Key Performance Indicators

Monitoring targets from the SET Plan's Deep Geothermal Implementation Plan with Reference plants & assets

Version 1

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Deep GEOTHERMAL IWG
SUPPORT UNIT

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Introduction

The Support Unit of the Deep Geothermal Implementation Working Group monitors the execution of the Deep Geothermal Implementation Plan (DG IP). The Support Unit of the DG-IWG has a mandate within task 6.3 of the coordination and support action "SU-DG-IWG" to define Key Performance Indicators. The task is led by EGEC and runs from July 2019 to February 2021.

To support the monitoring, the Support Unit has defined a set of complementary Key Performance Indicators (KPIs). The KPI's objectives is to monitor the targets of the DG IP, specifically those related to cost reductions and improved efficiency of deep geothermal energy utilization.

They aim at:

- Producing an ad-hoc qualitative assessment on the execution of each R&I activities,
- Focusing the execution of the IP's research and innovation activities (fiches) by suggesting Key Performance Indicators and targets.

The KPIs are relative to the state of affairs in January 2018, the date of endorsement of the Deep Geothermal Implementation Plan by the SET-Plan Steering Group. The KPIs are set up in reference to a number of unit cost items developed for reference plants and assets. The KPIs also take into account cost reductions achieved by continued deployment (economies of scale and scope), those set by new market conditions (e.g. drilling rig prices that are strongly influenced by the upstream oil and gas sector), and importantly those that benefit from ongoing RD&I projects.

The Support Unit proposed these KPIs to a wide range of geothermal stakeholders during a public online consultation, followed by a validation workshop of these KPIs on 5 February 2020 in Brussels (Belgium). This 2020 version is the first report on the KPIs, which will be updated on an annual basis. The Support Unit describes reference plants and assets, which are based on an European average profile for a range of plants, its components and size, and the corresponding costs. Data have been collected from the literature, reports of public authorities and interviews of market actors. For each reference plant, the Support Unit describes the source of data.

SET PLAN - DEEP GEOTHERMAL IMPLEMENTATION PLAN STRATEGIC TARGETS IN THE CONTEXT OF AN INITIATIVE FOR GLOBAL LEADERSHIP IN DEEP GEOTHERMAL ENERGY

The strategic targets for deep geothermal energy set in 2018 are:

1. Increase reservoir performance resulting in power demand of reservoir pumps to below 10% of gross energy generation and in sustainable yield predicted for at least 30 years by 2030;
2. Improve the overall conversion efficiency, including bottoming cycle, of geothermal installations at different thermodynamic conditions by 10% in 2030 and 20% in 2050;
3. Reduce production costs of geothermal energy (including from unconventional resources, EGS, and/or from hybrid solutions which couple geothermal with other renewable energy sources) below 10 €ct/kWh$_e$ for electricity and 5 €ct/kWh$_{th}$ for heat by 2025;
4. Reduce the exploration costs by 25% in 2025, and by 50% in 2050 compared to 2015;
5. Reduce the unit cost of drilling (€/MWh) by 15% in 2020, 30% in 2030 and by 50% in 2050 compared to 2015;
6. Demonstrate the technical and economic feasibility of responding to commands from a grid operator, at any time, to increase or decrease output ramp up and down from 60% - 110% of nominal power.

MONITORING BASELINE

In common with other Implementation Working Groups of the SET-Plan Actions, the DG-IWG decided to have as a baseline the state of affairs as captured on the date of endorsement of the Implementation Plan by the SET Plan Steering Committee, that is, on 24 January 2018. Since then, the Support Unit whose work started on 1 February 2019, has held extensive discussion on metrics that allow the tracking of progress against the targets culminating in the validation workshop n on February 2020.

APPROACH

In order to develop metrics for the strategic targets, the first aim was to identify cost structures of reference plants in typical European settings that cover the exploration phase, the construction phase such as capital expenditures associated with drilling of wells and constructing a power plant and operating expenditures. As cost structures and economic metrics strongly depend on the weighted average cost of capital (or discount rate), the Support Unit has assumed a uniform discount rate as described below in the section ‘System boundaries & clarifications’.

Key Performance Indicators

REFERENCE PLANTS

The choice of reference plants was defined to specifically address the challenges defined in the Implementation Plan's target to "Reduce production costs of geothermal energy (including from unconventional resources, EGS, and/or from hybrid solutions which couple geothermal with other renewable energy sources) to below 10 €ct/kWh$_e$ for electricity and 5 €ct/kWh$_{th}$ for heat by 2025".

Type of plants

Six plants are considered: three for power production including one on EGS, and three plants for heat supply including one combined heat & power system:

- 20 MW$_e$ high temperature plant (Flash turbine)
- 10 MW$_e$ medium temperature plant (Binary turbine)
- 5 MW$_e$ electric EGS plant (or thermal EGS plant with a capacity of 25 MW$_{th}$)
- 10 MW$_{th}$ heating plant
- 10 MW$_{th}$ heating plant assisted with large heat pumps
- 5 MW$_e$ and 20 MW$_{th}$ CHP plant

Sources of data

For each plant category, the reference plant has been taken from the costs of plants in operation. The source is often from a basket of plants in a developed area, for example:

- 20 MW$_e$ high temperature plant (Flash turbine): Tuscany, Italy
- 10 MW$_e$ medium temperature plant (Binary turbine): Bavaria, Germany
- 5 MW$_e$ electric EGS plant (or thermal EGS plant): Alsace, France
- 10 MW$_{th}$ heating plant: Paris region Ile-de-france, France
- 10 MW$_{th}$ heating plant assisted with large heat pumps: France, Netherlands
- 5 MW$_e$ and 20 MW$_{th}$ CHP plant: Bavaria, Germany

The costs of geothermal plants depend notably upon economies of scale. The levelized cost of electricity decreases with an increase in installed plant capacity. In general, economies of scale allow both, unit capital cost (in euros per kW installed) and unit operating and maintenance cost (in euros per kWh produced) to decline with increased installed capacity.

System boundaries & clarifications

We do not consider the impact of energy storage or other system services that geothermal plants may provide, as there are insufficient examples and reported costs to give a sufficiently detailed picture. Storage of electricity produced by geothermal power plants are promising but are not developed. Underground thermal energy storage associated to deep geothermal plants are still at an early stage of deployment.

Our reference plants have the following system boundaries:

- From project development until generation,
- We do not consider the transportation/transmission and distribution costs and benefits e.g. electricity distribution and DH infrastructure.

The expected lifetime of wells is more than 50 years. Overall, the useful lifetime of a plant is 25-30 years.

The weighted average cost of capital or the discount rate is fixed at 5%, for a period of 20 years. Wells or plants may not be fully depreciated but for our purposes, the residual value in the cash flow tail is of secondary importance.

Heat plant

For a geothermal heat plant, we assume that a plant will supply heat to a district heating network, to nearby greenhouses and agricultural businesses, or process heat to nearby industrial customers. Our reference plant is a geothermal doublet system accessing a reservoir at a depth between 2000-3000 m and a production temperature of around 80 °C. Operational hours range from 3800 to 6000 hours annually

Power plant

For the power plant, the reference plant has at least two wells to a depth between 2500-5000 m and a reservoir temperature in excess of 150 °C. Operational hours range from 6000-8000 annually.

Cost structure

Exploration and adaptation of a given technology to an unexplored geological context presenting a higher degree of risk than in commonly known and well-understood areas, and possibly the ambient temperature, are key concerns and cost drivers for geothermal projects. Geothermal energy projects require substantial up-front investments and from the investor’s point of view long time horizons before a venture becomes profitable. Furthermore, drilling and exploration may take several years, and 3 to 6 years can pass between exploration and first production, with the cumulative cash-flow becoming positive after quite a number of years after production has commenced.

Overall, unit costs for installed capacity for geothermal power generation per MW_e range between 4 and 7 million of euro (€ million) in Europe, and for heat generation about €1 and 2 million per MW_{th};

costs for the distribution systems excluded. Unit costs are higher than for virtually all other renewable energy technologies and depend highly on the specific site and technology chosen.
Capital costs depend strongly on the:

- Number of geothermal wells required;
- Depth of the reservoir, and hence drilling;
- Geological conditions;
- Location and access to drilling site(s) and size of the plant.

*Figure **1*** and 2 show the breakdown of the capital cost for the different development stages for two types of geothermal power plants: a 20 MW_e high temperature flash plant and a 10 MW_e medium temperature binary plant. Figure 3 addresses a 5 MW_e (or thermal) EGS plant (cost differences are attributable to the topside facilities such as those required for electricity generation (turbine, generator, substation and peripherals). Also, cost information is provided for a 10 MW_{th} geothermal district heating (DH) plant utilizing a well doublet (Fig. 4), a 10 MW_{th} heating plant integrated with large heat pumps to maximize energy yield (Fig. 5), and a combined heat and power (CHP) plant with an installed capacity of 5 MWe and 20 MW_{th} (Fig. 6).

Typically, operators begin with screening of a potential resource, obtaining permits, extensive and detailed planning, and obtaining finance for the project; these costs vary from€1 to 10 million.

The next step encompasses exploration to better quantify the size of the resource and to define targets for (exploration) drilling. Exploration typically encompasses investigating surface manifestations, geophysical surveys and subsurface modelling, but may also include drilling of exploration well(s). Exploration costs range from €1 to 7 million and are linked with the planning phase.

Once the resource has been outlined, the well field is designed and developed, adding another €20 to 30 million to the development (drilling) costs of a power project and €8 to 10 million on average for a geothermal heat project. Investing in exploration generally leads to a reduction of the subsurface unit technical cost because of higher certainty regarding the resource, its location/depth, spatial extent, location of inflow and outflow zones and so on. Hence, there is a relationship between exploration and field development phases and their respective costs.

The total subsurface development cost, prior to construction of the power plant amounts to around €20 to 40 million, and €10-14 million prior to construction of a heat plant. Until the well field has been developed, there is a risk of failure in connection with the expected subsurface geothermal resource and consequentially a substantial risk for financial loss. Also, adding to the time until first power and heat, is the need to first develop the subsurface and obtain data that allows for the appropriate sizing of surface facilities, in particular the power or heat plant.

Depending on the capacity of the plant and the technology used, constructing the power plant will add another €5 to 15 million of capital expenditures, and about €5 million for a heat plant. As mentioned a number of times, we do not include the cost related to transmission and distribution of, for example, a district heating network (about €1 million per km). Obviously, as both the field and plant have been constructed, the risk is mostly commercial and less governed by resource risks and hence has much more manageable financial consequences.

In total, the development of a geothermal power project until first power requires an overall investment ranging from €33 to 62 million for a 20 MW_e conventional high temperature plant, and €22 to 37 million for a 10 MW_e medium temperature, binary cycle power plant. Costs range from €35 to 50 million for 5 MW_e EGS plant. Note that costs may vary substantially for a large number of reasons.

The development of a geothermal heat project until first heat costs between €13 and 20 million for a 10 MW_{th} plant size supplied by a well-doublet, to which, for reasons of maximizing efficiency of energy recovery one may add about €4 million for the large heat pump (of 4 MW_{th} capacity).

Costs for the development of a 5 MW_e and 20 MW_{th} CHP project (including topsides for power generation) range between €18 and 25 million.

The optimal capital expenditure profile very much depends on trade-offs and probability of success for each of the phases, exploration, development and power/heat plant construction. One must not add the maximum of each phase to arrive at a cost estimate for a geothermal energy project. Each phase influences the cost for the subsequent phase. For example, a more extensive and hence expensive exploration phase may pay back through reduced unit drilling cost because the probability of a successful well increases, planning and design of wells is improved, and the likelihood of costly operational and technical interventions lowered because of improved knowledge.

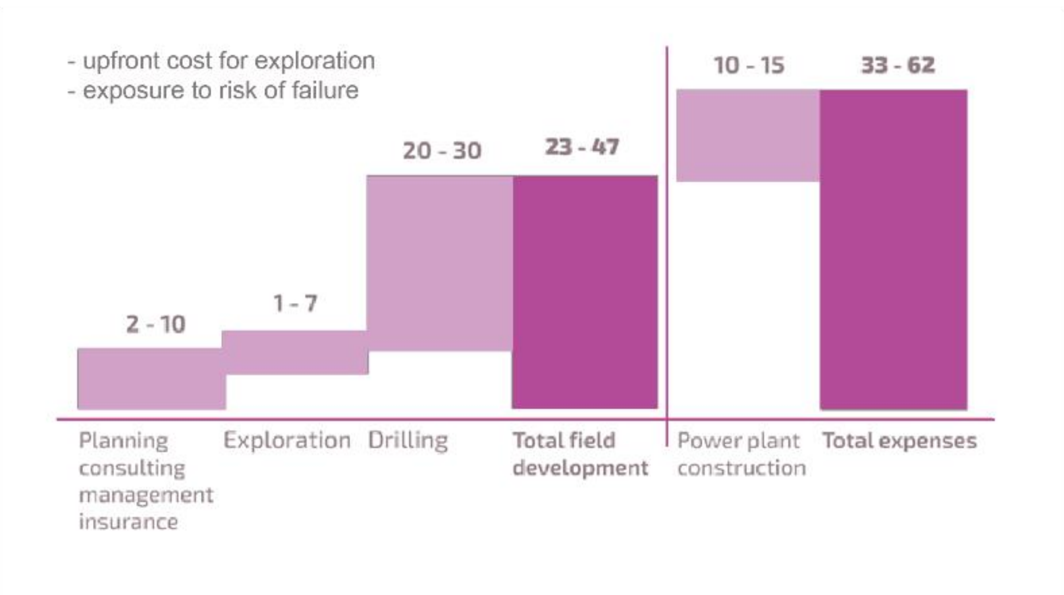

Figure 1: Cost range for the development of a 20 MW_e conventional high temperature plant with a flash turbine. The graph shows the cost range for the different steps in field deveolopment and the construction of the power plant.

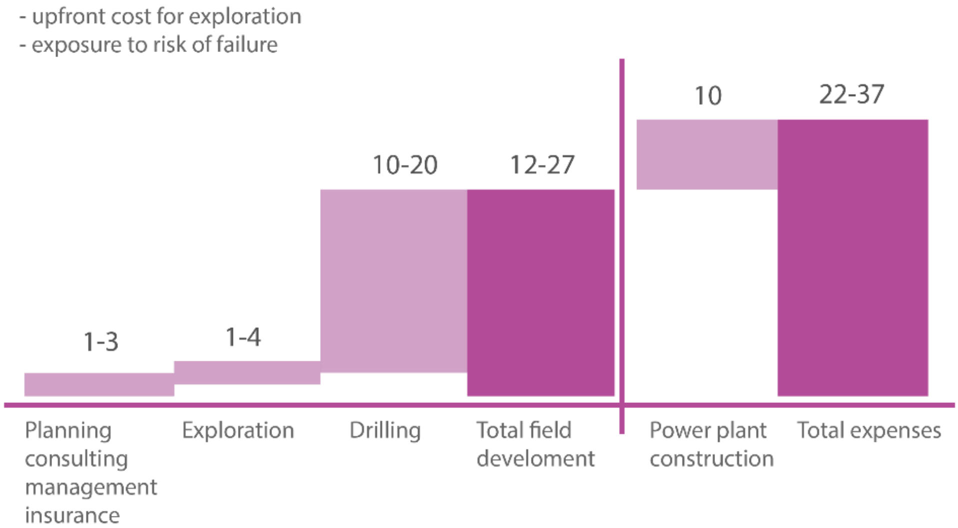

Figure 2: Cost range for the development of a 10 MW_e medium temperature plant with a binary turbine. The graph shows the cost range for the different steps in field development and the construction of the power plant.

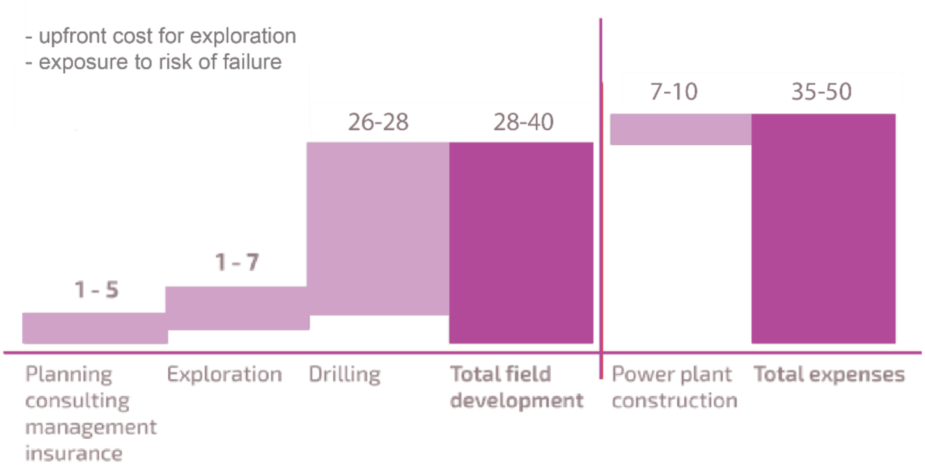

Figure 3: Cost range for the development of a 5 MW_e (or thermal 25 MW_{th}) EGS plant. The graph shows the cost range for the different steps in field development and the construction of the power plant with a turbo-generator.

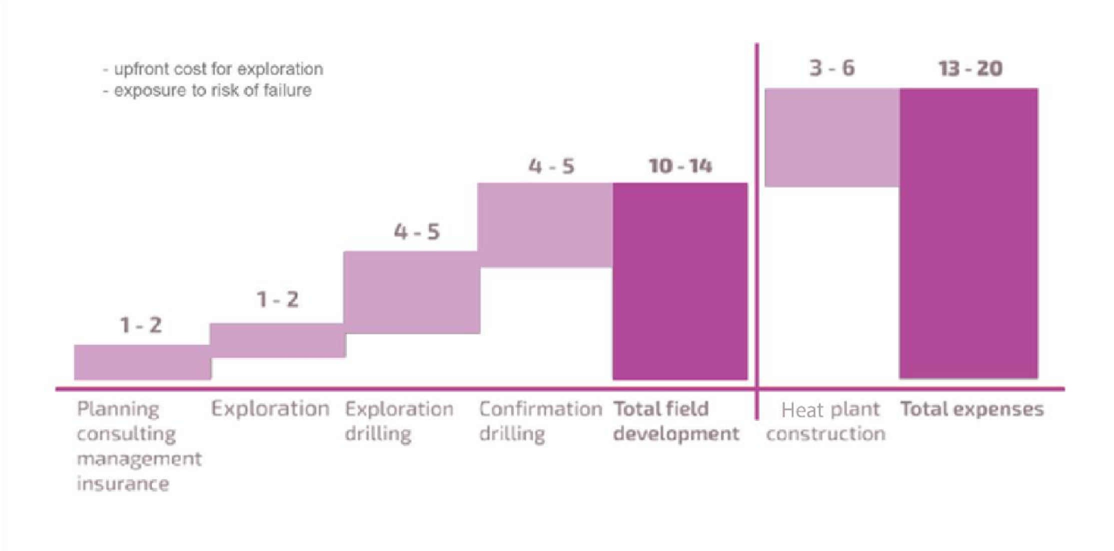

Figure 4: Cost range for the development of a 10 MW_{th} geothermal DH (doublet) systems, producing 40.000 MWh/year (investment cost = €1.3-1.8 million/ MW_{th}). Capital costs do not include costs for the installation of the district heating grid (about €1 million/km).

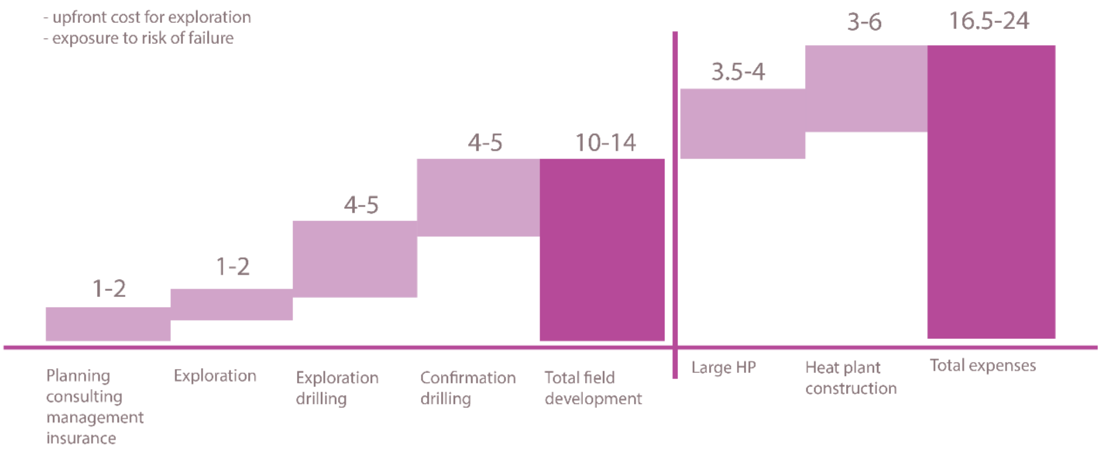

Figure 5: Cost range for the development of a 10 MW_{th} geothermal DH (doublet) systems, assisted with two large heat pumps of 4 MW_{th}.

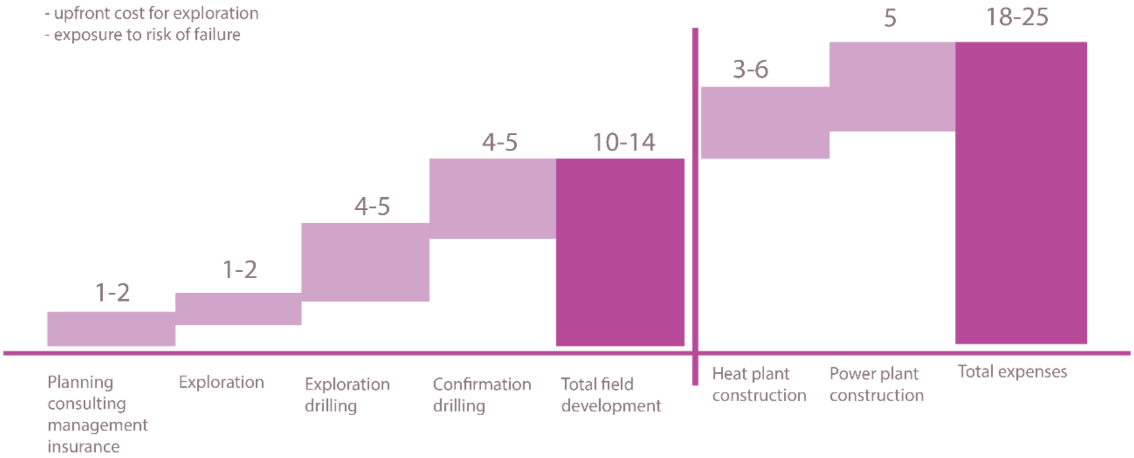

Figure 6: Cost range for the development of a 5 MW_e and 20 MW_{th} CHP plant (including a turbo-generator).

The ultimate profitability of geothermal energy projects strongly depends on the weighted average cost of capital. Generally, the cost of capital for investors in risky ventures is higher than for de-risked and predictable ventures. Geothermal energy projects are not only capital intensive, but also require significant up-front investments to de-risk a venture until parameters of the resource and hence, possible revenue streams can be quantified. Regarding the above figures, the high-risk stage corresponds to expenditures for resource identification and exploration and exploratory drilling. In the case of projects requiring stimulation or reservoir engineering, there is significant uncertainty on the potential capacity and output of the project until this task has been successfully completed. This means that between 25% and 50% of a geothermal project cost must be invested when there is a very high level of uncertainty regarding the success of the development. This usually translates in higher costs of capital and challenges to find investors with an appropriate risk appetite; typical investors in subsurface energy projects (such as oil and gas) are used to high returns on risky investments.

REFERENCE ASSETS

The reference assets are used to assess progress against the targets of the implementation plan of the SET-Plan's action on deep geothermal energy, which is one of a number of technologies that have been identified in two Actions whose purpose it is to position Europe as "No. 1 in Renewables". Those actions are (1) to sustain technological leadership by developing highly performant renewable technologies and their integration in the EU's energy system and (2) to reduce the cost of key technologies. The Deep Geothermal Implementation Plan has 8 research and innovation activities as well as 2 activities on non-technical barriers and enablers that serve to address the targets of the declaration of intent. The research and innovation activities are expected to yield concrete steps in the field of:

1. Artificial lift technologies (such as pumps in production wells) that will result in an increase reservoir performance by lowering the power demand for plant operations to below 10% of gross energy generation by 2030;

2. Development in turbine technologies are expected to improve the overall energy conversion efficiency, including efficiency gains in the bottoming cycle of geothermal installations at different thermodynamic conditions by 10% in 2030 and 20% in 2050;

3. The development of exploration tools that will reduce the unit finding cost (€ per potential capacity of a geothermal reservoir) by 25% in 2025, and by 50% in 2050 compared to 2015. The reduction in unit finding cost not only covers methods and tools that deliver improved reservoir definition prior to drilling but an increase of the probability of success for exploration wells;

4. Advances in drilling technologies are expected to reduce the unit cost (€/MWh) of a well's thermal output by 15% in 2020, 30% in 2030 and by 50% in 2050 compared to 2015;

5. Advances in geothermal power flexibility will enable geothermal plant operators to develop additional revenue streams resulting from the grid operator's need to improve reliability and stability, specifically geothermal power plant operators may demonstrate the feasibility of fast output ramp-up and -down between 60% - 110% of nominal power.

TYPES OF ASSETS

For the purposes of the development of key performance indicators for the Deep Geothermal Implementation Plan (the 8 research and innovation activities) we define as “assets” any activity that has the potential to help deliver the targets of the Deep Geothermal Declaration of Intent and specifically the cost targets. The activities have economic and commercial value and hence are characterized as “assets”.

1) Exploration techniques

Surface studies	Geochemical surveying	Geophysical surveying
• Gathering local knowledge • Locating active geothermal surface features • Assessing surface geology	• Geothermometry • Electrical conductivity • pH • Flow rate of fluids from active features • Soil sampling	• Gravity • Electrical resistivity • Magnetotelluric • Temperature gradient drilling • 2D & 3D Seismics

A reduction in exploration costs by 25% by 2025 (including the costs of exploratory drilling) compared to the current situation derives from an average cost of identifying a resource estimated to fall between €350,000 and €1,000,000. Cost estimates for resource exploration range from one to ten million euros for the full exploration phase. The contribution to the levelized cost of electricity or heat is estimated at €3.5 per MWh.

While many of the assets that constitute value of exploration techniques are low cost, the costs for 2D & 3D seismic surveys and sophisticated modelling tools may be substantial.

2) Drilling

In terms of drilling assets, cost drivers are the drilling rig with all equipment incl. BOP; drilling tools incl. bits, fishing tools etc., and raw material and consumables: drilling mud, cement, casing and casing accessories and so on. For a typical heat plant, drilling costs to a depth of 1800 m and rate of penetration (hole-making) of 5-10 m per hour are approximately €4 million per well. For drilling, the goal is to achieve cost reductions in resource development by:

- Reducing the time needed to drill and complete a well;
- Reducing delays due to wellbore stability issues;
- Reducing costs due to lost-in-hole accidents;
- Improving thermal output of a well.

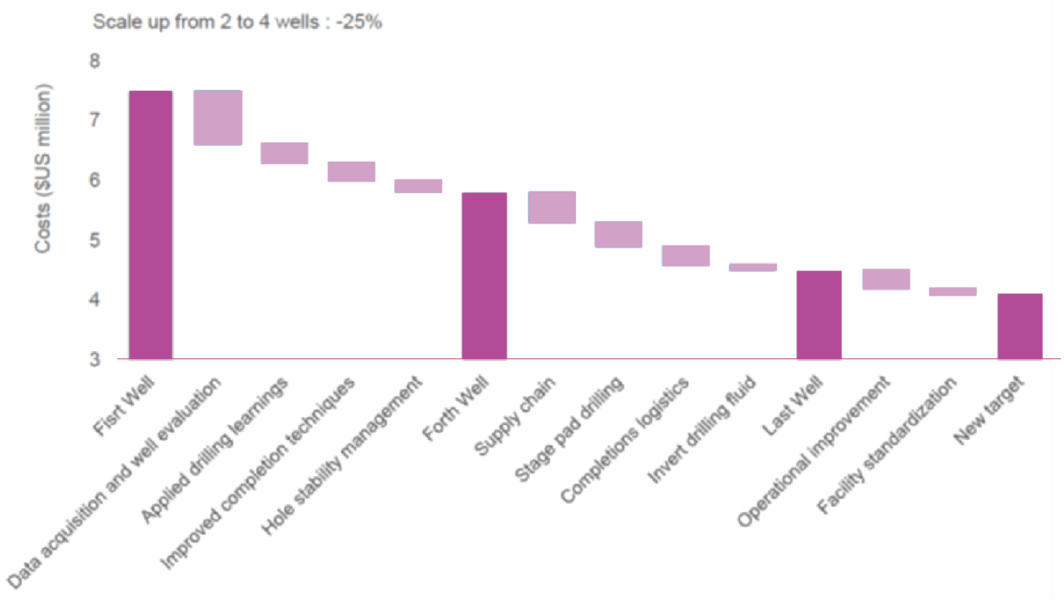

Figure 7 Break-down of well cost. (source EGEC Market Report 2015, Adapted from EnBW, 2011 (T. Kölbel))

3) Development of the resource, plant installation and energy generation:

A geothermal plant being for power or heat production includes many components for the underground system and the surface system. The components of a geothermal heat and/or power plant depend primarily about the type of the plants and especially the treatment of steam or brine and of non-condensable gas. Some more equipment can be considered for the steam & brine supply but are really specific of the conventional geothermal plants being flash or dry steam. It includes Silencers, sand/particulate removers, steam cyclone separators, flash vessels, brine booster pumps and moisture separators.
For geothermal district heating, the surface systems would include: the piping network; pumps; heat substations; and energy meters.

The table below aims at presenting a list of major equipment used per plants category:

Table 1: list of major equipment used per geothermal plants category

Equipments		Type of power plants			Type of Heat and CHP plants
		Dry steam	Single/Double flash	Binary	
Steam and/or brine supply					
	Downhole pumps				
	Wellhead valves and controls				
	Steam piping				
	Brine piping				
Heat exchangers					
	Evaporators				
	Condensers				
Turbine-generator and controls					
	Steam turbine				
	Dual admission turbine		Double flash		
	Binary turbine				
	Control system				
Plant pumps					
	Cooling water circulation				
	Reinjection of brine, separated water and condensate				
	Heat pumps				
Non condensable gas removal system					
	Steam-jet ejectors				
	Compressors				
	Vacuum pumps				
Cooling					
	Cooling tower				
	Air cooling				

Downhole pumps:

The investment cost for selecting and installing an ESP is in the range of between €180,000 and €300,000. Yearly operational costs are estimated to be between €60,000 and €100,000, without including the electricity costs for driving the pump.

Steam gathering:

The cost of steam piping typically depends on the distance from the wells to the plant, the flowing pressure and the chemistry of the fluids. The majority of geothermal projects use carbon steel pipelines. For highly corrosive brine, alloy systems such as various duplex stainless, high nickel alloys or lined pipes can be two to over five times the cost of carbon steel. The piping and controls (remote control is becoming the norm) can vary from €80 to more than €200/kWe. The steam gathering system of a high temperature flash system can exceed €300/kWe once installed. It can be observed that poor steam processing results in high O&M costs and low plant availability.

Heat Exchangers:

The cost of each heat exchanger is about €130,000 – 150,000[1]. The most expensive positions were manufacturing (welding, machining, assembling…) and the acquisition of tubes and sheet plates, representing about 37% and 30% of the total cost respectively. Other material acquisition (shells, flanges, bolts…) represented about 20% of the total cost, while engineering stood at 6%, painting and insulation at 5.5 %, and control and EC certification at 1.5 %.

Non-Condensable Gas (NCG) Removal System

The industry standard for removing the NCG of conventional geothermal power plants (flash or dry steam) has been steam jet ejectors or a hybrid turbo-compressor system of steam jet ejectors and liquid ring vacuum pumps. The European industry is actively developing technology to improve the environmental performance of high temperature geothermal plants by removing the H_2S and mercury from the stream of NCGs. An abatement plant comes at a cost of € 3.5 million per plant.

Cooling Systems

Geothermal plants employ water-cooled systems – typically using cooling towers or air cooling. The investment cost of wet cooling towers is much lower than the cost of air-cooled condensers.

Heat pumps

Cost of a large heat pump of 4 MW_{th} for a geothermal district heating systems, allowing to increase the energetically usable temperature range of geothermal fluids or to lower the temperature of the return/injection, range from €3.5 to 4 million.

[1] Design, manufacturing and commissioning of the ECOGI's heat exchangers at Rittershoffen (France): a case study – EGC2016.

Power Transmission Lines:

The costs of the individual components of a 1 MW_e -transfer station is:

- Envelope of the station: €35,000
- Medium-voltage switchgear: €20,000
- Transformer (1000 kVA): €18,000
- Low-voltage distribution: €6,000
- Incidentals: €3,000

For power plants with a higher electrical output, it is mainly the cost for the transformer that will change, while the remaining equipment stays more or less the same. Given the cost estimation of a 1 MW_e power plant, the transfer station will cost about €80,000 to €85,000. In contrast to this, the costs for routing and cable installation are strongly related to the grid connection point assigned by the grid operator and therefore have site-specific costs. Depending on the cable's diameter, a price of €100-150 per meter is quite common.

Operation & Maintenance (O&M)

The cost of O&M for deep geothermal heat and/or power plants represents about 2-4% of capital costs. Included are:

- Personnel costs for the following actions: remote control, regular routine inspections, start-up / shutdown of the plant and during maintenance.
- Routine maintenance costs: replacing or cleaning equipment such as valves, pumps, the generator, switchgear etc.
- Consumables for the operation: filters, oil and chemicals.

About 1 to 2 weeks of scheduled shutdowns are foreseen each year for general maintenance and 5-8 weeks every 3-6 years for major maintenance. This influences not only the maintenance cost but also the expected utilisation hours.

Operating and maintenance (O&M) expenditures are 2-4%, circa €500,000 - 1,000,000 per year. The biggest expenditure item is power acquired to run production pumps (e.g. a 200 kW production pump). Then, it includes operations at the power plant, on average € 114,000 per year; insurance premiums amount to €338,500 per year. Long-term maintenance costs are difficult to quantify but may be estimated around € 300,000 per year.

Technologies & costs reduction trends

Costs reduction of geothermal technologies can be reached via technology development and innovation, economies of scale but also through competition between market actors, the most experienced and innovative enjoying growth and new business. Also, geothermal energy plants deliver a range of system services (energy storage, flexibility, potentially environmental products such as emission reductions) that are in demand by the marketplace. Hence to value geothermal energy products and services, it is crucial to adopt an approach that goes beyond a levelized cost of heat or electricity (LCoE) methodology but instead adopts a quantification of the value of geothermal energy related products. However, for the time being and in line with the targets of the

Deep Geothermal Implementation Working Group, we continue to talk about cost reduction in terms of levelized cost of heat or electricity.

LEARNING CURVE AND POTENTIAL COST REDUCTION: BEYOND THE LCOE APPROACH

The competitiveness of the deep geothermal sector must be consolidated by first developing a fair basis of cost comparison between energy sources which goes beyond a limited LCoE approach, taking into account actual system costs and external factors. It should be noted that deep geothermal projects have low systems costs and negligible externalities, which means that the LCoE accounts for almost the full costs for the project.
Estimating the value of geothermal in the energy systems is a next step on approaching the costs of a technology.

This potential cost reduction is linked to the third strategic target of the targets from the SET Plan's Deep Geothermal Implementation Plan. The target is set at a maximum production cost of 10 €ct/kWh for electricity and 5 €ct/kWh for heat by 2025.
These cost targets apply to all types of deep geothermal projects, including EGS and super-hot geothermal systems (> 350°C). As of 2019, the levelized cost of energy (LCoE) for electricity production varies between 30 and 150 €/MWh (between 3 and 15 €ct/kWh_e). The higher values are typical for binary plants tapping into medium temperature resources.

The LCoE for flash plants typically is lower at an average value of about 40 €/MWh_e. The selling price for heat in existing geothermal district heating systems is usually around 60 €/ MWh, and within a range of 20 to 80 €/MWh. The price depends on the local geothermal situation, socio-economic conditions and pricing policies. In addition, district heating networks account for a significant share of the total costs for a geothermal district heating system.

The economic potential for geothermal electricity generation in Europe in 2030 and 2050 has been estimated as part of the GEOELEC project, using an LCoE value of less than 150 €/MWh_e for 2030 and less than 100 €/MWh_e for 2050.

TECHNOLOGY PERSPECTIVES

Heating & Cooling generation development

Thanks to continuous technological developments, geothermal resources that previously were out of reach will be explored and developed. The new technologies will make it technically and economically feasible to deliver hot fluids even in areas with an average or low geothermal gradient, by enhancing heat extraction, going deeper, or with the help of heat pumps to lift the temperature. High temperature geothermal sources will also drive absorption chillers, making deep geothermal a unique energy source for fourth generation district heating & cooling (DHC) networks and for industrial processes.

Over the last decades, the supply and return temperatures of DH networks have been reduced. Since modern, energy efficient buildings and new heating systems allow rooms to
be comfortably heated at supply temperatures of 40°C and less, the operative temperatures of the DHC network can be further reduced.
Third and fourth generation DH and DHC networks will be developed, and it will be possible to integrate low temperature geothermal resources in district heating in urban areas anywhere in Europe.

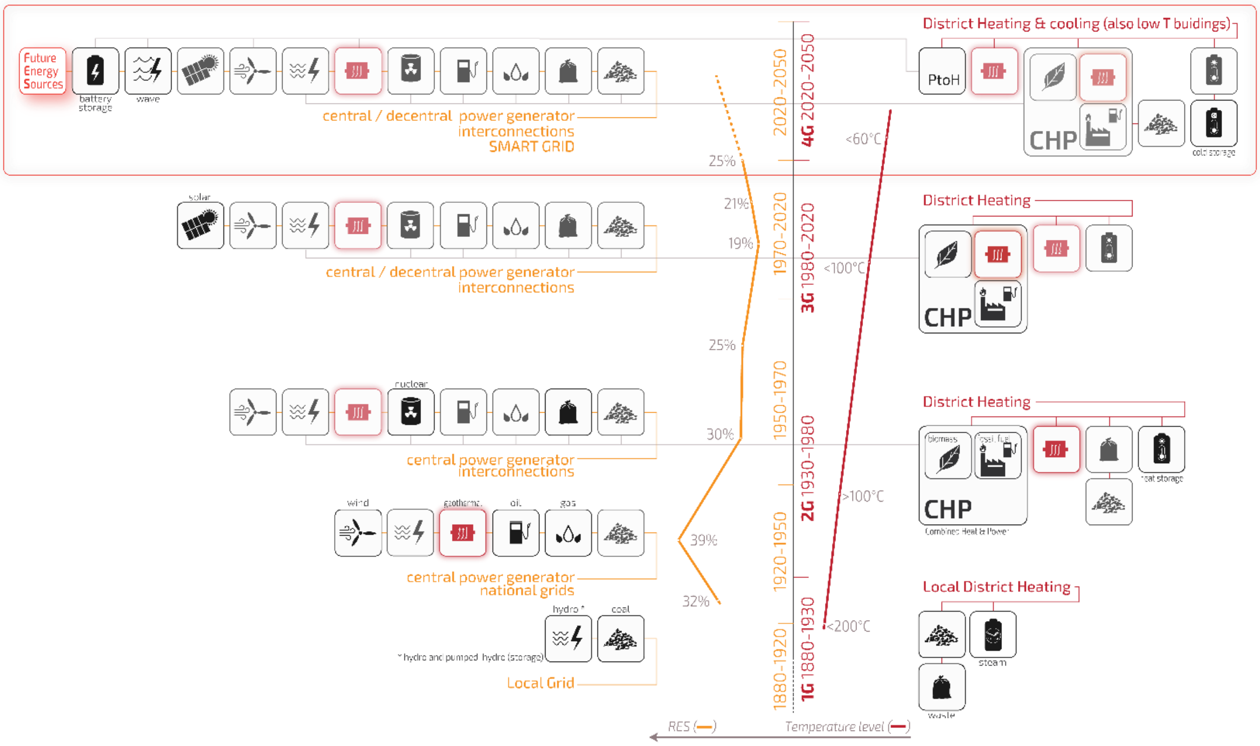

Figure 8: Evolution of district heating and electric power grids (based on: Lund et al., 2014; Harvey et al., 2017; data from History Database of the Global Environment), source: ETIP-DG

Through demand site management or thermal energy storage it will be possible to balance heat demand and supply in a DH network. While demand in a DH network fluctuates on a daily, weekly and seasonal basis, the supply from a geothermal source is constant all year round. Increasing the number of full load hours of the geothermal installations has a direct impact on profitability. One way to balance supply and demand is by demand site management in order to lower peak demands. Another option is to use thermal energy storage systems, to supply additional thermal power during periods of peak demand. Thermal energy storage can take different forms, e.g., local water storage tanks to balance daytime fluctuations in demand, large underground seasonal storage systems, or thermo-chemical storage systems.

The sequential operation of geothermal heat by integrating different technologies that use progressively lower temperatures, known as cascade applications, will further improve efficiency, with a positive economic impact in project development and major benefit for local communities in utilising clean cheap heat for air conditioning, agricultural or industrial applications.

Electricity generation development

The use of geothermal heat for producing electricity is the most flexible way to produce a clean renewable energy product with major sustainabillity benefits; a product that is easily transportable even over long distances and ready for use for the end-users.

Enhanced technical solutions will boost the electrical potential development:

- The utilisation of geothermal resources will be optimized, with a focus on increasing efficiency and reducing LCoE for low temperature binary plants;
- The existing high temperature technologies (heat exchanger, flash/steam plants) will be improved, even through disruptive ideas on cycle design, novel materials, and more;
- Technologies for enhancing heat extraction at depth will be optimized, proved at a large
- scale, and safety precautions will be standardized;
- The unique capability of geothermal energy to operate in hybrid mode with other renewable energy sources (photovoltaic, concentrated solar, biomass and biofuels) will be intensified, with an overall increase in total energy conversion factor;
- New technologies will enable us to access and manage deep and extremely hot resources, whose productivity will be ten times higher than in existing hot systems;
- Cutting-edge technologies will be extensively assessed for producing from untapped resources that pose peculiar issues, such those off-shore, close to magma shallow intrusions, depleted or unproductive hydrocarbon fields and more.

Combining heat & power

Combined production of cold, heat and electrical power (CCHP) will be optimized thanks to low temperature (binary) conversion technologies, which are less vulnerable to maintenance. These can be improved and made affordable by:

- Increasing the efficiency, and reducing losses and internal consumption;
- Improving reliability and durability (resistance to corrosion, abrasion) of equipment;
- Extending the economic resource base by breakthroughs in technologies for subsurface access and heat extraction from the underground;
- Reducing the overall cost for CCHP generation.

POTENTIAL COSTS REDUCTION

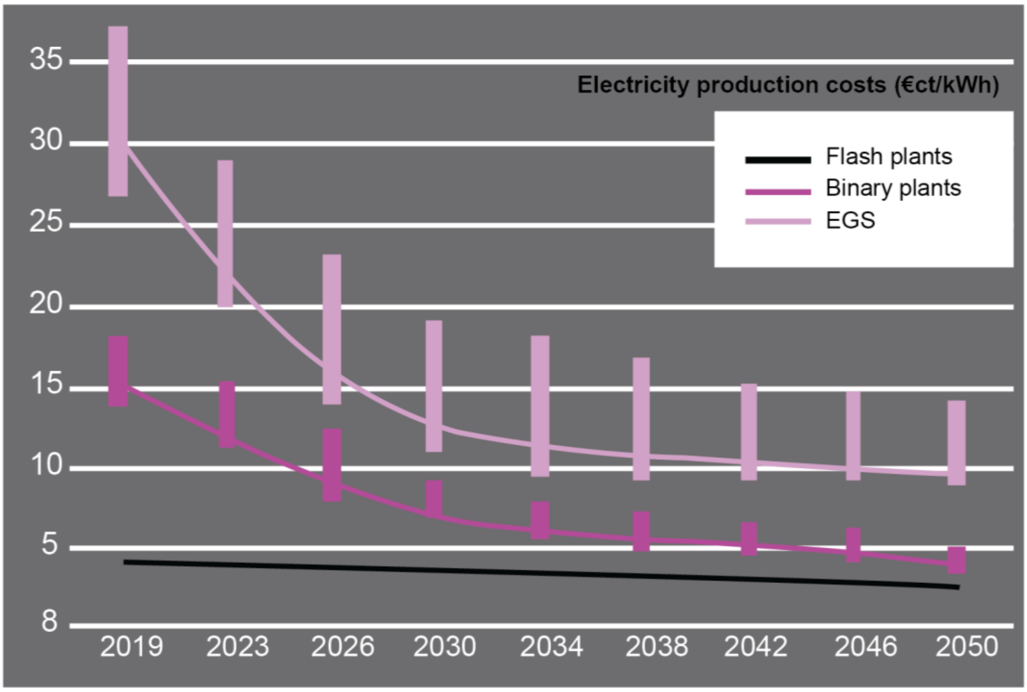

Figure 09: Graphs on Potential costs reduction for geothermal electricity production (costs on €ct/KWh)

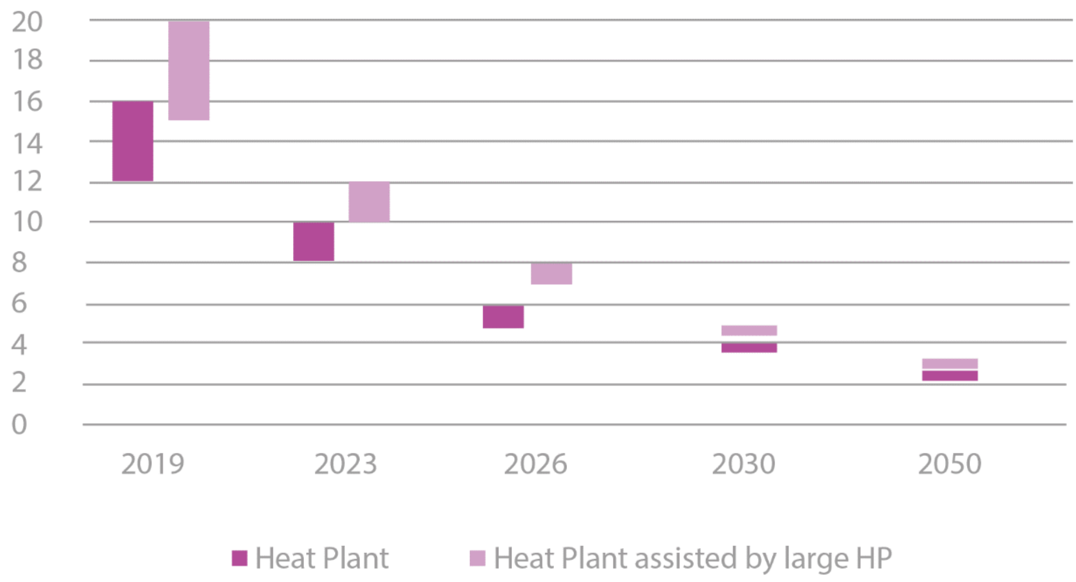

Figure 10: Graphs on Potential costs reduction for geothermal heat production (costs on €ct/KWh)