Economic analysis of geothermal energy provision in Europe

With its widely spread resources, geothermal energy is a resource which can noteworthy contribute to the future energy provision in Europe. Whereas the direct use of geothermal heat can already compete on the market due to the high oil and gas prices, geothermal electricity generation faces huge financial challenges in most European regions. Besides the use of high enthalpy fields – which are limited to a few places and are in most cases already used - an extended geothermal electricity generation in the future depends especially on the larger potential of low enthalpy or hydro-geothermal resources. These resources are scarcely exploited so far. Apart from technical challenges, economic barriers hinder the wider use of hydro-geothermal energy within Europe. Therefore the power production costs of geothermal low enthalpy fields will be analysed in this paper in order to identify the crucial cost drivers and to point out which measures could result in a widely economic feasible geothermal power production in Europe.

1. Introduction

The political goal to increase the share of green electricity from 14 to 22 % of gross electricity consumption and to double the share of renewable energy from 6 to 12 % of gross energy consumption in Europe by 2010 [1] has to be met by a variety of different measures and instruments. Besides hydropower, biomass and wind energy, also geothermal energy seems to be a promising option due to its large and widely spread potential and its base-load ability.

At the moment deep geothermal resources in Europe are predominantly used for heat provision and/or material use in spas (e.g. geothermal heat provision in the Paris Basin). Such a use of geothermal energy is often economic viable, especially regarding the increasing energy prices.

Geothermal electricity production, in contrast, is so far limited to a few sites in Europe which are mostly characterised by outstanding geological conditions related to high enthalpy fields (*Table 1*). The by far larger potential, geothermal low enthalpy resources, is only used to an almost negligible extent.

Table 1: 2005 installed electrical capacities of geothermal power plants in European countries [2]

	Dry Steam Plants in MW	Flash Plants in MW	Binary Plants in MW	Total capacity in MW	Used Reservoir
Austria			0,7	0,7	low enthalpy
France		14,7 [a]		14,7	high enthalpy
Germany			0,2	0,2	low enthalpy
Iceland		161,7	10,4	172,1	high, low enthalpy
Italy	770,5	20,0		790,5	high enthalpy
Portugal		3,0 [b]	13,0 [b]	16,0	high enthalpy
Russia		110,0 [c]		110,0	high enthalpy
Turkey		20,4		20,4	high enthalpy

[a] Guadeloupe; [b] Azores; [c] 9 MW Flash-Binary;

The wider use of geothermal energy for power production however depends on the further development of low enthalpy fields. Besides technological challenges, hydro-geothermal power plants are facing high investments and comparatively large risks. Regarding the success of geothermal power production in the future, the economic viability (also in the context of governmental set conditions) is therefore a determining factor.

The economic chances and barriers as well as the therewith connected risks will be analysed in this paper, having a closer look on the activities of geothermal electricity production in Germany. On the one hand, Germany comprises different geological conditions representative for other European regions, and on the other, the amendment of the Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG) assigned a comparatively large interest to geothermal electricity generation from low enthalpy resources (*Table 2*). Based on this case study, the influencing parameters will be identified and conclusions also for a European scale derived.

Table 2: Activities of geothermal power production in Germany [3]

	Borehole concept	El. capacity in MW	Th. water temp. in °C	Flow rate in m^3/h	Borehole depth[a] in m	Power plant cycle	Heat supply	Commis-sioning
Groß Schönebeck	aquifer doublet	ca. 1,0[b]	150	> 50[b]	4 294		-	2008[b]
Neustadt-Glewe	aquifer doublet	0,2	97	< 110	2 250	ORC	heating system	2003
Bruchsal	aquifer doublet	0,5[b]	118	86	2 500		heating system	2007[b]
Landau	aquifer doublet	2,5[b]	150[b]	250[b]	3 000	ORC	heating system	2007[b]
Offenbach, Bellheim	aquifer doublet	4,8[b] – 6,0[b]	150[b] – 160[b]	360[b]	2 500[b] – 3 500[b]	Kalina		2008[b]
Speyer	> aquifer triplet	5,4[b]	150	450[b]	2 900	ORC	heating system	2009[b]
Bad Urach	HDR triplet	ca. 1,0[b]	170	48[b]	4 500	ORC	heating system	stopped
Unterhaching	aquifer doublet	3,4[b]	122	< 540[b]	3 300	Kalina	heating system	2007[b]

[a] production borehole; [b] planned value;

2. Geothermal resources in Germany

The existing geothermal resources in Germany consist of some deep thermal water reservoirs but are for the most part based on heat stored in deep rocks. For power production, the development of these resources, using deep boreholes, faces two requirements: on the one hand, the temperature of the thermal water should possibly be higher than 100 °C, and on the other, the productivity of the borehole(s) needs to permit a sufficient flow rate. Due to economic viability, a hot water production of at least 100 m^3/h is oftentimes necessary. While a certain temperature can always be reached in a respective depth; the second requirement (and the therewith connected demand for a high permeability in the deep underground) limits possible geothermal power plant sites to a small number.

As long as stimulation measures to enhance the naturally occurring permeability are still in the R&D-phase, a (commercial) geothermal power generation is in Germany limited to Rotliegend sandstones of the North-German Basin, the Malmkarst of the South-German Molasse Basin and the Muschelkalk and Buntsandstein of the Upper Rhine Graben (*Figure 1*).

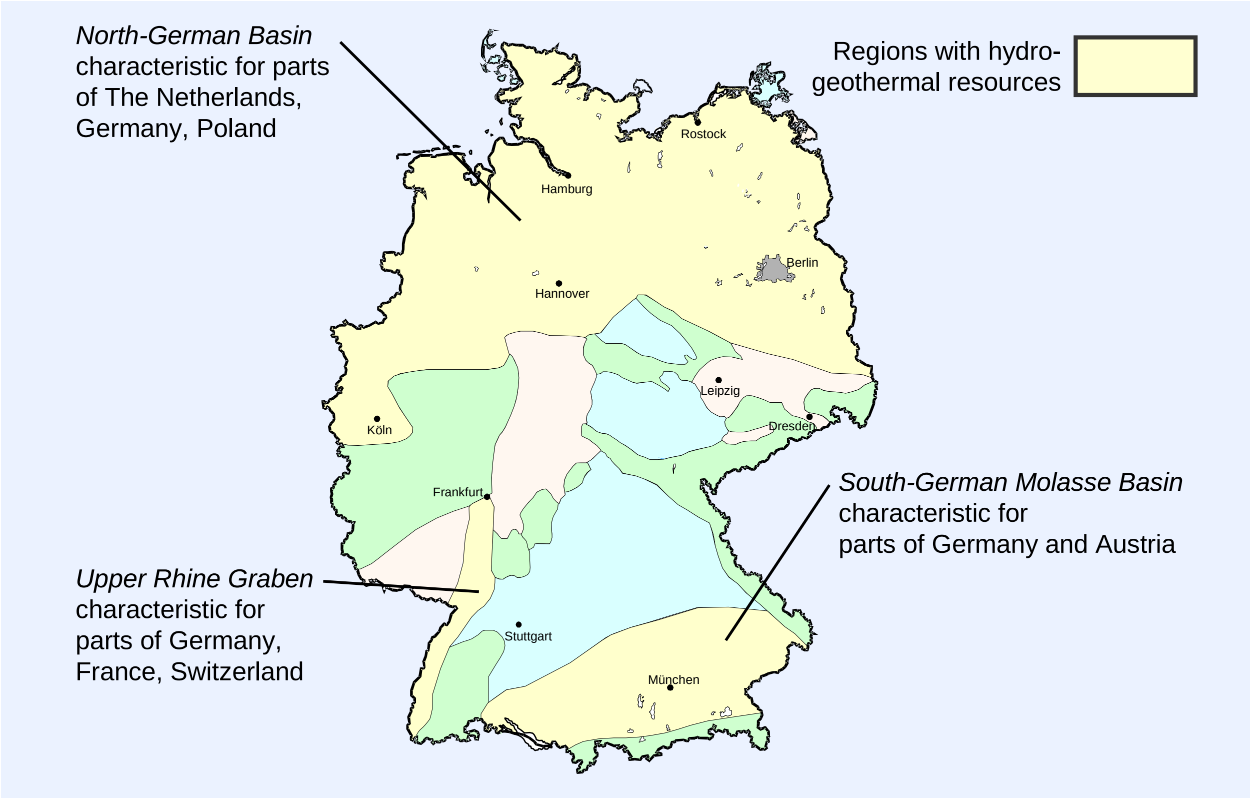


Figure 1: Regions with hydro-geothermal resources in Germany [4]

The Malmkarst, as karst aquifer, thereby provides the best hydraulic properties, so that the probability to reach sufficient flow rates is high – especially if stimulation measures like the injection of acids are scheduled (*Table 3*). The Buntsandstein and the Muschelkalk of the Upper Rhine Graben have convenient temperatures in comparatively low depths. High permeability however can only be expected in faults and karst zones. Building a compact network, the probability of success is not as low as core data might suggest – especially if water fracs are executed. The Rotliegend sandstones reach high temperatures only in larger depths but a sufficient permeability is limited to single regions particularly in the east of the North-German Basin. With the use of frac operations (like tested in the German research project Groß Schönebeck) however, a remarkable potential could be exploited in the North-German Basin. [3]

Table 3: Estimation of reachable flow rate and possibility of success for a flow rate of 100 m^3/h from hydro-geothermal doublets in Germany [5], [6]

	Aquifer	Maximum flow rate in m^3/h	POS [a] for 100 m^3/h
North-German Basin	Rotliegend-Sandstone	100	low – high
Upper Rhine Graben	Muschelkalk, Buntsandstein	300	medium
South-German Molasse Basin	Malmkarst	≥ 300	high

[a] POS: „Probability of Success“ relating low to 0 – 33 %, medium to 33 – 66 % and high to 66 – 100 %.

3. Economic analysis

According to the different hydro-geothermal regions, representative reference plants will be defined and subsequently analysed by means of economic criteria (guideline VDI 2067 [7]). The needed cost data for the analysis have been derived from price surveys and respective feasibility studies (e.g. [3], [8], [9]). The surveyed data is however afflicted with partly large insecurity, due to the novelty of geothermal power production in Germany; additionally, the large demand for drilling rigs in the oil and gas industry as well as the developments on the resource market lead to continuously rising steel prices. This will be considered within parameter variations, which will also identify the critical frame conditions.

Definition of reference plants

In Germany, geothermal power generation as well as combined power and heat production (using the residual heat of the thermal water) with hydro-geothermal doublets is representative and will be defined as reference (*Table 4*). Further, the successful development of the reservoir meeting sufficient flow rates and temperatures with two deep boreholes from one drilling site is assumed. The produced thermal water will aboveground transfer its heat to an Organic Rankine Cycle (ORC). Providing electricity, the ORC plant is assumed to run 7,500 full load hours per year. In case of an additional heat supply to a low temperature heating system, the electricity production is decreased to 6,500 respectively 6,100 full load hours per year. According to the different hydro-geothermal regions, supplementary assumptions (e.g. thermal water temperature and flow rate, borehole depth, pumping water level) are made in order to define economic analysable reference plants.

Table 4: Reference plants for geothermal power production from hydro-geothermal resources

	Upper Rhine Graben (URG)		South-German Molasse Basin (SGMB)		North-German Basin (NGB)	
	Power	Power &Heat	Power	Power &Heat	Power	Power &Heat
Thermal water temperature in °C	150		120		150	
Flow rate in m^3/h	130		300 [c]		100 [d]	
Pumping water level m [a]	400		400		400	
Power plant cycle	ORC		ORC		ORC	
El. installed capacity in MW_{el}	1.4		1.8		1.1	
Th. installed capacity in MW_{th} [b]	-	3,0	-	7,0	-	2,3
El. full load hours in h/a	7,500	6,500	7,500	6,100	7,500	6,500
Th. Full load hours in h/a	-	3,000	-	3,000	-	3,000

[a] under top ground surface; [b] heat supply to low temperature heating network: supply temperature 75 °C, return temperature 55 °C; [c] acid stimulation; [d] hydraulic stimulation;

Capital costs

The overall investment costs of geothermal power plants are dominated to approximately 70 % by the borehole costs (*Figure 2*) consisting of the set up and recultivation of the drilling site, the drilling lease (including personnel and energy costs), the costs for drilling bits and mud (including the disposal of mud and cuttings) as well as logging and borehole completion. For the reference plants, the investments for a hydro-geothermal doublet are assumed between 10 and 20 Mio. Euro (*Table 5*). The reason for the obvious differences lays in the different drilling, casing and cementation effort which increases with ascending borehole depth and flow rate (respectively borehole volume). Furthermore, the drilling costs are influenced by the rate of the drilling progress which is related to penetrated rock formation per time. For the reference plants, the specific borehole costs can be estimated with 1,600 to 2,400 Euro/m and more. Estimating the borehole costs, large uncertainties exist due to the limited availability of drilling rigs and the rising feedstock prices (e.g. steel). As another risk, unforeseen technological problems need to be considered which are estimated with an extra charge (16 % of to the borehole costs).

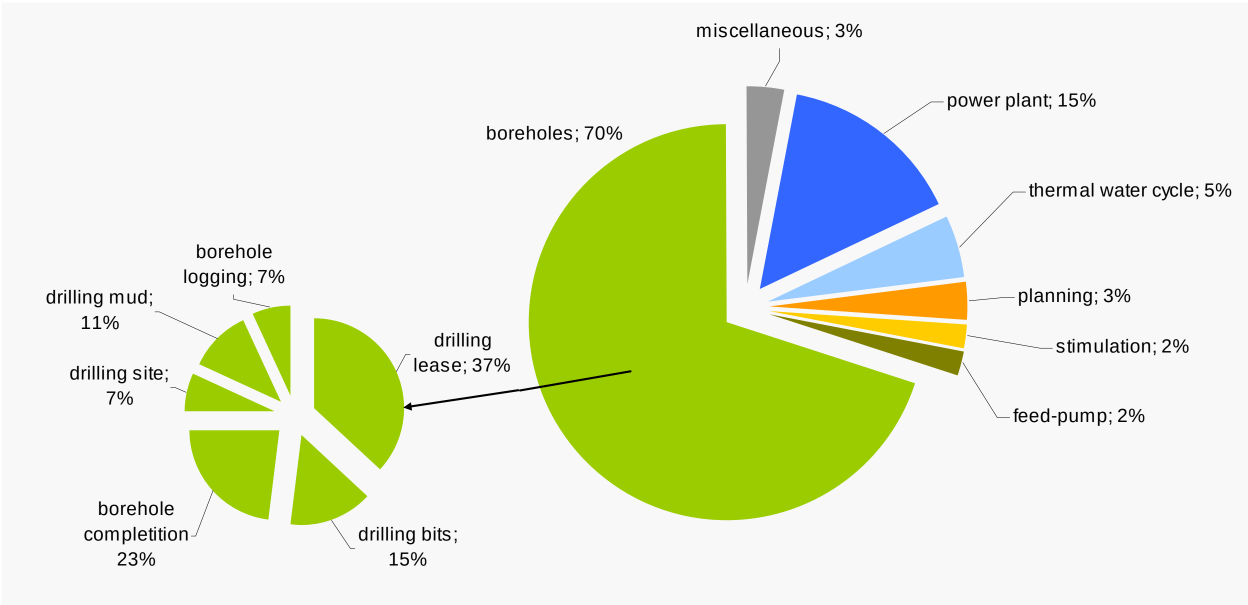


Figure 2: Average composition of the investment costs for geothermal power generation from hydro-geothermal reservoirs

The costs for stimulation measures for hydro-geothermal systems - such as acid injection and hydraulic fracturing - are significantly less cost intensive (approximately 2 % of the overall investments) compared to the borehole costs. The acid injection in the South-German Molasse Basin is estimated with 100,000 Euro; the hydraulic water fracs in the North-German Basin with 1 Mio Euro. However, the stated costs must be seen as very rough assumptions because stimulation costs can not be generalized and need to be assessed site specifically. In case of the reference plant in the Upper Rhine Graben, no secondary measures are defined.

The second largest investment with approximately 15 % of the overall capital costs are the expenditures for the power conversion cycle. For the defined ORC plant, the investment costs depend predominantly on the installed capacity and lay between 1.9 and 3.3 Mio. Euro respectively 1,700 to 1,900 Euro per kW_{el}. Regarding the reference plants with additional heat supply, also the costs for a further heat exchanger need to be considered. Hereby, 10,000 Euro per kW_{th} heat capacity have been estimated.

For the thermal water cycle - connecting production well, power plant and injection well - approximately take over approximately 5 % of the overall costs. The estimated investments thereby significantly depend on the length of the needed pipelines; with a doublet from one single site, only comparatively short pipelines are necessary. Also the circulated flow rate has influence on the investments, so that for the higher flow rate in the South-German Molasse Basin about 450,000 Euro and for the smaller flow rates, between 250,000 and 320,000 Euro have been calculated. In case of long-distance pipelines, the mode of laying (i.e. surface or subsurface) is further determining.

Table 5: Investment and operation costs for the reference plants

	Upper Rhine Graben (URG)		South-German Molasse Basin (SGMB)		North-German Basin (NGB)	
	Power	Power &Heat	Power	Power &Heat	Power	Power &Heat
Investment costs in Mio. €						
Boreholes [a]	9,5	9,5	16,1	16,1	19,9	19,9
Stimulation	-	-	0,1	0,1	1,0	1,0
Thermal water pumps	0,25	0,25	0,48	0,48	0,2	0,2
Thermal water cycle [b]	0,32	0,32	0,45	0,45	0,25	0,25
Power plant [c]	2,4	2,5	3,3	3,3	1,9	1,9
Heat extraction	-	0,11	-	0,14	-	0,08
Planning and miscellaneous	0,44	0,45	0,73	0,73	0,80	0,81
Additional charge for unforeseen [e]	1,6	1,6	2,6	2,6	3,2	3,2
Insurance	0,78	0,78	1,2	1,2	1,4	1,4
Total	15,2	15,5	25,0	25,1	28,6	28,7
Operation costs [d] in Mio. €/a						
Overhaul and maintenance	0,09	0,09	0,14	0,14	0,14	0,14
Management and personnel	0,25	0,25	0,37	0,37	0,41	0,41
Auxiliary power	0,23	0,23	0,40	0,40	0,23	0,23
Total	0,57	0,57	0,92	0,92	0,77	0,77

[a] incl. drilling site, borehole logging and production tests; [b] incl. filter and slop-systems, [c] incl. power connection and building; [d] basic year 2006; [e] referring to borehole construction

The needed feed and injection pumps add approximately with 2 % to the overall investments. The estimated capital costs thereby depend directly on the flow rate and the necessary pressure increase; but also parameters like chemism, gas content and temperature of the thermal water can be of influence. In most cases, a compromise between maximum durability and viable expenses is unavoidable. In case of the reference plants, the investment for the pumps, circulating the higher flow rate in the South-German Molasse Basin, have been assumed with 480,000 Euro, whereas smaller flow rates lead to investments between 200,000 and 250,000 Euro.

A further, possibly significant cost factor can be related to the needed respectively by the investor demanded insurances. The coverage for the risk in case of insufficient reservoir parameters (i.e. temperature and permeability) is thereby of special importance for geothermal projects. The extent of this risk depends predominantly on the quality and availability of forecasted and geological data. In Germany, the contracted insurances are on average 5 % of the overall investments.

The costs for planning and other advance performances (e.g. geologic expert's report, fees) are estimated with 3 % of the overall investment

Operation costs and revenues

The annual operation costs of geothermal power production consist of expenditures for personnel, overhaul and maintenance, management as well as expenses for auxiliary power (*Table 5*). Revenues are obtained in case of an additional supply of the residual heat.

Regarding personnel costs, an operation without supervision (i.e. one employee) is assumed. The annual overhaul and maintenance costs are estimated to amount 0.5 % of the investments for the boreholes, 1 % of the investments for the power, and 4 % of the investments for the thermal water cycle. Management and insurance expenditures are rated 0.5 respectively 0.75 % of the investments for surface installations.

Evaluating the expenses for auxiliary power, it must be defined, if the gross- or net-power output is fed into the public grid. For geothermal power production it needs to be considered that the need of auxiliary power is to large parts demanded by the cooling cycle and especially the pumps for the thermal water production. In case of a gross-power feed-in, the auxiliary power is taken from the grid, whereas in case of net-power supply it is covered by the power plant itself. In general, this question needs to be answered from a business-management viewpoint which results in a comparison of power production costs of the geothermal plant and the available electricity market prices. Considering the regarded German circumstances it is assumed, that most of the operation years, the auxiliary power will be taken from the public grid and the whole gross-power output is refunded with the valid feed-in tariff.

In case of an additional heat supply, the sale of the heat (free power plant) in an existing heating system is evaluated. Under the assumed conditions (*Table 5*), an average revenue of 0.032 Euro per sold kWh heat can be estimated.

Electricity production costs and economic comparison

In the following, the electricity production costs of the reference systems will be calculated and adjacently set into comparison to the expectable electricity prices respectively feed-in tariffs. For geothermal power plants up to 5 MW_{el} a guaranteed tariff of 0.15 Euro/kWh is valid.

Resulting from the specified capital and operation costs as well as the possible revenues, the electricity production costs will be estimated according the guideline VDI 2067. The specific technical life times of different plant components and therewith connected replacement purchases are included. The technical life time for the boreholes is rated 30 years, for the power plant 15 years, for the thermal water cycle 25 years and for the thermal water pumps 4 years.

As overall evaluation period, a borehole respectively reservoir lifetime of 30 years is defined. The amortisation period, however, is in case of the period of validity of the German feed-in law set to 20 years. Within this period, the annuity of the investment costs is calculated with a mixed rate of interest of 6.1 % disregarding a potential inflation (i.e. real monetary value of the year 2006). For the last 10 years of plant operation only the replacement purchases and operation costs need to be considered on the side of the expenditures.

Comparing the electricity production costs for the defined reference plants supplying electricity only (*Figure **3***), significant differences concerning the sites become evident. This can basically be derived from the investments for the boreholes which have the smallest influence on the electricity production costs in the Upper Rhine Graben due to the comparatively small borehole volume and vice versa the largest influence in the North-German Basin due to the comparatively large borehole volume. Other site-specific differences visibly affecting the electricity production costs are represented by the needed stimulation measures (largest influence in the North-German Basin) and the needed auxiliary (largest influence in the South-German Molasse Basin) where higher flow rates lead to higher operation costs. In contrast, with large flow rates also connected higher expenses for the thermal water cycle result in a negligible increase of the production costs. The share of the investments for ORC plant is determined by the installed capacity.

Is heat fed into a heating system additionally to the power supply, the resulting electricity production costs can be decreased, because the revenues of the yearly heat sales are significantly higher than the annuity of the additional investments for the heat extraction. This is especially the case if large heat amounts can be supplied such as the high flow rates in the South-German Molasse Basin allow for.

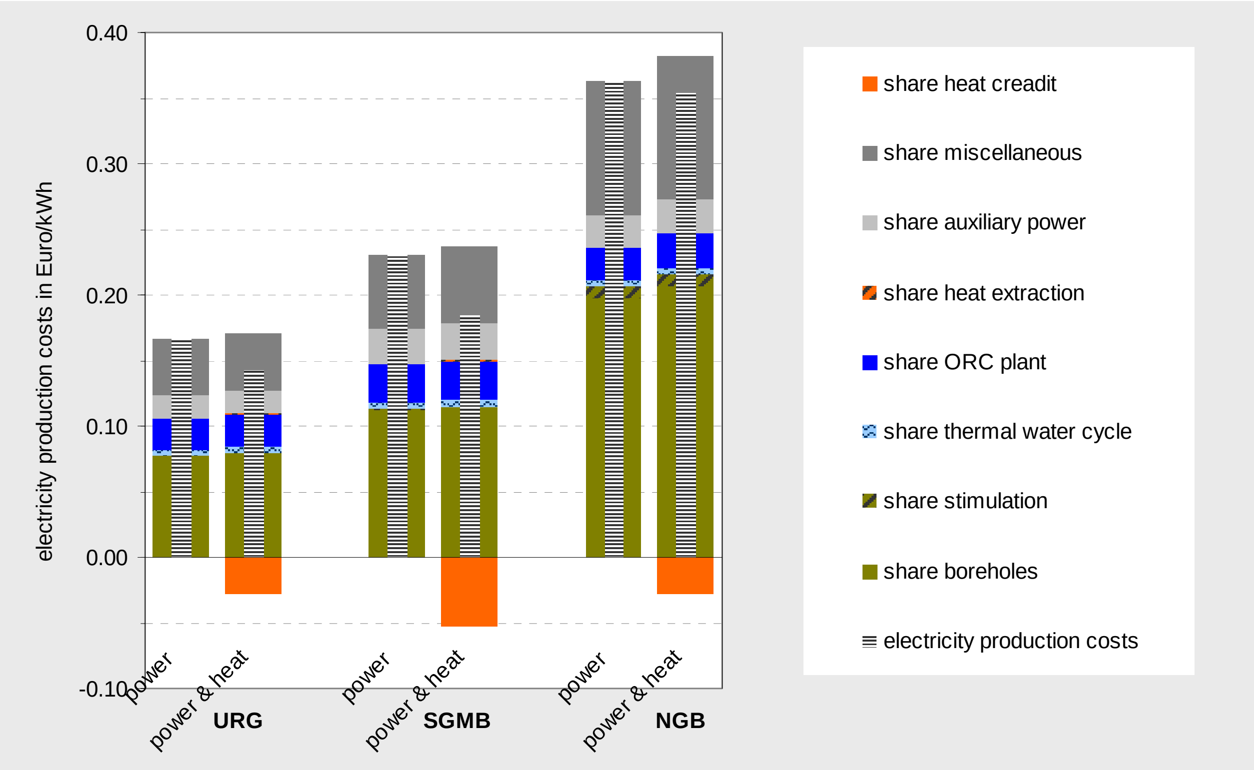


Figure 3: Average electricity production costs for the hydro-geothermal reference plants

Compared to the available feed-in tariff (0.15 Euro/kWh), no reference plant can presently operate economically viable under the assumed conditions. Therefore, the determining parameters will be identified in the following in order to economically evaluate future possible (technical) developments or learning and also to approach the calculated production costs on a European scale.

The most significant influence is reached by a variation of the **thermal water temperature** (*Figure 4*). A higher temperature gradient than expected therefore results in a higher power output, almost with the same investments. Accessing hydro-geothermal systems in Europe, the realistic deviation from the temperature gradients assumed for the reference plants is within a certain range. A 5 K colder water temperature in the Austrian part of the Molasse Basin would for example result in approximately 14 % respectively 3 Euro-Ct/kWh higher production costs; instead, a 5 K higher water temperature in other parts of the Molasse Basin can decrease the production costs by approximately 9 %.

Another determining factor is the **plant efficiency** of the overall power plant concept (*Figure 4*). It is thereby important to note that the variation of the efficiency is not only representative for the conversion cycle but also for the cooling of the thermal water and the plant availability. A higher conversion cycle efficiency (e.g. realised by a two stage ORC-process, a Kalina-cycle or an optimised cooling cycle) of 1 %-point can decrease the electricity production costs of the reference plant in the Upper Rhine Graben of about 13 % - assuming the cooling of the thermal water as well as power plant availability remains the same. The same effect on the production costs can be reached if the thermal water leaves the power plant 7 K cooler (same conversion cycle efficiency and availability) than assumed in the reference case or the plant availability can be increased to 8,125 full load hours per year (same conversion efficiency and cooling of the thermal water).

A comparable influence on the production costs like the plant efficiency is represented by the variation of the reservoir productivity respectively the achievable **flow rate** (*Figure 4*). With the further development of stimulation measures - such as acid injection but especially hydraulic fracturing of sedimentary structures - this parameter can (in contrast to the so far discussed parameters) be alternated in magnitudes (i.e. variation > 100 %). If an increase of the reservoir productivity in the North German Basin to flow rates up to 300 m^3/h will be possible in the future (which seems to be realistic regarding the recent outcomes of the German research project of the GeoForschungsZentrum Potsdam), a remarkable potential would be economically accessible.

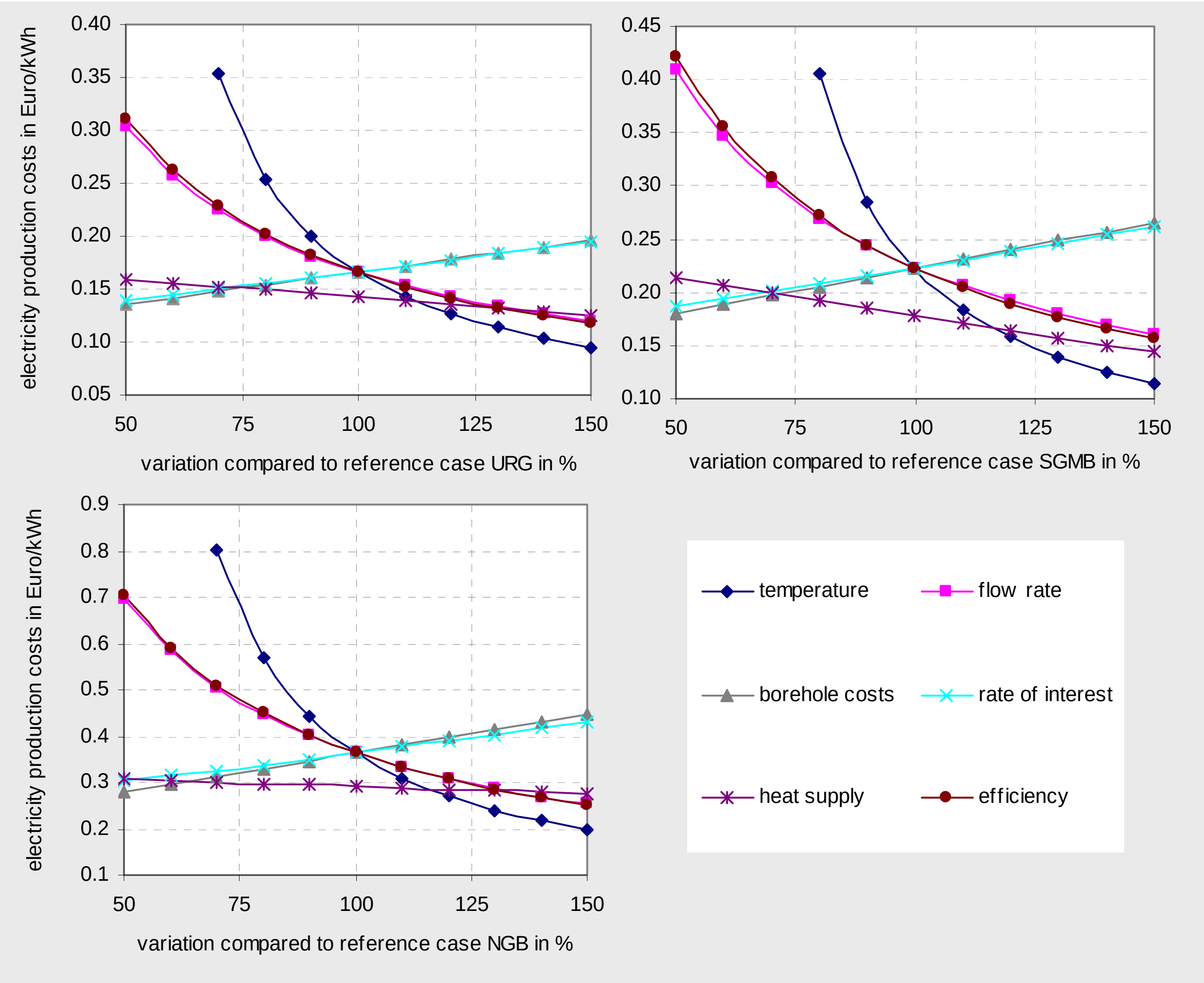


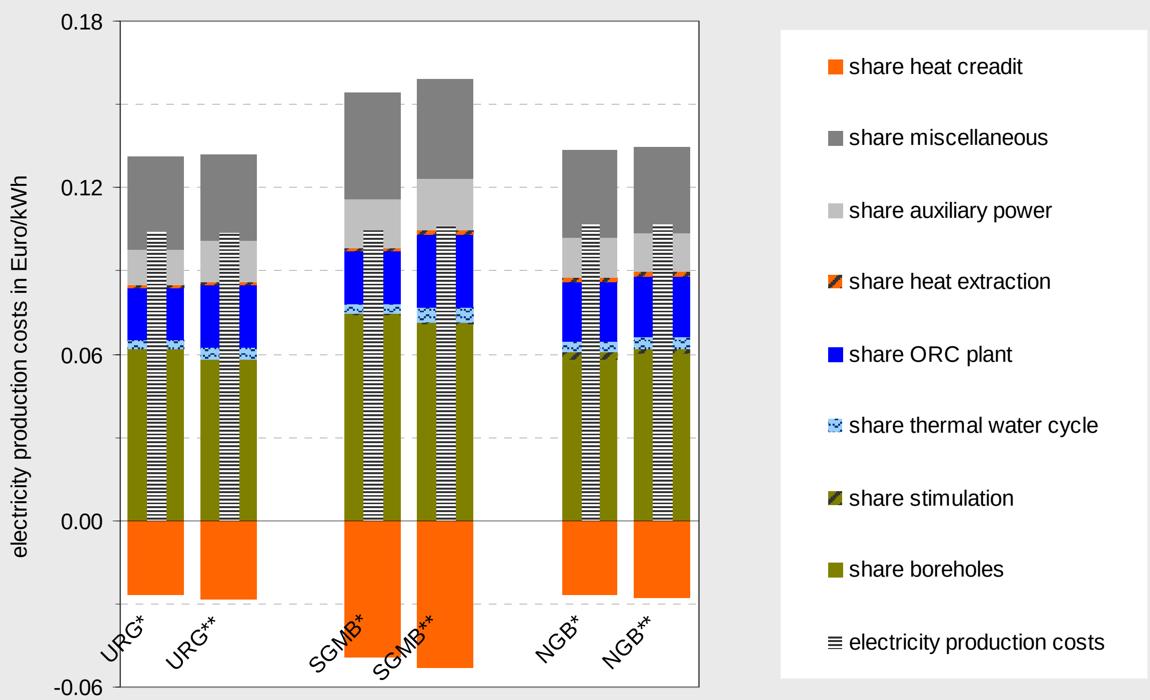
Figure 4: Parameter variation of the calculated electricity production costs

As largest rate of the overall investments, the **borehole costs** are a further decisive factor for geothermal electricity production costs (*Figure 4*). On the one hand, this can lead to significantly higher production costs if the expenses for the drilling lease or material costs keep on increasing; on the other, with an optimised drilling procedure and therewith achievable time and energy savings or other borehole concepts (e.g. triplets) realising an economy of scale, also lower production costs are realistic to a certain extent. In the case of the reference plant in the Upper Rhine Graben for example, a 5 % decrease of the borehole costs would lead to about 3 % lower production costs.

A further influencing factor for the production costs is given by the **rate of interest**, consisting of 30 %equity capital with 11 % rate of interest and of 70 % credit capital with 4 % rate of interest (*Figure 4*). Through a reduced rate of interest, also remarkable production costs reductions are realisable. In case of governmental granted loans reducing the rate of interest for credit capital by about 0.8 percentage points, the production costs can be decreased by 3 %.

In case of plants supplying power and heat, an additional influencing factor is the **heat supply** (*Figure 4*). An increased yearly heat credit reduces the production costs, especially for plants with large flow rates. On the one hand, a larger heat credit is achievable by selling more heat requiring respective customer structures (e.g. heat supply on different temperature levels (cascades), larger heat full load hours by supplying heat and cold); on the other, larger heat credits are also realisable through higher selling prices, possibly represented by a future heat market development or also the implementation of a feed-in law for renewable heat supply (like presently discussed in Germany).

Coming back to the economic feasibility of hydro-geothermal power production, not one single parameter of the above discussed factors results in the needed cost decrease; it is the concurrent influence on multiple parameters (*Figure 5*).



URG*: reduction borehole costs by 10%; reduction rate of interest to 5.8%; increase of thermal water temperature by 10°C; increase of flow rate by 15 m^3/h; increase of power plant efficiency by 0.5 %-points; increase of heat full load hours by 300 h/a
URG**: triplet (2 production and 1 injection borehole)

SGMB*: reduction borehole costs by 10%; reduction rate of interest to 5.8%; increase of thermal water temperature by 5°C; increase of flow rate by 100 m^3/h; increase of power plant efficiency by 0.7 %-points; increase of heat full load hours by 300 h/a
SGMB**: triplet (2 production and 1 injection borehole); increase of flow rate by 50 m^3/h

NGB*: reduction borehole costs -10%; reduction rate of interest to 5.8%; increase of thermal water temperature by 5 °C; increase of flow rate by 200 m^3/h; increase of power plant efficiency by 0.3 %-points; increase of heat full load hours by 100 h/a
NGB**: triplet (2 production and 1 injection borehole); increase of flow rate by 150 m^3/h

Figure 5: Future possible electricity production costs for hydro-geothermal power plants

4. Conclusions

Based on the calculated electricity production costs using geothermal low enthalpy resources with binary power plants, following conclusions can be drawn:

- Talking about geothermal power production from low-enthalpy resources, only regions with hydro-geothermal reservoirs such as discussed for the North-German Basin, the Upper Rhine

Graben and the South-German Molasse Basin seem suitable due to the present energy-economic situation.

- From a technical viewpoint, a successful geothermal power as well as power and heat supply is still a challenge because of the fairly new technology - especially regarding the reliable development of the deep underground, but also considering the further need for development and optimisation of surface technology and the overall system. Based on the fact that several projects are in the planning or construction stage in Europe, the development of the existing room of improvement can be expected for the years to come.
- Therefore, a geothermal power production from low-enthalpy resources is presently economic viable only for sites with very good geological conditions (i.e. reservoir temperatures higher than 120 °C and flow rates higher than 150 m^3/h). With the ongoing development of stimulation measures to enhance hydro-geothermal resources, this situation will continuously be improved.
- Besides assessing high temperatures und large flow rates, the borehole costs (as significant cost driver) need to be analysed more precisely regarding their cost reduction potentials. The same is true for further aspects characterising a geothermal power as well power and heat production: next to the improvement of power plant technology (i.e. increasing efficiency and availability), also a reservoir development with borehole concepts larger than two boreholes and financing plans with low rates of interest need to be taken into consideration.
- From an energy-economic viewpoint, the extensive use of the resulting low temperature heat is another critical aspect. Therefore, developing suitable heat customer structures is an important part, already in the beginning of the planning phase.

For a future contribution of geothermal electricity generation to a sustainable energy supply, intensive and focussed R&D efforts within the geo- and engineering-sciences need to be undertaken. Thereby, the reliable and simple reservoir development and the further development of measures to increase reservoir productivity as well as improving surface installations and the technological interaction of the overall system need to be considered. Only this way, risks can be reduced and efficiency factors increased which is necessary to successfully developed upcoming projects and to evolve a marketable geothermal power production.

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