Performance Assessment Tool
ENGINEPA.XLS
ENGINE DSS

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1 Introduction and Summary

Prior to ENGINE, forecasts have been made in 1995 for resource potential of geothermal electricity production (Figure 1), reflecting a steady growth based on successful geothermal exploitation such as in Iceland and Italy (Larderello).

As a consequence of rapidly increased fossil fuel prices, renewable energy sources have become economically significantly more attractive. In addition the particular countries in the EU have established incentive schemes. Currently the EU is supporting these with the aim to achieve renewable power production at costs in the range of 8-15 ct/kwh, leading to 5 cts/kwh in 2020. Consequently the uptake of Geothermal energy is currently anticipated by the European Geothermal Energy Council (EGEC) much higher than in 1995 (Figure 1)

Minimizing risks for project development plays a key role in promoting the uptake, as it is a new technology with a steep technological learning curve. It is marked by exploration risks which can be high, and public acceptance and legislation need to develop and to be adjusted if needed. Each of these aspects is treated individually in various chapters of the best practice of ENGINE, in terms as state-of the art workflow, technology, methods and lessons learned

This chapter takes an integrative approach to the various aspects in the workflow dealing with risk analysis. In the first section we will outline the various aspects of risk analysis, or rather performance assessment. Doing so we will show that major challenge for facilitating uptake needs to be achieved by sharing quantitative understanding of the economic impact of key technical and economic parameters in EGS at different phases in the workflow, from exploration to production. To do this quantitatively, we developed a simple techno-economic performance tool in EXCEL (enginePA.xls). The quantitative model is based on analytical models developed for EGS, including a streamline fluid flow approach, and a heat stored approach suggested by ENEL (courtesy R. Bertani). The models have also been implemented in a dedicated decision support system (Engine DSS), using best practices for asset evaluation from the Oil&Gas industry. This approach allows to take into account natural uncertainties and decision trees to evaluate sensitivities and different scenarios. Doing so we can evaluate the performance of geothermal systems, investigating sensitivities of the performance due to both natural uncertainties beyond control (e.g. flow characteristics, subsurface temperatures), engineering options (bore layout and surface facilities options) and economic uncertainties (e.g. electricity price, tax regimes).

Results show that the performance of the system is primary sensitive to subsurface temperature, flow rates which can be sustained in the fractured rock, and the number of fractures involved in the fluid flow. We also are capable to forecast effects of improved explorative approaches and technological performance as well as governmental incentives on viability of prospects.

The EXCEL performance assessment tool (EnginePA.xls) and the Engine DSS are public deliverables.

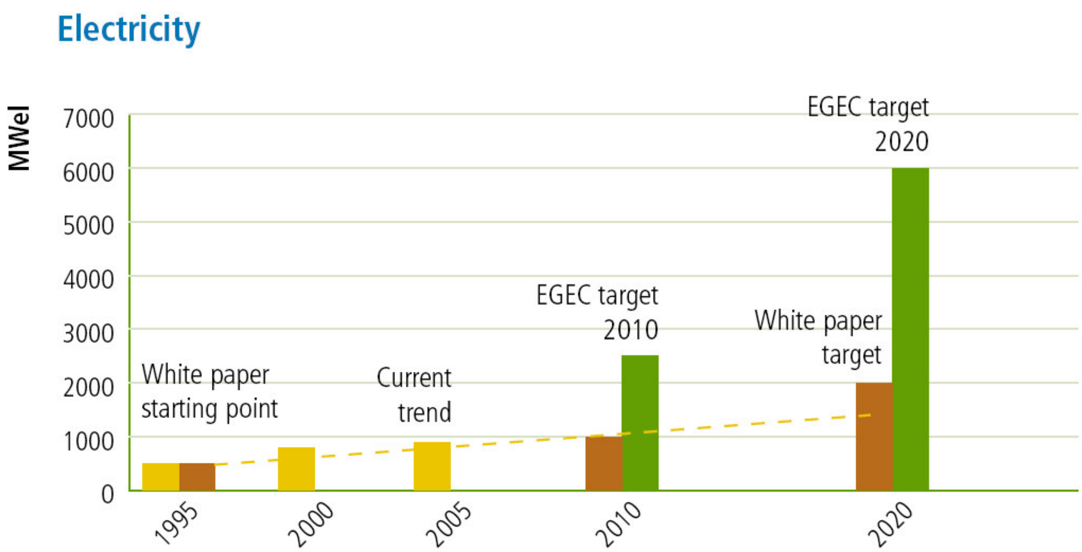


Figure 1. Forecast of EU whitepaper in 1995 and renewed targets by EGEC in 2007.

2 Performance assessment definition

Performance assessment is defined to forecast the economic performance of a prospect to be developed. The economic performance can be cast in terms of Net Present Value (NPV) or Unit technical Cost (UTC). NPV, is calculated from the discounted cash flow taking into account an internal rate of return for discounting (Figure 2) normally is 10%. The Unit Technical Cost is calculated as the ratio of cumulative discounted costs (CAPEX, OPEX and TAX) and cumulative discounted power produced. Figure 3 gives an example of the UTC reducing with depth (increasing temperature) and reduced through higher transmissivity.

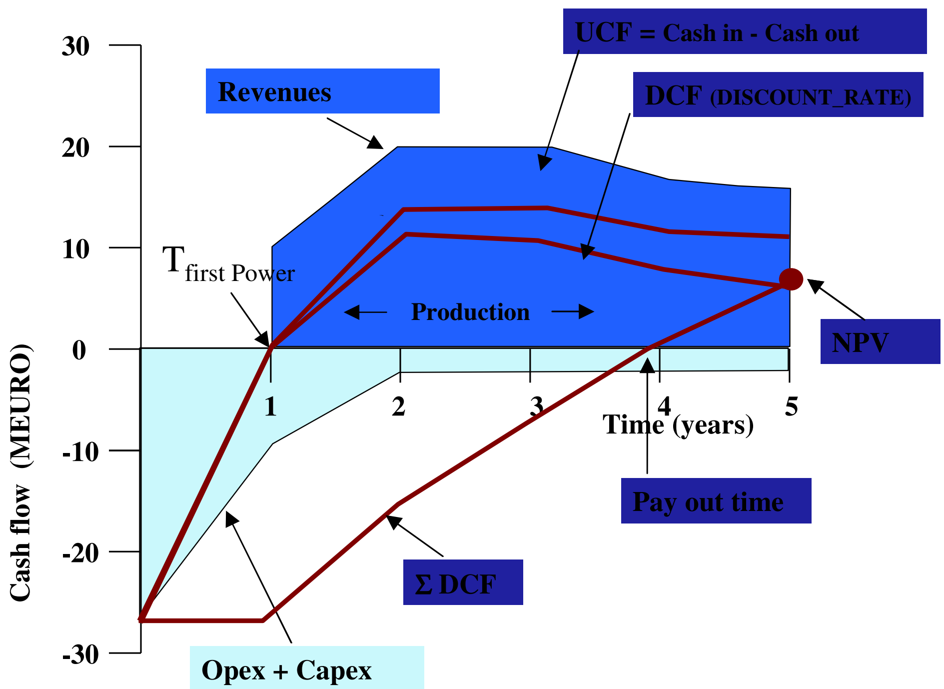


Figure 2. Calculation of the Net Present Value of a project. The NPV is calculated based on a forecast of cash-out (capital expenditure (CAPEX), operational expenditure (OPEX), on one hand and cash-in, based on the revenues of the sold electricity. The Undiscounted cash flow (UCF) is the difference of Cash in and cash out. The discounted cash flow (DCF) takes into account the costs project funding (marked by a discount rate). Cumulative DCF results in the NPV at the end the project

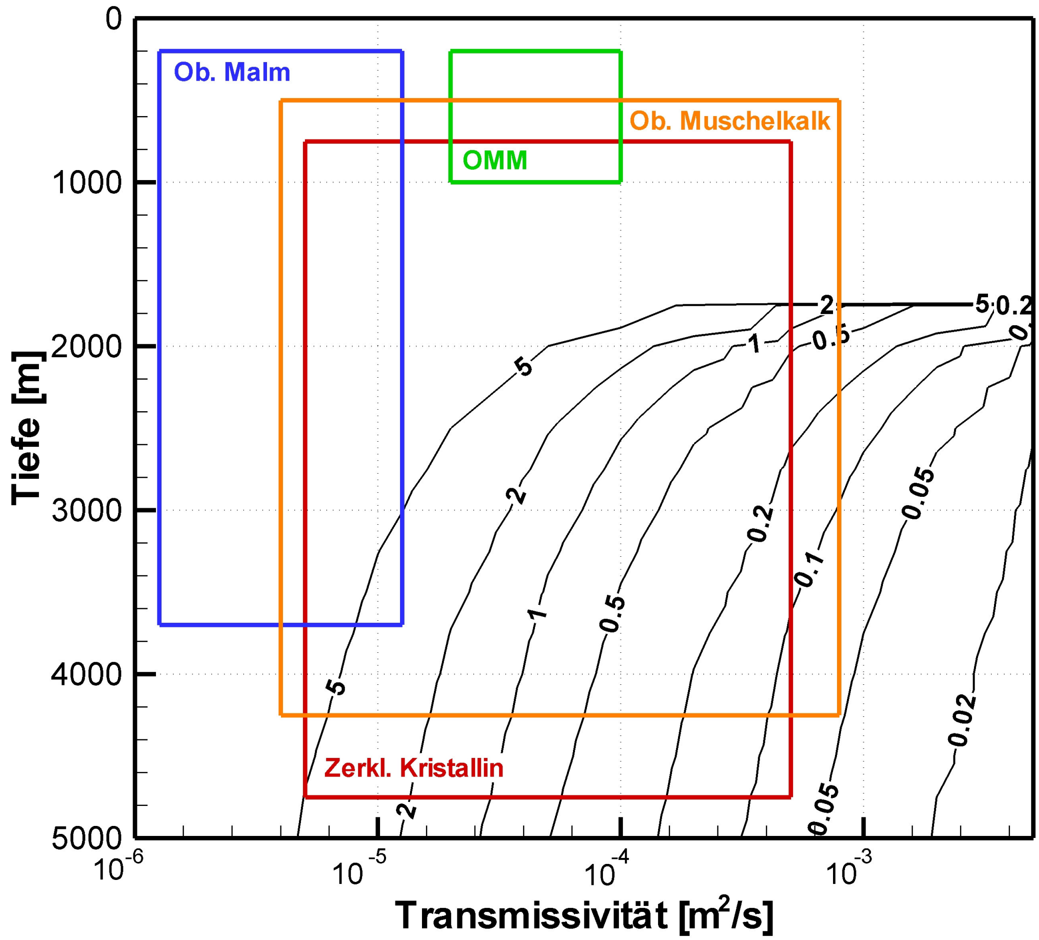


Figure 3. Unit Technical Costs (Electricity costs CHF/kWh) of different geothermal development options in Switzerland. These are preliminary outcomes .Source GeoWatt.

The NPV (and UTC) are calculated as a function of the technical and economical parameters in an integrated techno-economic model. In section 3 we introduce the techno-economic model which is implemented in enginePA.xls.

3 EnginePA.xls : Performance assessment of production

The Net Present Value (NPV) for a geothermal EGS reservoir is calculated by enginePA.xls according to the model described below. The model consists of various components using simplified physical approached for a fast calculation (cf. Fig. 3.1)

The model is designed for a multiple doublet approach with a fluid circulation in a subsurface reservoir. The construction of this model is separate in 4 main groups of parameters: basin properties, underground development, surface development, commercial aspects and financial aspects (Fig. 3.1)

Two of the groups correspond to “uncontrollable parameters” (basin properties and commercial aspects and financials aspects) meaning that you have no direct influences on them. The others (underground development, surface development) are mainly parameters related to engineering development for the project, corresponding to parameters the project-developer can largely control.

The parameters are used to describe the reservoir (Basin properties and a part of the underground development), the borehole specifications (the other part of the underground development), the surface facilities (surface development), and the commercial / financials (some of the engineering parameter from surface and underground development, commercial aspects, and financial aspects).

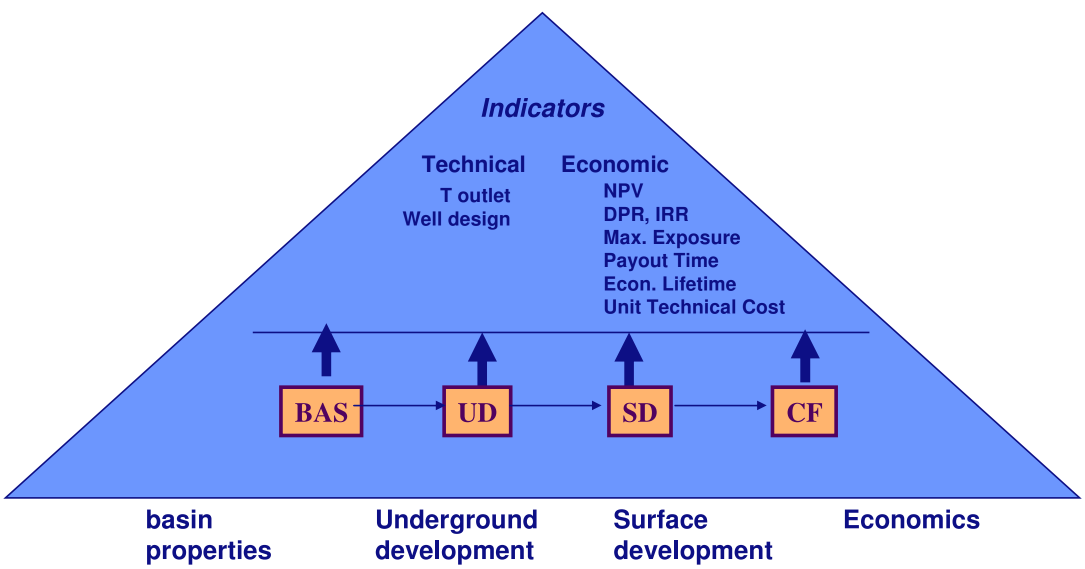


Figure 3.1: techno-economic chain of models capable of calculating geothermal performance (NPV). The chain is subdivided in 4 components. Geological basin properties (temperature) (BAS), underground development policy (UDP), surface development policy (SDP) and commercial and cashflow aspects (CF)

3.1 Two different model approaches

Two different model approaches are used to describe the energy extracted from the reservoir.

The first model is based on fluid flow circulation models developed in literature (e.g. Pruess and Bodvarsson, 1983; Heidinger et al., 2006) and describe the fluid flow through the reservoir. This model is described in detail in section 3.2. The second is based on the proportion of energy extracted from the energy stored in the reservoir, described in detail in section 3.3.

Both models use fast analytical models for the performance calculations. Slightly different parameters used in the model are representative for the steps of the model. The description of the model (Figure 3.2) is made first for the reservoir component. Later borehole, surface development (power plant) and economic parameters will be described.

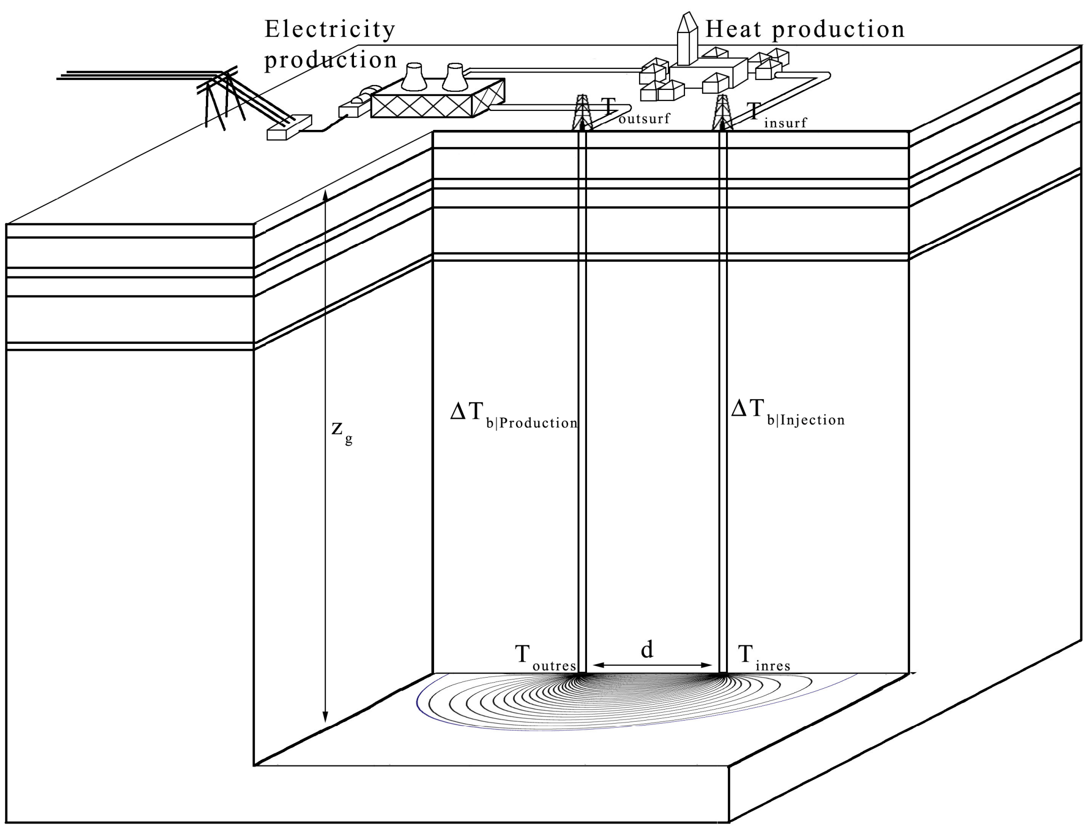


Figure 3.2. General circulation general representation

3.2 Thermal model at reservoir level: fluid flow calculation model (modes 1,2,3)

In the reservoir, we distinguish various possible media in which the water flows at reservoir level. These are

1. porous or densely fractured medium
2. evenly spaced fractures

For porous or densely fractured media we assume that the water can absorb all the heat which is stored in the reservoir over a specific Area A and thickness H, characterized by porosity ϕ_{res}. Optionally it can assumed that the reservoir can absorb heat outside the reservoir level (reservoir Mode 1) or not (reservoir Mode 0)

For fractures it is assumed that the water flows along a number of N fractures of area A and aperture H and 100% porosity (ϕ_{res}=1). Each fracture is thermally independent (e.g. the Soultz-sous-forêts case shown that with a 200m distance, two fractures can be considered independently). This is fracture Mode.

Following Pruess and Bodvarrson (1983) and Heidinger, et al. (2006) we can use relatively simple analytical solutions for the thermal evolution in between an injection and production well for the various

Firstly, the shape of the reservoir has to be defined. The model allows a choice within four approaches, called scenarios in the model. The distinction between each scenario is made by the thickness of the reservoir/fracture and the porosity.

The thermal equation used for each mode is further explained in section 3.2.2.

3.2.1 Streamlines: a discretization of the reservoir

In all reservoir and fracture modes, the flow paths for angular segments around the injection and production wells are calculated using a streamline solution as shown in Figure . This streamline approach, separating various flowpaths in the reservoir allows to account for the effect of flow path length and fluid velocity along the flow path on the heating effects of the fluid.

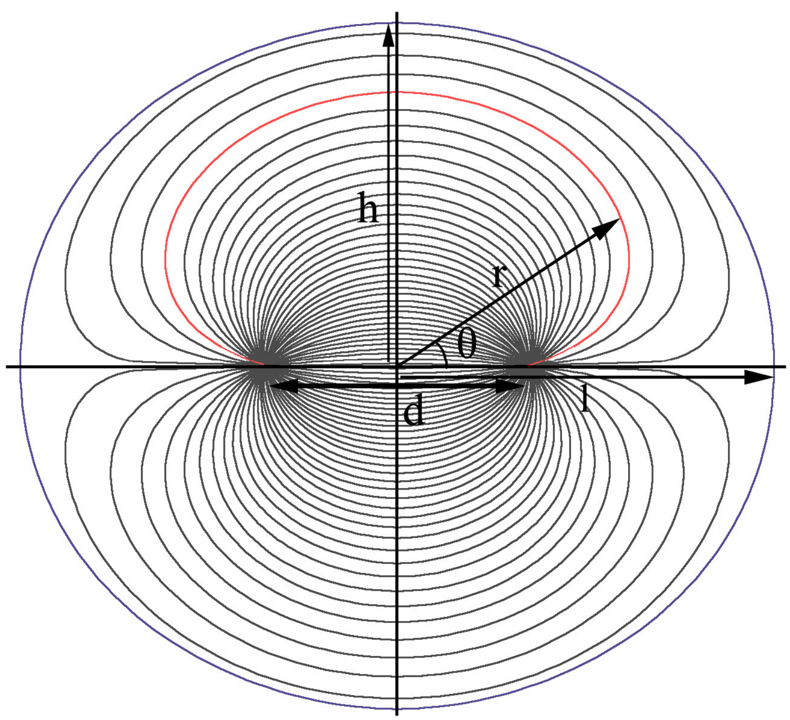


Figure 4a. streamlines solution in a doublet case (36×2 streamlines are here presented)

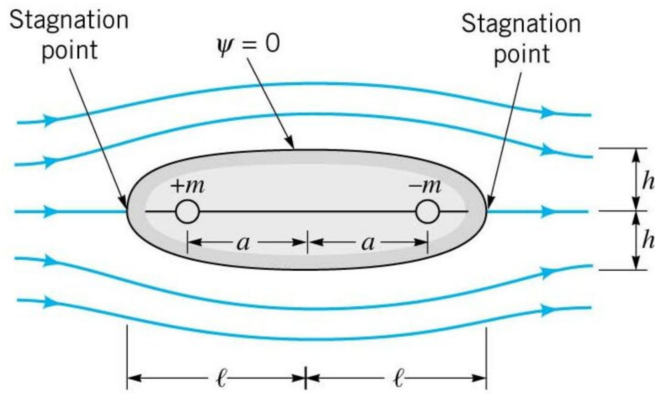


Figure 4b: Rankine solution for closed body flow

The streamline solution follows the Bears (1972) solution for source and sink, subject to a uniform directional flow in the x-axis, the so-called rankine-oval. Consequently the flow paths are limited in extent to a penny or slightly oval shape, of which the area is determined by A., for very large A the solution converges to a source and sink, in absence of uniform flow.

For the rankine oval the streamline ψ is described by the equation:

$$\psi = r\sin\theta - M\frac{\arctan\left(\dfrac{2ar\sin\theta}{r^2 - a^2}\right)}{2\pi} \qquad (1)$$

$$\text{with} \qquad M = 2\pi\frac{h}{\arctan\left(\dfrac{2ah}{h^2 - a^2}\right)} \qquad (1.1)$$

where r and θ are polar co-ordinates in the streamline plot, a is half distance of the doublet system, h is half the height of the oval. The area A of the fracture or reservoir is approximated through

$$A = \pi hl \qquad (1.2)$$

Where l is half the length of the oval. l is given by the rankine solution (equation (1)) as a function of M and h as:

$$l = \sqrt{\frac{M}{\pi} + a^2} \qquad (1.3)$$

h (and l) in agreement with A (cf equation (3)) is iteratively found from varying h, which determines M for ψ=0 and $\theta=\pi/2$ (equation (1.1) derived from equation (1)), and which determines l (equation (1.3))

Each streamline is marked by a surrounding volumetric segment (Fig. 5), which contains a portion of the in and out flow of the injection and production well. Given 36 segments each segment is marked by a mass flowrate Q_{seg} =Q /36, where Q is mass flow rate injected and produced. In the thermal solution of the reservoir the segment length (L_{seg}), segment area (A_{seg}) and average segment width (w_{seg}) are used as segment dependent parameters.

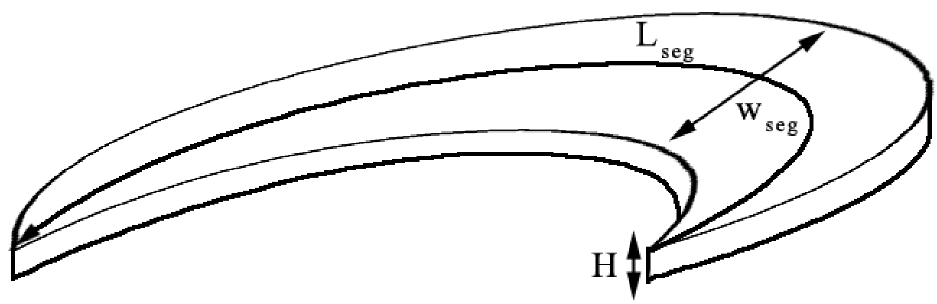


Figure 5. Volume segment of a streamline, used for the temperature calculation (L_{seg}: Length of the segment, wseg: average width of the segment, and H: thickness of reservoir)

3.2.2 Thermal Evolution in the reservoir

The temperature evolution in the reservoir is given by the equation of Pruess & Bodvarsson (1983):

$$T(x,t) = T_R - \left(T_R - (T_{inres})\right) erfc\left[\xi(x,t)\right] U(t - t_{DEL}) \tag{2}$$

$$\text{where:} \quad \xi(x,t) = \left[\frac{\sqrt{c_R \lambda_R \rho_R}\, x}{H c_F \phi_{res} \rho_F v_F \sqrt{t - t_{DEL}}} \right] \tag{2.1}$$

$$\text{and} \qquad U(t - t_{DEL}) = \begin{cases} 1 & for \quad t - t_{DEL} > 0 \\ 0 & for \quad t - t_{DEL} \le 0 \end{cases} \tag{2.2}$$

where T_G is initial reservoir temperature, T_{inres} is injection temperature at reservoir level, t is time and x is distance along the flow path measured from the injection well.

This equation is used for each streamline segment, in which $erfc(\xi(x,t))$ and $U(t - t_{DEL})$ and x for the production well become segment dependent. The outlet temperature for a segment is now described as:

$$T_{outres} = T_R - \left(T_R - (T_{inres})\right) erfc\left[\frac{\sqrt{c_R \lambda_R \rho_R}\, L_{seg}}{H c_F \phi_{res} \rho_F v_{F\_seg} \sqrt{t - t_{DEL\_seg}}} \right] U(t - t_{DEL\_seg}) \tag{3}$$

Where:

v_{F_seg} the velocity of the fluid in each segment:

$$v_{F\_seg} = \frac{Q_{seg}}{w_{seg} H \phi_{res} \rho_F N} \tag{3.1}$$

Where w_{seg} is calculated numerically from the ratio of the segment area and streamline length

t_{DEL_seg} the delay time for each segment

$$t_{DEL\_seg} = \frac{c_{res} \rho_{res} L_{seg}}{c_F \phi_{res} \rho_F v_{F\_seg}} \tag{3.2}$$

$$\text{with} \qquad \rho_{res} = \rho_F \phi_{res} + \rho_R (1 - \phi_{res}) \tag{3.2.1}$$

$$c_{res} = c_F \phi_{res} + c_R (1 - \phi_{res}) \tag{3.2.2}$$

For the complete solution at the outlet temperature of the reservoir, the outlet temperature of each stream line is used:

$$T_{outres} = \frac{\sum_{i=1}^{n_{seg}} T_{outres\_seg}}{n_{seg}} \tag{4.1}$$

The T_{outres} can be further adjusted to take into account a fraction of fluid which is produced from outside the fracture connected through the injection well (e.g. Soultz-sous-forêts; Sanjuan et al, 2006):

$$T_{outrestot} = f_{frac} T_{outres} + (1 - f_{frac}) T_R \tag{4.2}$$

As discussed previously, the calculation mode determined particular settings in the equations. The Table 1 highlights the differences in the general thermal equation (equation 3) for each calculation mode.

	Porosity (ϕ_{res})	**erfc(ξ(x,t))**	**U(t - t_{DEL})**
Fracture Mode: 1	1	erfc(ξ(x,t))	U(t - t_{DEL})
Porous media Mode: 2	depends	1	U(t - t_{DEL})
Porous media Mode: 3	depends	erfc(ξ(x,t))	U(t - t_{DEL})

Table 1. Differences of parameters for each mode in the thermal calculation at the reservoir Level

3.3 Thermal model at reservoir level: heat stored calculation model (Mode 4)

This model follows the assumption that the energy produce each year by the power plant at surface is a part of the whole energy available in the reservoir. From this assumption, two main strategies can be developed from that stage: one by fixing the number of years for the complete use of the energy stored which gives the maximum power plant capacity at surface, the other fixed the power plant capacity installed at surface which give the maximum number of years the reservoir can be used before his complete depletion.

In both cases, the energy stored in the reservoir is calculated with:

$$W_{stored} = c_{res} V_{res} \rho_{res} (\overline{T_{surfout}} - T_{surf}) \tag{5}$$

where the specific heat and the density of the reservoir is a balance between the rocks and the fluid driven by the porosity:

$$c_{res} = c_R (1 - \phi) + c_F \phi \tag{5.1}$$

$$\rho_{res} = \rho_R(1-\phi) + \rho_F\phi \tag{5.2}$$

and the volume of the reservoir is given by:

$$V_{res} = AH \tag{5.3}$$

The energy which can be recovered from this energy stored is described by:

$$W_{recov} = W_{stored}\ r_{res} \tag{6}$$

The recoverable thermal power Σ_{recov} is depends the strategy choose:

1. Subdivided over "numexploitationyears", giving thermal power which is extracted from the reservoir each year. This Multiplied by the thermal efficiency of electricity production (at average lifetime temperature) to obtain a target electrical production which is constant for each year (GWe) and determines the target power of the power plant to be built (actually this is corrected for the downtime, such that on average the plant is capable to deliver the targeted GWe output on a yearly basis)
2. The target power is used to establish the mass rate necessary to sustain the thermal power required. This actually depends on the thermal efficiency and the temperature and is determined for each year.
3. The required mass rate is divided over the number of doublets to obtain the correct mass rate for each doublet

The thermal values for the reservoir calculated by this model in any strategy case choose are then used for the underground development.

3.4 Underground Development, pressure and temperatures in boreholes

To complete the subsurface circulation, thermal evolution in the boreholes also has to be evaluated. In addition a pressure evolution needs to be made in the boreholes, in order to assess compressor dimensions.

3.4.1 Thermal Evolution in the borehole

The fluid temperature is affected to some degree in the borehole, depending on flow rate, typically up to a maximum of 10 °C.

In each of the boreholes, the evolution of the temperature is not simply a cooling or a heating evolution. As shown the Figure a for the injection well: if the surface temperature (T_{surf}) is 20°C with a geothermal gradient (ΔT_R) of 0.04°C/m and if the injected temperature (T_{insurf}) is 70°C, the fluid cools down up to 1750m depth and then it heats up. The same kind of calculation can be made in the production well (Figure b) but because the outlet temperature of the reservoir (inlet temperature of the borehole) can decrease through time, the depth where the temperature difference changes from cooling to heating moves through time.

The thermal evolution in a borehole is characterized by the Heidinger et al (2006) equation:

$$\Delta T_b = \nabla T_R \left[z - C_G \left(1 - e^{-\left(z/C_G \right)} \right) \right] \quad \text{result in °C} \tag{7}$$

$$\text{where } C_G = \frac{Q\, c_F}{4\pi\, \lambda_R} \left[\ln\left(\frac{16\, t\, \kappa_R}{d_B{}^2} \right) - 05772 \right] \tag{7.1}$$

where Q is massrate Q_b for the wells. For each borehole the cooling and heating contributions are determined substituting z values of table 2 below (see also Fig. 6)

	heating / cooling part	Z
Injection well	Cooling	$z = T_{insurf}/\nabla T_R$
	Heating	$z = z_R - T_{insurf}/\nabla T_R$
Production well	Cooling	$z = T_{outrestot}/\nabla T_R$
	Heating	$z = z_R - T_{outrestot}/\nabla T_R$

Table 2. parameters specifications for equation 5

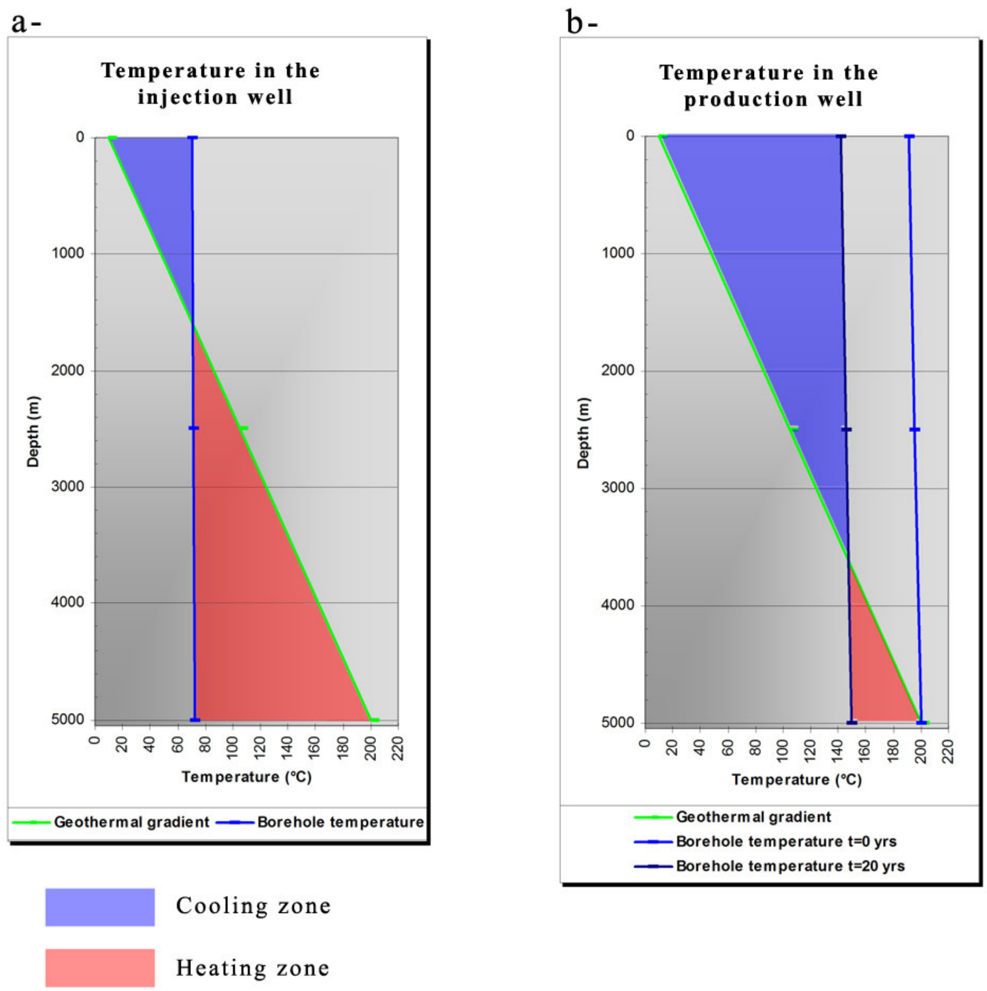


Figure 6. Temperature of the fluid: a- in the injection well, b- in the production well

Finally, the temperature effect for the production and injection wells becomes (cf Table 2)

$$\Delta T_b\big|_{injectionwell} = \Delta T_b\big|_{injectionwellheating} - \Delta T_b\big|_{injectionwellcooling} \tag{8.1}$$

$$\Delta T_b\big|_{productionwell} = \Delta T_b\big|_{productionwellheating} - \Delta T_b\big|_{productionwellcooling} \tag{8.2}$$

3.4.2 Injection temperature in the reservoir

T_{inres}, the injection temperature in the reservoir is given by the surface inlet temperature in the borehole T_{insurf} corrected for the heating effect downhole

$$T_{inres} = T_{insurf} + \Delta T_b\big|_{injectionwell} \tag{9.1}$$

3.4.3 Surface temperature at the production well

The production surface temperature is given by the temperature getting out the reservoir corrected by the thermal evolution during the rising of the fluid in the production well.

$$T_{outsurf} = T_{outrestot} + \Delta T_b \Big|_{productionwell} \tag{9.2}$$

3.5 Pressure Evolution

The target of the pressure modeling in the boreholes is to ascertain the pressure at the wellhead in order to keep a determinate flow rate in the reservoir.

To establish the pressure needed at the wellhead for a given flow rate, results of a circulation test are required. This experimental relation between pressure/flow rate in each borehole (Production and injection indices) can than be used the evaluated the pressure needed to sustain a chosen flow rate.

For the Injection well:

$$Q_{flow\_inj} = I_{index} \Delta p_{inj} \tag{10.1}$$

for the Production well:

$$Q_{flow\_prod} = P_{index} \Delta p_{prod} \tag{10.2}$$

Where Q_{flow} is sustained flow rate [l/s] at a relative pressure increase [MPa] relative to original reservoir pressure for the injection well (Δp_{inj}) and pressure decrease for the production well (Δp_{prod})

The flowrate during a test are measure at the surface. For this reason we assume that the relationship between flow rate Q_{flow} and mass rate Q relates to the density of the fluid at surface conditions:

$$Q = Q_{flow} \rho_F \tag{10.3}$$

The required differential pressure at the reservoir is a result of injection and production pumps installed near or at the wellhead. The actual effect on differential pressure required at depth should include friction effects and the effects column weight in the well, deviating from initial conditions. E.g. for the injection well the required pressure at the wellhead becomes

$$\Delta P_{wellhead} = \Delta p_{inj} + \frac{\Delta p_{column\_weight} + \Delta p_{friction}}{10^6} \tag{10.4}$$

Below we describe in more detail how these corrections are calculated

3.5.1.1 Pressure evolution due to the column weight

This pressure difference related to the column weight relates to the difference between a column at the reference geothermal gradient and the weight of the column during circulation. Using averaged densities and assuming these to be approximately a linear function of temperature; we can relate the column weight pressure $P_{columnweight}$ to the density at the average temperature T_{mean} in the borehole

$$P_{columnweight} = \rho_F (T_{mean}) z_R g + P_a \tag{11}$$

Were ρ_F (T_{mean}) is the density of the fluid (in $Kg.m^{-3}$) as a function of the mean temperature (from http://www.csgnetwork.com/h2odenscalc.html)

$$\rho_F (T_{mean}) = \rho_{F\_surf} \left[1 - \frac{T_{mean} + 288.9414}{508929.2 \times (T_{mean} + 68.12963)} (T_{mean} - 3.9863)^2 \right] \tag{12}$$

This mean density of the fluid in the borehole has to be determined for the injection and the production borehole during circulation and for the initial reservoir condition when the fluid in the borehole is considered at the geothermal equilibrium. For each of the three cases (production borehole, injection borehole, and borehole at the geothermal equilibrium) the mean temperature is given by:

- For the injection borehole: $$T_{mean\_inj} = \frac{T_{insurf} + T_{inres}}{2} \tag{13.1}$$
- For the production borehole: $$T_{mean\_prod} = \frac{T_{outrestot} + T_{outsurf}}{2} \tag{13.2}$$
- For a borehole at the geothermal gradient equilibrium: $$T_{mean\_geoth} = \frac{T_G + T_{surf}}{2} \tag{13.3}$$

3.5.1.2 Pressure loss due to frictions in the borehole

The pressure loss is related to the frictions of the fluid on the wall of the borehole. It is described following the Signorelli (2004) solution:

$$\Delta P_{friction} = \frac{\alpha z_R \rho_F v_{F\_b}}{2d_B} \quad (14)$$

Were ρ_F the density of the fluid is given by the equation 12 and v_s is the velocity of the fluid into the borehole given by:

$$v_{F\_b} = \frac{Q}{\pi\rho_F\left(\frac{d_B}{2}\right)^2} \quad (15)$$

and the friction factor α (after Heidinger et al, 2006) is depending on the Reynolds number describes as:

$$\mathrm{Re} = \frac{\rho_F v_{F\_b} d_B}{\mu} \quad (16)$$

for a Laminar flow (Re>2300): $$\alpha = \frac{64}{\mathrm{Re}} \quad (17.1)$$

for a turbulent flow (8.10^{-4}>Re>2300): $$\alpha = 0.00714 + 0.6104.\mathrm{Re}^{-0.35} \quad (17.2)$$

for a turbulent flow (8.10^{-4}<Re): $$\alpha = 0.25.\left[\log\frac{15}{\mathrm{Re}} + \frac{k_s}{3.715.d_B}\right] \quad (17.3)$$

with v_s the velocity is given by equation 15 and ρ_F the density is given by equation 12,
and μ the dynamic viscosity is described as:
(from http://www.mhtl.uwaterloo.ca/old/onlinetools/airprop/airprop.html)

$$\mu = \left(A - B\sqrt{T_{mean\_K}} + CT_{mean\_K} - D\left(T_{mean\_K}\right)^{1.5} + E\left(T_{mean\_K}\right)^2\right)^3 \quad (18)$$

$$\text{were} \quad \begin{cases} \mathrm{A} = 31.6371 \\ \mathrm{B} = 6.37804 \\ \mathrm{C} = 0.485827 \\ \mathrm{D} = 0.016519 \\ \mathrm{E} = 0.000211278 \end{cases} \quad (18.1)$$

And $T_{mean\_K} = T_{mean} + 273.15$ (18.2)

3.6 Surface Development – putting it technically together

The surface development describes the plant and operational parameters to collect the fluid coming from the production well and transform the thermal energy into electricity.

.

Directly related to the subsurface, the target flow rate Q_{flow} is one of the main parameter which has to be chosen from the surface. This flow rate gives the pressure required for compression and injection (cf. eq. (20)) and dimensions the pumps. From a technical point of view, the flow rate should be limited by the maximum pressure the pumps can provide1[1].

The inlet temperature is an other important surface parameter which influences the subsurface evolution.

One of the most important design parameters at the surface is the number of MegaWatts installed $MW_{e\_installed}$ for the power plant.

3.6.1 Temperature and Electricity produced

The surface power plant (a binary cycle in the model) converts thermal energy in electrical energy. The binary cycle is characterized by the efficiency η_{cycle}

$$MW_{e\_produced\_gross} = Max\left(\eta_{cycle} MW_{th\_elec}, MW_{capacity\_plant}\right) \tag{19.1}$$

$MW_{capacity\_plant}$ is the maximum capacity of the plant. The Megawatts thermal (MW_{th}) is related to the difference between the injected and the produced temperature, and the mass rate.

$$MW_{th\_elec} = N_{doublet}\left(T_{outsurf} - T_{outplant}\right) Q c_F 10^{-6} \tag{19.2}$$

Following Dipippo (2007), the efficiency of the binary cycle is partitioned in a relative Carnot efficiency η_{carnot} and the maximum theoretical Carnot efficiency:

$$\eta_{cycle} = \eta_{carnot} \frac{T_{outsurf} - T_{surf}}{\left(T_{outsurf} + 273.15\right) + \left(T_{surf} + 273.15\right)} \tag{19.3}$$

If the model predicts $MW_{e\_produced}$ in excess to the installed power of the plant $MW_{e\_installed}$ the power produced will be limited to $MW_{e\_installed}$

The model should take into account the numbers of running hours in a year subject to the relative capacity factors of the plant (f_{plant}) and reservoir ($f_{reservoir}$). The running hours are balance factor is related to the capacity factors of the plant and the boreholes.

$$R_{runninghrs/yr} = f_{plant} f_{boreholes} \left(24 \times 365\right) \tag{20}$$

[1] The maximum pressure is currently not used automatically as a limiting or optimizing constraint. In literature (e.g. Heidinger et al,2006) a value of 6 MPa is typically used.

3.6.2 Electricity consumption

For the geothermal operations, electricity consumption is made by the pumps and the plant and can be described as:

$$MW_{e\_used} = MW_{e\_pump} + MW_{e\_plant} \tag{21}$$

The energy consumption of the plant is assumed a fixed percentage of the total plant capacity. The energy consumption of each pump is given by:

$$MW_{e\_pump} = \left(P_{wellhead\_inj} + P_{wellhead\_prod}\right)e_{pump} \tag{21.1}$$

Where e_{pump} is the power consumption of a pump per MPa pressure at wellhead

The net power produced becomes:

$$MW_{e\_produced\_net} = MW_{e\_produced\_gross} - MW_{e\_used} \tag{21.2}$$

3.6.3 Co-heat generation

Co heat generation is generated by the efficiency η_{coheat}

$$MW_{th\_produced} = \eta_{coheat} MW_{th\_coheat} \tag{22.1}$$

$MW_{capacity\_plant}$ is the maximum capacity of the plant. The Megawatts thermal (MW_{th}) is related to the difference between the injected and the produced temperature, and the mass rate.

$$MW_{th\_coheat} = N_{doublet}\left(T_{outplant} - T_{insurf}\right)Qc_F 10^{-6} \tag{22.2}$$

3.7 Cash Flow

The cash flow is a function of Cash in and cash out (Fig. 2). After taking into account the effects of Tax and royalties, it is discounted and cumulated in order to provide a Net present Value (NPV) or Unit Technical Cost (UTC)

3.7.1 Cash in

The Cash-in [mln €/yr] for a single year is given by the electricity sale and potentialy the extra-heat sale after the energy extracted for electricity.
Relates to the Selling price of electricity E_{price_sell} [€ cts/kWh] and the electricity which is produced:

$$C_{cash\_in\_year} = C_{electicity\_year} C_{heat\_year} \tag{23}$$

Where :

$$C_{electricity\_year} = MW_{e\_produced\_gross} R_{runninghrs/yr} E_{price\_sell} 10^{-5} \tag{23.1}$$

$$C_{heat\_year} = MW_{heat\_gross} R_{runninghrs/yr} E_{heat\_price\_sell} 10^{-5} \tag{23.2}$$

3.7.2 Cash out

The Cash out consists of Capital Expenditure items (CAPEX), Operational Expenditure (OPEX), royalties and Tax.

$$C_{cash\_out\_year} = E_{capex\_year} + E_{opex\_year} + E_{royalty\_year} + E_{tax\_year} \tag{24}$$

CAPEX is related to investments made for the plant, stimulation and other costs. wells and pumps. These are one or more of the following terms depending if they are built in the specific year.

$$E_{capex\_well} = E_{well\,\cos tscaling} (0.2 z_R{}^2 + 700 z_R + 250x10^3) 10^{-6} \tag{25.1}$$

In enginePA.xls:

$$\begin{aligned} E_{capex\_year} &= 2N_{doublet} E_{capex\_well} + N_{doublet} E_{stimulation\_other\cos ts} + MW_{capacity\_plant} E_{capex\_plant\_MW} \\ &+ n_{pump} N_{doublet} E_{capex\_pump} + E_{grid\_connection\_\cos t} + E_{heat\_exchanger\_\cos t} \end{aligned} \tag{25.2}$$

In engine DSS:

$$\begin{aligned} E_{capex\_year} &= 2N_{doublet} E_{capex\_well} + N_{doublet} E_{stimulation\_other costs} + MW_{e\_produced\_gross} E_{capex\_plant\_MW} \\ &+ n_{pump} N_{doublet} E_{capex\_pump} + E_{grid\_connection\_\cos t} + E_{heat\_exchanger\_\cos t} \end{aligned} \tag{25.3}$$

Please note that a difference exists in the xls and DSS version, in that in DSS the final capacity of the plant is scaled to actual required capacity.

OPEX relates to yearly operation costs for the plant and wells, consumption of electricity and refurbishment of pumps. Fixed percentage (E_{opex_fixed}) and variable opex ($E_{opex\_variable}$) as a function of electricity produced are used:

$$E_{opex\_year} = E_{capex\_active} E_{opex\_fixed} + MW_{e\_produced\_gross} E_{opex\_plant\_variable} + n_{pump} N_{doublet} E_{refurbishment\_pump} + MW_{e\_used} E_{price\_buy} 10^{-5} \tag{26}$$

$E_{refurbishment\_pump}$ is not each year, the replacement of the pump is only after few years (e.g. in Soultz-sous-Forêts it has been fixed to happen every 5 years). This time between two replacements is given by $E_{years\_for\_fit}$

Royalties are taken from the cash in, as a fixed percentage.

$$E_{royalty\_year} = C_{cash\_in\_year} E_{royalty} \tag{27}$$

Taxable income is calculated as

$$E_{taxable\_year} = Max(C_{cash\_in\_year} - C_{cash\_out\_year} - E_{deductable\_capex}, 0) \tag{28}$$

The deductible Capex follows a SCLA (Straight Line Capital Allowance: Each capex item is depreciated in equal parts over the specified number of years).

Costs for tax deduction (e.g. investments prior to revenues especially at the start of the project) can be *transferred to a number of following years*, determined by UPLIFT. In the excel version the UPLIFT does not fully work. Its recommended to use a number equal to the lifetime of the project, meaning that cost can be deducted always as soon as revenues occur. In the DSS version the uplift is properly implemented.

Corporate tax compensation through other projects. Costs in the initial years can in some countries be used for tax reduction in other projects, which have a positive cash flow. The resulting tax reduction in the other project is taken into account as additional income when cash flow is negative. This option is activated by setting UPLIFT=0, in both the Excel and DSS versions.

Tax is a fixed percentage of the taxable income, resulting in the yearly cash flow:

$$E_{tax\_year} = E_{taxable\_year} E_{tax} \tag{29}$$

$$E_{income\_after\_tax\_year} = E_{taxable\_year} - E_{tax\_year} \tag{29.1}$$

3.7.3 Phasing of cash in and cash out

The CAPEX terms are made before the first electricity is produced ($y_{first\_electricity}$), typically various years after the evaluation start ($y_{evaluation}$). The time for the evaluation ($t_{evaluation}$) is followed by the drilling of the wells, which are assumed to be drill ($t_{drilling}$) within a year. Possible lagging times (tlagging) precede a number of years required to build the plant $t_{plant\_construction}$.

$$y_{first\_electricity} = y_{evaluation} + t_{evaluation} + t_{drilling} + t_{lagging} + t_{plant\_construction} \tag{30}$$

3.7.4 Discounted cashflow, NPV and UTC

The discounted cashflow is calculated as:

$$E_{income\_discounted\_year} = \frac{E_{income\_after\_tax\_year}}{\left(1 + E_{dicountrate}\right)^{\left(year - y_{evaluation}\right)}} \tag{31}$$

The Net Present Value is calculated as the sum of the discounted income:

$$NPV = \sum_{year=y_{evaluation}}^{year=economiclifetime} E_{income\_discounted\_year} \tag{32}$$

The Unit Technical Cost is calculated as the ratio of a) the cumulative discounted yearly Cash-out and b) the cumulative discounted electricity produced:

4 Synthetic case: The Soultz-sous-forêts example

The Soultz-sous-forêts geothermal system is located in the Rhine grabben in the north-west part of France. The 5km depth reservoir modeling here is placed in a fractured granite, overlain by 1400m of sediments (Sanjuan et al, 2006).

More technically, the geothermal system is composed of a triplet with one injector (GPK3) and two producers (GPK2 & GPK4), in our model we simplified the model into a doublet using the parameters with GPK3 as the injector and GPK2 as the producer.

In the excel approach of the model the parameters are regrouped in the upper part of the cashflow sheet (Fig.13).

The basin parameters at the reservoir level are mainly in the special Geothermics book made in 2006 about Soutz-sous-Forêt. The thermal gradient is derived from the temperature profile and gives an average gradient of 0.038 °C/m (Gerard et al, 2006). The conductivity, specific heat and density of the rocks are respectively of 3, 1000, and 2700 (Bachler et al, 2003). From a previous model at the Soutz-sous-Forêt presented in Heidinger et al (2006), the fracture total area is 3 km, the fracture are in number of 2 and the width of those fractures are 0.02 m. The Sanjuan et al (2006) publication about some tracer testing in the reservoir, the main flow path describe in our model drain 30% of the flow.

For the underground parameters, the scenario with best fit to the reservoir shape is the "Fracture scenario". The depth of the reservoir, corresponding to the boreholes length is 5000m (Gerard et al, 2006). The borehole diameter can be simplified to an unique value due to the last tubing which is of 7 inch (Baumgartner et al, 2000). The distance at the reservoir level between the two boreholes is 0.650 km (Gerard et al 2006). The number of segments used as flow path in the reservoir has been fixed to 36 in our model, this value has been chosen to give a good estimation of the thermal evolution. The indexes for the pump were determined from the pressure test presented by Megel et al (2005) to 3.2 for the apparent injectivity index (GPK3) and 7.5 for the apparent productivity index (GPK2).
The parameters for the economical part of those underground developments are concentrated on the drilling time and the cost of the well. From Gerard et al (2006), the drilling time has been estimated to be made within a year (for the Soutz-sous-Forêt case the boreholes has been drilled in two time : a first phase from surface to 3800m, and a second phase between 3800 and 5000m). The drilling cost is evaluated at about 1.2 to 1.5 mln euros per km (Heindinger et al, 2006) but this value evolve every years. The reservoir capacity factor describe in a year what is the proportion of working days, it's has been evaluates here at 0.9. And the roughness has not been taken in account.

The surface development parameters are mainly describing the fluid injected in the boreholes and the installations specifications developed to inject or recover this fluid.
Concerning the fluid injected in the boreholes, the injected temperature (which is the same fluid as the one recovered from the production well) has been estimated by Megel et al (2005) within a range of 50 to 70 °C. Also concerning this injected fluid, with a salinity calculated at the production well of 100 g/L (Gerard et al, 2006), the density at surface conditions (T_{surf}=10°C) is 1078 Kg/m3. The specific heat capacity of the fluid 4250 J/(Kg.K). From sensitivity analysis, the publication of Heidinger et al (2006) has fixed the flow rate at 50 L/s and the maximum pressure of the pump to 70 Mpa.
In the boreholes, the pumps have been incorporates at 500m depth, one pump in each of them. The power plant conversion of thermal energy to electrical energy is drive by a calculation of the efficiency of the conversion cycle, thermal parameters of this calculation are the outlet and surface temperatures, and the relative efficiency of the plant (a binary cycle in the case for our model) with a value of 0.7. The variable opex has been fixed to 100 keuros/yr

The economical parameters are also mainly concerning the pumps and the power plant. For the current use of the pump, the energy consumption of the pumps is given at 50 Kwhe per Mpa. The price of a pump is 0.9 mln euros (Heidinger et al, 2006), with a lifetime of the pump of about 5 years (cost replacement of the pump is lower than the initial installation with 0.5 mln euros per pump). For the plant Heidinger et al (2006) determine the cost of the installations, the base cost has been evaluated (associated to the stimulation of the reservoir) at 0.55 mln euros, the cost of the plant itself is 1.5 mln euros per MWe with an installed capacity of 4.5 MWe. As the reservoir capacity factor, a plant capacity factor is determined at 0.9. No electricity consumption has been used in the Soutz-sous-Forêt model (all the surface consumption is concentrate in the pumps). About the construction time of the surface installations, the model does not consider any lagging time between the drilling and the installation on surface and following what has been done in Landau (Baumgartner et al, 2007) a year has been taken for the plant construction before the plant can start.

For the economical part, the buying price of electricity for industrial purpose is fixed by the government (see http://www.industrie.gouv.fr/energie/statisti/pdf/hanprix2.pdf for further explanations) at 7cts/kWe and the selling price of electricity for the geothermal energy has been fixed by the decree of 2007 at the "Journal Officiel de la republique" relative to the buying conditions of energy produced with underground water (see http://www.industrie.gouv.fr/energie/electric/pdf/tarif-achat-geothermie.pdf for further explanations) to 12 cts/kWe. The capex and opex multipliers have been fixed to 1 for no influence. The fixed opex is fixed to 3.5%. And the economic limit is 1 Mwe.
The financials parameter gives a royalty of 0%, a tax of 45%, a discount rate of 10%, and a depreciation of 10 yrs.

5 Using the EnginePA.xls spreadsheet

5.1 Working with the enginePA.xls spreadsheet

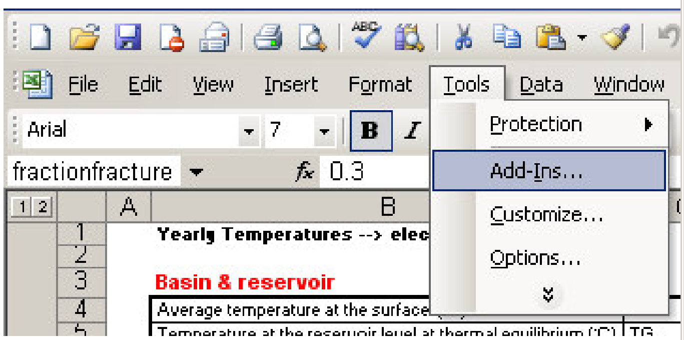
5.1.1 Opening first time,

In order to use the complete possibilities of the EnginePA.xls spreadsheet some tools have to be added (see fig. 13) following:

Tools>Add-Ins…>Analysis ToolPak

and *Tools>Add-Ins…>Analysis ToolPak – VBA*

These tools allow to use the ERFC function which is used for the thermal evolution in the reservoir when "fracture scenario", "porous media scenario" and "porous media & cooling" are chosen.



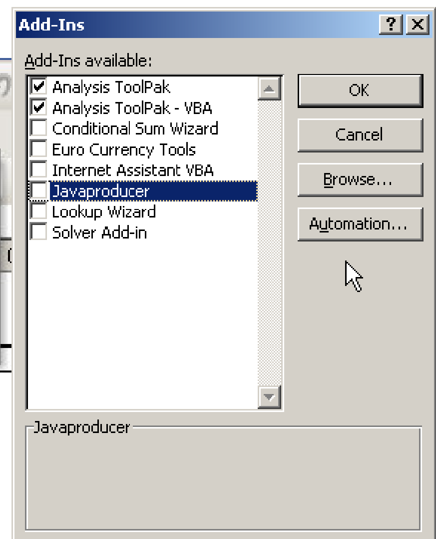


Figure 12: Location of the "Add-Ins" windows for the installation of the "Analysis ToolPak".

5.1.2 Structure of the worksheet

The EnginePA.xls is separated into three mains windows categories:

a. **Input spreadsheet** where user can fill-in his values and choose the scenario he what to use

Inputs are all regrouped in the upper part of the **Cashflow** spreadsheet (cf fig. 13), these parameters are regrouped in 4 mains groups: Basin & Reservoir, Underground Development, Surface Development, and Economical and Financials variables. Two other groups present the Phasing variables and some Technical parameters used for calculation.

figure 13a: parameters regrouped by origin:
Basin & Reservoir, Underground development, Surface development, Economical and financial variables, Phasing variables, and Technical parameters for calculations.

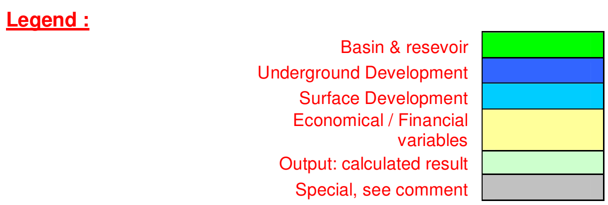


Fig. 13b Color legend explaining the meaning of different colors used

The calculation cells in the worksheet cashflow are locked. To unlock them the password used is TNO

b. **Calculations spreadsheet** where the calculations are made depending input parameters and the scenario choose

Figure 14 shows the spreadsheets used and the choices which can be made depends the scenario you want to use.

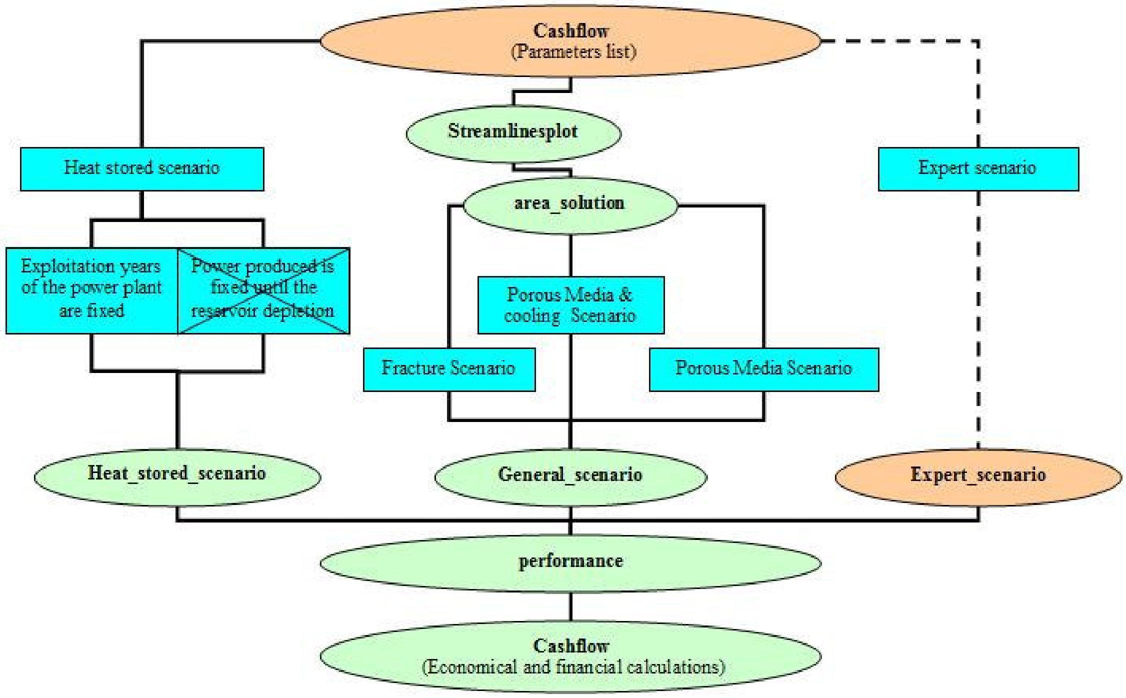


figure 14. spreadsheets used and mains choice available in the enginePA.xls calculation. Ovals represent the spreadsheets (green for calculations, brown for input spreadsheets) and squares represent the choices

For the “Heat Stored scenario” two main choices can be made: does the heat stored has to be extracted at a fixed power per year (the installed power plant is driving the all results and the number of years are calculated) or it has to be extracted in a fixed number of years (the calculation will give the maximum power plant value to be installed to extract all the power available in the reservoir). At this stage, only the fixed power is available in excel and the DSS version.
The calculations are executed in the Heat_stored_scenario spreadsheet for the reservoir temperature, the energy expected from this temperature, and the mass rate needed to sustain this power expected due to the temperature dropping down with time.
Some more general calculations are shared with the flowing scenarios and performed in the General_scenario spreadsheet: boreholes thermal evolution and pressure needed at the well head.

The reservoir main calculations are equal for “Fracture scenario”, “Porous media scenario” and “Porous media and cooling” (see § 3.2.2 for further explanations). The thermal evolution for the three “flowing” cases are driven by the flow in the reservoir described by the streamlines solution (fixed at 2*36 streamlines in the excel version) which perform the areas of the segments (a segment is the space between two streamlines) and their length. The streamlines calculations are made in the **streamlinesplot** spreadsheet, the areas and length in the **area_solution** spreadsheet. The streamlines are graphically presented in the **area_solution** (cf fig. 15)
The thermal underground evolution (boreholes and reservoir) are made in the **General_scenario** spreadsheet.

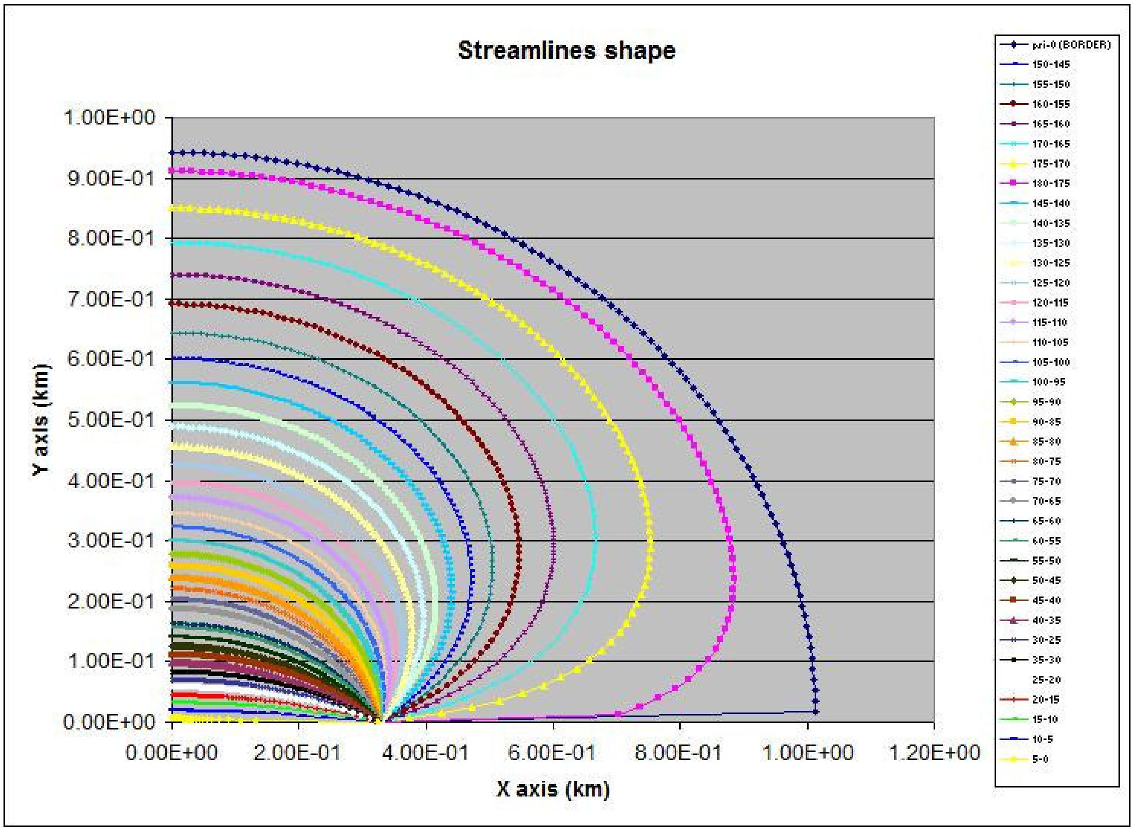


figure 15. streamlines plot corresponding to a quarter of the all reservoir surface

In the **expert_scenario** spreadsheet, the user can input personal values for temperature evolution, the pressure needed for the pumps and the massrate.

From the selected scenario depending on the choice made in the **Cashflow** spreadsheet (Heat stored scenario, the three reservoir flow scenario, the expert scenario) the values of temperatures, surface pressure, and mass rate are regrouped and selected in the **performance** spreadsheet (cf fig. 16),.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N
1														
2	This table is AUTOMATICALLY filled, depending which scenario you want to use (choice is made in the Cashflow sheet)													
3														
4	year		**0**	1	2	3	4	5	6	7	8	9	10	11
5		**Year correspondance**		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**
6	Tout	temperature into the plant	0	192.95	191.83	190.68	189.68	188.82	188.07	187.42	186.85	186.33	185.86	185.43
7	Toutres	temperature out of the reservoir	0	199.28	197.64	196.18	194.97	193.95	193.08	192.33	191.66	191.06	190.53	190.04
8	Tinres	temperature into the reservoir	0	71.53	71.42	71.37	71.33	71.30	71.28	71.26	71.25	71.24	71.23	71.22
9	IpumpP	(submersible) pump pressure increase for injection	0	30.56	30.56	30.56	30.56	30.56	30.56	30.56	30.56	30.56	30.56	30.56
10	PpumpP	(submersible) pump pressure decrease for production	0	12.34	12.42	12.49	12.56	12.61	12.65	12.69	12.73	12.76	12.78	12.81
11	massrate	kg/s	0	107.8	107.8	107.8	107.8	107.8	107.8	107.8	107.8	107.8	107.8	107.8
12														
13														

figure 16. example of the performance spreadsheet

The values in **performance** spreadsheet are then used in the lower half part of the **Cashflow** spreadsheet (Fig. 17).

The **Cashflow** spreadsheet is separated in five majors parts (cf fig. 17): production, Cash-in, Cash-out, Tax calculation and abandon parameters.

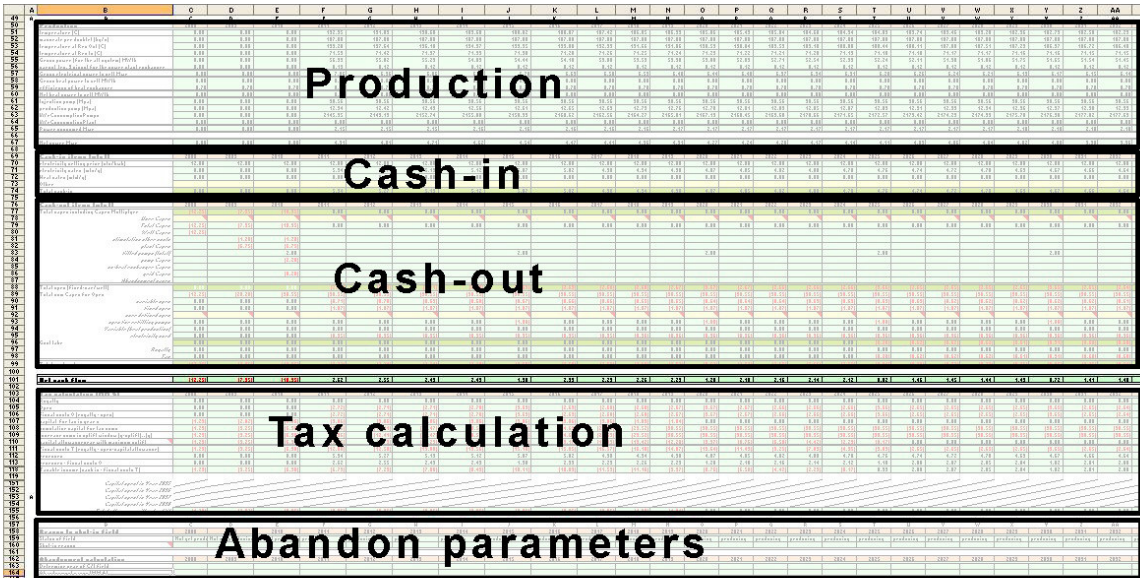


figure 17. cashflow down part for economical calculations

The production part describes (cf fig. 18) the energy produced, from the inlet temperature and outlet temperature of the power plant and the flow rate, the heat produced from the outlet temperature and the flow rate, and the energy used from the pumps.

Production	2008	2009	2010	2011	2012
temperature [C]	0.00	0.00	0.00	192.95	191.83
massrate per doublet [kg/s]	0.00	0.00	0.00	107.80	107.80
temperature at Res Out [C]	0.00	0.00	0.00	198.28	197.64
temperature at Res In [C]	0.00	0.00	0.00	71.53	71.42
Gross power (for the all system) MWth	0.00	0.00	0.00	56.33	55.82
carnot (eq. 9 pippo) for the power plant exchanger	0.00	0.00	0.00	0.13	0.12
Gross electrical power to sell Mwe	0.00	0.00	0.00	7.06	6.96
Gross heat power to sell MWth	0.00	0.00	0.00	0.00	0.00
efficiency of heat exchanger	0.70	0.70	0.70	0.70	0.70
Net heat power to sell MWth	0.00	0.00	0.00	0.00	0.00
Injection pump [Mpa]	0.00	0.00	0.00	30.56	30.56
production pump [Mpa]	0.00	0.00	0.00	12.34	12.42
kWeConsumptionPumps	0.00	0.00	0.00	2145.35	2149.13
kWeConsumptionPlant	0.00	0.00	0.00	0.00	0.00
Power consumed Mwe	0.00	0.00	0.00	2.15	2.15
Net power Mwe	0.00	0.00	0.00	4.91	4.81

figure 18. production calculations

The cash-in part (cf fig. 19) describes the cash-in from the electricity sales and heat sales.

Cash-in items [mln €]	2008	2009	2010	2011	2012
electricity selling price [cts/kwh]	12.00	12.00	12.00	12.00	12.00
electricity sales [mln/y]	0.00	0.00	0.00	5.34	5.27
Heat sales [mln/y]	0.00	0.00	0.00	0.00	0.00
Other					
Total cash-in	0.00	0.00	0.00	5.34	5.27

figure 19. Cash-in calculations

The cash-out part (cf fig. 20) describe the money spend, regrouped in two main calculations: the CAPEX (Capital expenditures) which correspond to the initial costs for the geothermal installations, and the OPEX (operational expenditure) which correspond to the costs during the geothermal use

Cash-out items (mln I)	2008	2009	2010	2011	2012
Total capex including Capex Multiplyer	(12.25)	(7.95)	(10.35)	0.00	0.00
User Capex					
Total Capex	(12.25)	(7.95)	(10.35)	0.00	0.00
Well Capex	(12.25)				
stimulation other costs		(1.20)	(1.20)		
plant Capex		(6.75)	(6.75)		
fitted pumps [total]			2.00		
pump Capex			(2.20)		
co-heat exchanger Capex					
grid Capex			(0.20)		
Abandonment capex					
Total opex (fixed+var/well)	0.00	0.00	0.00	(2.72)	(2.71)
Total cum Capex for Opex	(12.25)	(20.20)	(30.55)	(30.55)	(30.55)
variable opex	0.00	0.00	0.00	(0.71)	(0.70)
fixed opex	0.00	0.00	0.00	(1.07)	(1.07)
user defined opex					
opex for refitting pumps	0.00	0.00	0.00	0.00	0.00
Variable (heat production)	0.00	0.00	0.00	0.00	0.00
electricity used	0.00	0.00	0.00	(0.95)	(0.95)
Govt take	0.00	0.00	0.00	0.00	0.00
Royalty	0.00	0.00	0.00	0.00	0.00
Tax	0.00	0.00	0.00	0.00	0.00
Total cash-out	(12.25)	(7.95)	(10.35)	(2.72)	(2.71)

figure 20. Cash-out calculations
(CAPEX in the upper part, OPEX in the down part)

The CAPEX is subdivided into the costs for underground (the drilling of the plant, stimulation of the reservoir) and the surface installations (plant construction, heat exchanger construction, grid connection, initial pump emplacement).

The OPEX is subdivided into the costs during the use of the geothermal system: electricity used by the power plant and the heat exchanger, replacement of the pump (generally every 5 years), and the variable and fixed expenditure for the system operation.

The taxes and the royalty are also implemented in this Cash-out calculation, but the calculation itself is made in a separate part of the sheet (cf fig. 21).

Tax calculation (MM $)	2008	2009	2010	2011	2012
Royalty	0.00	0.00	0.00	0.00	0.00
Opex	0.00	0.00	0.00	(2.72)	(2.71)
fiscal costs O (royalty + opex)	0.00	0.00	0.00	(2.72)	(2.71)
capital for tax in year c	(1.23)	(2.02)	(3.06)	(3.06)	(3.06)
cumulative capital for tax sumc	(1.23)	(3.25)	(6.30)	(9.36)	(12.41)
increase sumc in uplift window (y-uplift)..(y)	(1.23)	(3.25)	(6.30)	(9.36)	(12.41)
capital allowanceyear with maximum uplift	(1.23)	(3.25)	(6.30)	(9.36)	(9.79)
Fiscal costs T (royalty + opex+capitalallowance)	(1.23)	(3.25)	(6.30)	(12.08)	(12.50)
revenues	0.00	0.00	0.00	5.34	5.27
revenues - fiscal costs O	0.00	0.00	0.00	2.62	2.55
Taxable income (cash in - fiscal costs T)	(1.23)	(3.25)	(6.30)	(6.73)	(7.23)
Capital spent in Year 2005					
Capital spent in Year 2006					
Capital spent in Year 2007					
Capital spent in Year 2008					
Total allowance without uplift	(1.23)	(2.02)	(3.06)	(3.06)	(3.06)

figure 21. Tax calculations

The last part of the spreadsheet is dedicated to abandonment parameters, it give the information if the geothermal system has started producing or still producing corresponding to the economic limit.

c. **Output spreadsheet** where the mains results are presented under tables and figures.

Firstly, three figures are interesting to be described as output values: undiscounted cashflow (in **fig undisc CF** spreadsheet), discounted cashflow (in **fig DCF** spreadsheet), and cumulative discounted cashflow (in **fig CumDCF** spreadsheet). The undiscounted cashflow directly show the values from the Cashflow spreadsheet previously described. The discounted cashflow takes in account the evolution of the cash flow with time, discounted for the discount rate. The cumulative discounted cashflow cumulates each parameter. The parameters followed in the three figures are: Total cash-in, Total cash-out, capex, opex, Government taxes, Net Cash flow (cash-in+cash-out).

In the undiscounted cashflow (cf fig. 22a) the cash-in parameter decreased with time due to the decreasing temperature in the reservoir.

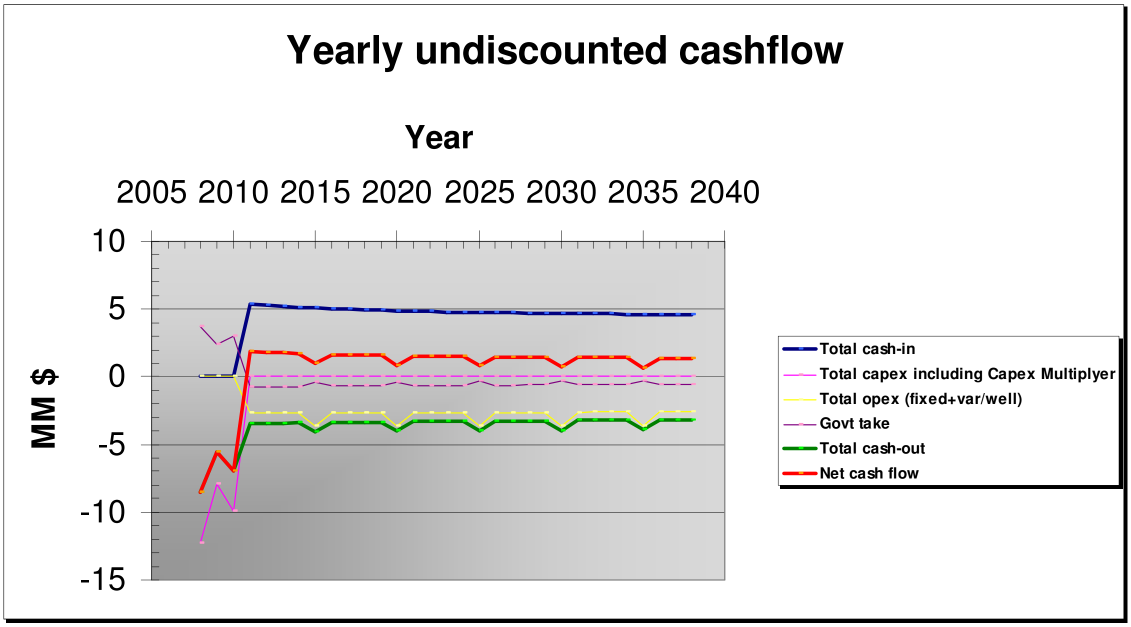


figure 22a. Undiscounted cashflow figure

In the discounted cashflow (cf fig 22b), due to the depreciation of the money value the parameters converge to 0. It is interesting to see that the Net cash flow, which is the main parameter in these figures, is close to 0 after only 15 years of exploitation of the geothermal site.

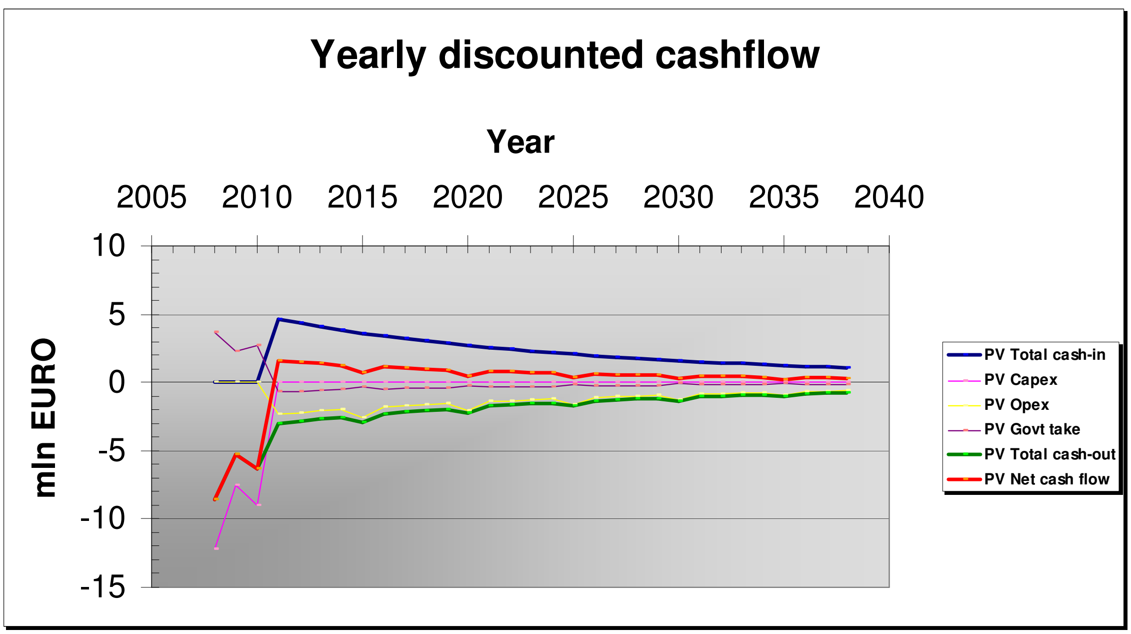


figure 22b. Discounted cashflow figure

In the cumulative discounted cashflow (cf fig 22c), the important parameter to follow is the present value of net cash flow which indicates if the project is economically sustainable.

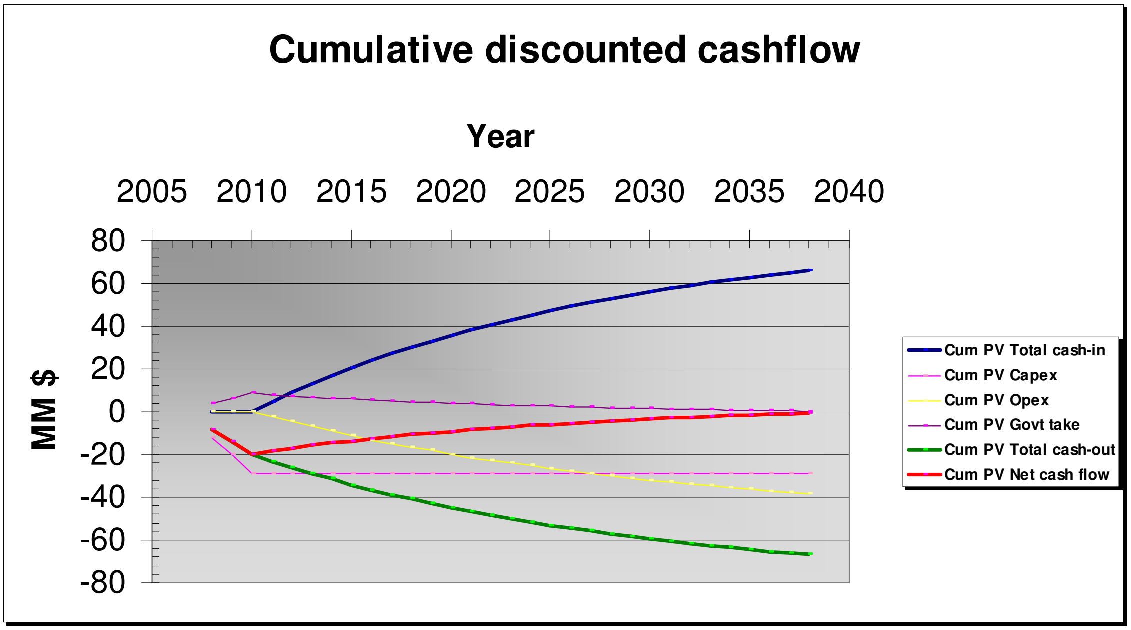


figure 22c.Cumulative Discounted cashflow figure

All the most important value in an economical decision for a geothermal project are regrouped in the KPIs (for Key Performance Indicators) spreadsheet (cf fig. 23).
The parameters presented in this synthesis table are: the total energy produced during by the geothermal system, the present value of the electricity sale, the net present value of the all system, the IRR (internal rate of return), the maximum exposure for undiscounted and discounted cashflow, the PIR undiscounted and discounted, the unit technical cost (UTC) which describe the minimal energy cost in order to make the system economically available), the Payout time for the undiscounted and the discounted cashflow, and the productive life for the system.
From a financial and economical point of the view, the mains parameters to follow are: the electricity sales, the NPV, the IRR, and the maximum exposure for the discounted cashflow.
The cumulative electricity sales give an idea of the energy produced during the all lifetime of the geothermal system. The NPV is very important to see if the investment is good for a long term investment. And the IRR allow to quantify this investment. The UTC is very usefull to investigate which level of feeder-tariff cab support production.

Project Key Performance Indicators

#REF!

Royalty = 0% & tax-deductible; Tax = 30%; Depreciation period = 1 yrsNo uplift

KPI	Value	Unit	Comment
Technical ultimate geothermal recovery	1126.3	GWe	not constrained
ultimate recovery produced economically	1126.3	GWe	only constrained by "economic limit"
PV electricity sales	66.3	mln €	
PV Government Take @PV5%, ref 2008	-0.2	mln €	
NPV@PV5%, ref 2008	-0.5	mln €	
IRR	-100.0%		IRR=-100% if NPV<0, result sometimes wrong
Maximum exposure (undiscounted CF)	-21.1	mln €	Max. undiscounted exposure in year 2010
Maximum exposure (discounted CF)	-20.2	mln €	Max. discounted exposure in year 2010
PIR undiscounted	0.60	ratio	
PIR discounted	-0.02	ratio	
Unit Technical Cost (PVcost/PVkWh)	0.12	€/kWh	
Pay-out time (undiscounted cashflow)	16	years	
Pay-out time (discounted cashflow)	31	years	Cum. disc. NCF<0 over full evaluation period
Productive life of asset	>27	years	Still producing at end of evaluation period

figure 23. Project Key Performance Indicators table

5.2 Fracture scenario example case

This is an example calculation. This scenario is based on a reservoir circulation through fractures, with a reservoir at 5km depth in granitics fractured rocks.

5.2.1 Input

Figure 24 describe the input parameters used for a fracture scenario.

Basin & reservoir

Average temperature at the surface (°C)	Tsurf	10
Temperature at the reservoir level at thermal equilibrium (°C)	TG	200
Thermal gradient from the surface to the res. level (°C/m)	grad_TG	0.038
Conductivity of the rocks (W/(m.K))	kg	3
Specific heat of the rocks (J/(kg.K))	cg	1000
Density of the rocks (Kg/m3)	rg	2700
Diffusivity of the rocks (m²/s)	kapg	1.11111E-06
Total area of the fracture (Km²)	AreaF	3
Number of fracture (-)	Num	2
Aperture of the fracture (m)	w	0.02
Porosity of the reservoir (-) !!! Always = 1 for this scenario	phi	1
Fraction from the reservoir	fractionfractur	0.3

Underground Development

Choice of the scenario for the temperature		
Fracture		
number of doublet	numdoublet	1
- not used for this scenario	Tdecrease	3
- not used for this scenario	recovery	0.125
Lenght of the borehole / depth of the reservoir (m)	zg	5000
Borehole diameter (inch)	dBinch	7
Borehole diameter (m)	dB	0.1778
Roughness of the pipes (mm)	ks	0
Distance between the two boreholes (Km)	Dist	0.65
Half boreholes distance at the reservoir level (Km)	aplot	0.325
Radius of the fracture (Km)	r	0.977
Square of the radius	r^2	0.955
number of segments	segments	36
Apparent injectivity index (l/s/Mpa)	II	3.2
Apparent productivity index (l/s/Mpa)	PI	7.5
Pressure require for the inj. borehole at the res. (Mpa)	PIr	31.250
Pressure require for the prod. borehole at the res. (Mpa)	PPr	13.333
Well cost scaling	wellcostscaling	0.7
single well cost (mln €)	costwell	6.125
Reservoir/borehole capacity factor	resfactor	0.8

Phasing variables

First year of evaluation	yeareval	2008
Lagging time (yrs)	Laggingtime	0
Plant construction time (yrs)	plantconstruct	2
Evaluation time (yrs)	evaluationtime	0
Drilling time (yrs)	drillingtime	1
Year when the drilling of the Injector well start	yearinjectorwel	2008
Year when the drilling of the Production well start	yearproduction	2008
Year whan the plant construction start	yearplantconst	2009
First year of production	yearprod	2011

Technicals parameters for calculations

Streamline parameters		
iterdif	iterdif	3.00E-03
at 0,ttiny	psimax	-4.46E+00
Uplot	Uplot	1
G-force (m/s)	g	9.81
Critical Reynold number	Rec	2300
conversion time in yrs -> time in seconds	tyts	31536000
control	3.65	0

Surface development

Exploitation strategy for the geothermal reservoir (Heat stored scenario only)		
Power produced is fixed until the reservoir depletion		
- not used for this scenario		20
Temperature inlet at the injection well (°C)	Tin	70
Temperature outlet the binary plant (°C)	Toutplant	70
density of fluid (Kg/m3)	rf	1078
Specific heat of the fluid (J/(kg.K))	cf	4250
target flow rate	Qtarg	100
Flow rate (L/s)	Q	100
Mass rate (kg/s)	Qms	107.8
Flow rate for one segment (kg/s)	Qs	1.497222222
Yearly average mass rate	Qms_y	77.616
Yearly average mass rate per segment	Qs_y	1.078
maximum pressure for pumps	Pmax	70
Dead State temperature (°C)	T0	20
Carnot relative efficiency for the plant	carnotrelative	0.55
co-heat exchanger efficiency	heatefficiency	0.7
Power consumption of a pump (kWe/Mpa)	Epump	50
Number of pump per doublet	numpump	2
pump replacement (yrs)	yearsforrefit	5
injection/production pump initial cost (mln €)	costpump	0.9
pump workover costs (mln €)	pumpworkover	0.5
plant electricity consumption (%)	powerplant	0.00%
plant cost (mln €/Mwe)		1.5
target maximum plant capacity (Mwe)		9
maximum plant capacity (Mwe)	plantcapacity	9.00
plant cost (mln €)	costplant	13.50
plant capacity factor	plantfactor	0.9
plant and reservoir factor	plantandresfactor	0.72
numbers of running yours per year	plantload	6307.2
stimulation and base plant costs (mln €)	baseplantcosts	2.4
Opex depending the power produced (k€/MWe)	variableopex	100
Distance to Grid (km)	griddistance	2
Price per km for connection to Grid (mln€/km)	priceconnecttogrid	0.1
Capex for connectionto grid (mln€)	capexforgrid	0.2
Capex for co-heat exchanger (mln€)	capexforheat	1
co-heat exchanger seasonal factor	seasonfactor	0.5

Economical / Financial variables

electricity price to sell (cts/kWh)	electricitypricesell	12
electricity price to Buy (cts/kWh)	electricitypricebuy	7
Heat price to sell (cts/kWhth)	heatpricesell	3
fixed opex of the capex active (%)	fixedopex	3.50%
Well Capex multiplier	wellmultiplier	1.00
plant capex multiplier	plantmultiplier	1
Discount rate	discountrate	5.00%
Economic field prod limit Netpower (Mwe)	economiclimit	-1
Royalty (% of the cash in)	Royalty	0
Is royalty tax deductible Y/N?	Royaltydeductible	Y
Tax (% taxable income)	Tax	30
Depreciation years (SLCA)	Depreciation	1
Uplift (#yrs from taxable income>0)	Uplift	0

figure 24. Parameters in the Cashflow Spreadsheet for the Fracture scenario

5.2.2 Output

The output results are shown in figures 22 and 23 (for the fracture scenario) and show a non-financial sustainable geothermal system with a negative NPV.

5.3 Porous Media Reference cases

5.3.1 Input

All the parameters used are equal to the fracture scenario except for the reservoir with a thickness of 250m, a porosity of 5%, and a fracture influence of 100% for the inlet fluid into the production borehole (cf fig. 25).

Basin & reservoir

Average temperature at the surface (°C)	Tsurf	10
Temperature at the reservoir level at thermal equilibrium (°C)	TG	200
Thermal gradient from the surface to the res. level (°C/m)	grad_TG	0.038
Conductivity of the rocks (W/(m.K))	kg	3
Specific heat of the rocks (J/(kg.K))	cg	1000
Density of the rocks (Kg/m3)	rg	2700
Diffusivity of the rocks (m²/s)	kapg	1.11111E-06
Total area of the reservoir (Km²)	AreaF	3
Number of fracture (-) !!!!! Always = 1 for this scenario	Num	2
Thickness of the reservoir (m)	w	250
Porosity of the reservoir (-)	phi	0.05
Fraction from the reservoir	fractionfractur	1

Underground Development

Choice of the scenario for the temperature
Porous media

figure 25. Basin & Reservoir specific parameters in the Cashflow Spreadsheet for the Porous Media scenario

5.3.2 Output

In this porous media scenario, the NPV became positive (cf fig 26) with a value of 1 mln euros, with an IRR of 5.3%. So the geothermal system is financially available with this porous media reservoir.

	A	B	C	D
1	**Project Key Performance Indicators**			
2	#REF!			
3	Royalty = 0% & tax-deductible; Tax = 30%; Depreciation period = 10 yrs; Uplift = 50 yrs			
4	**KPI**	**Value**	**Unit**	**Comment**
5	Technical ultimate geothermal recovery	1271.8	GWe	not constrained
6	ultimate recovery produced economically	1271.8	GWe	only constrained by "economic limit"
7	PV electricity sales	73.7	mln €	
8	PV Government Take @PV5%, ref 2008	4.2	mln €	
9	NPV@PV5%, ref 2008	1.0	mln €	
10	IRR	5.3%		IRR=-100% if NPV<0, result sometimes wrong
11	Maximum exposure (undiscounted CF)	-30.6	mln €	Max. undiscounted exposure in year 2010
12	Maximum exposure (discounted CF)	-29.2	mln €	Max. discounted exposure in year 2010
13	PIR undiscounted	0.93	ratio	
14	PIR discounted	0.04	ratio	
15	Unit Technical Cost (PVcost/PVkWh)	0.12	€/kWh	
16	Pay-out time (undiscounted cashflow)	14	years	
17	Pay-out time (discounted cashflow)	28	years	
18	Productive life of asset	>27	years	Still producing at end of evaluation period

figure 26. Project Key Performance Indicators table for the porous media scenario

5.4 Heat stored Reference cases

5.4.1 Input

In the heat stored scenario the parameters are equals to the porous media scenario presented in the paragraph 6.3.1, the only two changes comes from the number of years (cf fig. 27) the geothermal system is used (fixed to 20 years in this case), and the flow rate which are calculate automatically (up to 200 l/s in that case) to sustain the maximum energy produced by the power plant.

Surface development

Exploitation strategy for the geothermal reservoir (Heat stored scenario only)		
Exploitation years of the power plant are fixed		
Numers of years planed for the exploitation (yrs)		20

Temperature inlet at the injection well (°C)	Tin	70
Temperature outlet the binary plant (°C)	Toutplant	70
density of fluid (Kg/m3)	rf	1078
Specific heat of the fluid (J/(kg.K))	cf	4250
target flow rate	Qtarg	100
Flow rate (L/s)	Q	213.8336193
Mass rate (kg/s)	Qms	230.5126416
Flow rate for one segment (kg/s)	Qs	3.201564467
Yearly average mass rate	Qms_y	165.9691019
Yearly average mass rate per segment	Qs_y	2.305126416
maximum pressure for pumps	Pmax	70
Dead State temperature (°C)	T0	20
Carnot relative efficiency for the plant	carnotrelative	0.55
co-heat exchanger efficiency	heatefficiency	0.7

figure 27. Surface development technical parameters for the heat storage scenario

The specific parameters for the heat stored scenario are presented in the figure 28, the decreasing temperature has been cancelled with a value of 0, and the heat stored recovery is fixed at 0.125.

Underground Development

Choice of the scenario for the temperature
Heat stored

number of doublet	numdoublet	1

Fixed decreasing temperature (°C/yr)	Tdecrease	0
recovery factor	recovery	0.125
Lenght of the borehole / depth of the reservoir (m)	zg	5000
Borehole diameter (inch)	dBinch	7
Borehole diameter (m)	dB	0.1778
Roughness of the pipes (mm)	ks	0
Distance between the two boreholes (Km)	Dist	0.65
Half boreholes distance at the reservoir level (Km)	aplot	0.325
Radius of the fracture (Km)	r	0.977
Square of the radius	r^2	0.955
number of segments	segments	36
Apparent injectivity index (l/s/Mpa)	II	3.2
Apparent productivity index (l/s/Mpa)	PI	7.5
Pressure require for the inj. borehole at the res. (Mpa)	PIr	57.897
Pressure require for the prod. borehole at the res. (Mpa)	PPr	24.703

Well cost scaling	wellcostscaling	0.7
single well cost (mln €)	costwell	6.125
Reservoir/borehole capacity factor	resfactor	0.8

figure 28. Underground development technical parameters for the heat storage scenario

5.4.2 Output

In this heat stored scenario (cf fig. 29), the NPV became much higher than in the porous media scenario (cf § 6.3.2) with a value of 16.7 mln euros, and the IRR is not far from being multiply by two. These values can mainly be explained by the high flow rate in this scenario.

	A	B	C	D
1	**Project Key Performance Indicators**			
2	#REF!			
3	Royalty = 0% & tax-deductible; Tax = 30%; Depreciation period = 10 yrs; Uplift = 50 yrs			
4	**KPI**	**Value**	**Unit**	**Comment**
5	**Technical ultimate geothermal recovery**	**1740.2**	GWe	not constrained
6	**ultimate recovery produced economically**	**1740.2**	GWe	only constrained by "economic limit"
7	**PV electricity sales**	**118.0**	mln €	
8	**PV Government Take @PV5%, ref 2008**	**10.5**	mln €	
9	**NPV@PV5%, ref 2008**	**16.7**	mln €	
10	**IRR**	**9.9%**		IRR=-100% if NPV<0, result sometimes wrong
11	**Maximum exposure (undiscounted CF)**	-37.7	mln €	Max. undiscounted exposure in year 2010
12	**Maximum exposure (discounted CF)**	-35.9	mln €	Max. discounted exposure in year 2010
13	**PIR undiscounted**	**1.36**	ratio	
14	**PIR discounted**	**0.47**	ratio	
15	**Unit Technical Cost (PVcost/PVkWh)**	**0.10**	€/kWh	
16	**Pay-out time (undiscounted cashflow)**	**10**	years	
17	**Pay-out time (discounted cashflow)**	**13**	years	
18	**Productive life of asset**	**>27**	years	**Still producing at end of evaluation period**

figure 29. Project Key Performance Indicators table for the heat stored scenario

6 EGS DSS implementation

The models described in the previous section have been implemented in EGS DSS . This program is distributed as a zip file. Once unzipped, the program can be started by double clicking egsdss.exe To use the program and to use examples (in exercises) tutorial please follow the instructions in the readme _installation.txt. Start with exercises\fastmodels and conclude with exercises\exploration.

In extension to the excel spreadsheet the EGS Decision support System (EGS DSS) can do probabilistic (monte carlo) The model parameters are subdivided in the same model components as the excel spreadsheet. Each of these parameters can be defined as a distribution.

Uncertainty in earth parameters can be incorporated through:

- Discrete scenarios (e.g. having distributed fractured vs localized flow along faults), each having a probability for the scenario
- A continuous distribution of values in a scenario

The effect of both can be evaluated statistically through using a scenario tree and Monte Carlo simulation (e.g. Floris and Peersmann, 1999).

Monte Carlo runs

EGS DSS can do probabilistic (monte carlo) in extension to the excel spreadsheet. The model parameters are subdivided in the same model components as the excel spreadsheet. Each of these parameters can be defined as a distribution.

Fig. 30 depicts an example of the effect of incorporating uncertainty in the default fracture example (exercises\fastmodels). The fracture area ranges from 2-4 km^2 and the reservoir temperature ranges from 170 to 230 C. The effect on the produced power and NPV is considerable. For the distributions hundred monte carlo samples are taken serving as input for hundred model runs, of which the results are depicted in Fig. 30.

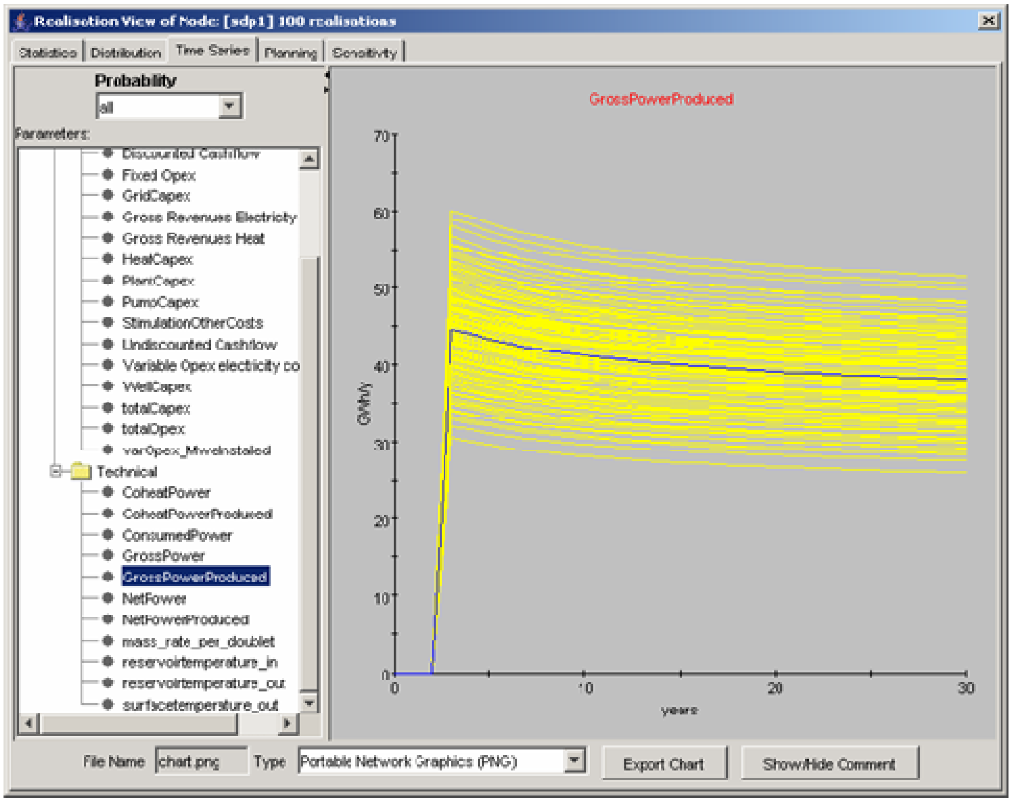
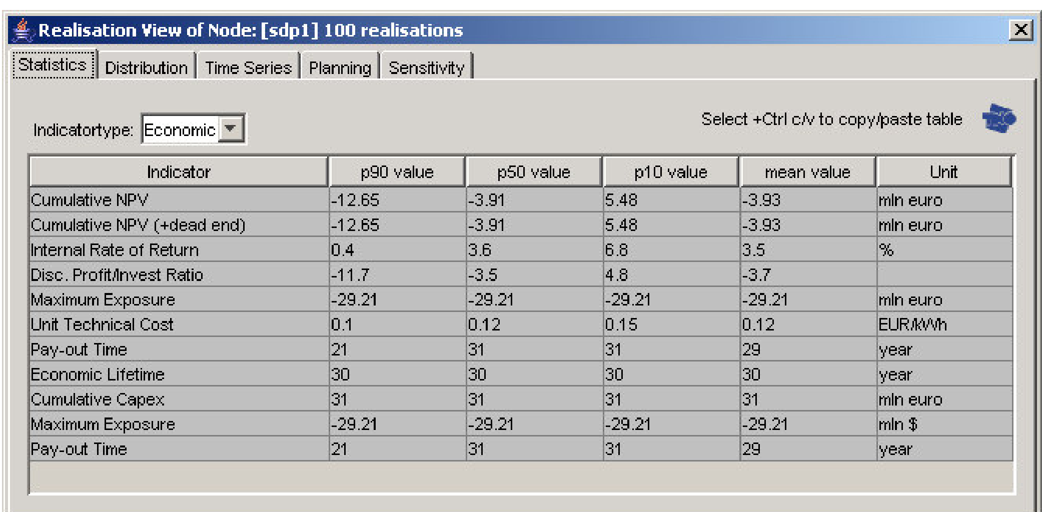


Fig.3: Forecasted power produced given uncertainties for Reservoir temperature and fracture Area


Realisation View of Node: [sdp1] 100 realisations

Statistics | Distribution | Time Series | Planning | Sensitivity

Indicatortype: Economic

Select +Ctrl c/v to copy/paste table

Indicator	p90 value	p50 value	p10 value	mean value	Unit
Cumulative NPV	-12.65	-3.91	5.48	-3.93	mln euro
Cumulative NPV (+dead end)	-12.65	-3.91	5.48	-3.93	mln euro
Internal Rate of Return	0.4	3.6	6.8	3.5	%
Disc. Profit/Invest Ratio	-11.7	-3.5	4.8	-3.7	
Maximum Exposure	-29.21	-29.21	-29.21	-29.21	mln euro
Unit Technical Cost	0.1	0.12	0.15	0.12	EUR/kWh
Pay-out Time	21	31	31	29	year
Economic Lifetime	30	30	30	30	year
Cumulative Capex	31	31	31	31	mln euro
Maximum Exposure	-29.21	-29.21	-29.21	-29.21	mln $
Pay-out Time	21	31	31	29	year

Fig. 4 Key Performance Indicator overview showing that NPV of project is negatibve with considerable spread in outcomes (P90 and p10 values).

Decision trees

EGS-DSS allows to build decision trees, in which for each branch a fully probabilistic calculation can be done. An example of a decision tree in EGS DSS is given in Fig. 5. In the tree, the top decision is a choice between a less expensive binary plant costing 1.5 Mln/MWe installed and having a relative efficiency of 0.55, whereas a more expensive plant costing 2 Mln/MWe installed has an efficiency of 0.60.

The choice between the two plants is represented by a “normal” and “high” branched in the tree, underyling the decision node “EffPlant”. The square denotes a decision. The reservoir is considered to have a major uncertainty on the number of fractures being either 1, 2 or 3. The respective probabilities for these are 80, 10 and 10 %. The different possible outcomes for the reservoir are reprensented by three scenaros in the tree.

The outcome of the project can be enhanced by using an exploration strategy in which we try to prevent to develop N1. Suppose we have an exploration stage which costs 250kEuro and which allows to establish the presence of N1. The decision tree representing this staged approach is depicted in Fig. 5.

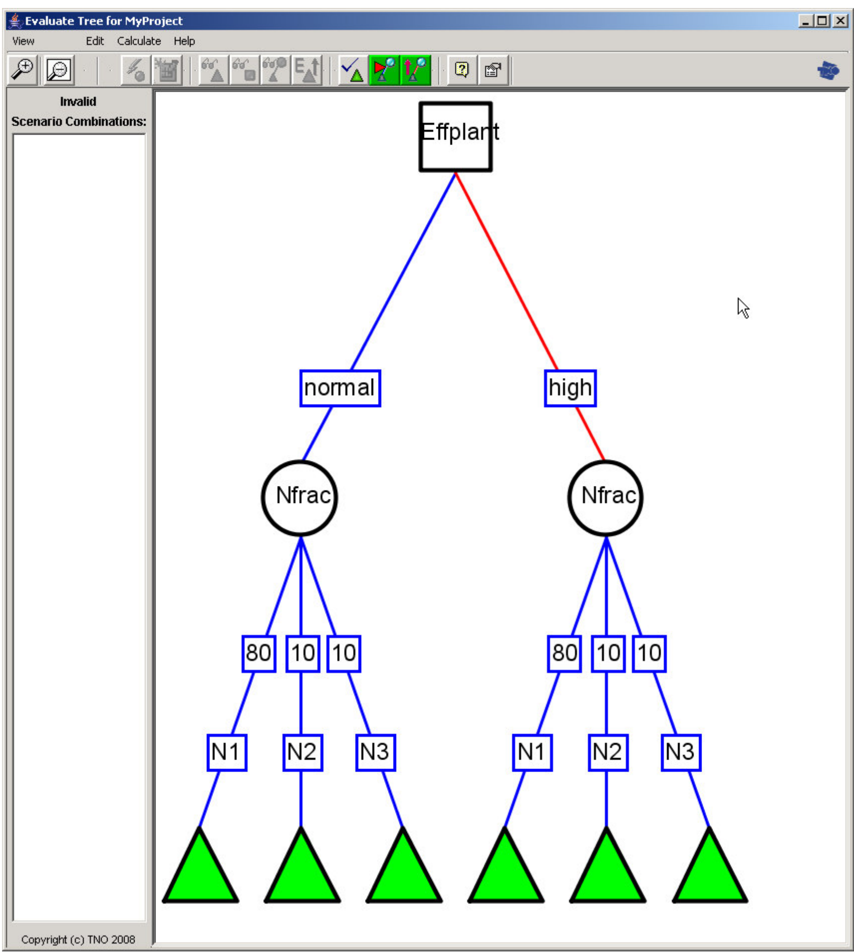


Fig. 5 Decision tree with a decision to build a normal or high efficiency plant, based on 3 different outcomes for the reservoir performance (N1, N2, N3). The expectation curve of the

cumulative NPV for the high efficiency plant, reflects a mix of results from the N1,N2,N3 reservoir scenario, resulting in an average NPV which is negative -3.71 Mln Euro. The N1 scenario is marked by strongly negative NPV

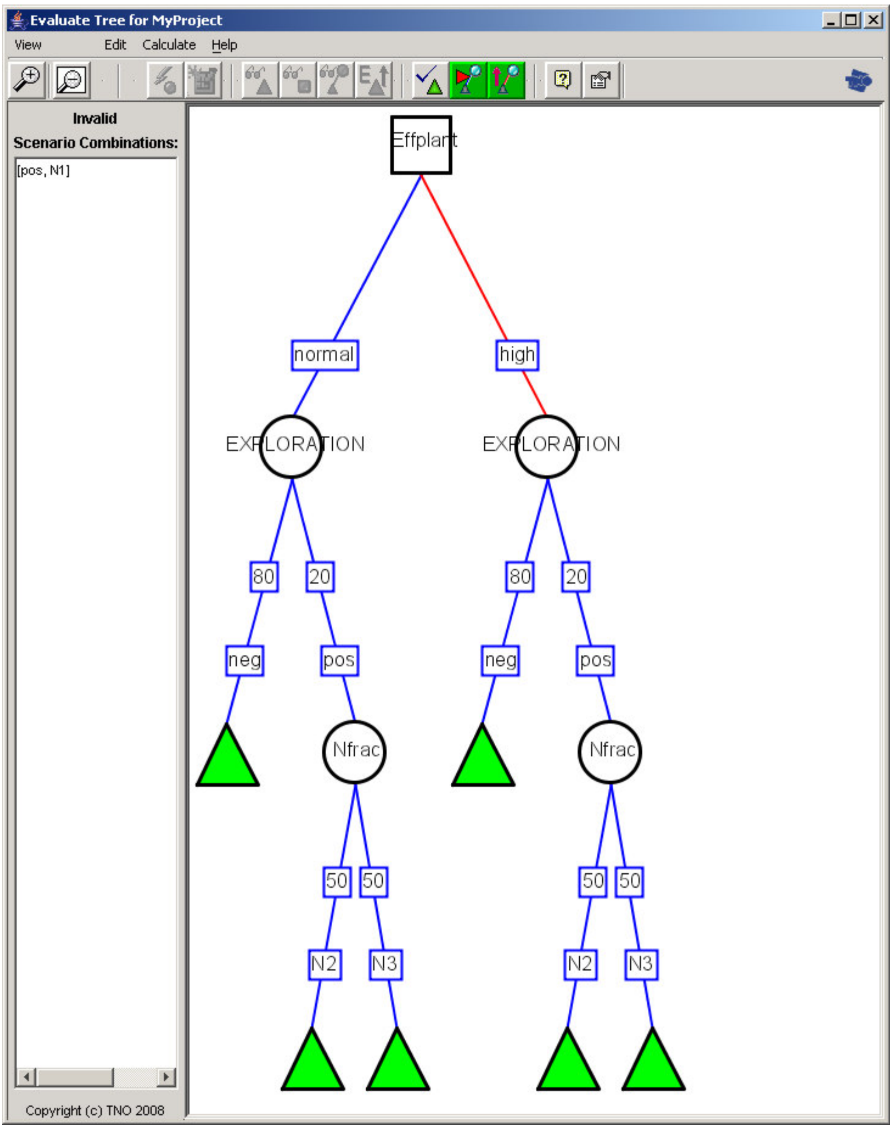


Figure 6. Staged approach using an exploration phase. When the outcome of exploration is negative (N1) the project is aborted with a cost of 250kEURO. When is positive (N1,N2 scenario) it is continued. The expectation curve of the cumulative NPV, reflecting a mix of results from a negative exploration phase and ,N2,N3. The average NPV is 0.21 Mln Euro.

7 Colophon

The performance assessment tools have been developed by Jan-Diederik van Wees, Damien Bonté, Christian Bos, and Tom van Tilburg from TNO.

The development of the performance assessment tools benefited considerably from constributions from Engine partners and stakeholders, in particular from comments and suggestions from Albert Genter (GEIE) and Ruggero Bertani (ENEL).

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http://www.csgnetwork.com/h2odenscalc.html

Dynamic viscosity as a function of the temperature:

http://www.mhtl.uwaterloo.ca/old/onlinetools/airprop/airprop.html

Electricity price to sell in France:

http://www.industrie.gouv.fr/energie/electric/pdf/tarif-achat-geothermie.pdf

Electricity price to buy in France:

http://www.industrie.gouv.fr/energie/statisti/pdf/hanprix2.pdf

8 Relationship between Symbols in equations and excel parameters

Basin & reservoir

Symbol	unit	Excel short name	Description
∇T_R	[°C/m]	grad_TG	thermal gradient from the surface to the reservoir level
T_{surf}	[°C]	Tsurf	average temperature at the surface
T_R	[°C]	TG	temperature at the reservoir level at the equilibrium
λ_R	[W/(m.K)]	kg	conductivity of the rocks
c_R	[J/(kg.K)]	cg	specific heat of the rocks
ρ_R	[Kg/m3]	rg	density of the rocks
κ_R	[m²/s]	kapg	diffusivity of the rocks
A	[Km²]	AreaF	total area of the fractures/reservoir
N	[-]	Num	number of thermally independent fractures/reservoirs
$N_{doublet}$	[-]	Numdoublet	number of doublets
H	[m]	w	aperture of the fracture/thickness of the reservoir
f_{frac}	[-]	fractionfracture	fraction from fracture

Underground Development

Symbol	unit	Excel short name	Description
Z_R	[m]	zg	length of the borehole / depth of the reservoir
d_B	[m]	dB	borehole diameter
k_s	[mm]	ks	roughness of the pipes
a	[Km]	aplot	half boreholes distance at the reservoir level
n_{seg}	[-]	segments	number of segments
I_{index}	[l/s/Mpa]	II	apparent injectivity index
P_{index}	[l/s/Mpa]	PI	apparent productivity index
$E_{wellcostscaling}$	[mln€/km]	wellcostscaling	Well cost scaling factor
$f_{boreholes}$	[-]	resfactor	reservoir/borehole capacity factor

Surface development

Symbol	unit	Excel short name	Description
T_{insurf}	[°C]	Tin	temperature inlet at the injection well
ρ_F	[Kg/m3]	rf	density of fluid
c_F	[J/(kg.K)]	cf	Specific heat of the fluid
Q_{flow}	[L/s]	Q	flow rate
Q	[Kg/s]	Qms	mass rate
Q_{seg}	[Kg/s]	Qs	flow rate for one streamline sector
η_{carnot}	[-]	curnotrelative	carnot relative efficiency

e_{pump}	[kWe/Mpa]	Epump	power consumption of a pump
$E_{years\_for\_fit}$	[yrs]	yearsforrefit	pump replacement
$E_{capex\_plant\_MW}$	[mln €/Mwe]		plant cost
$E_{refurbishment\_pump}$	[mln €]	pumpworkover	pump workover cost
E_{capex_pump}	[mln €]	costpump	injection/production pump initial cost
$MW_{capacity\_plant}$	[MWe]	plantcapacity	installed capacity
f_{plant}	[-]	plantfactor	plant capacity factor
$R_{runninghrs/yrs}$	[hrs/yr]	plantload	numbers of running yours per year
$E_{stimulation\_othercosts}$	[mln €]	baseplantcosts	stimulation and base plant costs

Economical / Financial variables

Symbol	unit	Excel short name	Description
E_{price_sell}	[€cts/kWh]	electricitypricesell	electricity price to sell
E_{price_sell}	[€cts/kWh]	electricitypricebuy	electricity price to Buy
E_{opex_fixed}	[%]	fixedopex	fixed opex of the capex active
$E_{opex\_plant\_variable}$	[k€/yr]	variableopex	opex depending the power produced
$E_{discountrate}$	[%]	discountrate	discount rate for cashflow
$E_{royalty}$	[%]	Royalty	royalty (% of the cash in)
E_{tax}	[%]	Tax	tax (% taxable income)
$E_{deductable\_capex}$	[yrs]	Depreciation	capex deductible of the taxes

Phasing variables

Symbol	unit	Excel short name	Description
$y_{evaluation}$	[yr]	yeareval	first year of evaluation
$y_{first\_electricity}$	[yr]	yearprod	first year of production
$t_{lagging}$	[yrs]	Laggingtime	lagging time between drilling and the plant construction
$t_{plant\ \_construction}$	[yrs]	plantconstructiontime	plant construction time
$t_{evaluation}$	[yrs]	evaluationtime	evaluation time
$t_{drilling}$	[yrs]	drillingtime	drilling time

9 Glossary of symbols used in the equations

Indices

F	fluid
R	rocks/solid
seg	Streamline segment
res	reservoir
b	borehole
inj	injection well
prod	production well
geoth	well at the geothermal equilibrium

Latin letters

Acronym	Unit	Description
A	[km^2]	total area fracture/reservoir
a	[km]	half boreholes distance at the reservoir level
c	[J/(kg K)]	specific heat capacity
$C_{electricity\_year}$	[mln €/yr]	yearly cash in for the electricity sales
C_{heat_year}	[mln €/yr]	yearly cash in for the heat sales
$C_{cash\_out\_year}$	[mln €/yr]	yearly cash out
$C_{cash\_in\_year}$	[mln €/yr]	yearly cash in
d_B	[m]	borehole diameter
E		economical parameters (the indices gives the definition)
E_{price_sell}	[€cts/kWh]	electricity price for sales
E_{price_sell}	[€cts/kWh]	heat price for sales
E_{price_buy}	[€cts/kWh]	electricity price for operations
$E_{grid\_connection\_cost}$	[mln €]	connection cost to the grid
$E_{heat\_exchanger\_cost}$	[mln €]	heat exchanger cost
$E_{wellcostscaling}$	[mln€/km]	wellcostscaling

$E_{stimulation\_otherscosts}$	[mln €]	stimulation and base plant costs
$E_{capex\_plant\_MW}$	[mln €/MW]	plant cost per MW installed
E_{capex_pump}	[mln €]	injection/production pump initial cost
E_{capex_active}	[mln €]	capex spend
E_{opex_fixed}	[%]	fixed opex of the capex active
$E_{opex\_plant\_variable}$	k€/MW	opex depending the power produced
$E_{refurbishment\_pump}$	[mln €]	pump workover cost
$E_{years\_for\_fit}$	[yrs]	pump replacement
$E_{royalty}$	[%]	royalty (% of the cash in)
$E_{deductable\_capex}$	[mln €]	capex deductible of the taxes
$E_{taxable\_year}$	[mln €/yr]	taxable income for a year
E_{tax}	[%]	tax (% of taxable income)
$E_{income\_after\ taxe\_year}$	[mln €/yr]	income after tax for a year
$E_{discountrate}$	[-]	discount rate for cashflow
e_{pump}	[kWe/MPa]	power consumption of a pump
$f_{boreholes}$	[-]	relative capacity factor of the boreholes
f_{frac}	[-]	fraction from fracture
f_{plant}	[-]	plant capacity factor
g	[m/s²]	g-force
h	[km]	half length of the fracture/reservoir ellipse in the boreholes alignment
H	[m]	Aperture/thickness of the reservoir/fracture
H_{seg}	[m]	Aperture/thickness of a segment
I_{index}	[l/s/MPa]	apparent injectivity index
k_s	[mm]	roughness of the pipe
l	[km]	half length of the fracture/reservoir ellipse perpendicular to the borehole alignment
L_{seg}	[m]	Length of a segment
MW	[MWe]	Power
$MW_{capacity\_plant}$	[MWe]	installed capacity
MW_e	[MWe]	electrical power
MW_{th_elec}	[MWth]	thermal power produced for electricity: f($T_{outplant}$, $T_{outsurf}$, Q)

MW_{th_coheat}	[MWth]	thermal power produced for co heat generation: f(T_{insurf}, $T_{outplant}$, Q)
N	[-]	number of fracture/reservoir
n_{pump}	[-]	number of pumps
n_{seg}	[-]	number of segments
NPV	[mln €]	Net Present Value
ΔP	[MPa]	pressure difference
P_a	[Mpa]	surface atmospheric pressure
P_{index}	[l/s/MPa]	apparent productivity index
Q	[kg/s]	mass rate
Q_{flow}	[l/s]	flow rate
r	[km]	distance coordinate for streamline
r_{res}	[-]	Recovery factor for the heat stored in the reservoir
Re	[-]	Reynold's number
$R_{runninghrs/yrs}$	[hrs/yr]	numbers of running yours per year
t	[-]	Time
t_{DEL}	[-]	delay time (time to go across a given flow path)
$t_{drilling}$	[yrs]	drilling time
$t_{evaluation}$	[yrs]	Evaluation time
$t_{lagging}$	[yrs]	lagging time between drilling and the plant construction
$t_{plant\_construction}$	[yrs]	plant construction time
∇T_R	[°C/m]	thermal gradient from the surface to the reservoir level
ΔT_b	[°C]	temperature difference in the borehole
T_R	[°C]	temperature at the reservoir level at the equilibrium
T_{inres}	[°C]	temperature inlet at the reservoir level, equal to temperature at the bottom of the injection well
T_{insurf}	[°C]	temperature inlet at the injection well, equal exit temperature at the co-heat generation plant
T_{surf}	[°C]	mean annual surface temperature
T_{outres}	[°C]	temperature outlet the reservoir
$T_{outrestot}$	[°C]	temperature inlet the production borehole (T_{outres} plus the proportion of the basin fluid)
$T_{outsurf}$	[°C]	temperature outlet at the surface
T_{surf}	[°C]	average temperature at the surface

v_F	[m/s]	velocity of the fluid
w_{seg}	[m]	width of the segment
W_{recov}	[J]	Energy recovered in the reservoir
W_{stored}	[J]	Energy stored in the reservoir
x	[m]	Length
$y_{evaluation}$	[yr]	first year of evaluation
$y_{first\_electricity}$	[yr]	first year of production
z	[m]	Depth
Z_R	[m]	length of the borehole / depth of the reservoir

Greek characters

Acronym	Unit	Description
α	[-]	friction factor
ϕ	[-]	porosity
η_{carnot}	[-]	Maximum Carnot efficiency
η_{cycle}	[-]	Relative efficiency of the binary cycle
η_{coheat}	[-]	efficiency of co-heat generation
κ	[m²/s]	diffusivity
λ	[W/(m.K)]	conductivity
μ	[Pa·s]	dynamic viscosity
θ	[°]	angular coordinate for streamline
ρ	[Kg/m^3]	density
ρ_{F_surf}	[Kg/m^3]	density of the fluid at surface condition
ψ	[-]	Streamline potential