DELIVERABLE D4.5
METHODOLOGY AND TOOL FOR AN ECONOMIC EVALUATION OF END-OF-FIELD LIFE CONVERSION

WP4: ENHANCING PETROLEUM SEDIMENTARY BASINS FOR GEOTHERMAL ELECTRICITY AND THERMAL POWER PRODUCTION

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PUBLIC SUMMARY

This public deliverable D4.5 was prepared within the framework of the MEET project (H2020) and demonstrates the possible scenarios for the conversion of oil field into the geothermal asset. Based on the different input data 5 scenarios of geothermal energy production with different production technologies are developed with main goal to compare different options for heat and/or electricity production and to choose the optimal one. One of the main features of the conversion is the temperature and spatial clustering which clusters the wells according to the geothermal fluid temperature into a different end-use group, and once again, clusters the wells into spatial groups according to the distance between each well. The latter clustering technique, spatial clustering, enables the user to include all wells on the field with high water-cut in the conversion to upscale the production quantities and to decrease the piping connection cost. Additionally, three sub-programmes are developed to calculate the power consumption of production pump, injection pump, and deep borehole heat exchanger pump. After entering the input data for each scenario, the conversion tool will calculate the five main outputs: produced energy quantities, levelized cost of electricity or heat, net present value, energy efficiency, and avoided CO_2 emissions. Based on these results the user should decide which conversion option is optimal for a given petroleum asset. Additionally, sensitivity analysis and optimization tool regarding the installed heat capacity are also developed to provide insight into the changeable parameters that could influence on the project development.

1 EXECUTIVE SUMMARY

The following document entitled “Methodology and tool for an economic evaluation of end-of-life conversion” is a Deliverable of Work Package 4 “Enhancing petroleum production sedimentary basins for geothermal electricity and thermal power” of the MEET project.

The MEET project (Multidisciplinary and multi-context demonstration of Enhanced Geothermal Systems exploration and Exploitation Techniques and potentials) aims to demonstrate the viability of EGS with electric and thermal power generation in all main kinds of geological settings (crystalline, sedimentary, metamorphic, volcanic). The economic viability of EGS projects is largely restricted with the high capital expenditures (CAPEX), related mainly to the deep drilling operations and stimulation process. This pushes the idea of re-using already existing infrastructures/boreholes. In that sense, by converting oil wells into geothermal wells at its end-of-life time, it could be possible to bypass the bottleneck of the drilling phase hence reducing the CAPEX, avoiding permit to explore and drill, and reducing project set-up time.

1.1 DESCRIPTION OF THE DELIVERABLE CONTENT AND PURPOSE

This report provides necessary explanations of used approaches, assumptions, and description of methodology. Additionally, the explanations on how to use the Excel-based support tool are provided in this report. The descriptions and guidelines provide a comprehensive overview of the Excel-based support tool alongside its limitations and interpretation of output data. The descriptions are detailed enough that the support tool could be used both by experienced users with knowledge and background in petroleum or geological engineering and by less experienced users such as policy makers.

One of the objectives of Work package 4 is to envisage the technical, economic, and regulatory conditions needed to generate value when converting an oil field to a geothermal site at the time oil production is no longer economic. In that scope, the purpose of this Deliverable 4.5 is to propose a methodology for the end-of-life conversion evaluation and corresponding support tool that uses different input data. Based on the inserted input data, different options for heat and/or electricity production can be simulated, and main economic, environmental and lifetime production output data calculated. Depending on the calculated output data the optimal option for a specific oil field can be found. The Excel-based tool is modelled in such a way that it should enable investors to conduct a pre-technical-economic feasibility study for converting an oil field to a geothermal field at the end of its economic “petroleum” life. The methodology covers primarily technical and economic aspects of end-of-life conversion process while regulatory and policy aspects of such action are left on the knowledge of the user/potential investor, since this is highly country specific.

1.2 BRIEF DESCRIPTION OF THE STATE OF THE ART AND THE INNOVATION BREAKTHROUGHS

Geothermal heat has been traditionally extracted at locations characterized by hydrogeological anomalies, but recent advances in engineering have enabled development of alternative approaches such as enhanced geothermal systems (EGS) and borehole heat exchangers (BHE) [1]. Both technologies can enable harvesting Earth's heat without any (or little) location constraints. EGS systems are used to produce energy by enhancing in-situ permeability and harvesting heat from hot rock reservoirs. The heat is transferred from hot rock to circulating fluid which is brought to surface via production well and reinjected via injection well. The connection between production and injection well is engineered by various stimulation techniques. The viability of an EGS project is mostly influenced by brine flow rate and production temperature, where higher flow rates and temperatures support electricity generation and lower values support direct usage of hot water, i.e. heating power production. Flow rates could be increased by applying reservoir stimulation, whereas temperatures can be increased only by drilling deeper wells. BHEs harvest the geothermal energy without direct interaction of flowing fluid with the soil or rock. Different from the EGS, the efficiency of deep BHEs strongly depends on heat exchanger configuration and the host rock thermal properties. The economic viability of both technologies, especially considering high depths (> 3 km) depends on emerging technologies, drilling technologies, reservoir technologies, etc. To bypass prospecting and drilling risks the mature and abandoned oil wells could be used. There are thousands of onshore wells in Europe and most of them are mature oil provinces where is expected that the existing wells are now producing much more water than oil, with an average water/fluid ratio higher than 90% and thus the cost of wastewater disposal increases. The oil reservoirs depth ranges between few hundreds to few thousands meters, therefore the fluid temperature at the surface can reach up to 90°C. In most cases, the hot water is reinjected into the reservoir to increase production through pressure support and sweep, hence the calorific energy of water is wasted. This is the coupling point between oil industry and geothermal energy production. Namely, the possibility of using these hot fluids to produce geothermal energy during the final stage of the life of an oil field and then convert the field into a geothermal one, is an emerging and interesting option. However, it's important to identify the exploitation technology best suited to the site and potentially close end users as in case of heating power production. Given its promising future, numerous studies on geothermal energy extractions from abandoned oil wells have been conducted and reported [2]. These studies have been mainly focused on the technical feasibility of retrofitting abandoned oil well for geothermal energy extraction, performance over years of operation, choices of wellbore heat exchanger (U-tube and double pipe), determination of open-loop or closed loop geothermal extraction, and heat transfer enhancements. Various key parameters such as the properties of working fluids, wellbore architecture, and operational parameters (working fluid flow rate, inlet temperature, operating pressure, and others) in geothermal energy production were investigated as well. Additionally, several studies have been reported economical aspects of retrofitting abandoned oil well as geothermal well. Moreover, the majority of work that has been done on retrofitting abandoned petroleum wells as a source for geothermal energy has been focused on open loop systems that repurpose the petroleum reservoir as a geothermal reservoir [3]. There are a multitude of countries that have sponsored research and/or work specific to adapting an open loop design to abandoned wells, including: Albania, China, Croatia, Hungary, Israel, New Zealand, Poland, and the US. Additionally, VERMILION is recovering heat from 2 producing oil fields in sedimentary basin in France. On the Parentis oil field in SW France, 60 wells producing a total of 400 m^3/h water at 60°C water have been used to heat up 8 Ha of tomato greenhouses since 2008, creating more than 100 jobs. In La Teste in SW France, two producer wells yield 40 m^3/h at 70°C which is enough to cover 80% of the heat need for 450 new flats. These 2 projects demonstrate that recovering heat from produced water creates value and jobs, at any scale (small or large oil fields).

End-of-life oil well conversion methodology towards geothermal wells will define the roadmap for further transfer of oil well fields into geothermal production wells, thereby enabling a certain niche for geothermal energy penetration into the market. Namely, mature and abandoned oil wells have a significant potential to be converted into geothermal wells as they are readily available, i.e. no drilling is required, and they usually have complete data logs throughout their production periods, enabling complete well performance estimation, minimizing risk and providing a better cost estimation [2]. Moreover, existing infrastructure and facilities available in the oil wells can be directly converted to enable geothermal energy extraction, saving a considerable cost as compared to constructing a new geothermal energy drill hole and power plant. Retrofitting mature or abandoned oil wells into geothermal wells also offers the benefit of minimizing or even eliminating decommissioning cost of old oil well, extending the economic life of the well, and minimizing the potential problem with liquid leakage of sealed wells.

The proposed methodology and corresponding support tool for an economic evaluation of end-of-life conversion will enable pre-technical-economic feasibility study for converting an oil filed to a geothermal field at the end of its economic “petroleum” life. The clustering feature, where wells can be clustered based on the production temperature and spatial distribution, enables including wells at a specific oil field in the calculations that are best suitable for a certain option – only heating power production, electricity generation or both (combined heat and electricity production, CHP). This two-level clustering method facilitates the decision process regarding the possible usage of the produced heat. Starting with temperature clustering which is based on sorting the oil wells into different groups based on the temperature ranges from modified Lindal diagram [4]. Additionally, the spatial clustering which is based on the grouping of a certain number of wells into one group according to their mutual distances, enables the best allocation of power plant installation and piping connection system between selected wells. The output results of the methodology are based on economic metrics (NPV, LCOE, LCOH) and production metrics (yearly/monthly production values, avoided CO_2 emissions) that are used in the decision-making process whether to invest in a specific project or not.

Development of an Excel-based support tool that incorporates proposed methodology also allows a user-friendly and familiar environment for users. This is one of the main characteristics of this support tool and it distinguishes work done for this Deliverable and approach applied here from the previous studies.

1.3 CORRECTIVE ACTION (IF RELEVANT)

N/A

1.4 IPR ISSUES (IF RELEVANT)

N/A

2 INTRODUCTION

The developed Excel-based methodology and tool for the end-of-field life conversion consists of Python included machine learning methods for spatial clustering and Python code for temperature clustering, and Matlab code for the heat capacity optimization which will be explained in the following text. In the Excel-based support tool, there are 16 worksheets, summarizing the general data about the developed methodology and the instruction on how to use the tool, main input parameters and output data with explanations, three individual sub-programmes used for calculating the pump power consumption, graphical representation of the results, and the sensitivity analysis. In the following text, the developed scenarios and the methodology will be explained and substantiated with the text and calculation procedures from the literature. After the explanation of the methodology, the tool and the use of the tool will be briefly explained.

3 METHODOLOGY

3.1 GENERAL DESCRIPTION

The methodology and tool for an economic evaluation of end-of-field life conversion is a decision-making framework and support tool that uses different input data which main goal is to compare different options for heat and/or electricity production and choose the most suitable option. The main purpose of the methodology and tool is to offer to user the optimal scenario for converting the petroleum asset to a geothermal one. Based on the user's input data of mature or abandoned petroleum field, economic or environmental parameters, and technological features, 5 scenarios are modelled which result in output data. The output data, based on the extensive and thorough calculations, will provide insight into the economic and environmental aspect of the geothermal project for each scenario.

One of the key benefits of the proposed work is the avoidance of decommissioning cost of wells and surface facilities and generating the income through electricity and heat production by repurposing the mature oil field to a geothermal asset. One of the main contributions of the methodology and tool is the two-stage clustering that enables the temperature and spatial arrangement of the wells and, among the oil wells, also includes the wells from the field that were previously flooded and were not producing oil or newly drilled wells in terms of upscaling the geothermal energy production. The two-stage clustering is an optimization process because it clusters the wells according to the temperature of the end-use and according to the spatial distribution so that the position of the geothermal plant can be determined and the inclusion of the wells in gathering system corresponding to the shortest distance from the geothermal plant.

The developed methodology and corresponding tool should serve as the pre-feasibility study of converting a petroleum field to a geothermal one. The methodology and tool provide guidelines in terms of retrofitting mature or abandoned petroleum fields to geothermal energy exploitation, and user-friendly environment whose outputs could encourage the possible users to invest into the geothermal projects.

There are 5 developed scenarios for possible conversion of an oil field to the geothermal asset:

- <u>1A Scenario – “Do nothing”</u>
  This scenario refers to the plugging and dismantling all the wells and surface facilities and can represents hundreds of thousands of € of abandonment cost per well, required by mining law. It is well-known that the operating life of oil field has a limitation, and when a field hits the end of its operational life, a strategy must be planned to have it plugged and discontinue the operations or to have it removed. Because decommissioning activity tends to pick up pace near the end stage of a given project when income from the oil field has dropped and the ageing infrastructure at times has low or no economic value, early decommissioning cost estimation is vital to guarantee a success of a project.
  The costs vary significantly due to factors such as location and type of the facility (level of complexity), number of structures needed to be removed, weight associated with the structure, the number and well depth and conductors, method of removal, transportation, and disposal options, etc [5].

- <u>2A Scenario – “Heat doublets”</u>
  The developed scenario concerns the heat production from production wells and injecting the geothermal fluid into the reservoir using the injection wells. A main challenge with the industry is related to the capital-intensive costs of drilling geothermal wells, hence the introduction of abandoned petroleum wells is of interest. The aforementioned wells can potentially be harnessed for geothermal energy for direct usage depending on the temperature of geothermal water [6–8]. This scenario consists of two sub-scenarios: *Temperature range* sub-scenario and *Heat needs* sub-scenario. The *Temperature range* sub-scenario is the scenario where the heat production is based on the utilizing the temperature range of geothermal fluid (production temperature and fixed injection temperature). The latter scenario, *Heat needs* sub-scenario is based on the satisfying the heat demand of the end-user. The heat demand is set as the user’s input, or it is calculated based on the heat demand of three different type of buildings.

- <u>3A Scenario – “Heat DBHE”</u>
  The modelled scenario regards the heat production using one well, i.e., the deep borehole heat exchanger (DBHE). Downhole heat exchangers can be used to extract heat without producing geothermal fluid from the abandoned oil wells to generate electricity or direct use applications, which decreases gas emissions to the atmosphere and energy need for reinjection. The circulating fluid is injected through annular space and produced at the wellhead through production tubing [8–11]. This scenario consists of two sub-scenarios: *Temperature range* sub-scenario and *Heat needs* sub-scenario. The *Temperature range* sub-scenario is the scenario where the heat production is based on the utilizing the temperature range of geothermal fluid (production temperature and fixed injection temperature). The latter scenario, *Heat needs* sub-scenario is based on the satisfying the heat demand of the end-user. The heat demand is set as the user’s input, or it is calculated based on the heat demand of three different type of buildings.

- <u>4A Scenario – “ORC Power”</u>
  This scenario represents the electric power generation using the Organic Rankine Cycle (ORC). The electricity can be produced using the production and injection wells or using the deep borehole heat exchanger. The power capacity is determined primarily by the production rate, temperature of produced water, ambient temperature, water salinity, conversion efficiency of the geothermal power plant, heat transfer efficiency between the reservoir rocks and circulating fluid, etc [7,12–16].

- <u>5A Scenario – “Power and heat”</u>
  The developed scenario refers to the combined heat and power production (CHP) with parallel configuration mode [17]. Total geothermal fluid flow is divided into two branches as following, primarily the heat demand (users input or calculated) is satisfied, and then electric power is produced with the residual flow. Two sub-scenarios are developed: the first one with the production and injection wells, and second one with the DBHE. The well for the DBHE is the well with the highest temperature according to the wells clustered by the "electricity" end-use [7,8,10,11,15,16].

3.2 INPUT DATA

The main input data used in the methodology for calculations and clustering process are shown in Table 1. Additional general data are also included and contain information such as country name, reservoir name, number of production and injection wells, total fluid flows, etc.
Even at very high water cut, an oil field often displays mixed flow, meaning that a given geological layer produces both oil and water. It is therefore expected to produce both water and oil after conversion. Since the oil cut is very low it is expected that gravity separation in water tanks will take place. Yearly water-cut increment is a linear percentage value of the annual average water-cut increase, based on the historical data. Yearly thermal dropdown is defined as the annual average temperature decline rate for petro-thermal reservoirs, as reservoir is expected to be cooled down by colder fluid injection. Additionally, at the beginning of the calculations it should be determined if the electric submersible pump (ESP) is already installed and running or not. If the pump is already installed, additional input regarding the pump power is required which is afterwards used to calculate the pump consumption power, i.e., parasitic load. In both cases, if the pump is already installed or not yet installed, the user should proceed with the calculation related to the ESP pump design to either design the required new pump that should be installed or to estimate the pump consumption for already installed pump. The temperature loss along the wellbore is also stated as the user’s input, and it is automatically subtracted from the reservoir temperature to calculate with the wellhead temperature, i.e., production temperature.

Table 1. List of general input data required for the clustering methods and calculations.

Input data	UNITS
Well name	-
Longitude	m
Latitude	m
Reservoir temperature	°C
Oil production	m^3/s
Water production	m^3/s
Bottomhole pressure	bar
Density of oil	kg/m^3
Density of geothermal fluid	kg/m^3
Specific heat capacity of oil	J/kg°C
Specific heat capacity of geothermal fluid	J/kg°C
Well depth	m
Yearly thermal dropdown	%
Yearly water-cut increment	%
ESP installed	yes/no
Temperature loss along the wellbore	°C

3.3 TEMPERATURE AND SPATIAL CLUSTERING

At the end of its economic life, a certain spatial footprint exists, based on the development history of the oil fields: well pads are made of several wells drilled from the same surface location, connected to the main facilities by flowlines. Each of the wells can have different surface flow rate and temperature. When converting the oil field to a geothermal usage, one will expect to optimise the well stock and keep the wells that deliver the most suitable flow rate and temperature.

The basis of the developed methodology and tool is the clustering of the wells, both temperature and spatial clustering. For both clustering layers, Python programming language is used with integrated pre-made libraries. In the first layer of clustering, temperature clustering, the production wells are sorted into the temperature groups according to their well temperature, and each well is sorted into group for one or more end-uses. The well that has more than one end-use goes into calculation for more than one scenario.

The second layer of clustering is the spatial clustering where the used method of clustering sorts the wells in certain number of clusters (users input or calculated value) based on their distances between each other. The spatial clustering enables the user to include in the calculations unused wells on the field, that have a high water-cut that is suitable for the geothermal energy production, which were not previously included into the oil production, and newly drilled wells which have a high water-cut and are drilled for the geothermal purposes on the mature or abandoned oil field. Adding new wells into the gathering system or excluding some of the old ones can influence the fluid flow and the pressure drop along the piping system which further influences the efficiency of the plant,

so the results of spatial clustering suggest which wells of the field to include in the potential new gathering system or in which cluster to add the new wells and connect them to the existing or new gathering system. Spatial clustering also defines the data point (centroid, most commonly an imaginary point) which is in the middle of the clusters and the well (existing data point that is nearest to the centroid) upon which the new thermal or power plant should be built so that the cost of potential new piping system would be the lowest.
Also, this method could be applied to the already existing geothermal fields to upscale the production of geothermal energy by adding new wells and decreasing the piping and associated costs.

The use of temperature and spatial clustering will be explained in detail in the “Tool” section. The clustering methods used in the methodology and tool will be explained in the following subsections.

3.3.1 Temperature clustering

One of the clustering layers is the temperature clustering which is based on the Lindal’s diagram [4] with minor modifications. Minor modifications of the Lindal’s diagram and the possible applications of geothermal energy made for the purpose of the methodology and tool are concerning the expansion of the temperature ranges for end-uses. The main modification is the expansion of temperature range for electricity production using the Organic Rankine Cycle (ORC) smart mobile units which is one on the main goals of MEET project, i.e., enhancing heat-to-power conversion al low temperature (60°C – 90°C). The temperature ranges for different end-uses are shown in Figure 1. The temperature spans from 0°C to 200°C with the heat pump, heat generation, and electricity generation as the end-uses. The electricity generation end-use covers the electricity production using smart mobile ORC units and electricity production in binary systems (ORC). The temperature range for heat pump is stated here as the informational data and it does not go into further calculation for the purposes of the methodology and tool.

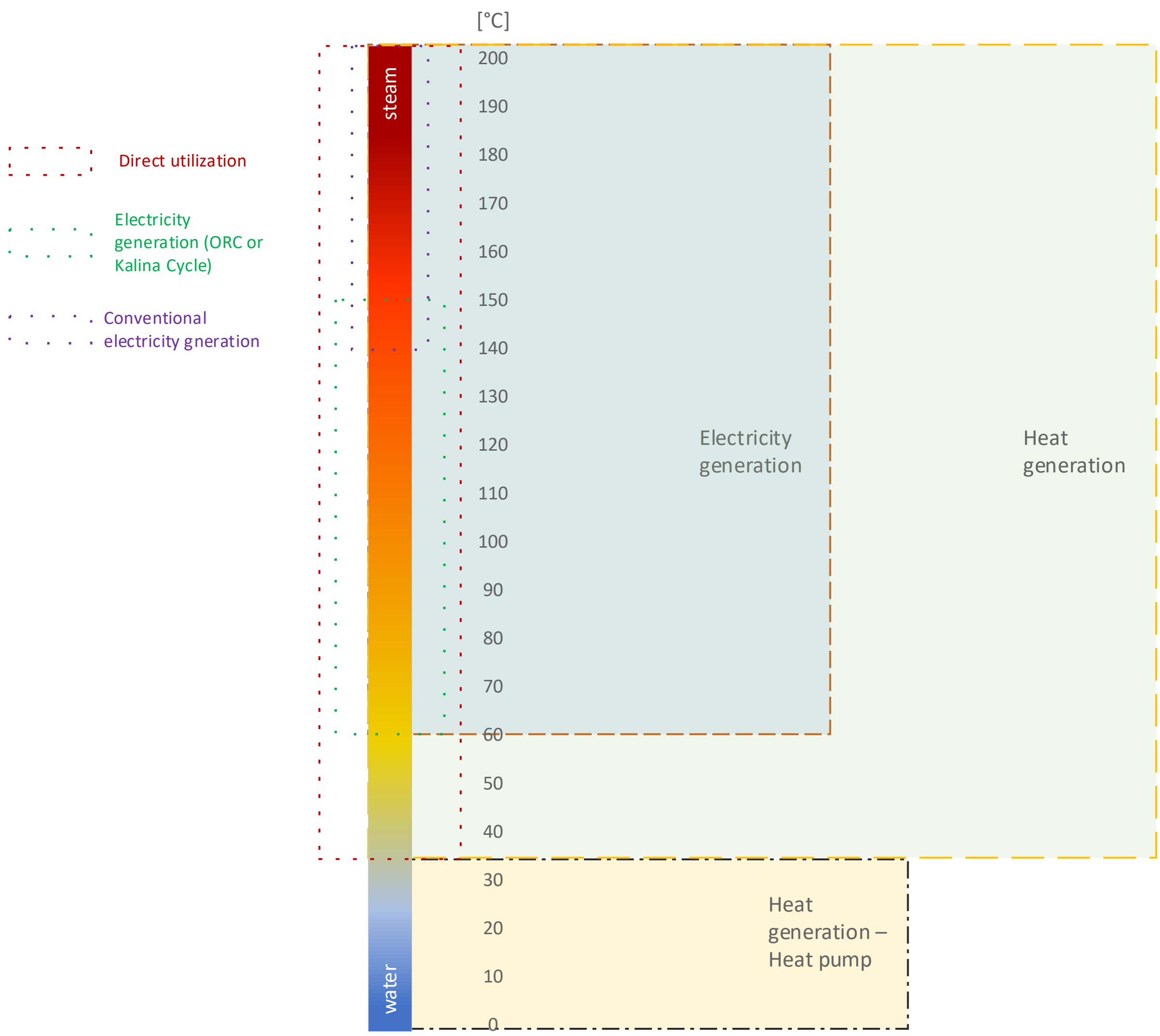

Figure 1. Modified Lindal diagram with temperature ranges for each methodology and tool end-use.

3.3.2 K-Means clustering method

K-Means Clustering is an unsupervised machine learning algorithm. In contrast to traditional supervised machine learning algorithms K-Means attempts to classify data without having first been trained with labelled data. This partitional clustering method divides object into non-overlapping groups. In other words, no object can be a member of more than one cluster, and every cluster must have at least one object. This method requires that the number of clusters is specified in advance.

K-Means algorithm divides the set of *N* data samples *X* into *K* separate clusters, from which each data sample is described with the distance from the closest centroid. Centroid point is the point which represents the centre of a cluster, i.e., the point which has the smallest distance towards the rest of the points in a given cluster. Centroid point can theoretically be a real point (if the set of data has the same distances between each other) in a set of data or imaginary point [18].

The number of clusters can be predetermined, or it can be calculated using the “elbow method”, i.e., calculating the sum of squared distance (SSE) between each member of the cluster and its centroid according to the Equation (1). As the number of clusters increases, SSE decreases, and as more centroids are added, the distance from each point to its closest centroid will decrease. The plotted curve, number of clusters vs. SSE, starts to bend at the spot known as the “elbow point”, where the trade-off between the SEE and number of clusters is the most reasonable, i.e. with the increase in the number of clusters, the SEE does not change significantly which means that the data point do not change the clusters and the distance between the centroid and the rest of the data point stays the same [19].

$$SSE = \sum_{i=1}^{n}(x_i - c_i)^2 \qquad (1)$$

The basic algorithm of the K-Means method has 4 significant steps, listed as follows:

- Specify the number of clusters (predetermined or calculated),
- Assign to each of the cluster’s centroid a data point by calculating the smallest distance,
- Compute new centroids considering the mean value of all data points assigned to previous centroid,
- Repeat the steps until the position of centroid does not change.

In Figure 2, K-Means clustering method is shown on the set of data where the number of clusters is calculated using the “elbow method”.

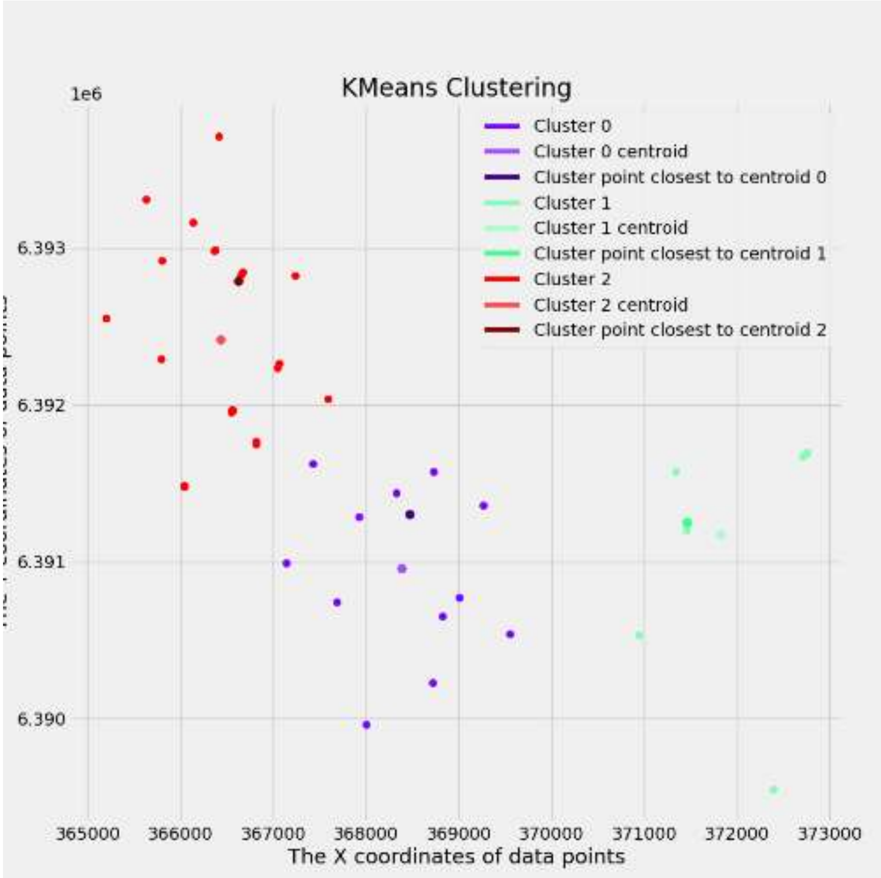

Figure 2. K-Means spatial clustering method on a given set of data points.

The main advantage of this method is that it can be used on the large set of data, and it works well when the clusters have a spherical shape. The main weaknesses of this method are that it is not well suited for the clusters with complex shapes, different sizes, or different densities, and it does not calculate the outlier data points because it takes all the data points into account [20].

3.3.3 Density-based clustering method – DBSCAN

DBSCAN, or Density-Based Spatial Clustering of Applications with Noise, is an unsupervised machine learning algorithm. Unsupervised machine learning algorithms are used to classify unlabelled data. In other words, the samples used to train the model do not come with predefined categories [21]. DBSCAN method examines the clusters as high-density region separated by low-density regions, therefore the clusters found by DBSCAN method can be of any shape.

For this clustering method, a few important parameters need to be predetermined:

- Epsilon, maximum distance between two samples for one to be considered as in the neighbourhood with other,
- Min_samples, the number of samples (or total weight) in a neighbourhood for a point to be considered as a core point and includes the point itself,

- Metric, the metric to use when calculating distance between instances in a feature array.

DBSCAN creates a circle of epsilon radius around every data point and classifies them into core point, border point, and noise point. A data point is a core point if the circle around it contains at least min_samples number of points. If the number of points is less than min_samples, then it is classified as border point, and if there are no other data points around any data point within epsilon radius, then it treated as noise point [22].

The “epsilon” value can be calculated as the average distance between each point in the data set and its “min_sample” nearest neighbours. The average distance is then plotted by ascending value where the sorted values produce a “k-distance” elbow plot which indicates on the point with maximum curvature, which is the “epsilon” value.

The main advantage of this method is the determination of outlier points and selection of cluster according to the different shapes of data set. The main weakness of the method is that it does not work well with the data set that has different densities (different distances between the points) and due to the fact that “epsilon” is a fixed value, it will characterize the points with different densities as outlier points.

For the methodology and tool purposes, the “epsilon” value is calculated as stated above, “min_sample” number is defined by the user, and the “metric” by default is set as the Euclidean distance. In Figure 3, the DBSCAN method is shown with the data set used further in the methodology.

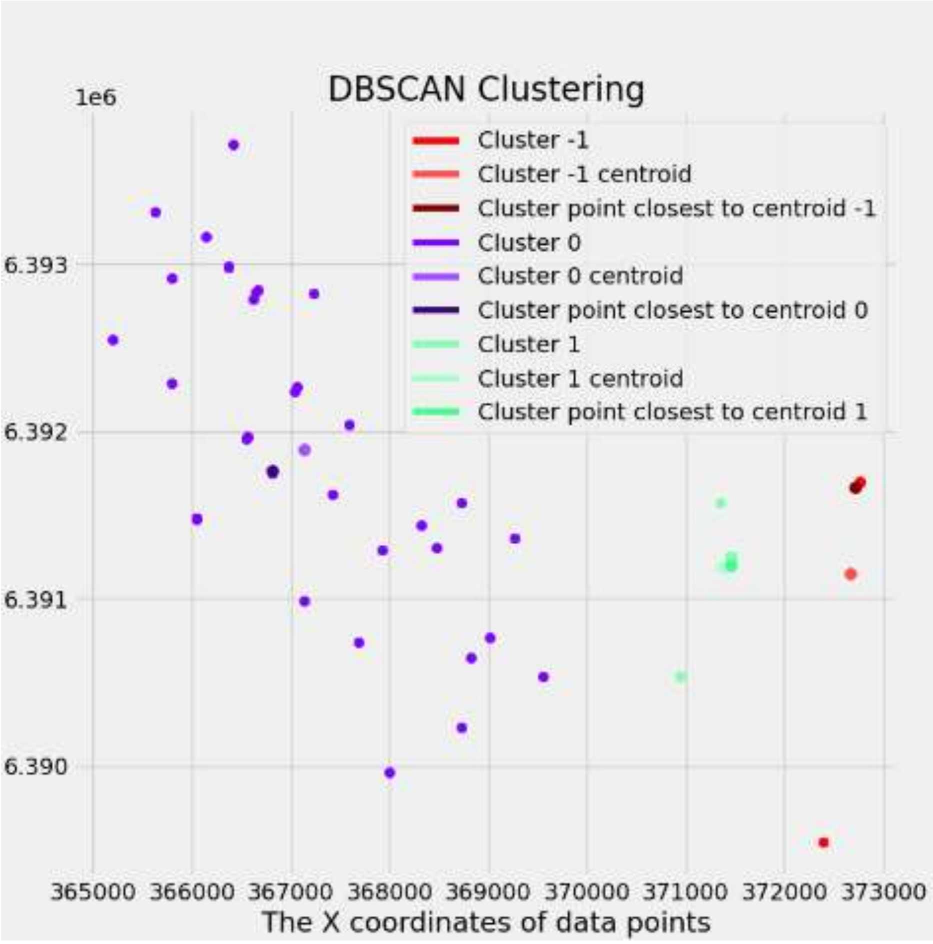

Figure 3. DBSCAN spatial clustering method on a given set of data points.

3.3.4 Hierarchical agglomerative clustering method

Hierarchical clustering is a type of unsupervised machine learning algorithm used to cluster unlabelled data points. Hierarchical clustering also groups together the data points with similar characteristics. In this type of hierarchical clustering used in the methodology and tool, the agglomerative type, the data points are clustered using a bottom-up approach starting with the individual data point. The steps to perform the hierarchical agglomerative clustering are listed as follows [23]:

- At the start, each data is one cluster for itself therefore, the number of clusters at the start will be *K*, while *K* is an integer representing the number of data points,
- Forming the cluster by joining the two closest data points resulting in *K-1* clusters,
- Forming more clusters by joining two closest clusters resulting in *K-2* clusters,
- Repeat the steps until one whole cluster is formed,
- Once the cluster is formed, dendrograms are used to divide into multiple clusters depending upon the problem.

The vertical height in the mentioned dendrogram represents the Euclidean distance between points. Once the one whole cluster is formed, the longest vertical distance without any horizontal lines passing through is selected and a horizontal line is drawn through it. The number of vertical lines that this newly created horizontal line is passing is equal to number of clusters. In the methodology and tool, the number of clusters is calculated and determined as the number of “leaf colours” in the Python code.

The parameter upon which a certain data point is assigned to the clusters is the distance (Euclidean or Manhattan distance). For the methodology and tool calculation, the Euclidean distance is set as default distance with which the calculations will be performed. There are few linkage types based on which the distance between the data points and/or clusters is calculated [24]. The linkage types used in the methodology and tool, from which the user should choose its option, are listed below and shortly described:

- **Ward** - Ward linkage type minimizes the sum of squared differences within all clusters. It is a variance-minimizing approach and in this sense, it is similar to the K-Means objective function,
- **Complete** – It minimizes the maximum distance between observations of pairs or clusters, i.e., returns the maximum distance between each data point,
- **Average** – It minimizes the average of distances between all observations of pairs of clusters,
- **Single** - It minimizes the minimum distance between the closest observations of pairs of clusters, i.e., returns the minimum distance between two points where each point belongs to two different clusters.

The main advantage of the hierarchical agglomerative clustering method is that it considers all the data from the data set, and it is simple to implement, and produces a dendrogram which enables a simple data understanding. The main disadvantage could be the difficulties with the identifying the number of clusters in the dendrogram. Regarding the linkage type, each stated type has its own disadvantages [25] (chaining effect, sensitivity to noise, inversion, etc.) and it is up to the user to decide which linkage type suits the most for a given set of data.

In Figure 4, hierarchical clustering method is shown with the linkage type “Ward” on the set of data used further in methodology.

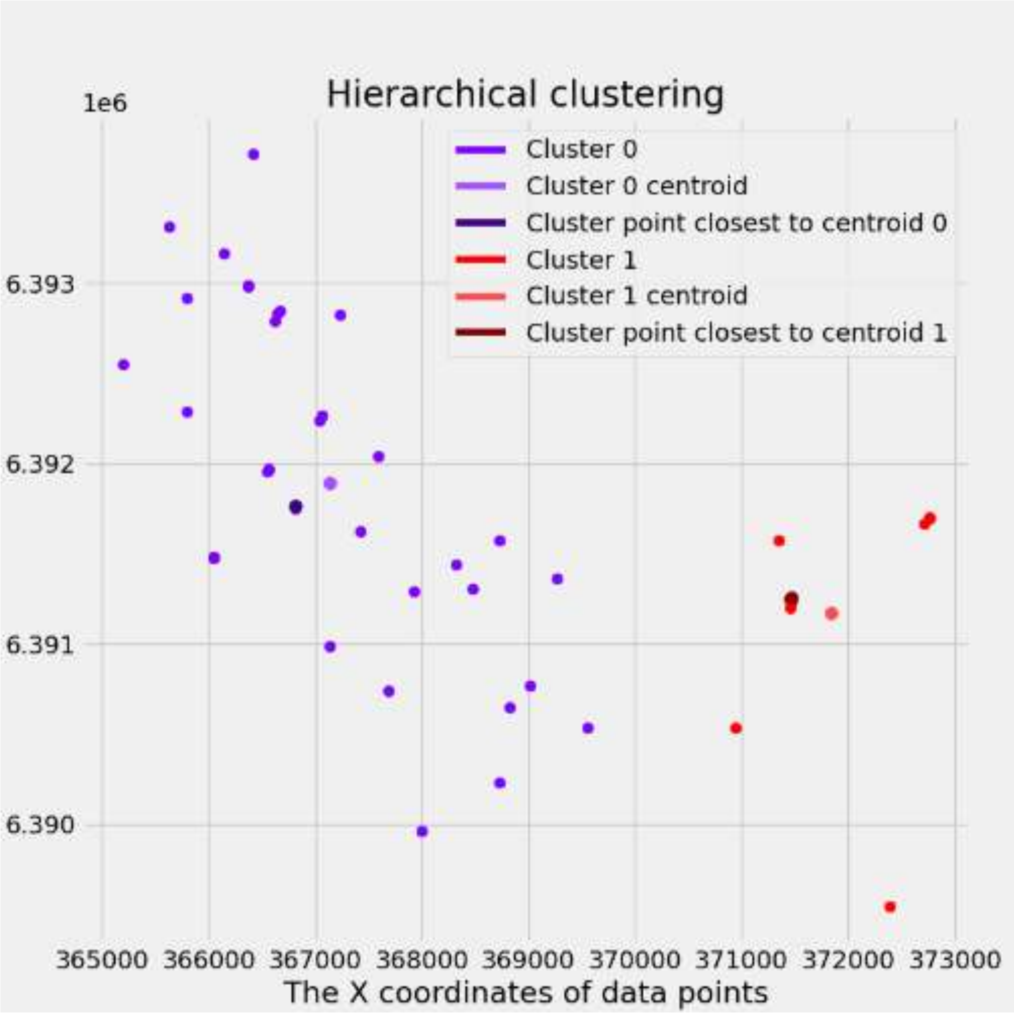

Figure 4. Hierarchical spatial clustering method on a given set of data, with linkage type "Ward".

3.3.5 Clustering output data

When the two-layer clustering is finished and the number of clusters in the specific field is obtained, the methodology enables the filtering option. Namely, various filtering options are possible: filtering of the individual wells, filtering the number of end-uses for each well, filtering desired end-uses to be included in further calculations, filtering regarding the wellhead temperature, and filtering according to the number of the cluster in which the well is located. This type of listing and filtering later enables the calculation of each scenario, both heat and electricity generation, and gives the user an option to include or exclude a particular well or cluster from the further calculations and scenario development.

The usage of the filtering option will be later explained in the “Tool” section.

3.4 PRODUCTION CALCULATION

Regarding the production, the monthly energy production values for each modelled scenario are calculated in the units of kilowatt hour in the project period. For each month in the project period the thermal dropdown and water-cut increment are calculated based on the user's input.
For both electricity and heat generation scenarios, when using the production – injection wells, the temperature of the mixed fluids, density of the mixed fluids, and specific heat capacity of the mixed fluids is computed from all the wells from the field which are filtered/chosen after the clustering process.
The temperature of filtered wells is calculated using the Richmann's rule of mixing [26] shown in the Equation (2),

$$T_m = \frac{q_1 \cdot c_1 \cdot T_1 + q_2 \cdot c_2 \cdot T_2}{q_1 \cdot c_1 + q_2 \cdot c_2} \tag{2}$$

Where the *T* represents the fluid's temperature [°C], *q* is the fluid flow $[\mathrm{m^3/s}]$, and *c* is the specific heat capacity $[\mathrm{J/kg°C}]$ of the geothermal fluid from each well.
Also, the density of the mixed fluid [27] from the geothermal water from all the wells used in the methodology is calculated using the Equation (3),

$$\rho_f = \frac{\rho_1 \cdot q_1 + \rho_2 \cdot q_2}{q_1 + q_2} \tag{3}$$

Where the ρ represents the density of the geothermal water $[\mathrm{kg/m^3}]$ from a specific well and *q* is the fluid flow $[\mathrm{m^3/s}]$ from the well.
The specific heat capacity of the mixed fluid is determined using the Equation (4) [28],

$$c_p = \frac{q_1 \cdot c_1 + q_2 \cdot c_2}{q_1 + q_2} \tag{4}$$

Where the *c* refers to the specific heat capacity of geothermal fluid $[\mathrm{J/kg°C}]$ and *q* is the fluid flow $[\mathrm{m^3/s}]$.
The fluid flow of a mixture of geothermal fluids $[\mathrm{m^3/s}]$, i.e., after the gathering system is the sum of all geothermal fluid flows from the wells that are inserted in the methodology.

3.4.1 1A Scenario - "Do nothing scenario"

In this scenario there is no energy production. The main activity is to plug and abandon wells and surface facilities.

3.4.2 2A Scenario - "Heat doublets"

In this scenario, the thermal energy production refers to the geothermal energy exploitation using the production wells and injecting the geothermal fluid back to the reservoir via injection wells. As mentioned before, two sub-scenarios are developed: Temperature range scenario and Heat needs scenario.

The first one regards the thermal energy production exploiting the fixed temperature range between geothermal fluid production temperature and fixed injection temperature where the heat could be delivered to the multiple end-users during the whole year or serve as the base load thermal power plant. The installed capacity (kW) is a direct function of specific heat capacity of geothermal fluid, density of geothermal fluid, fluid flow, and the temperature difference between the temperature inlet and outlet in the thermal power plant, as shown in the Equation (5) [15],

$$Q_{th} = c_p \cdot \rho \cdot q \cdot (T_i - T_o) \tag{5}$$

Where the c_p is the specific heat capacity of the geothermal fluid [J/kg°C], ρ represents the density of the geothermal water [$\mathrm{kg/m^3}$], q is the fluid flow [$\mathrm{m^3/s}$], the T_i is the production temperature [°C], i.e., the temperature at the inlet of the thermal power plant, T_o is the injection temperature [°C], that is the temperature at the outlet of the thermal power plant.

The produced heat (kWh) is calculated using the Equation (6),

$$E_{th} = c_p \cdot \rho \cdot q \cdot (T_i - T_o) \cdot t \cdot \eta_{HE} \tag{6}$$

Where the t is time [hours] in which the thermal power plant is operating, and η_{HE} is the efficiency of the heat exchanger between the geothermal (circulating) fluid and the working fluid [%] in the secondary loop (end user side). The operating time can be regulated by inserting the percentage of downtime which is the percentage of hours in a year when geothermal facility does not work due to the repairs, maintenance, workover, etc. In Table 2, a data needed for the calculation of "Temperature range" scenario are shown.

Table 2. List of data for calculating the heat production in the Temperature range scenario.

User's input	Calculated values
Downtime (%)	Production temperature (°C)
Injection temperature (°C)	Specific heat capacity of geothermal fluid (J/kg°C)
Efficiency of the heat exchanger (%)	Density of geothermal water ($\mathrm{kg/m^3}$)
	Fluid flow ($\mathrm{m^3/s}$)

The "Heat needs" scenario is based on the actual heating demand, provided by the user, or calculated in the methodology. The calculation of the heat demand in the methodology is based on daily and hourly air temperatures for a specific country, and on the heat needs of three different types of buildings and heat demand based on the surface and construction materials. After calculating the heat demand, the user further designs the heating system for the chosen object. The heating system refers to the secondary loop (cold loop) in the geothermal system. The "Heat needs" scenario calculates how much of a buildings heat demand can be satisfied with the given geothermal source. The explanation of the heat demand calculation is provided in the sub-chapter 3.5, and it also concerns the 3A and 5A scenarios.

3.4.3 3A Scenario - "Heat DBHE"

In the "Heat DBHE" scenario, the thermal energy is generated using the deep borehole heat exchanger (DBHE) (Figure 5). The circulating fluid is then injected into the well through annular space and produced at the wellhead through a thermally isolated production tubing or vice versa. The chosen well for implementing the deep borehole heat exchanger technology is the well with the highest reservoir temperature assuming that the depth of deep borehole heat exchanger will be the same as the well depth. If the user decides to install the deep borehole heat exchanger at lower depth, the reservoir rock temperature at that depth will be calculated as the multiplication of the depth and geothermal gradient. To estimate the temperature of the circulating fluid at the wellhead without conducting the heat transfer simulation between the reservoir rock and circulating fluid, a temperature ratio is defined. Temperature ratio is the number that represents the heat transfer correlation between the circulating fluid and reservoir rock, including the heat transfer through cement, casing, tubing, and tubing isolation, i.e., the ratio of the temperature outlet from the deep borehole heat exchanger and bottomhole temperature. It is assumed that the reservoir temperature is the same as the temperature of the reservoir (geothermal) fluid and that the changes in reservoir porosity and thermal conductivity do not change significantly in reservoir. The theoretical lower limit is 0, which means that there is no heat transfer between the fluid and the rock. The theoretical upper limit is 1, which means that heat transfer form reservoir rock to circulating fluid happened completely. Both of those cases never happen. The temperature ratio is derived from the database of several real and simulated cases of deep borehole heat exchanger performances which are provided in Table 3 bellow. The temperature ratio should imply how much heat is lost in the transfer process using the circulating fluid rather than geothermal fluid. The maximum ratio is 0.864, which means that more than 86% of heat from geothermal reservoir is transferred on the circulating fluid. The minimum ratio is 0.240, which means that only 24% of heat from reservoir rock is transferred to the circulating fluid. The main idea of this temperature ratio is the calculation of production energy without having to conduct a simulation or the measurements of the field. If the thermal conductivity of a material is low, less heat will be transferred onto the circulating fluid and if the specific heat capacity of the material is low, less heat is stored in the material, and the temperature will change quicker If the circulating fluid has a low specific heat capacity, it will take a larger amount of fluid to transfer the relatively small amount of heat which increases the overall cost of process and decreases the efficiency of process. If the circulating fluid has a high specific heat capacity, the amount of heat that fluid can transfer without changing its temperature will be greater. A high specific heat capacity enables greater heat transfer with smaller amount of circulating fluid. The desirable characteristics of circulating and working fluid (fluid in ORC power plant) are low viscosity, high thermal conductivity, high specific heat capacity, high boiling point, and environmental and economic acceptability. The general knowledge about the favourable technical and geological parameters and configuration are of key importance.

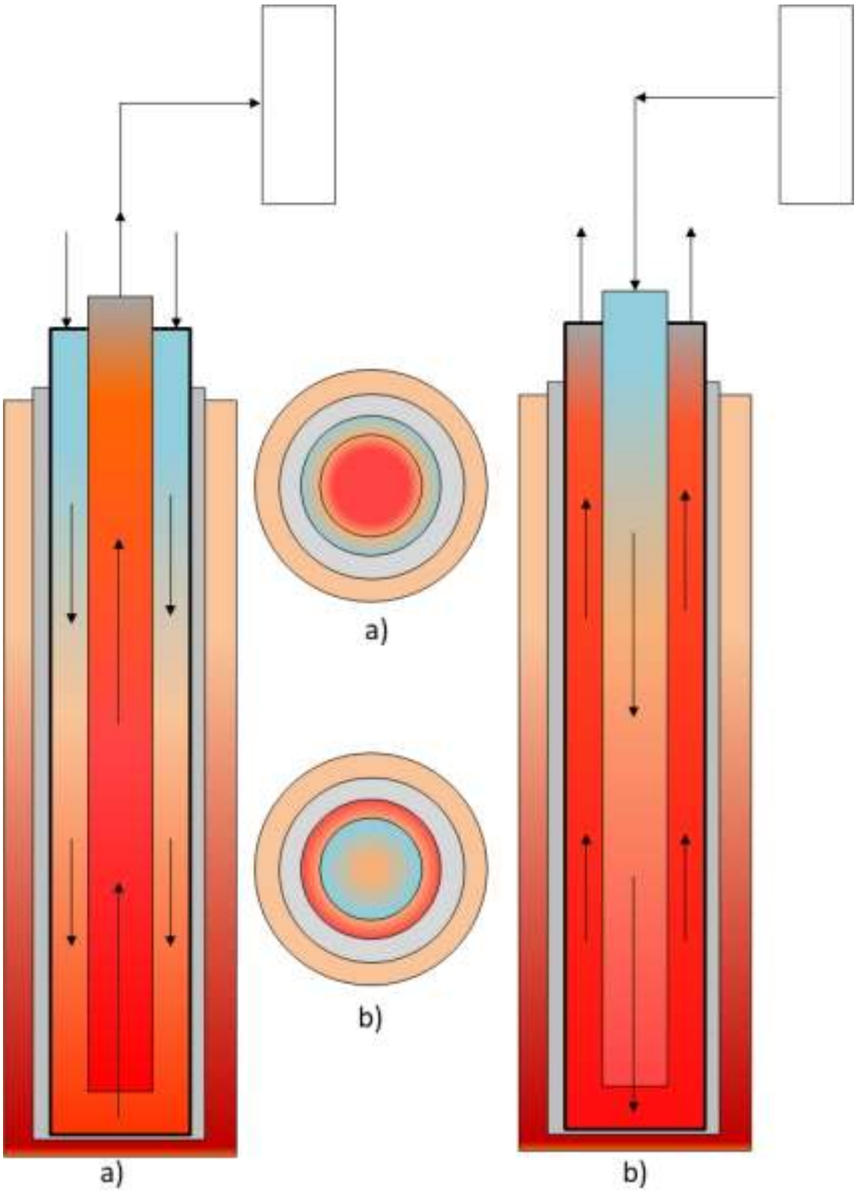

Figure 5. DBHE scheme and circulating path

Table 3. Database used for Temperature ratio computing.

Source	Case	Working fluid	Depth (m)	Bottomhole temperature (°C)	Outlet temperature from DBHE (°C)	Temperature ratio
[29]	Simulation	R – C318	5950	165	100.38	0.608
[30]	Real	Isobutane	1050	154.7	75.95	0.491
[30]	Real	Isobutane	1050	154.7	76.37	0.494
[30]	Real	Isobutane	1050	154.7	74.51	0.482

[30]	Real	Isobutane	1050	154.7	71.21	0.460
[30]	Real	Propane	1050	154.7	77.75	0.503
[30]	Real	Propane	1050	154.7	76.1	0.492
[30]	Real	Propane	1050	154.7	73.61	0.476
[30]	Real	Isopentane	1050	154.7	81.97	0.530
[30]	Real	Isopentane	1050	154.7	81.72	0.528
[30]	Real	Isopentane	1050	154.7	80.71	0.522
[30]	Real	Butane	1050	154.7	78.51	0.507
[30]	Real	Butane	1050	154.7	77.54	0.501
[30]	Real	Butane	1050	154.7	74.48	0.481
[31]	Simulation	Water	5593	350	84	0.240
[32]	Simulation	Decafluoro -Butene	1909	295.5	150	0.508
[33]	Real	Water	6800	211.48	130	0.615
[33]	Real	Water	6000	186.6	130	0.697
[33]	Real	Water	4900	152.39	130	0.853
[34]	Real	Water	2295	73	43	0.589
[35]	Simulation	Water	3950	105.7	68	0.643
[35]	Simulation	Water	3950	105.7	86.6	0.816
[35]	Simulation	Water	3950	105.7	53	0.501
[36]	Simulation	Water	2340	73.18	19.9	0.272
[37]	Real	Water	1000	185	128	0.692
[38]	Simulation	Water	4423	159.8	138	0.864
[39]	Simulation	CO_2	1800	54	24.19	0.448
[39]	Simulation	Water	1800	54	18.43	0.341
[39]	Simulation	R134a	1800	54	27.3	0.506
[39]	Simulation	R152a	1800	54	27.69	0.513
[39]	Simulation	R227ea	1800	54	27.65	0.512
[39]	Simulation	R245fa	1800	54	26.48	0.490
[39]	Simulation	R1234ze	1800	54	27.85	0.516
[39]	Simulation	R600a	1800	54	28.92	0.536
[39]	Simulation	Pentane	1800	54	28.09	0.520
[40]	Simulation	Water	4000	180	129.88	0.722
[40]	Simulation	Water	4000	180	129.28	0.718
[40]	Simulation	Water	4000	180	128.93	0.716
[40]	Simulation	Water	4000	180	128.96	0.716
[40]	Simulation	Water	4000	180	128.5	0.714
[40]	Simulation	Water	4000	180	128.35	0.713
[40]	Simulation	Water	4000	180	128.22	0.712
[40]	Simulation	Water	4000	180	128.11	0.712
[40]	Simulation	Water	4000	180	128.01	0.711
[40]	Simulation	Water	4000	180	127.92	0.711

This scenario also consists of two sub-scenarios: *Temperature range* scenario *and Heat needs* scenario. The *Temperature range* scenario relates to the production of energy by exploiting the temperature range between the circulating fluid temperature and fixed injection temperature. The circulating fluid temperature is calculated as the multiplication product of reservoir rock temperature at the certain depth and the presented temperature ratio. With this scenario the heat could be delivered to the multiple end-users, even during the whole year, as the excess of the cumulative energy produced is transferred to the next user. The produced thermal energy could also serve as the base load energy where the peak consumption will be met by exploiting other sources of energy. The installed capacity (kW) is calculated using the Equation (7) with the additional factor of temperature ratio [9],

$$Q_{th} = c_p \cdot \rho \cdot q \cdot (X_{TR} \cdot T_r - T_o) \tag{7}$$

Where the c_p is the specific heat capacity of the circulating fluid $[\mathrm{J/kg°C}]$, ρ represents the density of the circulating fluid water $[\mathrm{kg/m^3}]$, q is the circulating fluid flow $[\mathrm{m^3/s}]$, the X_{TR} is the temperature ratio used to describe the heat transfer between the reservoir and the circulating fluid [-], T_r is the reservoir temperature, T_o is the injection temperature [°C], that is the temperature at the outlet of the thermal power plant.
The produced energy [kWh] is determined using the Equation (8).

$$E_{th} = c_p \cdot \rho \cdot q \cdot (X_{TR} \cdot T_r - T_o) \cdot t \cdot \eta_{HE} \tag{8}$$

As same as in the 2A scenario, the operational time of the power plant can the regulated using the percentage of downtime which represents the percentage of hours in a year when geothermal facility does not work due to the repairs, maintenance, workover, etc.

The fluid flow of the circulating fluid will be user's input and it needs to be considered that the diameter of the well is reduced due to installation of deep borehole heat exchanger into abandoned hydrocarbon wells and the pumping system. Also, the fluid flow is the direct function of annular velocity which directly affects the pressure losses during circulation that needs to be minimized. The following equations of annular pressure loss and inner tubing pressure loss calculation [41] should provide the user the orientational value of pressure loss during circulation according to which the user can variate the fluid flow rate to minimize the pressure losses and consequently the pump power consumption. The Equations (9) and (10) present the calculation for annular and tubing velocity and Equation (11) demonstrates the calculation of pressure loss in the annular space and during circulation,

$$v_a = \frac{q}{\frac{\pi}{4} \cdot (D_h^2 - D_p^2)} \tag{9}$$

$$v_t = \frac{q}{\frac{\pi}{4} \cdot (D_p^2)} \tag{10}$$

$$P_{loss} = \frac{7.39 * 10^{-6} \cdot \rho \cdot L \cdot v_a^2}{(D_h - D_p)} \quad (11)$$

Where the v_a is the annular velocity [m/s], v_t is the tubing velocity [m/s], D_h is the casing inside diameter (hole size) in [m], and the D_p is the pipe outside diameter [m].
For the pressure loss [kPa] calculation, the annular velocity, v_a is the [m/min], L is the pipe length in [m], D_h is the casing inside diameter (hole size) in [mm], and the D_p is the pipe outside diameter [mm]. For the pressure loss in the tubing, the calculation in the developed sub-programme regarding the DBHE pump design should be considered, where the pressure loss is calculated as the part of surface pump power consumption calculation.

In Table 4, the required data for conducting the Temperature range scenario are shown.

Table 4. Users input data and calculated values for the 3A scenario.

User's input	Calculated values
Downtime (%)	DBHE production temperature (°C)
Temperature ratio (-)	
Injection temperature (°C)	
Specific heat capacity of circulating fluid (J/kg °C)	
Density of circulating fluid (kg/m^3)	
Circulating fluid flow (m^3/s)	
Efficiency of surface heat exchanger (%)	

Regarding the "Heat needs" sub-scenario, the same goes for deep borehole heat exchanger scenario, the sub-scenario is based on the actual heating demand, provided from the user, or calculated in the methodology. The calculation of the heat demand in the methodology is based on daily and hourly air temperatures for a specific country, and on the heat needs of three different types of buildings and heat demand based on the surface and construction materials. After calculating the heat demand, the user further designs the heating system for the chosen object. The heating system refers to the secondary loop (cold loop) in the geothermal system. The "Heat needs" scenario calculates how much of a building's heat demand can be satisfied with the given geothermal source as it can be seen in the paragraph 3.5.

3.4.4 4A Scenario – "ORC Power"

The 4A scenario refers to the electricity generation using the Organic Rankine Cycle (ORC) technology. Two sub-scenarios are developed: electricity generation using the production and injection well and electricity generation using the deep borehole heat exchanger.
In order to assess the heat exchange performance of the used binary power plant, thermal efficiency is analysed and calculated for both of sub-scenarios. For the wellhead

temperatures higher than 120°C the method proposed by the Massachusetts Institute of Technology [7] is used. Namely, the regression Equation (12), based on the data from fourteen ORC power plants, is used to calculate the thermal efficiency [%],

$$\eta_{ORC} = 0.0005 \cdot T_{Inlet}^2 - 0.0577 \cdot T_{Inlet} + 8.2897 \tag{12}$$

Where T_{inlet} [°C] represents the production temperature in scenario with the production and injection well and, in the DBHE scenario, it represents the product of temperature ratio (from DBHE database) and the reservoir temperature at a certain temperature.
The installed power is calculated using the Equation (13) [7].

$$Q_{el} = c_p \cdot \rho \cdot q \cdot (T_{Inlet} - T_o) \tag{13}$$

The produced energy is the direct function of installed power, thermal efficiency, and operating time, as shown in the Equation (14).

$$E_{el}(i) = q(\mathrm{i}) \cdot \rho \cdot c_p \cdot (T_{inlet}(i) - T_o(i)) \cdot t \cdot \eta_{ORC}(i) \tag{14}$$

Additionally, for wellhead temperatures lower than 120°C the approach from Deliverable D7.1 was applied. Namely, according to the approach applied in Deliverable D7.1, in order to evaluate ORC power plant production following parameters should be taken into account:

- DT - difference of temperature on primary (geothermal brine loop) side of ORC dedicated heat exchanger. This parameter is defined by end-user.
- η_{ORC} (T_{1b}, DT) - net ORC power plant efficiency as function of geothermal brine extraction temperature and DT and
- F_{COOL} (T_{1b}, DT) - net ORC power plant efficiency correction factor that considers different temperatures of ORC cycle coolant as function of geothermal brine extraction temperature and DT.

As it can be observed, both η_{ORC} and F_{COOL} are functions of two variables. In addition, there was limited number of ORC operating points available from ENOGIA. For that reason, 'MATLAB Curve Fitting Tool' was used to approximate these three-dimensional relationships. Polynomial approximation including third degree was performed.
Equation (15) represents functional relationship between net ORC power plant efficiency (*z*), brine extraction temperature (*y*) and DT (*x*):

$$\begin{aligned} z(x,y) \; = \; & p00 \; + \; p10 * x \; + \; p01 * y \; + \; p20 * x^2 \; + \; p11 * x * y \; + \; p02 * y^2 \\ & + \; p21 * x^2 * y \; + p12 * x * y^2 \; + \; p03 * y^3. \end{aligned} \tag{15}$$

Values of corresponding polynomial coefficients used in Equation (15) are following:

- p00 = - 0.06849,
- p10 = - 0.001452,
- p01 = 0.002209,
- p20 = - 1.017 e^{-5},

- p11 = 1.639 e^{-5},
- p02 = - 1.096 e^{-5},
- p21 = 3.241 e^{-8},
- p12 = - 4.203 e^{-8} and
- p03 = 1.866 e^{-8}.

It should be noted that relationship from Equation (15) between these variables is best suited for brine extraction temperature values in range from 80°C to 120°C and for DT values in range from 0°C to 40°C. In cases when Equation (15) is used for values outside of suggested ranges slightly less accurate results can be expected.

Equation (16) represents functional relationship between net ORC power plant efficiency correction factor (*z*), brine extraction temperature (*y*) and ORC cycle coolant temperature (*x*):

$$z(x,y) = p00 + p10 * x + p01 * y + p20 * x^2 + p11 * x * y + p02 * y^2 + p30 * x^3 + p21 * x^2 * y + p12 * x * y^2 + p03 * y^3. \tag{16}$$

Values of corresponding polynomial coefficients used in Equation (16) are following:

- p00 = 1.319,
- p10 = 0.003033,
- p01 = - 0.01699,
- p20 = - 7.256 e^{-5},
- p11 = 0.0001805,
- p02 = - 8.593 e^{-5},
- p30 = 3.315 e^{-6},
- p21 = - 8.5 e^{-6},
- p12 = - 2.611 e^{-6} and
- p03 = 2.136 e^{-6}.

It should be noted that relationship from Equation (16) between these variables is best suited for ORC cycle coolant temperature values in the range from 0°C to 40°C and for DT values in range from 0°C to 40°C. In cases when Equation (16) is used for values outside of suggested ranges slightly less accurate results can be expected.

Finally, ORC power plant net electricity production for each T time steps (i) is modified from the Equation (14) and is calculated as shown in Equation (17):

$$E_{el}(\mathrm{i}) = q(\mathrm{i}) \cdot \rho \cdot c_p \cdot (T_{inlet}(i) - T_0(i)) \cdot \eta_{ORC}(\mathrm{i}) \cdot F_{COOL}(\mathrm{i}) \tag{17}$$

The operating time can be managed by knowing the availability of the power plant, i.e., the plant downtime (yearly percentage of time) used for repairs, maintenance, workover, etc. The injection temperature or temperature at the outlet of the power plant, T_o, is set as a fixed value. The fluid flow is the user's input considering the pressure losses in the well and the fluids velocity, as stated in the paragraph 3.4.3.

For the DBHE sub-scenario, the chosen well for implementing the deep borehole heat exchanger technology is the well with the highest reservoir temperature assuming that the depth of deep borehole heat exchanger will be the same as the well depth. If the DBHE should be installed at lower depth, the reservoir rock temperature at that depth will be calculated as the multiplication of the depth and geothermal gradient.

In the Table 5, the user's input data and calculated values are listed for both sub-scenarios.

Table 5. Users input and calculated values for the electricity generation scenario.

<table>
<tr><th>User's input – Production & injection wells</th><th>Calculated values - Production & injection wells</th><th>User's input - DBHE</th><th>Calculated values - DBHE</th></tr>
<tr><td rowspan="2">Downtime (%)</td><td>Production temperature (°C)</td><td>Downtime (%)</td><td rowspan="2">Production temperature (°C)</td></tr>
<tr><td>Specific heat capacity of geothermal fluid $(\mathrm{J/kg°C})$</td><td>Injection temperature (°C)</td></tr>
<tr><td rowspan="4">Injection temperature (°C)</td><td>Density of geothermal water $(\mathrm{kg/m^3})$</td><td>Specific heat capacity of circulating fluid $(\mathrm{J/kg°C})$</td><td rowspan="4">Efficiency of ORC (%)</td></tr>
<tr><td>Fluid flow $(\mathrm{m^3/s})$</td><td>Density of circulating water $(\mathrm{kg/m^3})$</td></tr>
<tr><td rowspan="2">Efficiency of ORC (%)</td><td>Fluid flow $(\mathrm{m^3/s})$</td></tr>
<tr><td>Temperature ratio (-)</td></tr>
</table>

3.4.5 5A Scenario – "Power and heat"

The "Power and heat" scenario refers to the combined heat and power production with the parallel configuration mode. The parallel configuration mode assumes that geothermal energy extracted from geothermal and brought by geothermal or circulating fluid is used for both electricity generation and heating purposes. First, the heat demand is potentially satisfied with geothermal energy production and then, with the rest of available fluid flow, the electricity will be produced [17] simultaneously (Figure 6). Based on the inputs on heat demand, available geothermal fluid temperature, fluid flow, and the difference of inlet and outlet temperature of geothermal fluid from the geothermal plant, the user will be provided with the result that gives information on potentially satisfied or unsatisfied heat demand, and consequently information on potentially available output power from the ORC loop. The described production mode is greatly sensitive to potential seasonal character of the heat demand. If, for instance, there is a substantial heat demand for district heating during the winter season and a low or neglectable heat demand for district heating during the summer season, the available geothermal fluid flow and thermal energy for ORC loop will also variate depending on the seasonal character. Regarding this production mode and the heat demand, the user will be able to determine on the final ORC installed capacity. The optimization module regarding the installed heating capacity will be presented in Section 5. The installed heating capacity is based on the heat demand and the investment costs from which the installed capacity for power production can be determined.

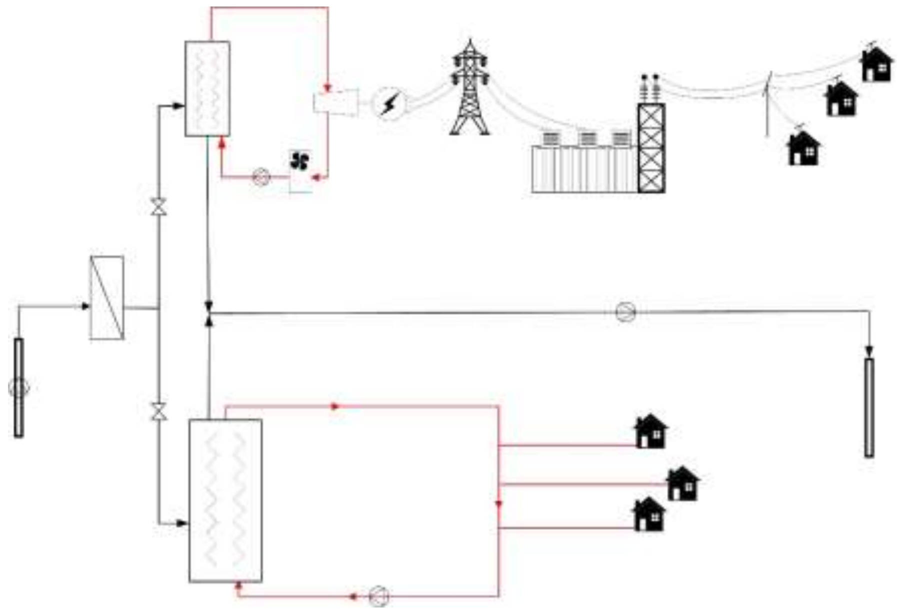

Figure 6. Combined heat and power production (CHP) scenario - parallel configuration mode.

The two sub-scenarios are developed: the first scenario is the CHP production using the production and injection wells and the second one is the CHP production using the deep borehole heat exchanger.
For the scenario where production and injection wells are used, only the wells that are sorted in the "Electricity generation" end-use are considered and go further into the calculation. The upper limit in the temperature clustering is the same for electricity and

heat generation, but the lower limit is different (60°C for electricity generation, 35°C for heat generation), so the wells that only go into the “Heat generation” end-use are excluded from the 5A scenario so that there are no wells which could lower the temperature of fluid bellow 60°C (minimum temperature for electricity production).
For the DBHE sub-scenario, the chosen well for implementing the deep borehole heat exchanger technology is the well with the highest reservoir temperature, for the electricity generation end-use, assuming that the depth of deep borehole heat exchanger will be the same as the well depth. If the DBHE should be installed at lower depth, the reservoir rock temperature at that depth will be calculated as the multiplication of the depth and geothermal gradient.

For both sub-scenarios, the calculation process is described in the following text and the formulas used are presented in the previous text:

- Heat production quantities (kWh) are calculated by exploiting a temperature range between the production temperature and the outlet temperature,
- Heat needs are then calculated or inserted by the user,
- The potential surplus of heat production is calculated, that is the difference between heat production quantities and heat needs,
- The surplus fluid flow is then calculated by reversing the Equation (6) or (8),
- The thermal efficiency of the ORC is calculated using the Equation (12),
- The electricity production quantities from the potential surplus flow are calculated using the Equation (14).

The downtime (yearly percentage) in this scenario refers to the downtime of the combined heat and power plant facilities. The fluid flow in the DBHE sub-scenario is the users input considering the pressure losses in the well and the fluids velocity, as stated in the Section 3.4.3.
If the heat demand is calculated (users input or calculated heat demand), the users should choose for which type of building the heat needs will be calculated.

In the Table 6, the input data and calculated values are listed for both sub-scenarios.

Table 6. Users input and calculated values for the combined heat and power scenario.

<table>
<tr><th>User’s input – Production & injection wells</th><th>Calculated values - Production & injection wells</th><th>User’s input - DBHE</th><th>Calculated values – DBHE</th></tr>
<tr><td rowspan="2">Downtime (%)</td><td>Production temperature (°C)</td><td>Downtime (%)</td><td rowspan="2">Production temperature (°C)</td></tr>
<tr><td>Specific heat capacity of geothermal fluid (J/kg°C)</td><td>ORC outlet temperature (°C)</td></tr>
<tr><td rowspan="4">ORC outlet temperature (°C)</td><td>Density of geothermal water (kg/m^3)</td><td>Specific heat capacity of circulating fluid (J/kg°C)</td><td rowspan="4">Efficiency of ORC (%)</td></tr>
<tr><td>Fluid flow (m^3/s)</td><td>Density of circulating water (kg/m^3)</td></tr>
<tr><td rowspan="2">Efficiency of ORC (%)</td><td>Fluid flow (m^3/s)</td></tr>
<tr><td>Temperature ratio (-)</td></tr>
<tr><td>Efficiency of the surface heat exchanger (%)</td><td rowspan="2">Remaining fluid flow for electricity generation (m^3/s)</td><td>Efficiency of the surface heat exchanger (%)</td><td rowspan="2">Remaining fluid flow for electricity generation (m^3/s)</td></tr>
<tr><td>Type of building</td><td>Type of building</td></tr>
</table>

3.5 HEAT DEMAND CALCULATION

Heating energy demand is the amount of heat that the heating system needs to bring to the building during a specific period to maintain the internal design temperature in the building. In the proposed methodology and work, heat demand can be either user’s input in monthly heat needs [kWh] or it can be calculated based on the three different types of buildings and corresponding heat demand [kWh].

For the heat demand calculation, firstly a base temperature, i.e., the heating degree day (HDD) needs to be determined for a specific location, i.e., the country of the project. HDD is a measurement designed to quantify the demand for energy needed to heat a building. HDDs are defined relative to a base temperature - the outside temperature above which a building needs no heating. For this calculation, the base temperature of 17°C will be taken as a fixed and default value for the simplification of whole heat needs calculation. The base temperature does not necessarily correspond to the building mean internal temperature, as standards may consider mean building insulation levels and internal gains to determine an average external temperature at which heating will be required [42]. The hourly and daily air temperature is acquired for the past year from the Visual Crossing which is the weather data service [43]. Next, the number of hours in HDD in which the heating is needed (hours in which the air temperature is bellow base temperature) is calculated and summarized by month. The HDD hours will repeat cyclically for the duration of the project. Next, the temperature classes are formed according to the Celsius degrees and temperature span of 1°C, e.g. [>17°C], [16°C; 17°C], and the last temperature class is the [- 21°C; - 20°C], and the number of hours in each temperature class is calculated.

Additionally, based on the three different type of buildings (residential building, public building, greenhouse) and their heat needs provided from the VERMILION company, a yearly heating demand of the chosen type of building is calculated and divided in the temperature classes in accordance with the user's input data (surface [m^2], HDD [hours], required inside temperature [°C]).

The next step is the modelling of the heating system (cold loop), i.e., the heating curve of the buildings heating system. The heating curve represents the required water temperature for heating in correlation with the outdoor temperature. In the Table 7, a list of input parameters (A, B, C, D, F, G) for the calculation of heating curve are defined [44].

Table 7. Input parameters for the calculation of heating curve.

Parameter	Definition	Value	Label
Basic outdoor temperature	It represents minimum hourly air temperature for a selected country.	Fixed value derived from the database of air temperatures.	A
Maximum water temperature	It is the maximum water temperature for which the entire heating system has been dimensioned and provides comfort in the middle of the winter.	Here it is calculated as the heating source (hot loop) temperature (the first temperature from 0.01 month) decreased by the pinch point temperature.	B
Outdoor non-heating temperature	The non-heating outdoor temperature is the outdoor temperature above which it is no longer necessary to heat.	17°C	C
Minimum water temperature	The temperature of the heated water when the heating installation reaches the limit of shutdown.	35°C	D
Outdoor non-heating temperature on the pivot point	Pivot point is the fixed point on the heating regulators around which the heating curve turns	20°C	F

	when the slope is varied. A basic pivot point is generally pre-set on the regulators ((20°C, 20°C), (35°C, 15°C)). The value is usually given in the technical manual of the device. The first number is the outside temperature at which the heating is no longer needed		
Minimum water temperature on the pivot point	The second number is the minimum water temperature in the cold loop before the heating. In this calculation it will be set at 20°C until the user inserts its own value.	20°C	G

The calculation of the slope of heating curve and the parallel displacement is shown in the Equations (18) and (19) and on the Figure 7, the heating curve for a specific scenario is shown.

$$Slope = \frac{(B - D)}{(C - A)} \tag{18}$$

$$Parallel\ displacement = D - (G + (F - C) \cdot Slope) \tag{19}$$

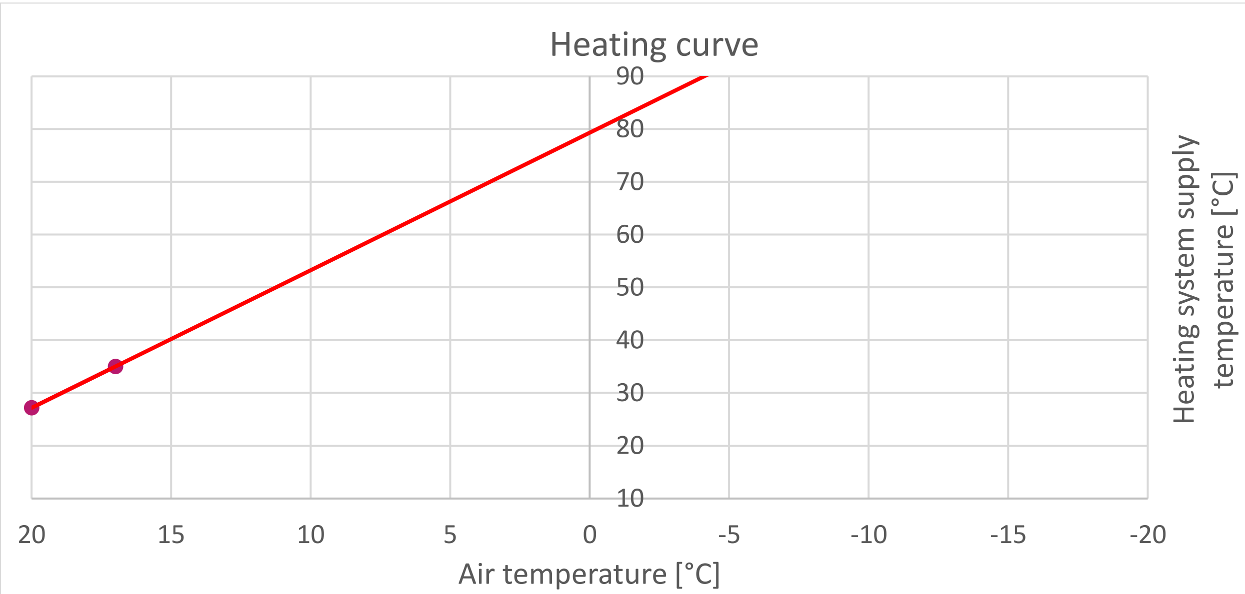

Figure 7. Heating curve for the 2A *Heat needs* scenario.

The slope and parallel displacement of the heating curve are calculated for every month of the project period due to thermal dropdown in the reservoir upon production and injection or circulation.
For calculation of geothermal contribution in satisfying the heating demand, additional input parameters are needed, such as the maximum and minimum flow on the cold loop $[\mathrm{m}^3/\mathrm{h}]$, specific heat capacity of the fluids in the cold loop and in the hot loop [J/kg °C], densities of the fluids in the hot loop and in the cool loop $[\mathrm{kg}/\mathrm{m}^3]$, geothermal fluid flow on the hot loop $[\mathrm{m}^3/\mathrm{h}]$, and the thermal pinch point in the surface heat exchanger [°C]. The maximum flow in the cold loop is the maximum flow in the heating system pipes determined by the lowest air temperature in observed period when designing the heating system and should be provided from the heating system manufacturer. In this calculation it will be set at 60 $[\mathrm{m}^3/\mathrm{h}]$. The minimum flow in the cold loop is the minimum flow in the heating system pipes determined by the outdoor non-heating temperature when designing the heating system and should be provided from the heating system manufacturer. In this calculation it will be set at 20 $[\mathrm{m}^3/\mathrm{h}]$. The thermal pinch point represents the point where the temperature difference between fluid from hot loop and fluid from cold loop is the smallest, i.e., the smallest temperature difference (Figure 8).

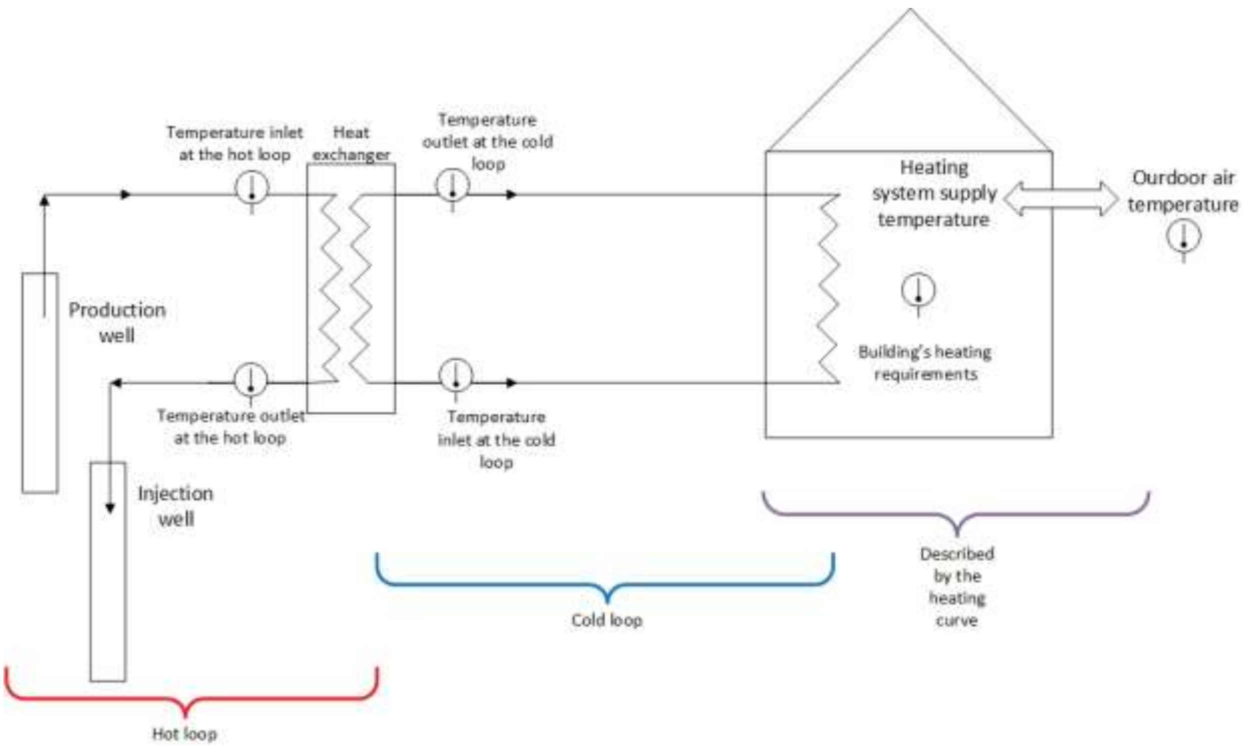

Figure 8. Geothermal source and buildings heating system scheme

The estimation of the geothermal source contribution in satisfying the heat demand consists of following calculations:

- Temperature of the fluid at the outlet of the cold loop,
- Temperature of the fluid at the inlet of the cold loop,
- The fluid flow in the cold loop,

- The theoretical value of the fluid temperature at the inlet of the hot loop,
- The theoretical value of the fluid temperature at the outlet of the hot loop,
- The real value of the fluid temperature at the outlet of the hot loop,
- The check-up of the heat exchanger performance,
- Geothermal source contribution in satisfying the heat needs,
- Satisfying the peak demand with natural gas.

The geothermal contribution is then summarized by each month of the project period, and the result indicates how much of heat demand was covered with the geothermal energy, i.e., how much heat is produced exploiting the geothermal energy.

3.6 PUMPING SYSTEM DESIGN

The pumping system design refers to the design of the production pumps, DBHE surface pumps, and injection pumps. The modelled pump designs will act as additional sub-programmes within the methodology and tool, and as such are not connected to the production calculation. The main purpose of the sub-programmes is the design, calculation, or assumption of variable operational cost, i.e., the pump power consumption, or additionally, the checkout for the installation of the production pump.
For the calculation of pump power consumption, the user should know the data about the pump power, if that is not the case the user can enter the sub-programme of one of the required wells and by entering the requested data, the pump power consumption will be estimated.
The variable operational cost is directly influenced by the pump power, operating time, and the electricity price, and is calculated in the sub-programme.

3.6.1 ESP pump design

In the methodology and tool, the production pump, its design, calculation, and estimation of power consumption was done based on the model of an electric submersible pumps (ESP). The ESP and mentioned calculations should be used as the substitute pump for every other type of production pump that is already installed in the well or at the wellhead. The ESP pump design and the connected calculations consist first of the checking the need for the pump installation (if there is the answer “No” on the “Input data” sheet, under the column “ESP installed”). The mentioned checkout examines weather the hydrostatic pressure of the fluid in the well is greater than reservoir pressure. If the answer is “Yes” then the user should approach to the following calculations [45].
The following calculations are:

- Design of production capacity and pump intake pressure,
- Calculation of total dynamic head,
- Pump-type selection from ESP manufacturer catalogue and fluid velocity check,
- Motor design,
- Cable losses calculation.

In the ESP design calculation, the pressures in the well are calculated: dynamic pressure, differential pressure between reservoir pressure and dynamic pressure, hydrostatic pressure correction which is the hydrostatic height difference between top reservoir depth and pump depth converted in bars, and the pump intake pressure (PIP). The pump intake pressure is the difference between dynamic pressure and hydrostatic pressure correction, and it needs to be a positive number. The PIP in the methodology and tool is set at 20 bar to enable the proper cooling of the pump and the submergence. The PIP value is set as the calculated value, but if it is different on the real site, it could be changed, i.e., overwritten with the user's input value.

Further, the total dynamic head and the net lift are calculated. The net lift is the actual height difference that pump needs to overcome. Next, the tubing friction losses during circulation are calculated. The correction factor for the pipes is taken as a default value: 100 for the old pipes, 140 for the new pipes, and 120 is set as a typical value.

The EPSs, based on which the methodology and tool are derived are from Schlumberger, REDA Electric Submersible Pump System Technology Catalogue.

The selection process is based on the 42 pumps, ranging from minimum capacity of 26 $[\mathrm{m}^3/\mathrm{day}]$ at 50 Hz to maximum capacity of 12,720 $[\mathrm{m}^3/\mathrm{day}]$ at 50 Hz. For each pump from the catalogue, a capacity at maximum efficiency is listed. Before selecting a pump, two conditions must be fulfilled: the *Velocity check* and the *Operating range check*. The Velocity check is a direct function of casing inside diameter, pumps outside diameter and the required flow, and it must be greater than 1 ft/s to allow proper cooling of the motor. The operating range check is the confirmation if the required flow is in the operation range of the pump from the catalogue. If both checks are "OK", the pump could be installed in the well for the given conditions. The programme selects the pump with the flow at the maximum efficiency which is nearest to the required flow.

It is up to the user now to read from the catalogue, from the performance curve of the selected pump, the head per stage and the horsepower per stage. The number of stages is then calculated, dividing the total dynamic head by the head per stage. The total number of stages multiplied with the horsepower per stage results in total required bottomhole power [kW].

The last calculation is the calculation of cable losses. The AC current is carried from the surface to the motor using either copper or aluminium cable conductors, For the ESP applications, four sizes of conductors have been standardized: #1, #2, #4, and #6 AWG (American Wire Gauge). Cable selection involves the determination of cable size, cable type, and cable length [46]. For the purposes of the methodology, the cable type is excluded from the calculation.

The proper cable size is dependent on the combined factors of voltage drop, amperage and available space between tubing collars and casing. At the selected motor amperage and the given downhole temperature, the selection of a cable size that will give a voltage drop of less than 30 volts per 1,000 feet is recommended. The curve, shown in the Figure 9, also enables to determine the necessary surface voltage (motor voltage plus voltage drop in cable) required to operate the motor.

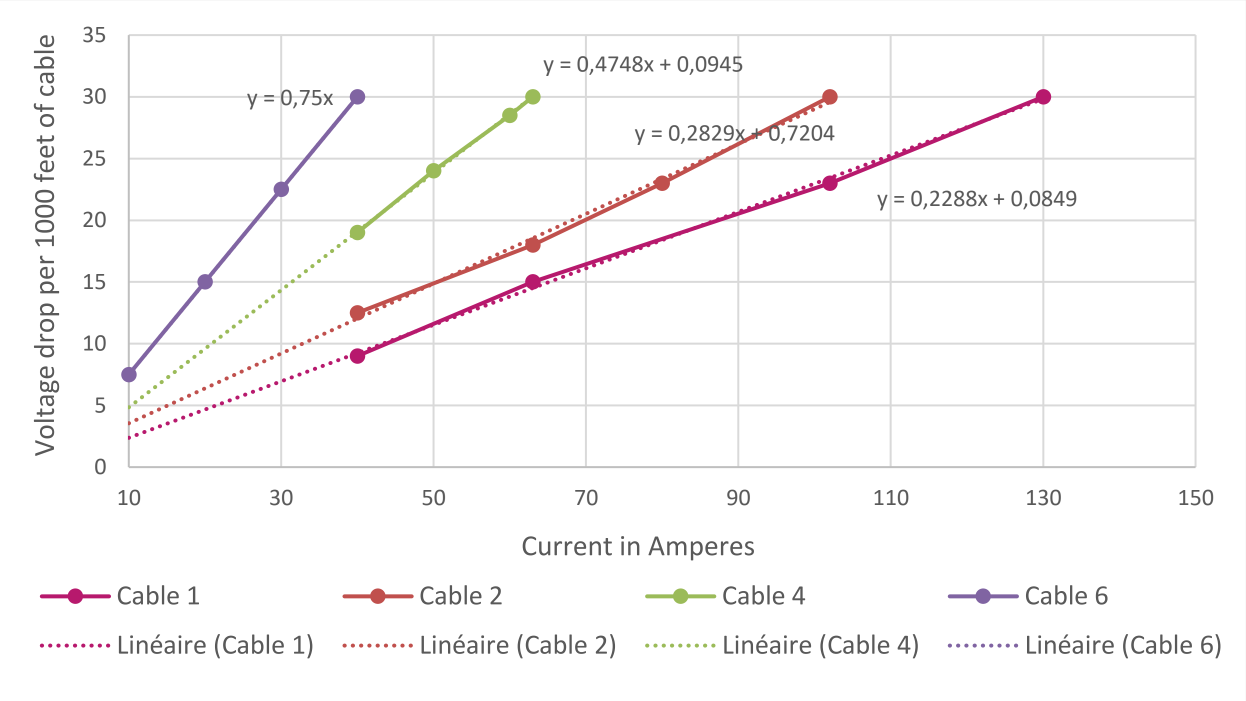

Figure 9. Recommended cables in correlation of motor current and voltage drop.

For the cables operating at different temperature, the voltage drop is determined by multiplying it with the temperature correction factor (TCF) as indicated in the Equation (20),

$$TCF = 1 + 0.00214 \cdot (T_{bth} - 77) \tag{20}$$

Where the T_{bth} [°F] is the bottomhole temperature.
According to the motor amperage, the list of possible cables to select is shown. The list is created in such way to not cross the recommended voltage drop. After selecting the cable, the voltage drop throughout the well depth is calculated, taking into account the resistance and the downhole temperature. Further, the cable losses [kW] for the well depth are calculated using the Equation (21),

$$Cable\ losses = 3 \cdot (I^2 * R)/1000 \tag{21}$$

Where *I* [A] is the motor current, and *R* [ohm] is the resistance of the selected cable.
Power consumption at surface is calculated by summing the cable power losses and required bottomhole power.

In the following Table 8, the input and calculated values for each calculation are stated.

Table 8. List of input data and calculated values for the ESP design.

Calculation	Input data	Calculated values	Explanation
ESP installation check-up	Top reservoir depth (m)	Average fluid gravity (-)	The condition is checked: Hydrostatic pressure > reservoir pressure.
	Water cut (%)	Average fluid density (kg/m^3)	
	Oil specific gravity (-)		
	Water specific gravity (-)	Hydrostatic pressure (bar)	
	Reservoir pressure (bar)		
ESP design	Well capacity (m^3/day)	Dynamic pressure (bar)	From the empirical data, the pump intake pressure should be around 20 bar.
	Water cut (%)	Differential pressure (bar)	
	Oil specific gravity (-)		
	Water specific gravity (-)		
	Reservoir pressure (bar)	Average fluid gravity (-)	
	Pump depth along the wellbore (m)		
	Pump depth – TVD (m)	Hydrostatic pressure correction (bar)	
	Top reservoir depth (m)		
	Productivity index (m^3/day/bar)	Pump intake pressure (bar)	
Pump selection	Wellhead pressure (bar)	Total dynamic head (m)	Correction factor for old pipes is 100, 140 for the new pipe, and 120 for a typical value. The pressure difference (m) is the tubing friction head loss.
		Pump intake pressure (m)	
		Net lift (m)	
	Production tubing ID (in)	Wellhead pressure (m)	
		dP/1,000 ft (ft/1,000 ft)	
	Correction factor for pipes (-)	dP (m/100m)	
		dP (m)	
Velocity check	Casing OD (in)	"OK" or "ERROR"	It is a direct function of casing ID, pump OD and the required flow, the output needs to be "OK" to keep the pump in further selection.
	Casing ID (in)		

Pump choice	Required flow (m^3/day)	Pump series (-)	The output is the pump that passes the Velocity check and Operating range check.
		Pump type (-)	
Schlumberger catalogue	Head per stage (m)	Number of stages	The input data needs to be read from the pump performance curves
	Horsepower per stage (hp)	Bottomhole power (kW)	
Cable losses	Motor current (Amps)	Possible cables to select	A voltage drop of less than 30 volts per 1,000 ft is recommended. Calculation also compensates for the high temperature in the well.
		Resistance (ohm/1,000 ft)	
		Voltage drop/1,000 ft of cable @ 25°C	
		Downhole temperature (°F)	
	Cable selection	Temperature correction factor	
		Voltage drop at the downhole temp/1,000 ft	
		Voltage drop for the well length	
		Cable length (m)	

3.6.2 Injection pump design

In the developed methodology and tool, the injection pump design is a sub-programme whose main purpose is to estimate the injection pump power consumption. The estimation is modelled based on the proxy curves from the injection pump performance curves provided from VERMILION. The result of the whole calculation is the pump power consumption. If the user knows the information about the pump power [kW], that data is taken directly and used later to calculate the variable operating cost of injection pump. This variable operating cost is directly dependent on the pump power, operating time, and electricity price, and it is calculated in the mentioned sub-programme.
For the purposes of the methodology, it is considered that number of injection wells through which the injection will be done is stated, and that all the stated wells have suitable properties and injection parameters for proper injection. The total flow that needs to be injected is the maximum flow from all the production wells on the field that are included in the calculation. The mentioned flow is divided by the number of injection wells (if no injection pump is installed, one injection pump should be installed on each well) or with the number of pumps (the user wants to estimate the power consumption of existing pumps or wants to install the exact number of pumps).
The main calculation consists of 5 steps:

- Check up if the injection flow is in the operating region of the pump,
- Calculation of pump power,
- Calculation of pump head,
- Calculation of wellhead injection pressure,
- Check up for bottomhole injection pressure.

The first step is to check if the flow that needs to be injected is in the operating region of the injection pump. The operating region implies for the region where the pump runs the best and it is close to the best efficiency point (BEP) where the risk of pump malfunctioning is reduced (temperature rise, noisy operation, cavitation surge, high vibration, etc.) [47]. If the flow is in the operating region, the calculations process continues otherwise the specific pump is excluded from the calculations and could/should not be chosen.
The next two steps, the calculation of pump power and head are directly connected to the pump performance curves and are depending on the injection flow. If calculation continues after the step 1, the step 2 and 3 will result in calculated numerical values. Otherwise, the specific pump will remain excluded from the calculations.
In step 4, the calculation of wellhead injection pressure is performed. The wellhead injection pressure can be calculated or measured from injectivity tests. It is dependable on the pump head. Namely, the higher the pump's head, the higher the wellhead injection pressure. The wellhead injection pressure is calculated as the sum of pump head [bar] and pump intake pressure [bar], and the condition that needs to be overcome is that the wellhead injection pressure needs to be lower than maximum allowable wellhead pressure (MAWP). By default, for methodology purposes, the pump intake pressure is set at 10 bars and MAWP is normally 3,000 psi or 5,000 psi, depending on the installed surface equipment, i.e., depending on the installed blow out preventers which usually have the rams who can take 3,000 psi of wellhead maximum burst pressure, or rams

which can support a maximum allowable operating wellhead burst pressure of 5,000 psi. The pressure drop between the injection pump and wellhead is neglected. If the mentioned condition is not fulfilled, the output from the calculation will suggest either surface equipment should be changed or the pump with other performance characteristics should be chosen.
The last step is the check of bottomhole injection pressure, where the sum of wellhead injection pressure and hydrostatic pressure of the fluid in the well needs to be greater than the reservoir pressure do that the injection can be conducted. If that is not the case, the output from the calculation step will be "Choose another pump", which is the proper step along with the changing the wellhead equipment in order to have greater pressure at surface.

For the calculation, the average depth of the injection wells is taken into account due to assumption that the fluid is being injected into the same reservoir layer.

If the outputs from all five calculation steps were positive (Yes) or numerical value, the pump with the lowest pump power is selected.
In Table 9, a set of input data and calculated values for the design of injection pump is listed.

Table 9. Users input and calculated values of the injection pump design.

User's input	Calculated values
Total flow (m^3/day)	One well flow (m^3/day)
Number of injection wells (-)	
Average depth of injection wells (m)	
Fluid density (kg/m^3)	Hydrostatic pressure (bar)
Pump intake pressure (bar)	
MAWP (bar)	
Reservoir pressure (bar)	

3.6.3 DBHE pump design

For the purposes of the methodology and tool, the calculation of the power consumption and variable operational costs of the deep borehole heat exchanger pump is developed. Since the methodology's main purpose is the conversion of oil wells to a geothermal one, it implies that there is no surface pump for the deep borehole heat exchanger yet installed on a particular well, so the main purpose of this calculation is to estimate the pump power consumption and provide guidelines for the future pump design.

The well for which the pump is designed is the well which is chosen in the scenarios with the deep borehole heat exchanger technology.
The calculation of pump power consumption consists of following steps:

- Determination of absolute roughness,
- Determination of the kinematic viscosity from the properties of geothermal fluid,
- Calculation of fluid velocity from the fluid flow and pipe surface,
- Calculation of Reynolds number,
- Calculation of friction losses using the Darcy-Weisbach equation,
- Calculation of pressure loss and head loss
- Calculation of the required pump power.

The absolute roughness is taken as the default value from [48] for carbon and alloyed steels, austenitic steels, and aluminium. Kinematic viscosity is then calculated as the ratio of dynamic viscosity and the density of the circulating fluid. Further, the fluid velocity is calculated from the ratio of circulating fluid flow and the pipe's flowing surface. The next step is the calculation of Reynolds's number using the equation (22) [33],

$$R_{e=}(v \cdot d_h)/\nu \qquad (22)$$

Where the R_e is the Reynolds number [-], v is the circulating fluid velocity [m/s], d_h is the hydraulic diameter [m], and ν is the kinematic viscosity $[\mathrm{m}^2/s]$.
After calculating the Reynolds number for determining the flow pattern, a Darcy-Weisbach equation is used to calculate the friction factor [49], as shown in the Equation (23),

$$1/\lambda^{\frac{1}{2}} = -2 \cdot \log\left[2.51/(Re \cdot \lambda^{\frac{1}{2}}) + (k/d_h)/3.72\right] \qquad (23)$$

Where the λ is the Darcy-Weisbach friction factor [-], and *k* is the ratio of the absolute roughness of pipe and pipes inside diameter [m]. The following calculation for head loss is performed using the Equation (24),

$$\Delta h_{loss} = \lambda * (l/d_h) \cdot (\rho_f \cdot v^2/2)/Y_w) \qquad (24)$$

Where the Δh_{loss} is the head loss [m], *l* is the length of the well, i.e., the heat exchanger, ρ_f is the density of the fluid [kg/m^3], and Y_w is the specific gravity of water [-].
The last calculation is the pump power calculation, *P*, [W], [33] using the Equation (25),

$$P = \rho_f \cdot g \cdot q \cdot \Delta h_{loss}/\eta_{pump} \qquad (25)$$

Where η_{pump} [%] is the efficiency of the surface pump and it is a user's input.
As mentioned before, the fluid flow is the user's input data along with the choice of circulating fluid and its properties.
In the Table 10, a list of user's input data and the calculated values are shown.

Table 10. List of user's input data and calculated values for the design of DBHE surface pump.

User's input data	Calculated values
Well name	Kinematic viscosity (m^2/s)
Density of circulating fluid (kg/m^3)	Pipe's flowing surface (m^2)
Fluid flow (m^3/s)	Fluid velocity (m/s)
Specific heat capacity of circulating fluid (J/kg °C)	Reynolds number (-)
Absolute roughness of the pipe (m)	k/d (-)
Dynamic viscosity (Pa·s)	Darcy-Weisbach friction factor (-)
Pipe's inside diameter (m)	$\text{Fluid velocity}^{\wedge 2}$ (m^2/s^2)
Well depth (m)	Head loss (m)
Pump efficiency (%)	Pump power (W)

3.7 OUTPUT DATA

3.7.1 Levelized cost of electricity (LCOE)

The LCOE is defined as the total discounted lifetime costs of an energy project divided by the total discounted amount of energy it either produces or saves in its lifetime [50]. An electricity price above this value would yield a greater return on capital while a price below it would yield a lower return on capital or even a loss.
This metric is principally used by policymakers for long-term planning, as well as formulating incentive mechanisms. Investors are often interested in LCOE to understand long-term economic trends, especially for renewable energy sources, for which the decrease in cost greatly improves their competitiveness.
Additionally, the LCOE varies by technology, country, and project, capital and operating costs, the efficiency/performance of the assessed technology, and financial parameters such as discount and inflation rate. The approach used in this methodology is based on a discounted cash flow (DCF) analysis and the lifetime costs for generation can be categorized into following groups:

- Capital costs – up-front costs to construct the power plant and/or to convert the oil wells and belonging infrastructure into geothermal wells;
- Operation and Maintenance (O&M) costs – all costs incurred to run the power plant. Additionally, these costs can be sub-categorized into fixed and variable costs. Fixed O&M costs occur regardless of the produced amount of energy (electricity) and are composed of personnel salaries that are based on the size and type of the project, maintenance work, supervision of reservoir, potential royalty payments, taxes etc. Variable O&M costs are directly associated with the produced amount of energy (electricity) and include costs of production and injection pumps (if available or needed for production).

It must be emphasized that the LCOE metric should be considered rather as and informing measure for investment decisions than an absolute decision metric. Actual system and project planning should also consider reliability issues and other factors. Namely, the availability factor of the power plant, i.e. the time that the plant is available for running, influences the produced amount of electricity in specific period of time.
The LCOE is calculated according to Equation (26).

$$LCOE = \frac{\sum_{t=1}^{T} \frac{I_t - S_t}{(1+r)^t} + \sum_{t=1}^{T} \frac{OM_t \cdot (1-TR)}{(1+r)^t}}{\sum_{t=1}^{T} \frac{EE_t}{(1+r)^t}} \tag{26}$$

In Equation 1, T represents the lifetime of the project [years], r the nominal discount rate [%/100], I_t investment costs in year t, S_t incentives or subsidies in year t, OM_t operation and maintenance costs in year t, TR effective tax rate, EE_t generated electricity in year t. Total investment costs I_t for specific year t in Equation 23 are calculated as shown in Equation (27):

$$I_t = I_t^{exp,est} + I_t^{prod,inje} + I_t^{ppinst} + I_t^{admi,man} + I_t^{other} \ , \tag{27}$$

where $I_t^{exp,est}$ represents yearly exploration and establishment costs (summarizes the cost of concession or lease acquisition of oil field, permitting, environmental studies, civil work, support facilities, surface exploring, shallow drilling, make-up well deepening, pre-feasibility and feasibility studies), $I_t^{prod,inje}$ yearly production and injection wells and system costs (includes mobilization, drilling, logging, testing, production piping, separators, water tanks, injection piping, production and injection pumps, corrosion inhibitor systems), I_t^{ppinst} yearly power plant installation costs (It includes power plant design and engineering, procurement procedures and complete phase of construction, testing and controlling, grid connection, transmission), $I_t^{admi,man}$ yearly administration and management costs (It includes project management, project and company administration, insurance costs, different financing fees), and $I_{other,t}$ yearly other investment costs not included in any of the aforementioned categories. Additionally, operation and maintenance costs OM_t in year t are calculated according to the Equation (28):

$$OM_t = FO\&M_t + O\&M_t^{production\ pump} + O\&M_t^{injection\ pump} + O\&M_t^{other} \ , \tag{28}$$

where $FO\&M_t$ represents yearly fixed O&M (including labor costs, maintenance of field and/or wells and/or power plant) in [€], $O\&M_t^{production\ pump}$ [€] yearly production pump variable costs that depend on the installed power of the pump, working hours and electricity price, $O\&M_t^{injection\ pump}$ [€] yearly injection pump variable costs that depend on the installed power of the pump, working hours and electricity price, and $O\&M_t^{other}$ [€] yearly variable costs that were not covered by other defined categories.

The nominal discount rate r is calculated from the real discount rate r_r and inflation rate i according to the Equation (29):

$$r = (1 + r_r) \cdot (1 + i) - 1 \tag{29}$$

For CHP application, a more complex equations are used, depending on what the main product is. Namely, the LCOE is used if the main product is the electricity, consequently, when calculating the LCOE for CHP plant, revenues from heat sales must be deduced (Equation (30)).

$$LCOE(chp) = \frac{\sum_{t=1}^{T}\frac{I_t - S_t}{(1+r)^t} + \sum_{t=1}^{T}\frac{OM_t \cdot (1-TR)}{(1+r)^t} - \sum_{t=1}^{TS}\frac{RHS_t \cdot (1-TR)}{(1+r)^t} - \sum_{t=TE+1}^{T}\frac{RHM_t \cdot (1-TR)}{(1+r)^t}}{\sum_{t=1}^{T}\frac{EE_t}{(1+r)^t}}, \tag{30}$$

where RHS_t represents revenues from subsidized heating power sales in year t, RHM_t revenues from the market heating power sales in year t, TS duration of subsidized price of electricity or heating power, and TD duration of depreciation period.

3.7.2 Levelized cost of heat (LCOH)

In scenarios where, only heating power is produced the levelized cost of heat (LCOH) is used as metric and decision output.
Same as for the LCOE, the approach used in this methodology is based on a discounted cash flow (DCF) analysis and the lifetime costs for generation can be categorized into following groups:

- Capital costs – up-front costs to construct the power plant and/or to convert the oil wells and belonging infrastructure into geothermal wells;
- Operation and Maintenance (O&M) costs – all costs incurred to run the power plant. Additionally, these costs can be sub-categorized into fixed and variable costs. Fixed O&M costs occur regardless of the produced amount of energy (heat) and are composed of personnel salaries that are based on the size and type of the project, maintenance work, supervision of reservoir, potential royalty payments, taxes etc. Variable O&M costs are directly associated with the produced amount of energy (heat) and include costs of production and injection pumps (if available or needed for production).

It must be emphasized that the LCOH metric should be considered rather as and informing measure for investment decisions than an absolute decision metric. Actual system and project planning should also consider reliability issues and other factors. Namely, the availability factor of the power plant, i.e. the time that the plant is available for running, influences the produced amount of heat in specific period of time.
The LCOH is calculated according to Equation (31).

$$LCOH = \frac{\sum_{t=1}^{T}\frac{I_t - S_t}{(1+r)^t} + \sum_{t=1}^{T}\frac{OM_t \cdot (1-TR)}{(1+r)^t}}{\sum_{t=1}^{T}\frac{EH_t}{(1+r)^t}} \tag{31}$$

In Equation 28, T represents the lifetime of the project [years], r the nominal discount rate [%/100], I_t investment costs in year t, S_t incentives or subsidies in year t, OM_t operation and maintenance costs in year t, TR effective tax rate, EH_t generated heat in year t.

Investment costs I_t for year t, operating and maintenance costs OM_t for year t, and nominal discount rate are calculated according to the Equations (27), (28), and (29).

For CHP application, a more complex equations are used, depending on what the main product is. Namely, the LCOH is used if the main product is heating power and sequentially, when calculating the LCOH for CHP plant, revenues from electricity sales must be deduced (Equation 32).

$$LCOH(chp) = \frac{\sum_{t=1}^{T} \frac{I_t - S_t}{(1+r)^t} + \sum_{t=1}^{T} \frac{OM_t \cdot (1-TR)}{(1+r)^t} - \sum_{t=1}^{TS} \frac{RES_t \cdot (1-TR)}{(1+r)^t} - \sum_{t=TS+1}^{T} \frac{REM_t \cdot (1-TR)}{(1+r)^t}}{\sum_{t=1}^{T} \frac{EH_t}{(1+r)^t}}, \quad (32)$$

where RES_t represents revenues from subsidized electricity sales in year t, REM_t revenues from the market electricity sales in year t, TS duration of subsidized price of electricity of heating power, and TD duration of depreciation period.

3.7.3 Net present value (NPV)

Net present value (NPV) is the value of future cash flows (either positive or negative) over the entire lifetime of an investment/project discounted to the present day. NPV metric and analysis is used widely across finance and determining the value of investment, capital project, and anything that involves cash flows. It helps investors to determine how much an investment or project is worth. It is an all-encompassing metric since it considers not only capital costs, but expenses and all revenues that occur in different period of project's lifetime. In NPV analysis the cash flows are discounted for two reasons, which makes this metric a precious indicator, (1) to adjust for the risk of an investment opportunity and (2) to account for the time value of money. Reason number one is necessary because not all investments or projects have the same level of risk, i.e. the probability of receiving a cash flow from different projects varies significantly. To account that risk, the discount rate is higher for riskier projects and lower for a safer one. Second reason is required due to inflation, interest rates and opportunity costs, since money is more valuable the sooner it's received.
The NPV metric is in this methodology and support tool calculated as shown in Equation (33):

$$NPV = \sum_{t=0}^{T} a_t \cdot S_t = \frac{S_0}{(1+r)^0} + \frac{S_1}{(1+r)^1} + \cdots + \frac{S_T}{(1+r)^T} \quad , \quad (33)$$

where S_t is the balance of cash flow (inflows minus outflows) at the time t, a_t is the financial discount factor chosen for discount at the time t and r is the nominal discount factor. The nominal discount factor is calculated according to the Equation (29).

3.7.4 Avoided CO_2 emissions

To assess the environmental impact of such conversion project and consequently, based on this indicator to approximate the money savings, the avoided CO_2 emissions during operational phase of the plant are proposed and calculated in this methodology. The avoided emissions during operational phase are calculated based on the comparison with the production of the same services with the reference electricity mix and reference heat mix, respectively. The reference mixes are country specific and represent business-as-usual development until 2019 for each country.
For scenarios with only electricity generation the amount of avoided CO_2 emissions (tons) is calculated as stated in Equation (34):

$$E_{CO_2} = \sum_{p=1}^{t_{op}} \left(\dot{E}_p \cdot e_{CO_2,elemix} \right) \ , \tag{34}$$

where t_{op} represents the duration of the operational phase of the plant, $\dot{E}_p$ is the net electricity production by system at the operating conditions of period p (MWh_e), $e_{CO_2,elemix}$ is the specific CO_2 emissions of electricity production from the reference electricity mix ($kgCO_2/MWh_e$).
For scenarios with only heating power production the amount of avoided CO_2 emissions (tons) is calculated as stated in Equation (35):

$$E_{CO_2} = \sum_{p=1}^{t_{op}} \left(\dot{Q}_p \cdot e_{CO_2,heatmix} \right) \ , \tag{35}$$

where t_{op} represents the duration of the operational phase of the plant, $\dot{Q}_p$ is the produced heat energy to cover heating requirement during period p (MWh_{th}), $e_{CO_2,heatmix}$ is the specific CO_2 emissions of heating production from a heat mix ($kgCO_2/MWh_{th}$).
In case of CHP scenario, the Equations (34) and (35) are combined into Equation (36):

$$E_{CO_2} = \sum_{p=1}^{t_{op}} \left(\dot{E}_p \cdot e_{CO_2,elemix} + \dot{Q}_p \cdot e_{CO_2,heatmix} \right) \tag{36}$$

4 EXCEL-BASED TOOL

In this chapter, the usage of the Excel-based tool will be explained. There are 16 spreadsheets and each of them contains a short description of the sheet and short instructions on how to use and fill the sheet.
For better managing between the data and user-friendliness, different data types are marked in different colours. The blue colour represents the data that the user needs to fulfil or choose from the dropdown menu, the green colour represents the output data and calculated values which do not need to be changed, if it is not stated differently, but are used further in the calculation. The black colour represents the values that are set as default for the purposes of the methodology and do not need to be changed.

If the data is underlined, that means that there is a hyperlink to that data which will, by clicking on it, lead the user on the “Explanations” sheet where the short descriptions of the data could be found.
If the right top corner of the cell is market in red colour, it means that there are short notes for that data in the cell. It usually represents a short guideline for the user about which data to insert.
The user should first fill all the data on the “Input data” sheet and “Production” sheet, and then, by clicking on the button “Calculate the production energy” on the “Production” sheet, the production quantities will be calculated, and the rest of the outputs will be calculated automatically. The user can fill the sub-programmes about the pumps later or before clicking on the mentioned button because the sub-programmes are not directly connected to the production quantities.
For the comparison of different scenarios, the users should insert the same parameters and initial condition (e.g., heat needs and heating system parameters, injection temperature, downtime, etc.).
In Table 11, a list of developed Excel-sheets is shown.

Table 11. List of developed spreadsheets in the methodology and tool.

Developed spreadsheets
MEET – Read Me
Unit conversion
Input data
Output data
Production
ESP pump design
Injection pump design
DBHE pump design
Explanations
LCOE
LCOH
NPV
Energy efficiency
Carbon intensity
Graphical results
Sensitivity analysis

4.1 MEET – READ ME

At the very first sheet of the methodology, the general data about the MEET project and the Deliverable 4.5 are listed. The important note is declared which states that the developed methodology and tool are the “Beta” version and are subjected to the changes and further detailed check, validation, updates, and upgrades. The latter sentence derives from the possible and planned future work on the articles and workshops regarding the oil-to-water conversion within the MEET project. The note also states that the methodology and tool are the approximation of the stated outputs based on the user’s input, default values, proxy values or correlations, and calculation from the tool. The values that are not direct user’s input are based on the historical data, database correlations, empirical conclusions, or extensive literature review conclusions. The main disclaimer in the methodology and tool concerns the output data, that is, if the user provides the input values that are unrealistic and improbable, the methodology will result in the corresponding unrealistic and improbable scenarios.

The caveat of the methodology and tool is that the given results should serve as the orientational scenarios upon which the user should decide which scenario to perform on the mature or abandoned oil field. Also, the results and the outputs are not intended to be represented as the “official” performance result of a given reservoir, and as such, the authors do not endorse or recommend any of the technologies described and defined in the methodology and tool.
The last subsection on the sheet describes the use of the methodology and the tool, for example, which data are the input data, default values or output data, where the user can choose between several options, which data to insert and calculate first, or where to find the explanations of some parameters, etc. On the Figure 10. The display of the "MEET - Read Me" sheet, a short display of “MEET – Read me” sheet is shown.

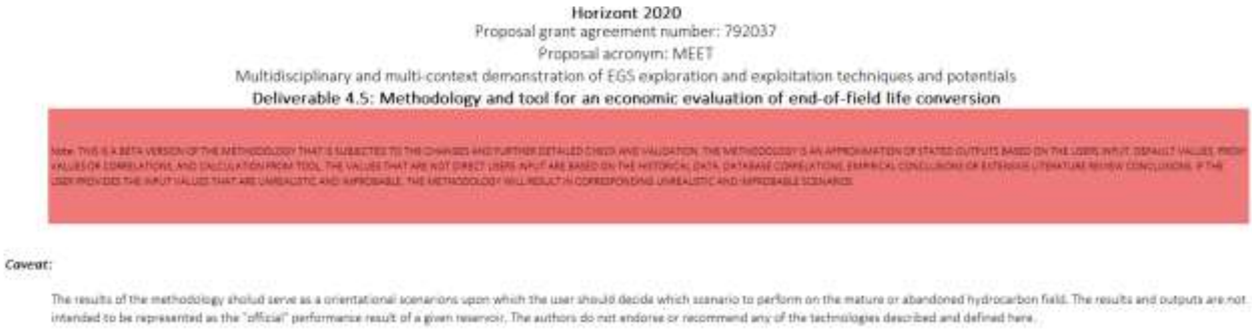

Figure 10. The display of the "MEET - Read Me" sheet.

4.2 UNIT CONVERSION

On the “Unit conversion” sheet, the constant numbers used in the methodology and tool are listed, together with the unit conversion for different parameters and in different units, as seen in the Table 12. The need for this unit conversion sheet comes out from the data that are mainly used on the field and which are not in the International System of Units (SI Units). Also, different calculations have different source units, so the conversion enables switching to the units needed for the further calculations. In the sheet, the array of 340 values can be converted into the required unit. In the Figure 11, a short display of “Unit conversion” sheet is displayed, i.e., temperature unit conversion.

Table 12. Constant numbers and unit conversion used in the methodology and tool.

Constant numbers:	Values and units
Acceleration of gravity (g)	9.80665 (m/s^2)
Density of water at standard temperature and pressure (ρ)	1,000 (kg/m^3)
Unit conversion	Units (from – to)
Temperature	K - °C
	F - °C
	R - °C
	°C - F
Flow	m^3/Day - m^3/s
	m^3/h - m^3/s
	m^3/s - m^3/Day
	l/s - m^3/s
Pressure	Pa – bar
	Bar - Pa
	Psi - pa
Specific gravity	P (kg/m^3) – SG (-)
Specific heat capacity	Cal/kg °C – J/kg °C
	Btu/lb °F – J/kg °C
Length, depth, distance	ft -m
	inch - m
	m – inch
	m - ft
Power	hp - Kw
Viscosity	cP – Pa·s
Speed	m/h – m/s
Energy	kCal – Wh
	J - kWh
Volume	$ft^3 - m^3$
	L - m^3
Area of surface	$in^2 - m^2$
	$ft^2 - m^2$

Temperature							
From	To	From	To	From	To	From	To
K	°C	F	°C	R	°C	°C	F
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8
1	-272.2	1	-17.2	1	-272.6	1	33.8

Figure 11. Temperature unit conversion.

4.3 INPUT DATA

On the “Input data” sheet, the short general instruction about the sheet can be found (eg. The Input data will be marked in blue colour, and the Output data will be marked in green colour, etc.). There are also general data about the field (country, reservoir name, number of production and injection wells, total fluid flow, calculation period start and end). The maximum possible number of wells to enter is 238, so the total fluid flow is the sum of the stated water production. Longitude and latitude of the wells are in the format of “Packed DMS with decimal point” (WGS 84), and as such enter the spatial clustering calculation. The oil production is stated here as the informational data and does not go into further calculations, because it is considered that the oil field is mature with high water-cut, and that there is also a separator of oil and water on the field before the water enters the geothermal facilities and plant. Fluid rate is the sum of the oil rate and water rate and is stated as the calculated value which does not go into further calculations. Yearly thermal dropdown is listed here as the percentage value and is defined as the annual average decline rate for petro-thermal reservoirs. Yearly water-cut increment is stated here as the linear percentage value of the annual average water-cut increase based on the historical data. The “ESP installed” input data refers to question is there any production pump installed in the well and the user can choose between “Yes” or “No”. The answer later refers to the calculation of pump power consumption. If it is “Yes”, then user should insert the pump power on the “ESP pump design” to further calculate the cost of power consumption. If the answer is “No” or user does not have the data about the pump power, then the user needs to access to calculation in the “ESP pump design” sheet to see if there is a need for production pump installation, and if the answer is positive than design the pump, or to estimate the pump power consumption of already installed pump using the same calculation. The rest of the needed input data are straight forward. On the right side of the required input data is a button for starting the calculation of three different spatial clustering techniques: K-Means, Density-based clustering technique and Hierarchical clustering technique from which the user should choose one for the calculation. In Figure 12, a short representation of "Input data" sheet is shown with part of the input data.

General Instructions About This Sheet:

Input	The input data will be marked in blue color.
Output	The Output data will be marked in green color.

Longitude (x) and latitude (y) are converted to the 2D Cartersian system.
The user should choose one of the three clustering methods and press the button.
Once the button is pressed, an "Output" sheet will appear with clustered wells from Phyton script.
On the "Output" sheet, the user should only choose the cluster using the filter option in column "G" or choose the wells according to his preferences in column "C".

General Data:

Country:	France
Reservoir name:	Site 1
Number of production wells:	2
Number of injection wells:	2
Total fluid flow (m3/s):	0.008101
Calculation period start:	2040
Calculation period end:	2060

Well Name	Longitude	Latitude	Well Temperature	Oil Production	Water Production	Fluid Rate	BottomHole Pressure	Density of Oil	Density of Geothermal Fluid	Specific Heat Capacity of Oil
Units	m	m	°C	m3/s	m3/s	m3/s	bar	kg/m3	kg/m3	J/kg °C
Well 1	370089.7	6403126	60	0.000058	0.001157	0.001215	250	850	1010	2280
Well 2	370082.6	6403130	90	0.000116	0.006944	0.007060	250	850	1010	2280

Figure 12. The display of the "Input data" sheet.

4.4 OUTPUT DATA

On the "Output data" spreadsheet, the results of two-layer clustering are presented. The used clustering method is stated as well as the number of clusters in the field. The main component of the spreadsheet is the filtering option which includes filtering of the individual wells, number of end-uses on each well, end-use, well temperature, and the number of clusters in which the well is located. On the right side of the filtering option, the data about each cluster are listed, that is the number of clusters, centroid point, existing point (well) closest to the centroid, and well names together with the corresponding geographical coordinates.

In Figure 13, the filtering option is displayed, where every well is listed as many times as there are end-uses. This type of listing later enables the calculation of each scenario, both heat and electricity generation, and gives the user an option to include or exclude a particular well or cluster from the further calculations and scenario development. The user should only use the filtering option in the "Well name" column, "Temperature" column, and "Number of clusters". That option will enable the user to include or exclude any well in the field from the further calculation. For the 3A scenario, the well with the highest temperature is chosen for the implementing the deep borehole heat exchanger technology.

Method used:
KMeans clustering

Number of clusters in field:
1

Well name	Number of end-uses	End-use	Temperature	Number of cluster
Well 1	2	Heat Generation	60	0
Well 1	2	Electricity Generati	60	0
Well 2	2	Heat Generation	90	0
Well 2	2	Electricity Generati	90	0

Number of cluster:	0	
Centroid point:	370086.15	6403128
Well closest to centro	370082.6	6403130
Well name	X coordinat	Y coordinat
Well 1	370089.7	6403126
Well2	370082.6	6403130

Figure 13. The "Output" sheet with the results and the filtering option.

4.5 PRODUCTION

The production quantities will be expressed in units of kWh (thermal or electric energy). There are 5 rectangles for each of the developed scenario and each one of them is divided in half, the left part is for the *Heat needs* scenario or *Production and injection wells* scenario and the right part of the rectangle is for the *Heat needs scenario* or *DBHE* scenario. The choice of the type of building is made via dropdown menu. The choice between the two options is made like a dropdown menu. When the user selects one of the options, the production quantities for the chosen scenario will be shown and every other output will be based on the chosen option. Above each data for the scenario, there is a short description of scenario. After inserting all the data marked with the blue colour, the user should press the “Calculate the production energy” button, which is right beneath the last scenario. On the right side of the scenarios, the production quantities for each month of the project period and for each scenario are shown. In Figure 14, an interface for a 2A scenario is shown with all the data (user’s input or calculated values) stated in the paragraphs 3.4.2 and 3.5. For every other scenario, the interface with the requested input data and calculated values is similar as the mentioned one.

2A SCENARIO - "HEAT DOUBLETS"

2A SCENARIO - "HEAT DOUBLETS" is the scenario which consist of two sub-scenarios; the first one (Heat needs scenario) is the scenario based on the heat needs of particular building and calculation of heat yield, the second one (Temperature range scenario) is the calculation of heat yield using the temeprature range (production and injection temperature).

User scenario selection: Heat needs scenario

Downtime (%):	10%
Production temperature (°C):	85.6798
Injection temperature (°C):	40
Specific heat of water (J/kg°C):	3900
Water Density (kg/m3):	1010
Total fluid flow (m3/s):	0.0081
Efficiency of heat exchanger (%):	100%

Type of building:	Public building
Base temperature for HDD (°C):	17
Building surface (m2):	6000
Required inside temperature (°C):	19
Basic outdoor temperature (°C):	-1.3
Max. water temperature (°C):	82.6798
Outdoor non-heating temperature (°C):	17
Min. water temperature (°C):	35
Thermal pinch point in HEX (°C):	3
Outdoor non-heating temperature (°C) of the pivot point:	20
Min. water temperature (°C) of the pivot point:	20
Maximum flow in the cold loop (m3/h):	30
Minimum flow in the cold loop (m3/h):	10
Specific heat capacity of fluid in the cold loop (J/kg/°C):	4180
Density of the fluid in the cold loop (kg/m3):	1000

Figure 14. The interface for calculating the production energy of the 2A scenario.

4.6 ESP DESIGN

The sheet first starts with the short description of the calculation and with the general guidelines. As stated in the 3.6.1, the user should first fill the check-up if there is a need for an ESP installation, as shown in Figure 15.

Check if there is a need for a ESP installation	
Top reservoir depth (m):	3000
Water cut (%):	100%
Oil specific gravity:	0.915
Water specific gravitiy:	1
Average fluid gravity:	1
Average fluid density (kg/m3):	1000
Hydrostatic pressure (bar):	294.2
Reservoir pressure (bar):	250
ESP installation and design:	**Yes**

Figure 15. The check up for the ESP installation.

After the check-up, if the answer is “Yes” or the user wants to estimate the power consumption of already installed pump, the next step is to proceed to the left side of the calculation. In Figure 16, the first part of the pump design process is shown. It is stated in the methodology that the pump intake pressure is set as the default value (20 bar) based on the empirical data, based on that default value, the pump depth can be determined by pressing the button "Set pump depth" for the first installation of the ESP in the well. If the user only estimates the power consumption, the value of PIP can be overwritten by inserting the user's input value in the cell E25.

	ESP design	
	Well capacity (m3/day):	500
	Water cut (%):	100%
	Oil specific gravity:	0.915
	Water specific gravitiy:	1
	Reservoir pressure (bar):	250
	Pump depth along the wellbore (m):	3000
	Pump depth - TVD (m):	1674.34
	Top reservoir depth (m):	3000
	Productivity index (m3/day/bar):	5
	Dynamic pressure (bar):	150
	Differential pressure (bar):	100
	Average fluid gravity:	1.000
	Hydrostatic pressure correction (bar):	130
	Pump intake pressure (bar):	20
	Pump selection	
	Total dynamic head (m):	1588.62
	Pump intake pressure (m):	203.948
	Net lift (m):	1470.39
	Wellhead pressure (bar):	1
	Wellhead pressure (m):	10.1974
	Production tubing ID (in):	2.9
	Correction factor for pipes:	120
Tubing friction head loss	dP/1000 ft (ft/1000 ft):	36.0095
	dp (m/100m):	3.60095
	dP (m):	108.028

Figure 16. First part of the calculation for ESP design.

In Figure 17 and Figure 18, a selected pump type and series for the required flow is shown and the whole list of the pumps, as well as the velocity check input data. The next step is to click on the link "Go to Schlumberger catalogue" and read from the performance curve of the chosen pump, the head per stage and horsepower per stage. On the right side of the mentioned calculation is the table where all the pumps from the catalogue are listed, the first pump from the list is the chosen pump, and every other pump that also has the status “Select this pump” can come into consideration for the installation in the well, but it will work at lower efficiency, as explained in 3.6.1.

Pump choice	
Required flow (m3/day):	500
Pump series	400
Pump type	D3500N
Velocity check	
Casing OD (in)	7
Casing ID (in)	6.276
Go to Schlumberger catalogue	
Head per stage (m)	8.5
Horsepower per stage (hp)	0.6
Number of Stages - Calculated	186.896
BHP (hp) - Calculated	112.138
BHP (kW) - Calculated	**83.621**

Figure 17. Second part of the ESP design with the calculated pump power consumption.

Q required (m3/day)								
500								
	Q Pump	Pump type	Pump OD (in)	Velocity Check	Minimum Capacity @ 50 H	Maximum Capacity @ 50 H	Op. range Check	Status
1	460	D3500N	4	OK	318	596	OK	Select thic pump
2	569	GN4000	5.13	OK	424	636	OK	Select thic pump
3	571	RC4000	4	OK	467	933	OK	Select thic pump
4	370	A2700N	3.38	OK	238	450	ERROR	Select another pump
5	335	RC2500	4	OK	133	427	ERROR	Select another pump

Figure 18. A list of ESP from the Schlumberger catalogue for the possible installation in the well.

In Figure 19, the calculation of cable losses is presented, where the user must insert the following input data: the current of the motor and to select the cable in cell E61. The possible cables to select are shown in the cell E60 and are stated as informational value from which the user can see which cables, regarding the motor current, are suitable for selection. The power consumption of the surface is also shown.
After the calculation of pump power, the user should enter the calculated value in the cells for operating cost calculation, starting from cell AC3 to the right. For each well the operational cost is then calculated regarding the operating time and the electricity price for every scenario where the ESPs are used.

Cable losses

A voltage drop of less than 30 volts per 1000 ft is reccomended

Motor current (Amps):	30
Possible cables to select:	1, 2, 4, 6
Cable selection:	2
Resistance (ohm/1000 ft)	0.17
Voltage drop/1000 ft of cable @ 25 °C:	9.2074
Downhole temperature (°F):	140
Temperature correction factor:	1.13482
Voltage drop at the downhole temp/1000 ft:	10.4487
Voltage drop for the well lenght:	102.842
Cable lenght (m):	3000
Power losses for the well depth (kW):	**4.5177**
Power consumption of the surface (kW):	**88.139**

Figure 19. Cable losses calculation.

4.7 INJECTION PUMP DESIGN

At the top of the sheet, there is a short description of the calculation and the guidelines for the calculation. The user should first fill the input data on the right side, shown in Figure 20. Next, on the right side, the calculation steps, as described in the 3.6.2, are shown in Figure 21, together with the results of each step for the 7 injection pumps and their curves. At the bottom, the pump power is calculated and presented. After the calculation of the pump power, the user should enter the calculated value in the cells for operating cost calculation, starting from cell Y2 to the right. For each pump or well, the operational cost is then calculated regarding the operating time and the electricity price for every scenario where the injection pumps are used.

Total flow (m3/s):	0.0099
Total flow (m3/day):	855.36
Number of injection well/pump:	2
One well flow (m3/day):	427.68
Average depth of injection wells (m):	3000
Fluid density (kg/m3):	1010
g (m/s2):	9.80665
Pump intake pressure (bar):	10
MAWP (bar):	200
Hydrostatic pressure (bar):	297.141
Reservoir pressure (bar):	250

Figure 20. Input data for the injection pump design.

		PUMP 1	PUMP 2	PUMP 3	PUMP 4	PUMP 5	PUMP 6	PUMP 7
Step 1	Q in O.R.?	Exclude pump from selection	Yes	Yes	Yes	Yes	Yes	Yes
Step 2	Calculate power	Exclude pump from selection	145.7302457	100.7609475	85.33692723	48.33581453	130.1380327	265.0182305
Step 3	Calculate head	Exclude pump from selection	226.7016544	118.9223706	86.3232167	60.36118258	120.0048407	208.781312
Step 4	Calculate WHIP	Exclude pump from selection	Choose another pump	125.9223706	105.3232167	70.36118258	130.0048407	Choose another pump
Step 5	Check BHIP	Exclude pump from selection	Choose another pump	427.0638856	402.4647117	367.3026773	427.1463357	Choose another pump
	TOTAL POWER	Exclude pump from selection	145.7302457	100.7609475	85.33692723	48.33581453	130.1380327	265.0182305
	TOTAL POWER	0	145.7302457	100.7609475	85.33692723	48.33581453	130.1380327	265.0182305

Pump power	48.33581453

Figure 21. Calculation steps for the injection pump design.

4.8 DBHE PUMP DESIGN

At the top of the sheet there is a short description of the sub-programme. Since the main purpose of the methodology is the conversion of an oil field to the geothermal one, it is considered that there are no deep borehole heat exchanger technologies implemented yet on the field, so the DBHE pump design is the approximation of the pump power needed for circulation of the fluid. The circulating fluid flow is user's input where the pressure drops, when circulating, needs to be reduced to a minimum, as described in the 3.4.3.

The user should fill the data about the configured well as seen in Figure 22. The pressure drop along the wellbore will be calculated using the Colebrook's equation, that is, the Darcy-Weisbach friction factor calculation. To calculate the friction factor, the user should first insert a small positive random number in the cell C22, per example 0.01, and then press the button "Calculate Darcy-Weisbach friction factor". Pump efficiency should also be a user's input. At the bottom, the pump power is calculated. After the calculation of the pump power, the user should enter the calculated value in the cell for operating cost calculation, i.e. in the cell W4. For the DBHE pump, the operational cost is then calculated regarding the operating time and the electricity price.

Well name:	LES PINS 5D	
Density of circulating fluid (kg/m3):	1000	
Flow (m3/s):	0.004	
Specific heat capcity of circulating fluid (J/kg°C):	4187	
Absolute roughness of the pipe (m):	0.000015	
Dynamic viscosity (Pa*s):	0.0012	
Kinematic viscostiy (m2/s):	0.0000012	
Tubing inside diameter (m):	0.102	
Tubing flowing surface (m2):	0.0081713	
Fluid velocity (m/s):	0.4895192	
Reynolds number:	41609.135	
k/d	0.0001471	
Darcy Weisbach friction factor	0.03405	
Colebrook left side:	5.4192266	Calculate Darcy Weisbach friction factor
Colebrook right side:	5.3910337	
Objective:	0.0007948	
Well depth (m):	1000	
Fluid velocity^2 ((m/s)^2):	0.2396291	
g (m/s2):	9.80665	
Head loss (m):	4.0786277	
Pump efficiency (%):	65%	
Pump power (W):	246.13953	

Figure 22. The calculation of the DBHE pump design.

4.9 EXPLANATIONS

On the “Explanations” sheet, there is a short description of every underlined value. The explanation usually defines the value or proposes the range of the value. Under every explanation there is a hyperlink for the return to the considered value. The example of one of the explanations is shown in Figure 23.

Pivot point is the fixed point on the heating regulators around which the heating curve turns when the slope is varied. A basic pivot point is generally preset on the regulators ((20 °C, 20 °C), (35 °C, 15 °C)). The value is usually given in the technical manual of the device. The first number is the outside temperature at which the heating is no longer needed. In this calculation it will be set at 20 °C until the user inserts its own value.
Go back to the outdoor non-heating temperature of the pivot point

Figure 23. The example of one of the explanations in the "Explanations" sheet.

4.10 LCOE AND LCOH

For both calculation of levelized cost of electricity (LCOE) and heat (LCOH), the input parameters are the same as explained in the 3.7.1 and 3.7.2. and at the top of both sheets there is a short description of the calculation followed by the input parameter as seen in

Figure 24. For every input data there is an explanation hyperlink which leads to the "Explanations" sheet where all input parameters are explained, and it is defined in which group of costs does each of the parameter go. The costs and other related input data are the same for production and injection well scenario and the deep borehole heat exchanger scenario. The user should insert one input value by one. When all the input data are filled, the LCOE and LCOH are calculated on the right side of the input parameters for every year of the project period.

Investment cost (EUR/kW):	**4290**
Exploration and establishment:	250
Production and injection wells and system:	1700
Cost of power plan installation:	2040
Administration and management:	200
Other investment costs:	100
Operation and maintenance fixed costs (EUR/kW):	5
Operational and maintainance variable cost (EUR/kWh):	
OPEX of ESP:	26.3
Other variable OPEX:	15
Discount rate:	7%
Incentives:	
Effective tax rate:	20%
CHP	
Revenues from subsidized heating power sales:	
Revenues from the market heating power sales:	
Duration of subsidized price of electriciy or heating power:	
Duration of depreciation period:	

Figure 24. Input data for calculating LCOE and LCOH.

4.11 NET PRESENT VALUE (NPV)

A short description of the NPV calculation is given at the top of the sheet. The calculation is conducted as described in 3.7.3. The two user's input parameters are a_t, financial discount factor and, *r*, nominal discount factor. For every developed scenario, the calculation output of NPV is shown on the "NPV" sheet for every year of the project period.

4.12 AVOIDED CO_2 EMISSIONS

On the "Avoided CO_2 emissions" sheet, the CO_2 saved when exploiting geothermal energy are calculated for each of the developed scenarios, as explained in the 3.7.4. At the top of the sheet, there is a short description of the calculation. As seen in Figure 25, all the input parameters are set as the default values and are country specific. If the user has more recent and accurate data, the default values can be overwritten with the user's input. Due the confidential data of Emission factors for each country and for each fossil fuel, the default values of the mentioned data will be hidden and protected.

COUNTRY: France	Default values
gCO2 eq/kWh of ELECTRICITY ONLY - COAL	
gCO2 eq/kWh of ELECTRICITY ONLY - OIL	
gCO2 eq/kWh of ELECTRICITY ONLY - NATURAL GAS	
gCO2eq/kWh of HEAT ONLY - COAL	
gCO2eq/kWh of HEAT ONLY - OIL	
gCO2eq/kWh of HEAT ONLY - NATURAL GAS	
gCO2eq/kWh of ELECTRICITY AND HEAT - COAL	
gCO2eq/kWh of ELECTRICITY AND HEAT - OIL	
gCO2eq/kWh of ELECTRICITY AND HEAT - NATURAL GAS	
Share of COAL in total fossil fuel ELECTRICITY GENERATION	23%
Share of OIL in total fossil fuel ELECTRICITY GENERATION	13%
Share of NATURAL GAS in total fossil fuel ELECTRICITY GENERATION	65%
Share of COAL in total fossil fuel HEAT GENERATION	7%
Share of OIL in total fossil fuel HEAT GENERATION	11%
Share of NATURAL GAS in total fossil fuel HEAT GENERATION	82%

Figure 25. Input data for calculating the avoided CO_2 emissions.

5 SENSITIVITY ANALYSIS

To cope with the uncertainty of the parameters and data, and to get a better understanding of the potential deviation from the obtained results of the reference case, sensitivity analysis can be carried out. The input value will be presented as the percentage of the reference scenario. The input data will be divided as the common influencing factors and scenario specific influencing factors. The results of the sensitivity analysis on the main outputs will be shown numerically and graphically. The results of the sensitivity analysis can later be used for creating more suitable scenarios. In Figure 26, a part of the sensitivity analysis input data is shown.

Reference values:	% of change:	New value:
Yearly thermal dropdown		
Yearly thermal water-cut increment		
Transsmission temperature loss		
Fluid flow		
2A Scenario		
Injection temperature		
Efficiency of surface heat exchanger		
Required inside temperature		
Share of COAL in total fossil fuel ELECTRICITY GENERATION		
Share of OIL in total fossil fuel ELECTRICITY GENERATION		
Share of NATURAL GAS in total fossil fuel ELECTRICITY GENERATION		
Share of COAL in total fossil fuel HEAT GENERATION		
Share of OIL in total fossil fuel HEAT GENERATION		
Share of NATURAL GAS in total fossil fuel HEAT GENERATION		
Nominal discount rate		
Effective tax rate		

Figure 26. Sensitivity analysis input data.

6 OPTIMIZATION MODULE

For this deliverable special optimization module has also been created. Investor in heating capacity will face different needs of its future customers. Sometimes these needs are stable over the whole year, for example industrial heat needs, and sometimes they greatly vary during year and have seasonal character, for example district heating, heat needs. For stable heat consumers economic analysis is straightforward. Investor needs to calculate annualized construction costs and compare it to expected profit from selling heat to customer. In cases expected profit is greater than expected lifetime costs project will be marked as feasible and in cases expected profit is lower than expected lifetime costs project will be marked as infeasible. Decision on feasibility of heat provider investment for very variable seasonal heat consumers will require more investigation. One example of heat needs over the one-year span is shown in Figure 27.

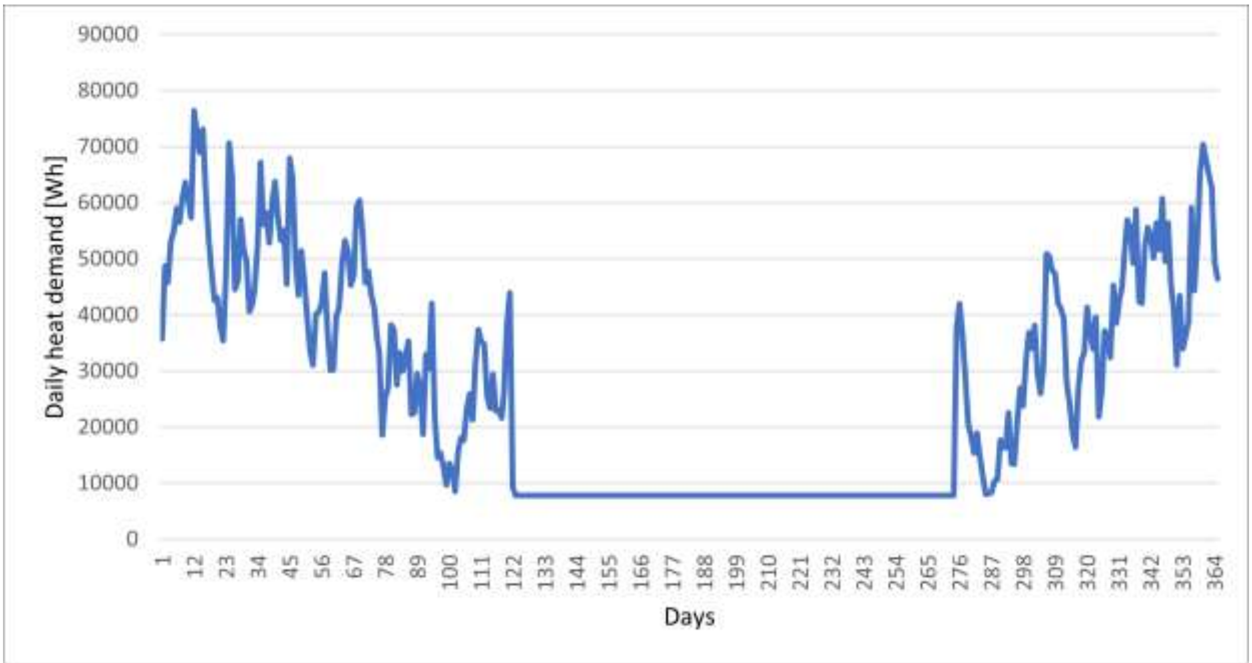

Figure 27. An example of chronological daily heat demand.

In Figure 28 chronological heat needs are transformed into monotonically decreasing heat need curve that shows for how many days customer requires exact heat value. It is obvious that very large heat needs have very short duration and therefore it is usually not feasible to satisfy all required heat needs during the whole year. Therefore, investor has to decide what level of installed heat capacity is optimal in terms of maximum profit. Profit is dependent on investment costs and selling price of heat. Starting from zero profit, installed capacity profit rises (if the price is high enough) until certain level where additional investment will start to produce financial losses due to very low utilization factor of installed capacity. For this reason, special optimization MATLAB based module has been created. Its goal is to find optimal installed heat capacity, in other words heat capacity that will generate maximum profit. For optimization purposes special add-in,

YALMIP, is needed for MATLAB. All information about YALMIP and its installation can be found on link: https://yalmip.github.io/.
Besides optimal installed capacity, user will get information on expected profit and also unsatisfied heat demand to final user. Dependence between optimal installed heat capacity, investment costs, and heat prices is quite straightforward. The higher investment costs are the lower the optimal installed heat capacity will be. On the other hand, the higher the heat price, the higher the optimal installed heat capacity will be.

Source code for this optimization module in MATLAB is following:

```
% FIRST - read mat data file, alternatively uncomment below
% adjust location and write in A1 cell on Sheet2 Demand then execute

% reading data
% opts = spreadsheetImportOptions("NumVariables", 1);
% opts.Sheet = "Sheet2";
% opts.DataRange = "A2:A366";
% opts.VariableNames = "Demand";
% opts.VariableTypes = "double";
% heat = readtable("C:\Users\Lin
Herenèiæ\Documents\Doktorat\Predmeti\Optimizacijski postupci\heat load
cro.xlsx", opts, "UseExcel", false);
% heat = table2array(heat);
% clear opts

x = sdpvar(1,1); % decision variable - installed capacity in W
Q = sdpvar(365,1); % daily heat demand
cost = 2; % cost of investment in EUR per W
years = 20; % project lifetime in years
profit = 0; % objective function, maximum profit in EUR
priceHeat = 0.035 % price of heat in EUR per kWh

obj = zeros(1,1);
for d=1:length(heat)
    obj = obj + Q(d)/1000*priceHeat;
end
obj = obj - x*cost/years;
Objective = obj;

heatConstraints = [];
profitConstraints = [];
positiveConstraints = [];
positiveConstraints = [x>=0];

for d=1:length(heat)
   positiveConstraints = [positiveConstraints, Q(d) >= 0];
   heatConstraints = [heatConstraints, Q(d)<=heat(d)];
   profitConstraints = [profitConstraints, Q(d)<=x*24];
end
```

```
Constraints = [positiveConstraints, heatConstraints,
profitConstraints];

% Set some options for YALMIP and solver
options = sdpsettings('verbose',2);% , 'solver', 'gurobi');

% Solve the problem
sol = optimize(Constraints,-Objective,options);

% Analyze error flags
if sol.problem == 0
 % Extract and display value
 powerValue = value(x)
 profitValue = value(Objective)
 QValue = value(Q);
 unserved = heat - QValue;
 unservedPerc = sum(unserved)/sum(heat)*100

else
 disp('Hmm, something went wrong!');
 sol.info
 yalmiperror(sol.problem)
end
```

In this formulation 'x' is the decision variable or optimal installed heat capacity. In each time step 'd' produced heat Q(d) has to be nonnegative and lower than required heat demand from users and lower than x multiplied by 24, because time step, d, is set as one day in this example.

Solution for investment cost of 2,000 €/kW and heat price of 0.035 €/kWh is shown on following figures (Figure 28, Figure 29).

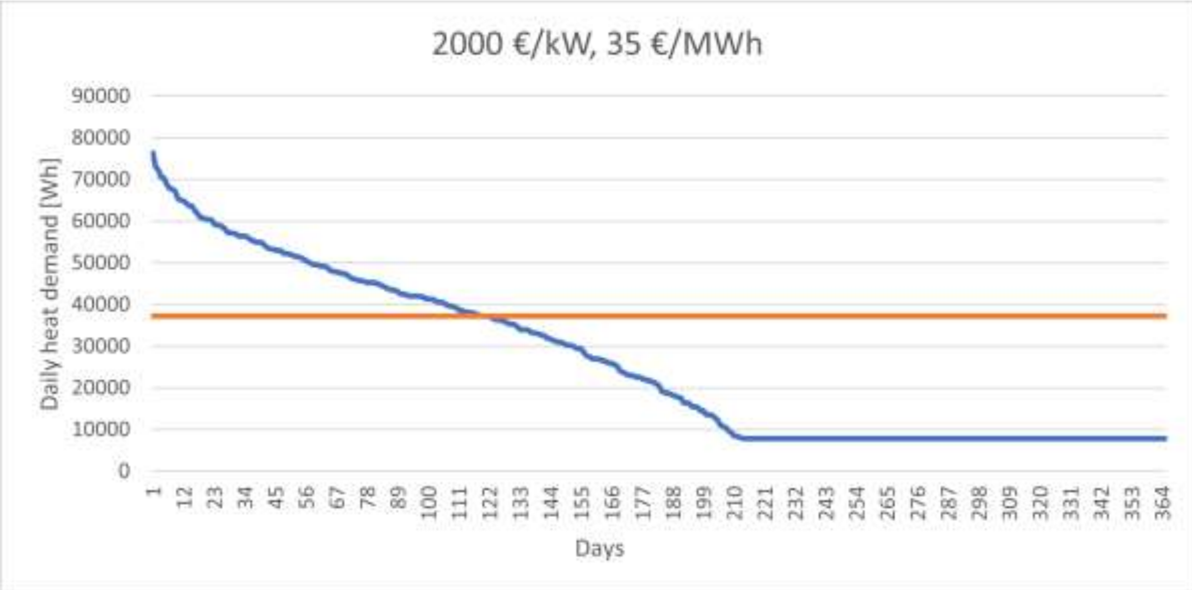

Figure 28. Optimal heat capacity solution on monotonically decreasing heat demand for investment cost of 2,000 €/kW and heat price of 0.035 €/kWh.

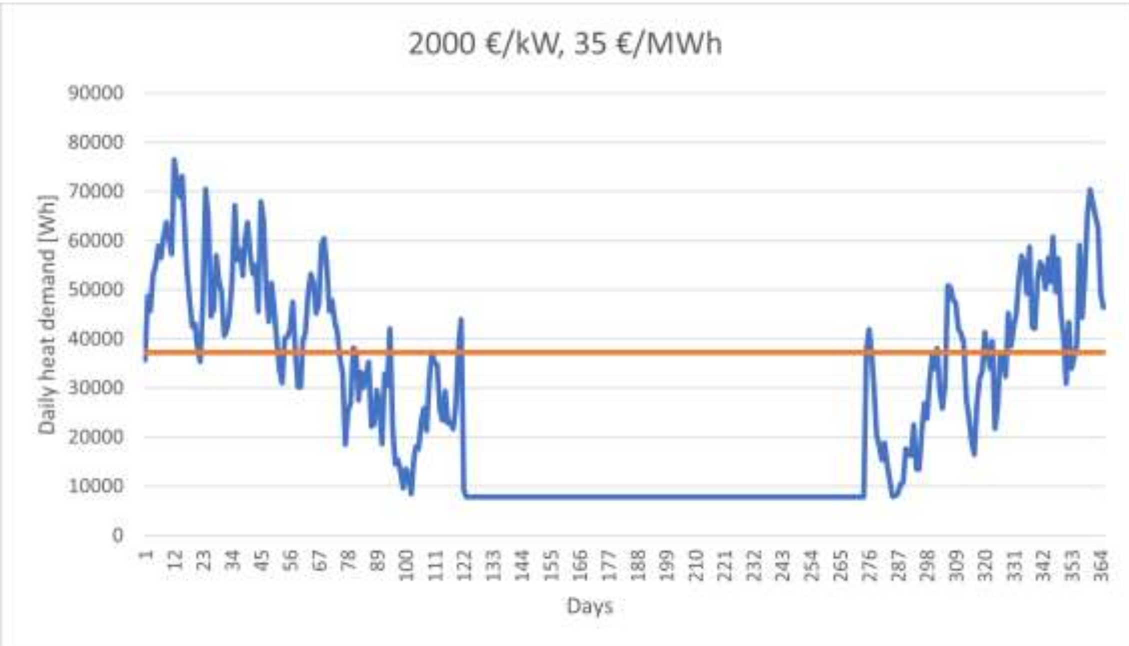

Figure 29. Optimal heat capacity solution on chronological heat demand for investment cost of 2,000 €/kW and heat price of 0.035 €/kWh.

For this specific case optimal installed heat capacity is 1.55 kW, one year profit is 122.38 € and profit during the technical lifetime of 20 years is 2,447.63 €. Unserved heat demand is around 17 %.
This solution can be verified by calculating profit for different installed capacities. It is shown in Figure 30 with step of 200 W.

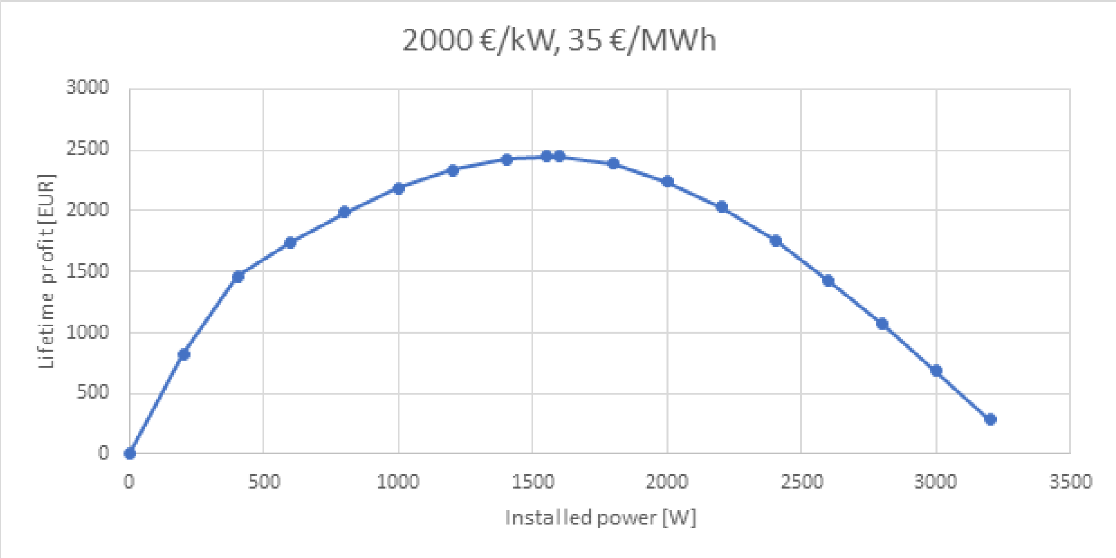

Figure 30. Validation of solution for investment cost of 2,000 €/kW and heat price of 0.035 €/kWh.

It is obvious that from installed level of heat capacity of 0 W to 1.55 W profit is increasing and after that point increase in installed heat capacity results in steady profit decrease due to low utilization factor of installed heat capacity.

For the sake of comprehensiveness, special sensitivity analysis has been conducted. Namely, investment cost of 2,000 €/kW are lowered first to 1,000 €/kW and then to 500 €/kW and for each case optimal solution is obtained. Results for 1,000 €/kW are shown in Figure 31 and Figure 32. And for 500 €/kW the results are shown in Figure 33 and Figure 34.

Figure 31. Optimal heat capacity solution on monotonically decreasing heat demand for investment cost of 1,000 €/kW and heat price of 0.035 €/kWh.

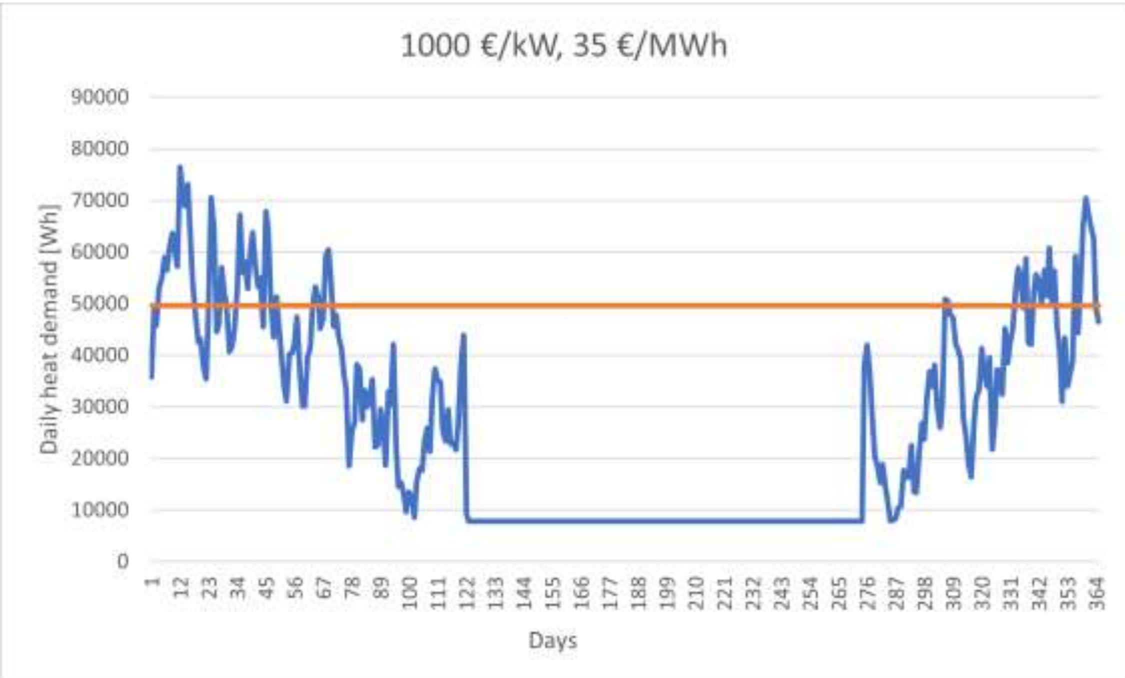

Figure 32. Optimal heat capacity solution on chronological heat demand for investment cost of 1,000 €/kW and heat price of 0.035 €/kWh.

For this specific case (investment cost of 1,000 €/kW and heat price of 0.035 €/kWh) optimal installed heat capacity is 2.07 kW, one year profit is 212.35 € and profit during technical lifetime of 20 years is 4,246.91 €. Unserved heat demand is around 5.6 %.

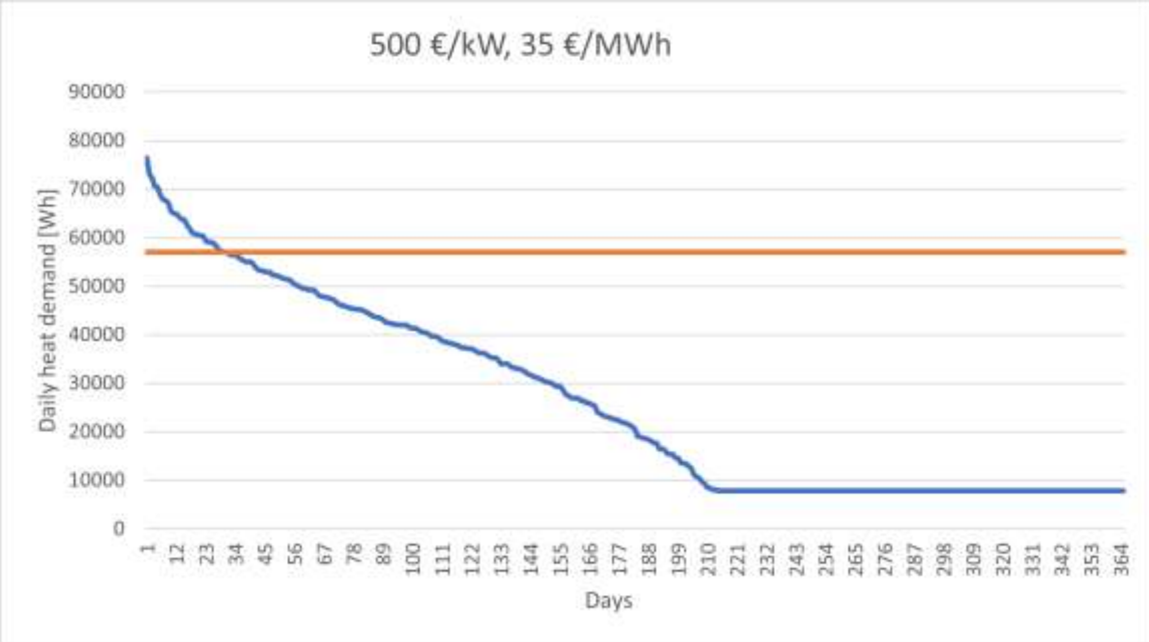

Figure 33. Optimal heat capacity solution on monotonically decreasing heat demand for investment cost of 500 €/kW and heat price of 0.035 €/kWh.

For this specific case (investment cost of 500 €/kW and heat price of 0.035 €/kWh) optimal installed heat capacity is 2.38 kW, one year profit is 267.83 € and profit during technical lifetime of 20 years is 5,356.52 €. Unserved heat demand is around 2.1 %.

From this sensitivity analysis it is obvious that decrease in investment costs of heat capacity increases expected profit and decreases unserved heat demand. Same effect will have increase in heat price.

All results from this analysis are summarized and shown in Table 13.

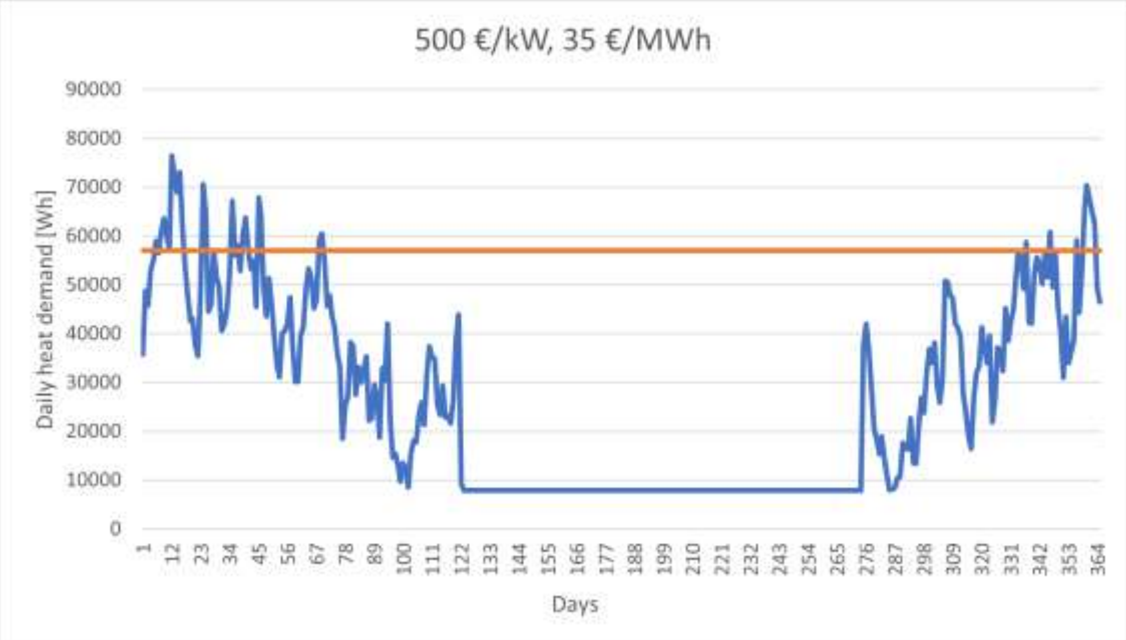

Figure 34. Optimal heat capacity solution on chronological heat demand for investment cost of 500 €/kW and heat price of 0.035 €/kWh.

Table 13. Results for different investment costs.

Investment costs [€/kW]	Heat price [€/MWh]	Optimal installed heat capacity [kW]	Expected one year profit [€]	Expected profit during lifetime [€]	Unserved heat demand [%]
2,000	35	1.55	122.38	2,447.63	17
1,000	35	2.07	212.35	4,246.91	5.6
500	35	2.38	267.83	5,356.52	2.1

7 CONCLUSION

This Deliverable Report provides extensive description of methodology and tool for an economic evaluation of end-of-life oil fields conversion. Different scenarios and approaches of the conversion process have been described. Additionally, main mathematical models used in the methodology have been both linguistically described and provided in terms of equations, three different clustering methods are named and explained, all assumptions are stated and elaborated, main input data have been described, and all output parameters have been thoroughly presented.

One of the main features of the conversion is bi-level clustering which facilitates firstly clustering of the wells according to the geothermal fluid temperature into a different end-use group, and secondly, clustering of the wells into spatial groups according to the distance between each well. This approach allows the optimal conversion and usage of the cumulative production flow from the production wells while minimizing the costs for the piping infrastructure, and power plant spatial positioning.

Beside the explanatory part of the methodology itself, concise user manual for the Excel-based support tool has been reported. The support tool enables user friendly, easy-to-manage interface to the developed methodology and is modelled in such a way that it can straightforwardly be used by more or less experienced users.

Presented methodology and support tool are developed in order to ease the pre-techno-economic analysis of conversion process of an oil filed to a geothermal field at the end of its economic "petroleum" life. The methodology covers primarily technical and economic aspects of end-of-life conversion process while regulatory and policy aspects of such action are left on the knowledge of the user/potential investor, since this is highly country specific and project specific.

The developed methodology is intended to be used as the basis for the work in Deliverable 4.6. "Detailed technical-economic study for a specific Vermilion site".

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