)
10'000	Hydraulic connection Baden	(10% of investment costs p.a.)
3'000	Connection devices	(1.5% of investment costs p.a.)
14'880	Pipe 1	(1% of investment costs p.a.)
10'190	Pipe 2	(1% of investment costs p.a.)
50'000	Staff	
375'825		

The main part of the costs for a deep geothermal plant is drilling costs. Drilling costs depend mainly on drilling depth and increase exponentially per km depth:

7.4.3 Estimation of drilling costs per km depth

The best scientific method to estimate costs for a deep geothermal drilling is to ask a drilling company to do a cost calculation for a specific drilling site. To be precise the best method is to get different drilling offers from several companies in order to compare projected drilling costs. Since this is considerable unpaid work for drilling companies this is not possible in a research project.

Thus for GeoHEAT a study of average drilling costs in Germany and the USA was taken (Legarth 2003) as an first approximation for specific drilling costs at the site of Baden:

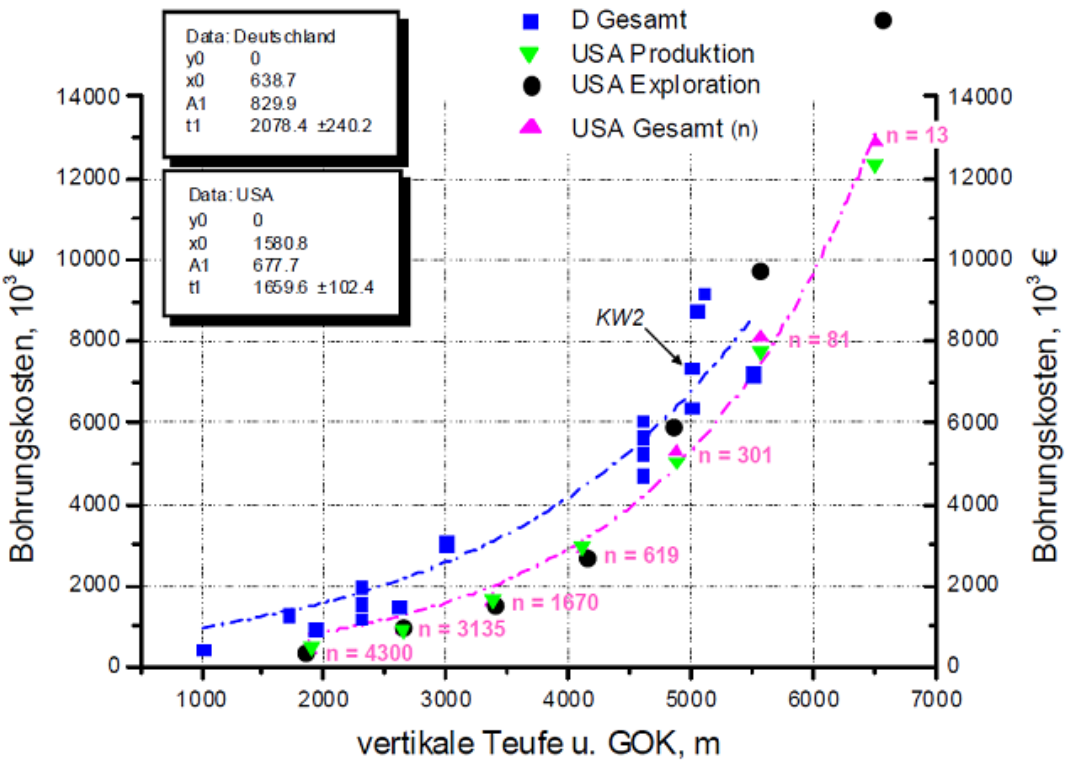

Figure 47: exponential increase of drilling costs per km depth (Source: Legarth 2003, taken from GeoHEAT 2014, Götzl, Saurer and Niederbrucker, p. 12)

The blue curve shows average costs for deep geothermal drillings in Germany: for a 3000 m deep drilling costs were on average about 3 million EUR, whereas for a 5000 m deep borehole costs were about 7 million EUR.

The pink curve shows average drilling costs in the US, they are lower than in Europe which is due to a higher number of drilling companies in the US. Furthermore drilling costs are volatile since they depend on the demand of oil and gas drillings and, which is especially true for Europe, there is only a limited number of drilling companies that are able to drill boreholes deeper than 2.000 m (GeoHEAT 2014, Götzl, Saurer and Niederbrucker, p. 11-12).

In order to estimate drilling costs for the specific site at Baden in addition to the above shown exponential prognosis function a second study was available that indicates that drilling costs increase sharply at different depth levels (GeoHEAT 2014, Götzl, Saurer and Niederbrucker, p. 12-13):

Table 13: Prognosis of drilling costs (Million EUR / 100 m); Source: GeoHEAT 2014, Götzl, Saurer and Niederbrucker, p. 13

Tiefenintervall (m u. GOK)	Spez. Kostenzunahme (Mill. EUR / 100 Meter)	Sockelwert (Mill. EUR)
0 bis 100*	0.0045	0
100 bis 3,500	0.167	0.14
3,500 – 4,000	0.34	0.14
4,000 – 4,500	0.44	0.14
4,500 – 5,000	0.54	0.14
Ab 5,000	0.6	0.14

* Sonden oberflächennaher Geothermischer Nutzungen

To identify a prognosis function for drilling costs at Baden both above described studies were used and compared to drilling costs of two current deep geothermal drilling projects in Austria (*Ried im Innkreis* and *Wien Aspern*):

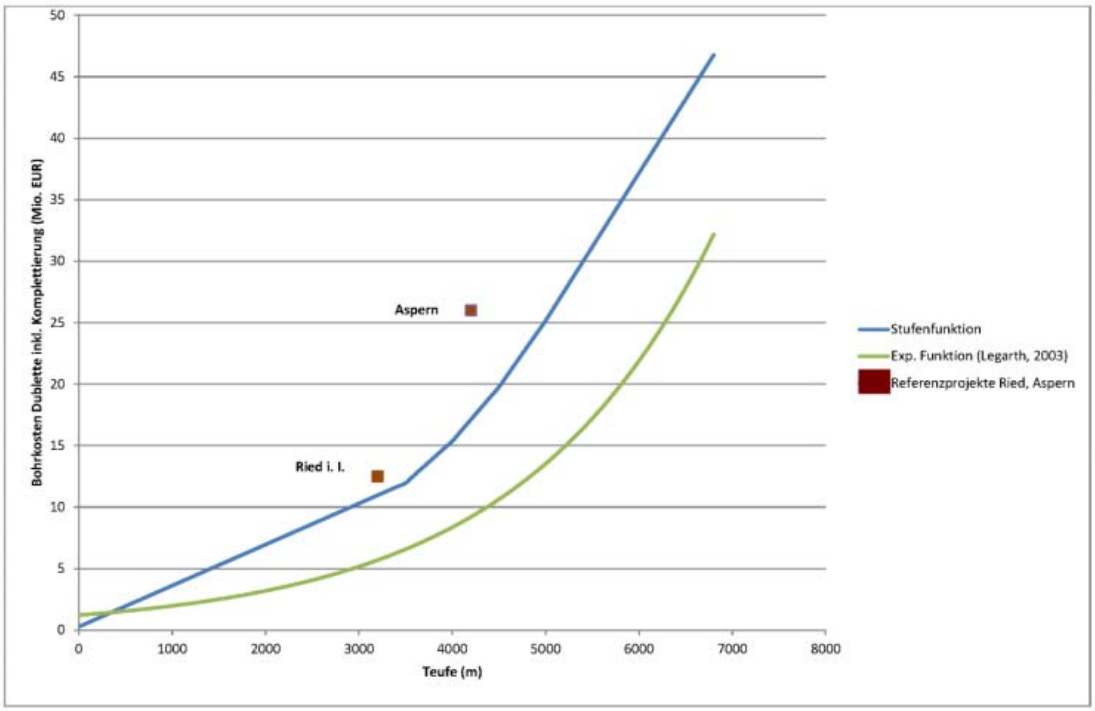

Figure 48: Comparison of Prognosis functions of drilling costs and actual drilling costs of two current deep drilling projects in Austria – *Ried im Innkreis* and *Wien Aspern*[22] (Source: GeoHEAT 2014, Götzl, Saurer and Niederbrucker, p.13)

[22] Please note: drilling costs for *Ried im Innkreis* and *Wien Aspern* were taken from media reports and represent rough approximations.

In the figure above drilling costs for a dublette are shown (2 boreholes: one production and one reinjection drilling). For example at *Wien Aspern* drilling costs for the first borehole (depth 4.000-5.000 m) was approximately 13 million euro. The green curve indicates average drilling costs in Europe and is taken from Legarth 2003 and the blue curve shows the prognosis of drilling costs (million Euro / 100m) as described above.

Both, the blue and green curves, indicate average drilling costs and represent thus a rough approximation to estimate site specific drilling costs for a newly planned geothermal plant. As actual drilling costs for *Ried im Innkreis* and *Wien Aspern* indicates actual drilling costs may be higher and always depend on site specific geological conditions. It may also happen that drilling costs are lower than indicated by the blue and green curve.

For a precise estimation of drilling costs it would need to ask drilling companies for site specific offers for drilling cost calculations – which is hardly possible in a scientific research project. Thus it was assumed that a combination of the prognosis function representing average drilling costs (blue curve in figure above) and actual drilling costs at *Ried im Innkreis* and *Wien Aspern* are the best method available to estimate site specific drilling costs at Baden.

For reasons of investment security the study from Table 13 with higher average drilling costs (blue curve in Figure 48) is taken to calculate specific drilling costs for this work:

Drilling depth: 4.300 m

Table 14: Cost calculation for a 4.300 m deep drilling at Baden (Source: Walter Saurer, own calculation based on GeoHEAT)

Drilling depth	Marginal drilling costs (Mill. EUR / 100 m)	Cumulative costs (Mill. EUR)
0-100 m	0.140	0.140
100-3500 m	0.167	5.678
3500-4000 m	0.340	1.700
4000-4300 m	0.440	1.320
Total costs for 1 borehole: (production drilling)		**8.838**
Total costs for 2 boreholes: (production drilling + reinjection drilling)		**17.676**

Thus for this work drilling costs were assumed with 17,676,000 EUR. For the risk of non-discovery only the first drilling is relevant: 8,838,000 EUR.

Please note: if the production drilling proves to be successful (i.e. hot water is found in sufficient quantity and temperature) there is no risk of non-discovery for the reinjection borehole. The only risk that remains is a negative impact on ground-water level (probability of less than 1%, yet this would lead to a complete loss of investment since the whole project needs to be stopped then) and during the operation phase an inflow of cold water from the reinjection well may occur. This can be prevented if the distance between production and reinjection well is properly calculated.

7.5 Risk of non-discovery: calculation of expected distribution of generation costs

Since “Hauptdolomit” has proven to be the most promising rock layer at the site of Baden – according to geological research in the GeoHEAT project – I have chosen

"Hauptdolomit" for a calculation of expected generation costs under consideration of the risk of non-discovery of the hydrothermal resource.

7.5.1 Rock layer Hauptdolomit

The geological cross-section of Baden is depicted in the figure below indicating the potentially water containing rock layers Dachsteinkalk, Hauptdolomit and Wettersteindolomit:

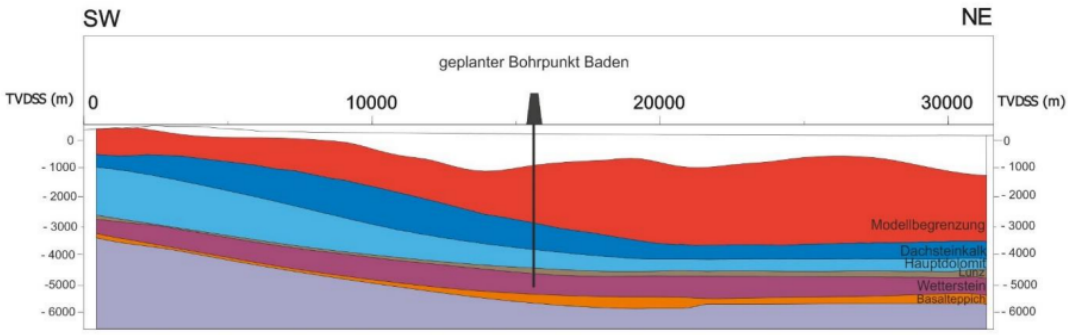

Figure 49: Geological cross-section at the site of Baden (AP3_Detailbericht1 p.18) (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.18)

At the prospective point of drilling (black arrow in the figure above) the three water containing rock layers are expected at following depths (GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.18):

- Dachsteinkalk (dark blue): 3,091 – 4,011 m
- Hauptdolomit (light blue): 4,011 – 4,663 m
- Wettersteindolomit (purple): 4,843 – 5,548 m

Rock layer "Hauptdolomit is expected in a depth of 4,011 – 4,663 m and as shown in the chapter above it is the most promising rock layer for discovery of the hydrothermal resource.

7.5.2 Calculation of prospective distribution of flow of water for rock layer Hauptdolomit at Baden

For the rock layer "Hauptdolomit" (in a depth of 4300m) I will calculate the power of the geothermal well and the extractable energy. The aim is to get a distribution of potential capacities in MW_{th}. Thus values for flow of water and expected water

temperatures are needed. In a first step I will calculate the distribution for the expected values for flow of water (l/s) from existing data for transmissivity (m^2/s) of the rock layer "Hauptdolomit" from GeoHEAT:

Table 15: Transmissivity of the rock layer „Hauptdolomit" at Baden (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.29)

Percentiles [%]	Transmissivity [m²/s]
P10	1.04E-05
P20	2.47E-05
P30	8.54E-05
P40	1.51E-04
P50	3.04E-04
P60	5.09E-04
P70	6.91E-04
P80	1.15E-03
P90	3.71E-03

Data for transmissivity in the table above are given in percentiles. That means e.g. for P10 that with a probability of 10% transmissivity is ≤ 0.0000104 m^2/s (=1.04E-05 m^2/s). For P20 transmissivity is with a probability of 20% ≤ 0.0000247 m^2/s (= 2.47E-05 m^2/s) and so on. The median value (P50) is marked yellow and shows that with 50% probability transmissivity is 0.0003044 m^2/s (=3.04E-04 m^2/s). With given transmissivity I have calculated the expected distribution for the flow of water (l/s) for rock layer "Hauptdolomit" at Baden:

Table 16: Calculation of flow of water (l/s) for rock layer Hauptdolomit at Baden (Source: calculation with Gregor Götzl, head of geothermal at Geological Survey of Austria, expert interview 1.9.2017)

Percentiles [%]	Transmissivity [m²/s]	u(r,t)	W(u)	Flow water [m³/s]	Flow water [l/s]
P10	1.04E-05	2.02E-06	1.25E+01	5.21E-03	**5**
P20	2.47E-05	8.51E-07	1.34E+01	1.16E-02	**12**
P30	8.54E-05	2.46E-07	1.46E+01	3.67E-02	**37**
P40	1.51E-04	1.39E-07	1.52E+01	6.23E-02	**62**
P50	3.04E-04	6.91E-08	1.59E+01	1.20E-01	**120**
P60	5.09E-04	4.13E-08	1.64E+01	1.95E-01	**195**
P70	6.91E-04	3.04E-08	1.67E+01	2.59E-01	**259**
P80	1.15E-03	1.83E-08	1.72E+01	4.19E-01	**419**
P90	3.71E-03	5.67E-09	1.84E+01	1.27E+00	**1266**

Used formulas:

u (t,r) = r2 / (4·t·T)

W(u) = -0.5772 - ln(u) + u(t,r)

Q = (4d·π·T) / W(u)

Q...flow water [m^3/s]

Flow water [l/s] = Q · 1000

Constant parameters:

d = 500 m (drop of water level in drilling)

r = 0.5 m (distance to well)

t = 30 years = 946080000 seconds (time period of water extraction)

Please note: t is calculated in seconds according to SI standards.

7.5.3 Input parameters for calculation of distributions of prospective capacities in MW_{th}

In order to calculate the power (P_{geo}) of a geothermal well, i.e. the capacity in MW_{th}, the flow of water Q (l/s) and the temperature of the water T_{geo} (°C) is needed:[23]

$$P_{geo} = \left(T_{geo,VL} - T_{geo,RL}\right) \cdot Q \cdot \langle cp \cdot \rho \rangle_{geo}$$

P_{geo} ... Power (MWth)

$T_{geo,VL}$ ... Temperature of the geothermal fluid in the production well before heat extraction

$T_{geo,RL}$ ... Reinjection Temperature of the geothermal fluid after heat extraction

Q … flow of water (l/s)

$(cp \cdot \rho)_{geo}$ = 4.180.000 J/m³/K

J … Joule

K … Kelvin

[23] Formula taken from GeoHEAT 2014, “Aufbau geologischer 3D-Modelle”, p.15.

The distribution of expected water temperature can be calculated with expected geothermal gradients for Baden from GeoHEAT. Geothermal gradients indicate temperature increase per km depth at the specific site and are derived from nearby temperature measurements from geological research. Since a variety of temperature measurements are used (nearby for shallow geothermal and old gas and oil exploration drillings in a distance of several kilometers) the geothermal gradient for the specific drilling site was estimated on the basis of existing data and is given in percentiles (distribution of prospective temperature gradients):

Table 17: Geothermal gradients for Baden (Source: GeoHEAT 2014, "Aufbau geologischer 3D-Modelle", p.25)

Percentile	$Gradient_{geo}$ [°C/100m]
P10	1.09
P20	1.992
P30	2.202
P40	2.542
P50	2.844
P60	2.895
P70	2.909
P80	2.926
P90	3.748

Given the values for the geothermal gradient and water flow I will calculate three distributions of prospective capacities (MW_{th}). The distributions of capacities are calculated with P10-P90 for temperature gradients and for flow of water I have chosen P50, P40 and P20. This will finally result in three distributions of generation costs:

1.) Distribution of expected generation costs with P50 for flow of water = 120 l/s = 50% probability for flow of water

2.) Distribution of expected generation costs with P40 for flow of water = 62 l/s = 60% probability for flow of water

3.) Distribution of expected generation costs with P20 for flow of water = 12 l/s = 80% probability for flow of water

7.5.4 Distribution of expected generation costs

7.5.4.1 Distribution of expected generation costs with P50 for flow of water = 120 l/s (=50% probability for flow of water)

In the table below I have calculated the distribution of expected capacities P_{geo} [MW_{th}] with P50 for flow of water (Q = 120 l/s):

With:

P[%] … Percentiles

$Gradient_{geo}$ … geothermal Gradient

Drilling depth … rock layer Hauptdolomit = 4300 m

T_0 ... surficial temperature = 10°C

$T_{geo,VL}$ ... Temperature of the geothermal fluid before heat extraction

$T_{geo,RL}$ ... Temperature of the geothermal fluid after heat extraction

Q … flow rate of water (l/s)

Table 18: Percentiles with expected distribution of prospective capacities (MWth) for „Hauptdolomit“ at Baden with flow P50 = 120 l/s (source: Walter Saurer, own calculation)

P50 = 120 l/s

P [%]	$Gradient_{geo}$ [°C/100m]	drilling depth [m]	T_0 [°C]	$T_{geo,VL}$ [°C]	$T_{geo,RL}$ [°C]	Q (l/s)	cp·p [J/m³/K]	P_{geo} [MW_{th}]
P10	1.09	4300	10	57	60	120	4180000	-2
P20	1.992	4300	10	96	60	120	4180000	18
P30	2.202	4300	10	105	60	120	4180000	22
P40	2.542	4300	10	119	60	120	4180000	30
P50	2.844	4300	10	132	60	120	4180000	36
P60	2.895	4300	10	134	60	120	4180000	37
P70	2.909	4300	10	135	60	120	4180000	38
P80	2.926	4300	10	136	60	120	4180000	38
P90	3.748	4300	10	171	60	120	4180000	56

With a given flow of water of P50 with 120 l/s (50% probability) the following distribution of capacities is expected according to temperature percentiles:

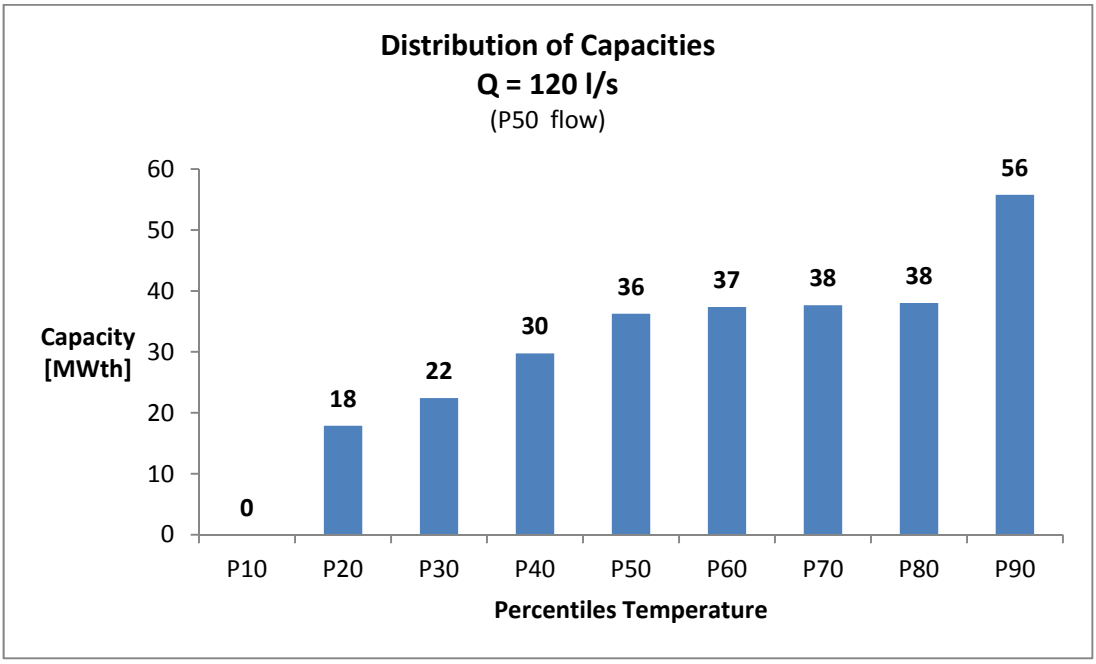

Figure 50: Distribution of prospective Capacities in MWth (P50 flow: Q = 120 l/s, Percentiles for temperature gradient 10-90), (Source: Walter Saurer, own calculation)

With a probability of 80% for temperature gradient (P20) installed capacity is at least 18 MWth, under the assumption of 120 l/s flow of water (50% probability). According to temperature percentiles installed capacity ranges between 0 to 56 MWth depending on expected temperature of the water. With the given range of 0-56 MWth I have calculated the distribution of generation costs with following parameters:

Table 19: Parameters for the calculation of generation costs (Net present value method) for 0-56 MWth with flow P50 (120 l/s). Source: own calculation based on figures taken from GeoHEAT

Variable Parameter:		
installed capacity	0-56	MWth
Fixed parameters:		
investment horizon	30	years
interest rate (WACC)	6%	
full load hours	7884	h/year
investment costs	22'664'000	EUR
operating costs (O&M)	375'825	EUR/year
prospective sales price	36	EUR/MWh

This results in the following distribution of generation costs with water flow of 120 l/s (P50) and temperature Percentiles P10-P90:

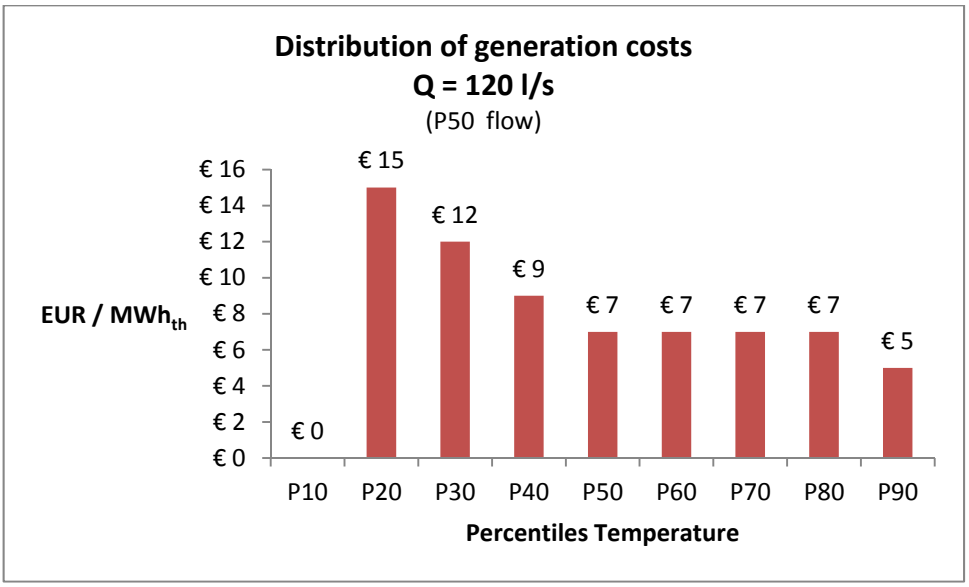

Figure 51: Distribution of generation costs for Q = 120 l/s (P50 flow). Source: Walter Saurer, own calculation.

Expected generation costs range from 5-15 EUR / MWh_{th} under the assumption of a flow of water of 120 l/s flow (P50). The probability that the flow of water actually reaches 120 l/s is 50%. Temperature of the water in a depth of 4300 m is expected between 57°C and 171°C according to the distribution of estimated temperature gradients (P10-P90). Thus the distribution of generation costs ranges between 5-15 EUR / MWh_{th}. For example, for P20 of the temperature gradient the probability that generation costs are less or equal to 15 EUR / MWh_{th} is 80%, given a 50% probability of a flow of water of 120 l/s. This reflects the uncertainty of discovery of the hydrothermal resource.

From a technical point of view this is an optimistic case since a flow of water of 120 l/s is a comparatively high value for flow of water and the expected temperature value needs to exceed 100°C. From a financial point of view this is highly profitable with a given sales price of at least 36 EUR / MWh_{th}.

7.5.4.2 Distribution of expected generation costs with P40 for flow of water = 62 l/s (= 60% probability for flow of water)

In analogy to the above described calculation I have calculated the distribution of expected capacities P_{geo} [MW_{th}] with P40 for flow of water (Q = 62 l/s):

With:

P[%] … Percentiles

$Gradient_{geo}$ … geothermal Gradient

Drilling depth … rock layer Hauptdolomit = 4300 m

T_0 ... surficial temperature = 10°C

$T_{geo,VL}$ ... Temperature of the geothermal fluid before heat extraction

$T_{geo,RL}$ ... Temperature of the geothermal fluid after heat extraction

Q … flow rate of water (l/s)

Table 20: Percentiles with expected distribution of prospective capacities (MWth) for „Hauptdolomit“ at Baden with flow P40 = 62 l/s (Source: Walter Saurer, own calculation)

P40 = 62 l/s

P [%]	$Gradient_{geo}$ [°C/100m]	drilling depth [m]	T_0 [°C]	$T_{geo,VL}$ [°C]	$T_{geo,RL}$ [°C]	Q (l/s)	cp·p [J/m³/K]	P_{geo} [MW_{th}]
P10	1.09	4300	10	57	60	62	4180000	-1
P20	1.992	4300	10	96	60	62	4180000	9
P30	2.202	4300	10	105	60	62	4180000	12
P40	2.542	4300	10	119	60	62	4180000	15
P50	2.844	4300	10	132	60	62	4180000	19
P60	2.895	4300	10	134	60	62	4180000	19
P70	2.909	4300	10	135	60	62	4180000	19
P80	2.926	4300	10	136	60	62	4180000	20
P90	3.748	4300	10	171	60	62	4180000	29

With a given flow of water of P40 with 62 l/s (60% probability) the following distribution of capacities is expected according to temperature percentiles:

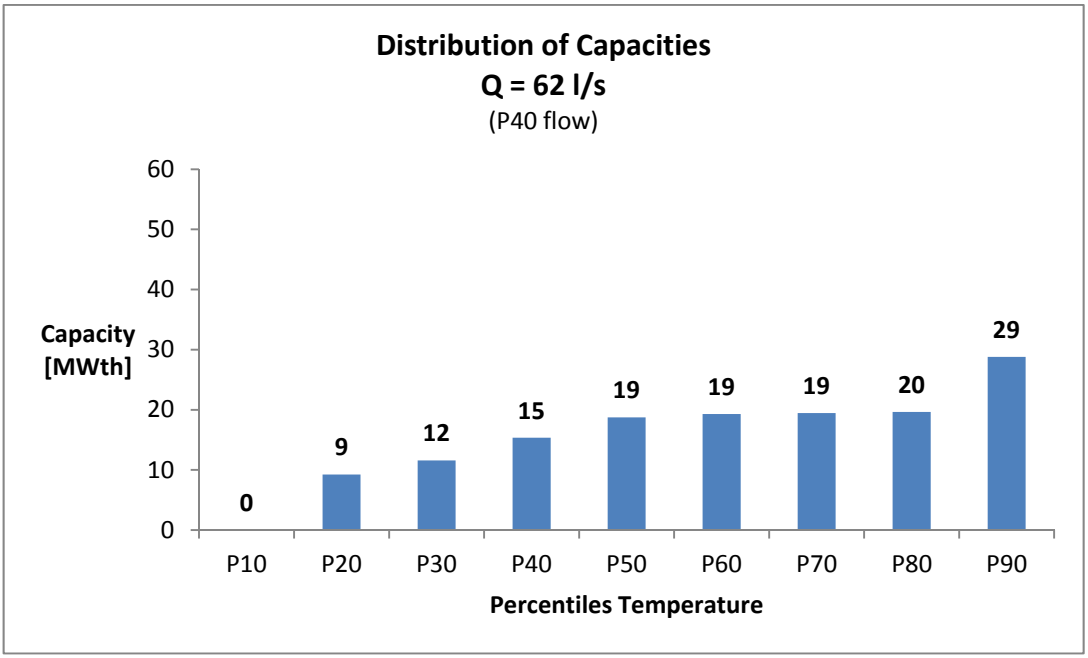

Figure 52: Distribution of prospective Capacities in MWth (P40 flow: Q = 62 l/s, Percentiles for temperature gradient 10-90), (Source: Walter Saurer, own calculation)

With a probability of 80% for temperature gradient (P20) installed capacity is at least 9 MWth, under the assumption of 62 l/s flow of water (60% probability). According to temperature percentiles installed capacity ranges between 0 to 29 MWth depending on expected temperature of the water. With the given range of 0-29 MWth I have calculated the distribution of generation costs with following parameters:

Table 21: Parameters for the calculation of generation costs (Net present value method) for 0-29 MWth with flow P40 (62 l/s). Source: own calculation based on figures taken from GeoHEAT

Variable Parameter:		
installed capacity	0-29	MWth
Fixed parameters:		
investment horizon	30	years
interest rate (WACC)	6%	
full load hours	7884	h/year
investment costs	22'664'000	EUR
operating costs (O&M)	375'825	EUR/year
prospective sales price	36	EUR/MWh

This results in the following distribution of generation costs with water flow of 62 l/s (P40) and temperature Percentiles P10-P90:

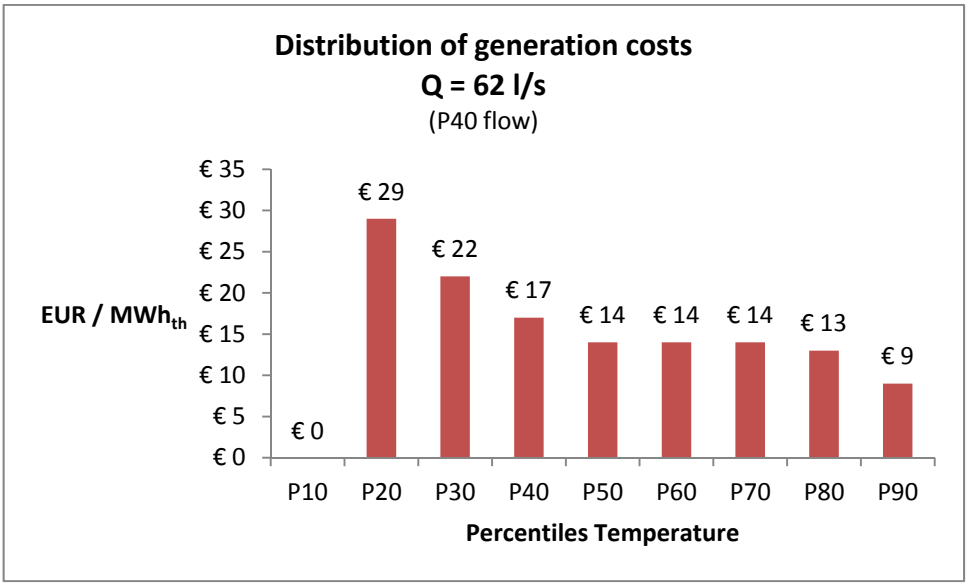

Figure 53: Distribution of generation costs for Q = 62 l/s (P40 flow). Source: Walter Saurer, own calculation.

Expected generation costs range from 9-29 EUR / MWh$_{th}$ under the assumption of a flow of water of 62 l/s flow (P40). The probability that the flow of water actually reaches 62 l/s or more is 60%. Temperature of the water in a depth of 4300 m is expected between 57°C and 171°C according to the distribution of estimated temperature gradients (P10-P90). Thus the distribution of generation costs ranges between 9-29 EUR / MWh$_{th}$. For example, for P20 of the temperature gradient the probability that generation costs are less or equal to 29 EUR / MWh$_{th}$ is 80%, given a 60% probability of a flow of water of at least 62 l/s. This reflects the uncertainty of discovery of the hydrothermal resource.

From a technical point of view this is a realistic case since a flow of water of 62 l/s is a comparatively common value for flow of water and the expected temperature value needs to exceed 100°C. From a financial point of view this is profitable to highly profitable with a given sales price of at least 36 EUR / MWh$_{th}$.

7.5.4.3 Distribution of expected generation costs with P20 for flow of water = 12 l/s (= 80% probability for flow of water)

In the table below the distribution of expected capacities P_{geo} [MW$_{th}$] is calculated with P20 for flow of water (Q = 12 l/s):

With:

P[%] … Percentiles

$Gradient_{geo}$ … geothermal Gradient

Drilling depth … rock layer Hauptdolomit = 4300 m

T_0 ... surficial temperature = 10°C

$T_{geo,VL}$ ... Temperature of the geothermal fluid before heat extraction

$T_{geo,RL}$ ... Temperature of the geothermal fluid after heat extraction

Q … flow rate of water (l/s)

Table 22: Percentiles with expected distribution of prospective capacities (MWth) for „Hauptdolomit“ at Baden with flow P20 = 12 l/s (source: Walter Saurer, own calculation)

P20 = 12 l/s

P [%]	$Gradient_{geo}$ [°C/100m]	drilling depth [m]	T_0 [°C]	$T_{geo,VL}$ [°C]	$T_{geo,RL}$ [°C]	Q (l/s)	cp·p [J/m³/K]	P_{geo} [MW_{th}]
P10	1.09	4300	10	57	60	12	4180000	0
P20	1.992	4300	10	96	60	12	4180000	2
P30	2.202	4300	10	105	60	12	4180000	2
P40	2.542	4300	10	119	60	12	4180000	3
P50	2.844	4300	10	132	60	12	4180000	4
P60	2.895	4300	10	134	60	12	4180000	4
P70	2.909	4300	10	135	60	12	4180000	4
P80	2.926	4300	10	136	60	12	4180000	4
P90	3.748	4300	10	171	60	12	4180000	6

With a given flow of water of P20 with 12 l/s (80% probability) the following distribution of capacities is expected according to temperature percentiles:

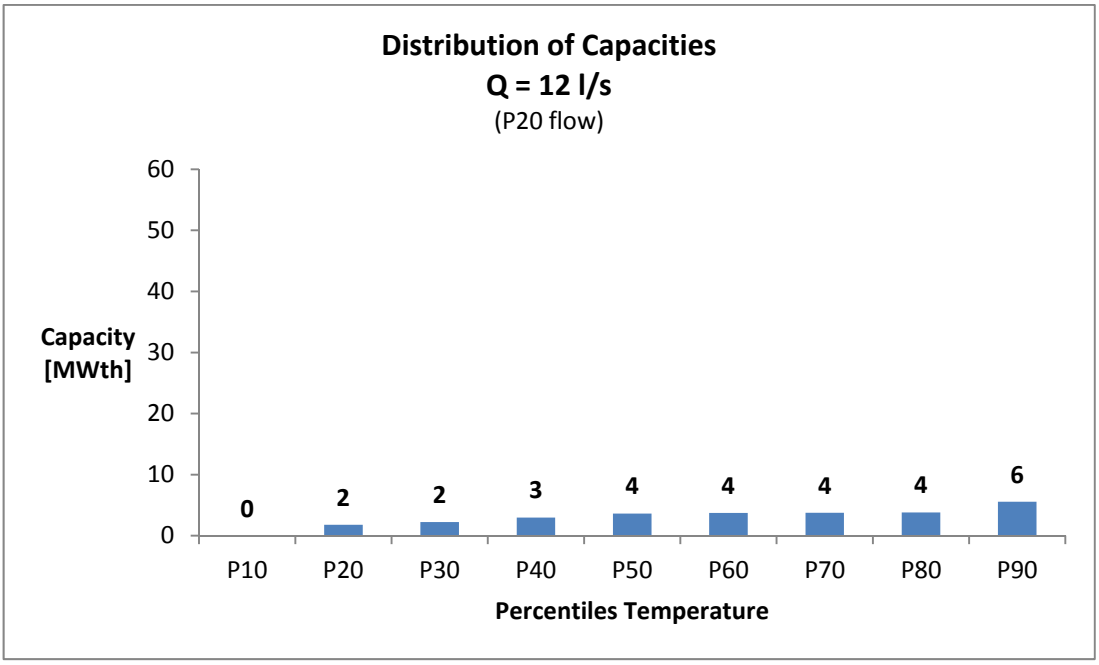

Figure 54: Distribution of prospective Capacities in MWth (P20 flow: Q = 12 l/s, Percentiles for temperature gradient 10-90), (source: Walter Saurer, own calculation)

With a probability of 80% for temperature gradient (P20) installed capacity is at least 2 MWth, under the assumption of 12 l/s flow of water (80% probability). According to temperature percentiles installed capacity ranges between 0 to 6 MWth depending on expected temperature of the water. With the given range of 0-6 MWth I have calculated the distribution of generation costs with following parameters:

Table 23: Parameters for the calculation of generation costs (Net present value method) for 0-6 MWth with flow P20 (12 l/s). Source: own calculation based on figures taken from GeoHEAT

Variable Parameter:		
installed capacity	0-6	MWth
Fixed parameters:		
investment horizon	30	years
interest rate (WACC)	6%	
full load hours	7884	h/year
investment costs	22'664'000	EUR
operating costs (O&M)	375'825	EUR/year
prospective sales price	36	EUR/MWh

This results in the following distribution of generation costs with water flow of 12 l/s (P20) and temperature Percentiles P10-P90:

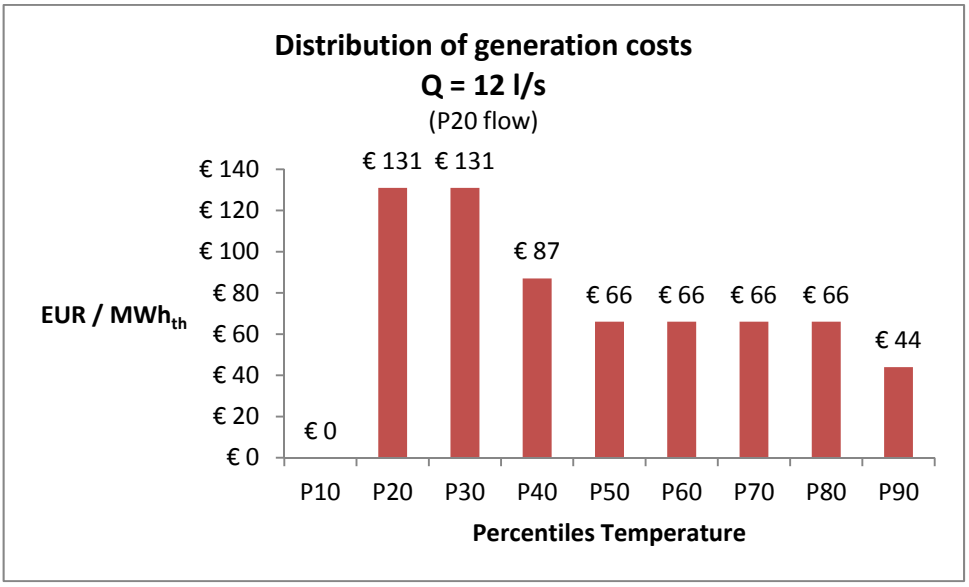

Figure 55: Distribution of generation costs for Q = 12 l/s (P20 flow). Source: Walter Saurer, own calculation.

Expected generation costs range from 44-131 EUR / MWh$_{th}$ under the assumption of a flow of water of 12 l/s flow (P20). The probability that the flow of water actually reaches 12 l/s or more is 80%. Temperature of the water in a depth of 4300 m is expected between 57°C and 171°C according to the distribution of estimated temperature gradients (P10-P90). Thus the distribution of generation costs ranges between 44-131 EUR / MWh$_{th}$. For example, for P20 of the temperature gradient the probability that generation costs are less or equal to 131 EUR / MWh$_{th}$ is 80%, given an 80% probability of a flow of water of at least 62 l/s. This reflects the uncertainty of discovery of the hydrothermal resource.

From a technical point of view this is realistic since for both parameters flow and temperature of water the probability is 80% that flow of water is at least 12 l/s with a minimum temperate of at least 100°C. Yet, it is a pessimistic or very conservative estimation since 80% of geological measured data predict higher values for both temperature and flow of water. Technically, 12 l/s flow is a comparatively low value while water temperature of 100°C or more seems to be realistic if the hydrothermal resource is found. From a financial point of view this reflects the risk of non-discovery. According to an investment decision calculation this is not profitable since the risk is too high that only moderate to low hydrothermal resources are found (i.e. temperatures and flow of water). Given the high investment costs and the risk that only a low amount of extractable energy may be found, costs of extraction clearly exceed a prospective sales price of 36 EUR / MWh$_{th}$.

8 Comparison of results and conclusions

The non-discovery of the hydrothermal resource is the main investment risk for deep geothermal. The core question of this master thesis was how to depict the risk of non-discovery at the investigated site at Baden in an investment decision calculation. Thus I have chosen Percentiles of flow of water and temperature of the hydrothermal resource to calculate expected distributions of installable capacities and respective distributions of generation costs. For P50 (120 l/s), P40 (62 l/s) and P20 (12 l/s) flow rate of water expected generation costs range from 5-15 € / MWh_{th} for P50 (120 l/s = 50% probability), 8-29 € / MWh_{th} for P40 (62 l/s = 60% probability) and 44-131 € / MWh_{th} for P20 (12 l/s = 80% probability). Distributions of generation costs are calculated with Percentiles P10-P90 for temperature gradient and with net present value method. Limit of the method of approach and derived conclusions is the question whether the *Geological Model* correctly reflects expected depth, flow rate and temperature of the hydrothermal resource. Since the Geological Model derived from GeoHeat.at is best available data, it is assumed for this work that indicated depth of rock layers and Percentiles for temperature and flow rate of the hydrothermal resource are correct.

Prospective market sales price is assumed with 36 € / MWh_{th} and thus the site of Baden may be profitable for geothermal heat production. In order to depict the risk of non-discovery in an investment decision calculation it can be either used a higher discount rate (reflecting the risk of non-discovery) or if a risk insurance against non-discovery is possible, this is shown in investment costs (premium for risk insurance). To solve the risk of non-discovery from an economic point of view the investment risk needs to be spread across a given portfolio as it is done in the oil and gas industry *(Portfolio Approach)* which would make it possible to insure individual geothermal drilling project against the risk of non-discovery. Given the geological risk whether the hydrothermal resource is found in sufficient quantity (l/s) and quality (°C) the establishment of an international or *European Geothermal Risk Insurance Fund (EGRIF)* may be able to solve the investment risk of non-discovery. This can facilitate market deployment of deep geothermal energy especially in low and medium enthalpy areas.

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List of Abbreviations

CHP	Combined Heat and Power
DH	District Heating
EJ	Exajoule
GeoDH	Geothermal District Heating
K	Kelvin
ktoe	kilotonne of oil equivalent
LCOE	Levelized cost of electricity/energy
MW_{el}	Megawatt electric
MW_{th}	Megawatt thermal
MWh_{el}	Megawatt hour electric
MWh_{th}	Megawatt hour thermal

List of Tables

List of Figures