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TEC-DBHE Techno-economics of closed-loop deep borehole-heat exchangers

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The authors bear the entire responsibility for the content of this report and for the conclusions drawn therefrom.

Zusammenfassung

In der Schweiz wird die geothermische Energie in grossen Tiefen (über 1000-1500 m unter der Erdoberfläche) direkt genutzt. Es gibt eine Reihe von Konzepten, die auf technischer Ebene entwickelt wurden, um geothermische Energie nutzbar zu machen, für den Fall, dass die natürliche Produktivität für eine wirtschaftlich tragfähige geothermische Versorgung nicht ausreicht. Bei den meisten Konzepten handelt es sich um geothermische Systeme mit geschlossenem Kreislauf, da sie als besonders einfach und sicher gelten. Wir haben die bekannte analytische Lösung von Ramey (1962) verwendet, um die quasi stationäre Temperaturverteilung eines Wärmetauscherfluids zu berechnen, das innerhalb einer Bohrung durch einen geothermischen geschlossenen Kreislauf zirkuliert. Wir haben das Ergebnis mit einem Modul gekoppelt, das Energieumwandlungs- und Kostendaten spezifiziert, um zu einem Cash-Flow-Modell zu gelangen. Mittels dieses Cash-Flow-Modells lassen sich die technischen Einheitskosten für geothermische Wärme und Strom sowie die spezifischen Investitionskosten abschätzen. Wir stellen fest, dass geothermische Wärme und Elektrizität, die von geothermischen Systemen mit geschlossenem Kreislauf geliefert werden, um einen Faktor 10-100 teurer sind als das, was heute auf dem Markt angeboten wird. Einige Konzepte, insbesondere das Eavor- oder das GreenFire-Konzept, sind vielversprechend, haben aber noch einen weiten Weg vor sich, bis sie kommerziell nutzbar sind. Nur durch bahnbrechende Forschung und Innovation, insbesondere bei der Bohrung und Fertigstellung von geothermischen Bohrungen mit geschlossenem Kreislauf, haben solche Konzepte eine Chance, kommerziell lebensfähig zu werden.

Résumé

En Suisse, l'énergie géothermique profonde (plus de 1000 à 1500 m sous-sol) est exploitée directement. Un certain nombre de concepts ont été développés au niveau technique pour exploiter l'énergie géothermique lorsque la productivité naturelle des forages est insuffisante pour un approvisionnement géothermique économiquement viable. La plupart de ces systèmes sont des systèmes géothermiques en circuit fermé, en raison de perception leur haut degré de simplicité et de sécurité. Nous avons utilisé la solution analytique bien connue de Ramey (1962) pour calculer la distribution de température quasi stationnaire d'un fluide d'échange thermique circulant dans une boucle géothermique fermée. Nous avons couplé le résultat avec un module qui spécifie les données relatives à la conversion de l'énergie et aux coûts, afin d'obtenir un modèle cash-flow qui, à son tour, estime un coût technique unitaire pour la chaleur et l'électricité géothermiques ainsi qu'un coût d'investissement spécifique. Nous constatons que la chaleur et l'électricité géothermiques fournies par des systèmes géothermiques en circuit fermé sont 10 à 100 fois plus chères que ce que le marché demande aujourd'hui. Certains concepts, notamment ceux d'Eavor ou de GreenFire, sont prometteurs mais il reste encore beaucoup de chemin à parcourir avant d'atteindre la viabilité commerciale. Seules la recherche et l'innovation, en particulier dans le domaine du forage et de la réalisation de puits géothermiques en circuit fermé, permettront à ces concepts d'atteindre la viabilité commerciale.

Summary

In Switzerland deep (more than 1000-1500 m below ground) geothermal energy is harnessed directly. There are several concepts that have been developed at a conceptual technical level to harness geothermal energy when natural productivity of boreholes reaching these depths is insufficient for economically viable geothermal supply. Most are closed-loop geothermal systems owing to a perceived high degree of simplicity and safety. We have used the well-known analytical Ramey (1962) solution to calculate the quasi steady-state temperature distribution of a heat exchange fluid circulating through a geothermal closed loop. We have coupled the result with a module that specifies energy conversion and cost data, to arrive at a cash-flow model which in turns estimates a unit technical cost

for geothermal heat and power as well as a specific capacity investment cost. We find that geothermal heat and electricity supplied by closed-loop geothermal systems are a factor 10-100 more expensive than what the market commands today. Some concepts, particularly the Eavor or GreenFire concepts, show early promise but still have a considerable distance to go until they reach commercial viability. It is only through game-changing research and innovation, particularly in drilling and completion of closed-loop geothermal wells that such concepts have a chance to reach commercial viability.

Main findings

1. Ramey's seminal 1962 paper on wellbore heat transmission readily enables parametric studies of the temperature evolution of a heat exchange fluid (water) in a closed-loop geothermal system.
2. When coupled with additional technical parameters that describe energy conversion and when coupled with economic parameters, one can use Ramey's solution to develop a simplified techno-economic analysis tool using standard MS Office software (Excel).
3. The tool is suitable for assessing a range of single wellbore heat exchanger systems that are core to closed-loop geothermal systems. The tool informs early discussions on technical maturity and pathways to commercial maturity. In addition, stakeholders will be invited to discuss assumptions and inputs for a techno-economic analysis, arrive at points of common understanding and identify divergent opinions.
4. When the tool is applied to closed-loop concepts and systems that have been proposed for Switzerland, results for standard economic metrics such as unit technical cost or specific capacity investment strongly suggest that there is little hope for commercial viability.
5. Considering Switzerland's geology which is characterized by a relatively low geothermal gradient of approximately 30-35 ^{o}C per km and an expensive cost base for drilling and completing wells suitable for close-loop wellbore heat exchangers, break-even price would have to be 10-100x higher than today for such systems to be successful in the marketplace.
6. A material lowering of the unit technical cost for geothermal heat and electricity supplied by such systems requires major investments in drilling and completion's research and innovation. Of secondary importance is research and innovation that will lead to an increase in the net thermal power of closed-loop wells.

1 Introduction

1.1 Background information and current situation

Broadly speaking, geothermal energy projects in Switzerland that target aquifers or hot formations at depths more than 1’000-1’500 m intend to utilize geothermal energy directly. If depths are more than 3’000-4’000 m, project developers may also consider the supply of electricity. This depth range owes to an average geothermal gradient in Switzerland of 30-35 ^{o}C per km depth. Depending on the capital expenditures and options for power and heat supply to customers, Swiss project economics are marginal or below investment grade if thermal output of wells is less than 15-20 MW_{th}. This figure derives from recent geothermal energy projects that have been sanctioned and progressed to drilling wells (e.g., Basel EGS, Zürich Triemli, St. Gallen).

Particularly for the case where there are facilities and customers who benefit from cascaded use of geothermal energy, utility companies integrate deep geothermal energy into more holistic energy supply systems. By doing so utilities may use part of the geothermal energy transported to surface directly and “indirectly” by using heat pumps to extract more of the useful geothermal energy. This approach is best exemplified in Riehen (RS)[1] or in Lavey-les-Bains (VD).

Where exploration drilling for geothermal reservoir has been less successful than anticipated, project developers may still use an uneconomic well by completing it with a borehole heat exchanger, such as at Zurich / Triemli (ZH). This project has been subject of a techno-economic study[2] the methodology of which will be used here to study a more general class of related concepts. The key result is that all prior cost of exploration and drilling of a particular well have to be ignored to render such an operation (completing an uneconomic well with a borehole heat exchanger) viable.

Economic failure arises from considering cut-off criteria for direct use which are insufficiently high production rates and/or lower than expected temperatures. In case of economic failure of a direct heating geothermal energy project, project developers sometimes chose to complete a commercially unsuccessful well with a borehole heat exchanger to capture some economic value. Deep borehole heat exchangers in Switzerland have an installed capacity between 100-600 kW_{th} with steady-state flowrates up to 3-5 liters per second and undisturbed bottom hole temperatures of 50-100^{o}C. Average heat extraction rates in operating projects are on the order of 50-200 W per meter[3,4,5].

There is a persistent, high exploration risk for conventional hydrothermal energy projects in Switzerland. The high exploration risk owes to poor knowledge of subsurface conditions suitable for geothermal energy use and a lack of an experienced, technically competent, and financially strong subsurface industry.

Rather than taking the exploration risk, there are project developers who intend to avoid the risk by pursuing development concepts based on wells that are hydraulically isolated from the reservoir. The hydraulic isolation stems from a well being fully cased, from a well having been drilled with muds acting as a fluid barrier to flow from the reservoir into the well and thus essentially leads to a virtually inexistant flow (infinite positive skin factor). Heat flow from a hot geothermal reservoir to the geothermal well is then essentially governed by the heat conductive properties of rock. This mode of heat extraction is by and large independent of the transmissivity of target geothermal energy reservoir, and thus postulates a virtual elimination of the exploration risk.

This concept is at least in conceptual terms highly attractive. Often, proponents of such concepts suggest that there is “no” risk for induced seismicity. The claim of “no” seismic risk, however, is potentially misleading because in extraordinary circumstances a well intervention during drilling operations may also give rise to unwanted but felt seismicity. This, for example, has happened in the St Gallen geothermal energy project where attempts to regain full control over a well that started to flow when natural gas inadvertently entered the well. The well control operations involved injecting a high-density fluid of sufficient amounts to push natural gas that entered the well back into the formation which then arguably caused slip on a pre-existing fault system; an earthquake which was felt on surface and caused minor damages valued at of less than a few hundred thousand of Swiss Francs.

Such single wellbore concepts are envisaged for low or very low permeability reservoir rocks where – mostly for safety reasons – the developer does not wish to improve well inflow performance by massive hydraulic (or other chemical and thermal) stimulation.

Dating back to the 1960s, there is a large body of literature which, based on extensive numerical modeling and field observations, argues that sustainable heat extraction rates for wells that rely on conductive heat transfer from the reservoir to a fluid circulating in the wellbore and connected to surface, are low[6]. Subtleties aside, heat extraction rates of closed-loop systems are strongly driven by geothermal temperature gradients and well depth, flow/circulation rates and well completions.

The process of heat extraction is, however, limited by the poor thermal conductivity of low-porosity rock. To minimize any heat loss from the heat exchanger fluid and despite the high cost and operational challenge during well completion operations, vacuum insulated tubing is deemed essential to allow heat extraction in a technically meaningful manner[7]. However technically meaningful and necessary this may be today, there remain significant cost challenges owing to the high completion cost of wells. In general, sustainable heat extraction rates have been modeled to vary between 30 W/m to under exceptional circumstances 300 W/m[8],.

In recent years "U-shaped" systems[9] have attracted significant attention. If a developer proposes a closed-loop geothermal system comprising two wells that are connected via an underground horizontal section of varying length, the situation is somewhat improved by a factor of 3 – 30, that is, up to 1000 W/m. Hence, this configuration is – in terms of sustained heat extraction lasting several decades – attractive when compared to single wellbore co-axial heat exchangers.

1.2 Purpose of the project

In recent years many concepts have been put forward for discussion to the Swiss Federal Office of Energy that target those deep geothermal reservoirs, which have a distinct lack of natural flow, using borehole heat exchangers. Today, such concepts – particularly when referred to as nominally "closed" in the sense of no direct exchange of pore fluids or gases between formation and wellbore – are grouped among AGS (Advanced Geothermal Systems).

The Swiss Federal Office of Energy is also often presented with such concepts with requests for funding in the realm of "research and development", "pilot and demonstration projects", and subsidies for technologies that are not yet commercially viable but postulated to be close to market deployment. However, the Swiss Federal Office of Energy lacks a tool which allows a scoping assessment of such concepts and to subsequently form an opinion regarding a concept's commercial readiness as wells as a potential identification of technical research topics that may be pursued to ultimately achieve commercial viability of such concepts.

This project has the purpose to furnish the Swiss Federal Office of Energy and interested stakeholders with a simple-to-use tool which supports early techno-economic feasibility studies of such concepts.

1.3 Objectives

The target audience of this study and its output is firstly the Swiss Federal Office of Energy and specifically units that assess novel technology concepts as well as those units that develop and implement research, innovation, and market development programs. The second audience for the output of the study are technically versed users who wish to undertake an early scoping techno-economic analysis of single wellbore heat exchanger concepts operated in closed loop.

All targeted audiences are thought to share the desire or need for such scoping techno-economic analysis without having the means or time to resort to more sophisticated numerical models that have been successfully developed by academia or commercial entities. Yet, both target audiences and interested readers are deemed to be cognizant of tradeoffs between simplifying assumptions and the realm of reasonable interpretation of such analyses.

A first goal is to develop an easy-to-use excel-based techno-economic scoping tool for AGS concepts. Such a tool may be used to calculate – for scoping purposes – the unit technical costs (Fr./ MWh_{th}) as well as specific capacity costs (Fr. / $kW_{installed\ capacity}$) and compared to other published studies. The unit technical cost is a useful metric to arrive at a real terms break-even price for heat or electricity.

A second goal is to make the scoping tool available to the wider public. Best efforts will be undertaken to make the workbook fully self-explanatory.

Another goal of this research project is to provide short summaries of various concepts around deep single wellbore heat exchangers which will be subject to a simplified techno-economic evaluation.

Finally, the techno-economic evaluation will be used to explore what type of further research and innovation may be of value for AGS concepts to become economically viable in Switzerland's energy market.

2 Procedures and methodology

The techno-economic scoping tool, a Microsoft Office Excel workbook (TEC_SWBHE.xlsx) is composed of several individual worksheets. The workbook and its worksheets allow for straightforward modification of the input data. The flexibility is granted to enable the user to tailor the approach to address her or his specific problem. We will first discuss the principal elements of the worksheets that build on the user's input various worksheets.

2.1 Introductory remarks concerning procedures and methodology

Our economic estimates are strongly driven by cost estimates capital and operating expenditures. Overall, our approach aims to provide a Class 5 cost estimate[10] which reflects a maturity level of project definition of 0% to 2% and serves the purpose of conceptual planning. As discussed below, we use simplified parametric models, our judgement as well as analogies to arrive at our cost data that feed into the economics part of the techno-economic scoping tool. We expect variations in the low range from -20% to -50%, and in the high range from +30% to +100%.

Our base case is a simple "U"-shaped geothermal well (Figure 1). The main bore is drilled to depth z and will be completed with at least two tubing strings to and from depth z which will act as conduit of the heat exchange medium (assumed to be water) from surface to the targeted hot rock reservoir and back to surface.

This "U"-shaped configuration is currently under significant investigation both, in the research community and in companies entering the geothermal energy market. Given the current state of the art and progress of drilling complex well geometries, one may build on the concept of a "haybob"-type well[11] and drill a "lasso"-type well comprising a main bore from which is drilled a circular horizontal well to allow a heat exchange fluid to enter and leave the hot reservoir at depth via the main bore (note that Fig.1 represents then only a 2-dimensional representation).

The well can have one or more horizontal laterals of length x to access and extract heat from hot rock. The fluid heated by the hot rock, may be produced to surface via insulated tubing which forms part of the completion of the first main bore. This constitutes a special (at least) dual completion whereby one tubing string serves as the injection leg while the other tubing string (or more tubing strings) serves as the production leg. It goes without saying that a well with one main bore and several horizontal legs may constitute a highly complex multilateral well of high “Technology Advancement of MultiLaterals” (TAML) level and the corresponding construction and operation’s challenges[12]. We also assume that the operator leaves enough spacing between each of the laterals to avoid thermal interference among laterals.

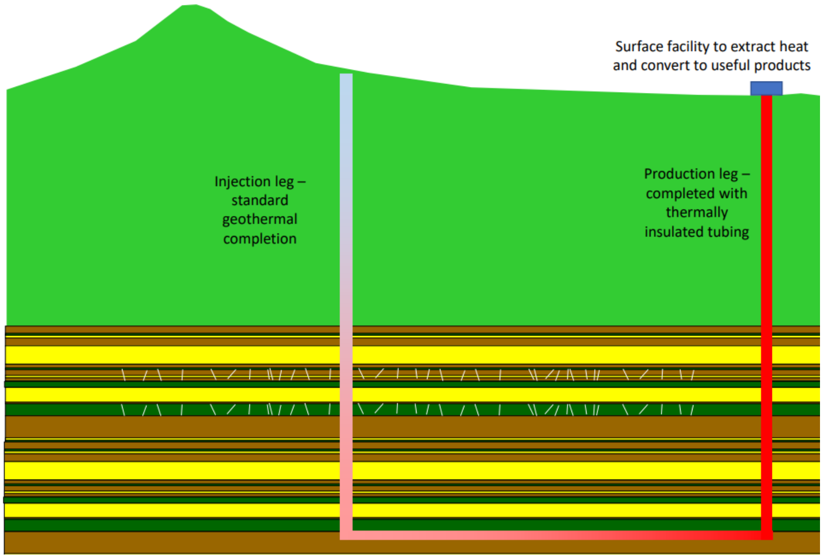

Figure 1. Simplified base case of geothermal well, functioning as a single wellbore heat exchanger. The injection leg of the geothermal well is drilled to a depth z. An idealized horizontal section extends to length x. Finally, the production leg is completed with insulated tubing to ensure that any heat loss during the ascent to surface is minimized. For the purposes of calculating the net power of the well, we assume no heat loss.

2.2 Key worksheets of the TEC_SWBHE workbook

Leading to a “Summary CH” worksheet which will be described later, there is a worksheet targeted towards technical calculations related to the temperature evolution of the circulating heat exchanger fluid, assumed to be water (worksheet “Technical parameters TEMP”). The user may input related to ambient conditions, the geothermal well including potential horizontal laterals in the targeted hot rock formation, as well as information to the principal geological factors such as the geothermal gradient and rock thermal conductivity as well as the heat capacity of the heat exchange fluid (which we take to be water in the liquid phase).

Details of the thermal power of the subsurface geothermal system and the conversion of the geothermal energy produced to surface are worked in the worksheet “Technical parameters PROD” which provides estimates of the system capacity of a power plant or the system capacity of a thermal plant.

The worksheet “Economic parameters” allows a user to determine load factors of the power and heat plants. The worksheet gives an assessment of the capital and operating expenditures based on the subsurface geometry (the well and its laterals) and based on the installed capacities of power and heat plants. Also, the user is invited to specify wholesale prices that can be realized in the marketplace. We do not ask the user to specify any project development cost prior to final investment decision.

2.2.1 Calculating the temperature of the heat exchange fluid along the well trajectory (worksheet “Technical parameters TEMP”)

Once the heat exchanger fluid at a user-specified inlet temperature (e.g., 35°C, a possible reject temperature from a heat plant) enters the injection leg at the head of the injection tubing, we assume the fluid to extract heat from the surrounding rock once the temperature of the formation exceeds the temperature of the heat exchanger fluid. To ensure simplicity and ease of use, we have used the analytic expression of Ramey (1962)[13] to calculate the quasi steady-state temperature distribution in which the rate of heat loss (or gain) is a monotonically decreasing function of time:

$$\mathrm{T}(z,t) = b + az - aA + (T_o + aA - b)e^{\left(-\frac{z}{A}\right)},$$

where z *[m]* is the depth below surface. A fluid may also travel along the horizontal leg of a geothermal well, in which case we use x *[m]* to denote the position along the horizontal section of a well. The surface temperature is b *[K]*, the geothermal gradient is a *[Km⁻¹]* and T_o *[K]* is the fluid temperature of the injectate at the injection wellhead.

A *[m⁻¹]* is an approximate heat transfer coefficient function which – with several assumptions – is given by:

$$A = (m\, C_{p,f}\, f(t))/(2\pi k_r)$$

where m *[kg/s]* is the mass flow rate circulating through the geothermal well, $C_{p,f}$ *[J kg⁻¹ K⁻¹]* is the fluid specific heat capacity at constant pressure, k_r $[Wm^{-1}\,K^{-1}]$ is is the rock thermal conductivity.

The assumptions mentioned above are principally that the liquid in the well is in the liquid phase, the injection string or liner is completed without insulated tubing, and the thermal resistance of the well to be negligible (Ramey, 1962 p. 428). The time function $f(t)$ in the expression of A captures the transient heat conduction in the formation and may be estimated from solutions for radial heat conduction from an infinitely long cylinder (Ramey, 1962, p. 428). The time function at sufficiently long time scales (i.e., typically after a week of operations) can be estimated as follows:

$$f(t) = -\ln\left(\frac{r_{co}}{2\sqrt{\alpha_r t}}\right) - 0.29 + \left[order\ of\left(\frac{{r_{co}}^2}{4\alpha_r t}\right)\right]$$

where r_{co} $[m]$ is the casing outer diameter, α_r $[m^2 s^{-1}]$ is the rock thermal diffusivity and t $[s]$ is time. We neglect the higher order terms in our calculations.

Compared to conventional geothermal energy developments where geothermal brine flows into a production well, the heat extraction from the surrounding formation of a closed geothermal system (i.e., no connate hot brine is produced) is inefficient. Hence, we assume that the production liner in a closed system is completed with insulated tubing to minimize the heat loss of heated fluid during the ascent to surface. Essentially, we assume that the fluid does not lose any temperature once it leaves the hot geothermal reservoir.

Ramey's solution has frequently been benchmarked in a large variety of settings. Of note is the study of Nalla et al. (2005)[14] with significant detail provided in an earlier accompanying report[15] and Alimonti et al. (2018)[16] have provided an in-depth technical review. Beckers et al. (2022)[17] have developed detailed techno-economic models and assessments of AGS. They benchmarked their numerical model for heat extraction to Ramey's and derivative approximate analytical solution and observed good agreement between their and Ramey's approach.

We draw the user's attention to some auxiliary calculations in this worksheet (cells Q3:AD36). We calculate the evolution of the tubing head temperature with time and generate plots that show the relationship of a range of production/circulation rates on quasi steady-state temperatures.

We emphasize two observations: high production/circulation rates have an overwhelmingly negative impact on quasi steady-state peak temperatures of the heat exchanger fluid. This is a fundamental problem of closed geothermal systems which makes potential commercial viability almost exclusively dependent on future cost trends for the subsurface components of such a geothermal system, that is, wells and completions. We also use the plots to justify why we pick a snapshot at 10 years of production/circulation to feed our assessment of the thermal power of the subsurface system, and the system capacities for electricity and heat plants.

The errors and uncertainties of our simplified adaptation of Ramey's model are therefore not expected to materially impact the techno-economic scoping calculations. Also, cost data are notoriously difficult to obtain and are subject to significant uncertainties.

As described above, we assume that the production leg(s) of the subsurface components is completed with vacuum (or other) insulated tubing because otherwise the heat loss during the ascent of the heat transfer fluid to surface is prohibitively large. Another factor that may help preserve a high temperature owes to the Joule-Thomson effect[18].

Hence, we assume in the scoping project economics that the production string is – as a default – completed with vacuum insulated tubing. The cost is substantial at approximately US$ 2000 per ton (approx. six 30 ft. or some 60 m of tubing joints). But while such a completion of the production leg may cost a few hundred thousand of Swiss Francs, and is operationally highly challenging to deploy, we assume this cost to have, for the purposes of scoping calculations, only a secondary effect.

2.2.2 Economic parameters (worksheet "Economic parameters")

2.2.2.1. The principal cost driver: estimating well cost

The principal driver for the cost of generating heat or power using single-wellbore heat exchangers is the construction and completion of the well. For Switzerland, there are no high-fidelity data available on well costs.

Instead, we have used historic data and data inferred from public statements of operators that have been granted exploration grants by the Swiss Confederation. To enable an extrapolation to greater depth and to assess the cost associated with drilling horizontal wells at great depth, we have used cost estimates developed in a study on the "feasibility of an extremely deep geothermal well in Switzerland" which was undertaken by German Clausthal University of Technology (Bierenriede, 2011)[19].

It is customary to assume that drilling cost increases exponentially with depth. However, we have introduced all costs in a lump-sum fashion into a table of costs (see also worksheet "Economic parameters", Cells E46 to Q97). We observe that not only is a linear fit of cost versus depth almost as good as a quadratic fit of cost versus depth, but either (linear or quadratic) are a better fit than an exponential curve fit. Hence, we have assumed the simplest; a linear fit that has well cost increase linearly with depth which is consistent with well cost estimates but very likely an optimistic assumption.

We have also assumed that horizontal well legs can be fitted to the same curve. We very strongly emphasize that this approach yields only a highly approximate estimate which is suitable only for scoping economics. In principle and for a given well design, one needs to develop and use a more refined cost estimate; an example of the advanced degree of planning that identifies data needed for a sound cost estimate, is a spreadsheet that has been developed by the Swiss Federal Office of Energy for cost data submission as part of an application to a geothermal energy subsidy scheme[20].

Sandia National Laboratories have published a technical study[21] within the US Department of Energy's GeoVision framework which focuses on the future role of geothermal energy in the US energy system. The Sandia technical study provides an update on geothermal well cost in the USA and provided some indications on possible future cost evolution by 2050. By drawing attention to this study, we make two points:

Firstly, when comparing Swiss and USA well costs, we generally observe a factor 3-4 higher costs in Switzerland. The reasons for this spread have anecdotally been attributed to a lack of a well-functioning market (lack of a dynamic local drilling industry, a lack of experienced operating companies, expensive series of “one of a kind” projects and an associated lack of standardization and simplification) as well as a lack of an experienced permitting and regulatory sector. To what extent generous subsidy schemes in Switzerland distort the market is an open question.

Secondly, we wish to draw attention to some forward looking statements of the study in connection with a scenario where the energy market is successfully penetrated by geothermal energy with a correspondingly large and vibrant industry that has achieved not only a large market share but also has built up and applied experience (both in terms of learning and the introduction of novel technologies) that have resulted in significant reductions of the unit technical cost of a well (CHF per MWh). We have adopted the cost trends as mapped out by Sandia in the worksheet “Economic parameters” Cells S46 to AE97) and feed those into a set of worksheets (“Cash-Flow Model GeoVision” and “Summary GeoVision world”) to illustrate a what-if scenario for a given concept.

A further caveat on well costs: while the oil and gas industry have experience in drilling horizontal wells with horizontal sections more than 10’000 m[22], there are additional challenges in a geothermal setting owing to high temperatures and generally very hard and abrasive crystalline or metamorphic rock formations. The operational requirements (e.g., hook loads) are non-standard and only few rigs exist worldwide capable for drilling (very) extended reach geothermal wells.

We estimate the cost of a lateral wellbore (including casing and completion as well as testing, logging etc.) to be about CHF 10’000 per meter with approximately 50% accounted for by drilling the well. This estimate of CHF 5’000 per meter for drilling operations is a factor of 5-10 higher when compared to the targeted drilling cost component that is postulated based on the Eavor-Lite project[23]. Note that the Eavor-Lite concept involves wells without casing but instead, intricate, and proprietary completions of closed-loop cased geothermal wells. Whether “casing-less” geothermal wells – even when drilled at large depths with many natural barriers and far removed from any useful groundwater source – will ever be permitted in Switzerland is difficult to predict. The evolution of groundwater protection rules and regulations as well as the strict adherence to overruling precautionary principles for environmental protection in Switzerland are strong barriers to deploying such innovative concepts.

2.2.2.2. Sales prices for electricity, heat, and CO_2 emission allowances as environmental products

We make several assumptions for modeling revenue streams from sales of electricity, heat, and CO_2 emissions allowances (environmental products). We do not account for potential revenue streams from co-produced hydrocarbons, raw minerals such as lithium, nor do we account for additional revenues from energy services (e.g., energy storage) that geothermal energy projects may generate.

There are two principal energy products; electricity which is sold wholesale and heat which is sold to a heat distributer. If the temperature of the water at the top of the insulated production tubing is greater than 90ºC, the economic temperature cut-off, one of the revenue streams will derive from electricity sales[24].Geothermal waters with a temperature of less than 90ºC (reject fluid temperature for power generation) will be used for generating heat suitable for sales. The latter’s’ economic cut-off is determined by the temperature at the tubing head of the injection leg of the geothermal well (e.g., 35ºC).

We also explore the option of generating CO_2 allowances, an environmental product which may be of value provided the geothermal heat displaces a fossil fuel, specifically heating oil with an emissions factor of 74 tons per GJ[25] of heat supplied.

2.2.2.3. Cost of surface facilities

We assume minor costs for most of the surface facilities; the specific capacity cost for power generation is CHF 4’000 per MW_{el} installed capacity[26]. When heat is a marketable product, we assume minor costs for connecting into an existing heat plant which has already been installed in a local energy system. Next, we assume that the power plant operates around 8’000 hours per year and heat is supplied 4000 hours per year. No other surface facility costs are included. We adopt financial data that has been described elsewhere[27], particularly we assume a weighted average cost of capital (WACC) of 5.44%.

2.2.2.4. Other items that influence cash-flows

From the cash-in items (revenues), we subtract costs that relate to the operation and maintenance of project assets (e.g., wells, monitoring networks, pipelines, production facilities such as heat- and power plant, operations staff, overhead for research and analysis and insurance) and government take (that is, taxes, fees, and royalties). Unlike the actual experience of geothermal operations in Germany[28], where operating expenditures are closer to 2% of capital expenditures, we surmise that the operation of a closed-loop system is less costly at 1% of capex because the focus is on operating and maintaining a well and virtually no need for standard reservoir management which goes beyond wells. Government take is heterogeneous in Switzerland with Cantons exercising their constitutional right to govern the utilization of the subsurface. Again, we simplify and assume a 20% tax rate. Assets are simply depreciated over 25 years noting a more complex situation for Swiss depreciation rules[29]

We do not explicitly consider any unusual "financial or fiscal engineering" such as picking an optimized company specific debt-equity structure. Instead, we assume – much like the Swiss Federal Office of Energy when setting the WACC for renewable energy subsidy schemes – a 50% equity-50% debt financing of the geothermal venture. Further we assume no loss carryforward rules; the latter would have a strong impact on the generation of operating cash flows and thus on some key financial performance indicators.

2.2.3 The cash-flow model (worksheet "Cash-Flow Model").

Unless the user wishes to explore the impact of Switzerland's subsidy schemes for geothermal energy projects, the cash-flow model does not require any input from the user.

Regarding the output of the techno-economic scoping tool, we focus on (1) a metric that is a strong indicator for the likely economic performance: the present value of the <u>subsurface component</u> of the unit technical cost (UTC) at the given weighted average cost of capital. This metric is defined as the sum of present value of the capital expenditures (CAPEX), added to which is the present value of the operating expenditures (OPEX); the sum is subsequently divided by the present value of the heat produced/supplied to the heat and/or power plant:

$$Present\ Value\ of\ UTC_{subsurface} = \frac{\text{Present Value of CAPEX}_{subsurface} + \text{Present Value of OPEX}_{subsurface}\ [\text{CHF}]}{\text{Present Value of Production [MWh]}}$$

This metric gives a strong indicator of the pre-tax constant real terms break-even price for heat and/or electricity.

We also focus on the overall unit technical cost, which includes the contribution of capital and operating expenditures for surface facilities required for power generation and heat supply to customers. Unit technical cost thus emphasizes the reward, or the limiting factor, of production.

$$Present\ Value\ of\ UTC = \frac{\text{Present Value of CAPEX} + \text{Present Value of OPEX}\ [\text{CHF}]}{\text{Present Value of Production [MWh]}}$$

We pay less attention to other metrics, such as the net present value of a project which is a metric that is more useful if there were essentially infinite of capital available or ventures that yield most return.

3 Results and discussion

3.1 The GEOHIL/GEOStrom GmbH concept[30]:

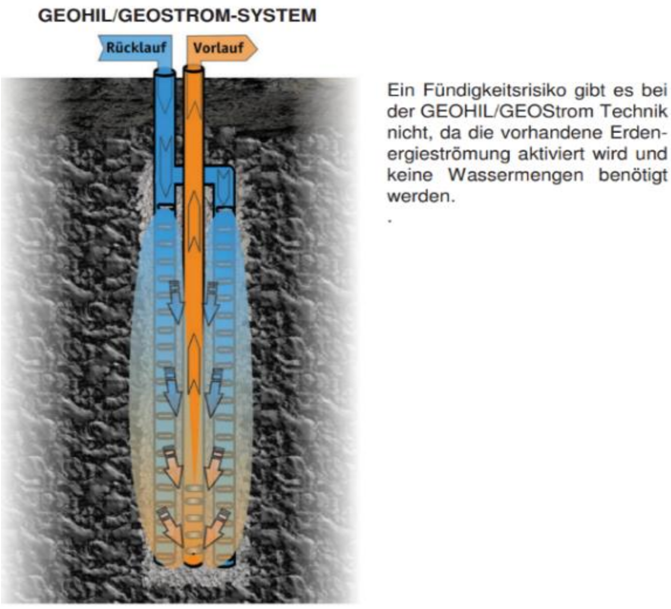

Figure 2 The GEOHIL concept emphasizes the absence of a risk of finding a suitable resource as it relies on naturally occurring heat flow and no addition of water to the natural geothermal system.

In this concept (Figure 2 The GEOHIL concept emphasizes the absence of a risk of finding a suitable resource as it relies on naturally occurring heat flow and no addition of water to the natural geothermal system. a single well is drilled to a true vertical depth which is determined by the prevailing temperature gradient and the targeted use of the geothermal energy extracted from the subsurface. The concept advertises target depths range from 5'000 m to 8'600 m true vertical depths. The wells are completed with a small diameter production string, outside of which are securely mounted several smaller sized injection strings. In addition, there is a thermal isolation barrier sandwiched between the two (production and injection) tubing systems. The tubing systems are housed in a slotted liner or screen which rests against the borehole wall.

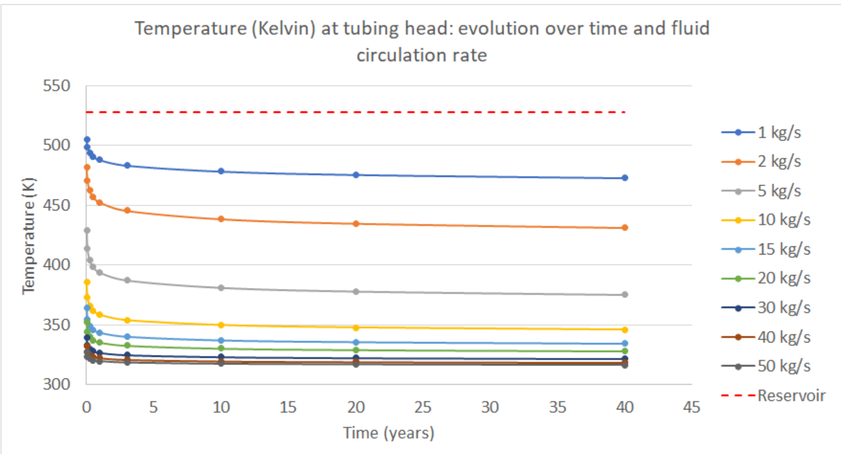

Figure 3 Peak tubing head temperatures in an 8 km deep GEOHILL system. The steady-state temperature of the reservoir is 255 ºC. Only very low production/circulation rates (and hence high residence times of the heat exchanger fluid in contact with hot rock) result in a meaningfully high temperature of the circulating fluid (water) at the head of the thermally insulated production string available for conversion to useful products (heat and electricity).

Circulating 5 kg/s of heat exchanger fluid through this system constructed to a depth of 8'000 m, suggests a peak tubing head temperature of 108 ºC after 10 years of production (Figure 3).

A well to a true vertical depth of 8000 m has an overall thermal power of 1.6 MW_{th} when produced at 5 kg/s. The overall thermal power can furnish a power plant with an installed capacity of 40 kW_{el} and a heat plant designed for 1.24 MWh_{th}. The high cost for drilling and completing an 8'000 m deep well results in a specific capacity investment cost for power/electricity more than CHF 650'000 per kW_{el}; approximately a factor of 100 higher than conventional geothermal power plants[31]. Since the bulk of the heat produced to surface is converted to usable heat the specific investment cost is significantly lower but still prohibitively expensive at slightly above CHF 34'000 per kW_{th}. It is futile to comment on the exceedingly high unit technical costs for electricity and heat.

Project specifics	
Production	Electricity, Heat, CO2 Allowances
Reservoir depth	8'000 m
Maximum temperature of circulating heat exchanger fluid	108 °C
Length of horizontal lateral	0 m
Number of laterals	0
Production or Circulation Rate	5 kg/s
System capacity (electricity)	0.04 MW_{el}
System capacity (heat)	1.24 MW_{th}

Capex	Total
Total investments geothermal source (subsurface)	69'637'020 CHF
Total investments power plant (surface)	1'171'704 CHF
Total investments heat plant (surface)	1'000'000 CHF
Total	**71'808'724 CHF**

Net Present Value NPV (CHF)	*20 years*	*25 years*	*30 years*	*40 years*	*50 years*
NPV Real (without inflation)	-75'541'392	-75'732'533	-75'786'350	-75'859'329	-75'902'298
NPV Nominal (with inflation)	-76'979'311	-77'222'742	-77'295'210	-77'400'782	-77'469'443

Specific investment cost	
Specific capacity investment for power (CHF/kW_{el})	652'849
Specific capacity investment for heat (CHF/kW_{th})	34'396

Unit Technical Cost UTC (CHF/MWh)		*20 years*	*25 years*	*30 years*	*40 years*	*50 years*
Total UTC	Total UTC Electricity	6'767	6'511	6'063	5'557	5'301
	Total UTC Heat	758	683	635	582	555
Subsurface Unit Technical Cost	Subsurface UTC of Electricity	3'930	3'160	2'644	1'993	1'600
	Subsurface UTC of Heat	444	360	303	230	185

Suffice to say that even if well costs were cut by a factor of 10, unit technical costs would not be favorable in a competition with other renewables options. We conclude that any set of reasonable, yet optimistic assumptions will not allow such a concept to reach commercial viability. We do not foresee any drilling and completion technology on the horizon which would lower the cost of such a well to just 10% of the initial cost[32].

3.2 The Geyser concept[33]

This concept developed by Klaus Heller and presented at the Stanford Geothermal Workshop in 2014 centers on a novel concept of a boiler that operates at the bottom of a deep geothermal well of suitable dimensions. Access of water in the liquid phase into the boiler via the annular space of the well is pressure-valve controlled. Once water enters the low-pressure boiler, it evaporates. The overheated steam travels via an insulated production string to surface where the geothermal energy is converted to useful products. The developers have also developed concepts that extend the exposure time of the heat exchanger liquid to the hot rock surrounding the boiler chamber at depth.

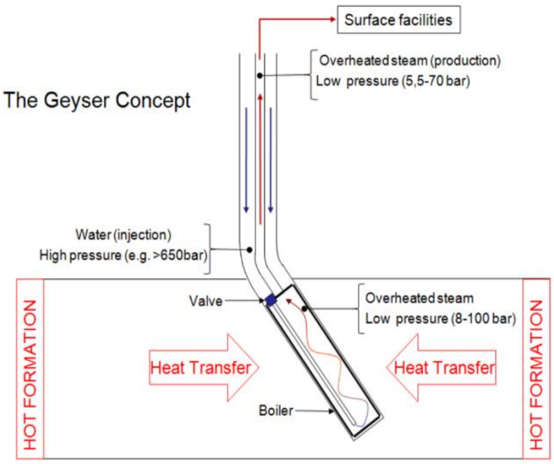

Figure 4. The Geyser concept (Heller et al., 2014)

Strictly speaking, the techno-economic scoping tool does not include a module that addresses phase changes in the heat exchange medium nor more complex paths that have a positive impact on the amount of heat transferred from the hot rock to the heat exchange medium. The concept suggests the potential thermal output to be between 2 and 8 MW_{th}. Owing to the potential to produce super-heated steam on surface the energy conversion to electricity may be high enough to enable filling a plant with 2 MW_{el} installed capacity. The authors conclude that increasing heat flow from the rock to the working fluid, the overall efficiency as well the cost-effectiveness are some of the barriers to development.

However, based on the discussion in section 3.1 even a potential quadrupling of (the net present value of) production will cut any metric such as unit technical cost or specific capacity investment cost by only a factor of 4 which leaves this concept still far from commerciality. Again, it is difficult to envisage a novel drilling technology, which would cut well and completion costs by one order of magnitude**Error! Bookmark not defined.**.

3.3 Eavor concept

The Eavor concept[23] has attracted significant amounts of attention in recent years. Drilling and completion technologies that have been developed and honed are one of the linchpins that have driven the impressive growth of the upstream, unconventional natural gas sector. Coupled to the reductions in well cost, patents[34] have been developed by Eavor that envisage casing-less wells. With those two technological advances, Eavor has in recent years successfully demonstrated[35,36] several aspects (application of drilling technology developed in the traditional oil and natural gas sector, operability of a thermosyphon which lowers operational expenditures, sustainability of production) in a Eavor-Lite demonstration project in the very well characterized Western Canadian Sedimentary Basin near Sylvan Lake in Alberta, Canada.

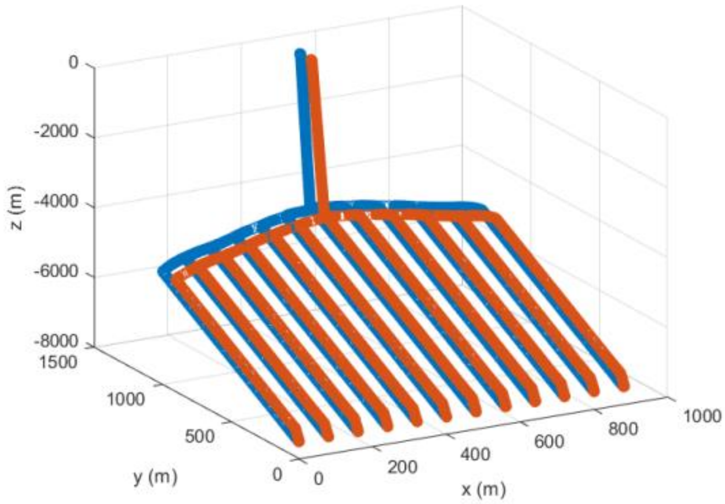

Figure 5 Commercial concept for Eavor technology (from Beckers and Johnston, 2022): main bore has 12 laterals with total depth of approximately 7 km. Blue represents the injection side; red represents production side. For the techno-economic analysis, we assume a depth of 6 km and horizontal laterals of 2 km length in a geology that is characterized by a 30ºC per km depth, temperature gradient. First, we use Swiss well cost data and then GeoVision 2050 cost data to illustrate the fact that well and completion cost have to dramatically decrease.

Beyond the demonstration of the concept, there exists a challenging path to commerciality (Figure 5) which is, while extremely optimistic, not unrealistic. The path to commerciality rests on an exceptionally fast experience curve for drilling and completing ultra-cheap multilateral wells (Figure 6) which implies not only game-changing innovation and roll-out to the industry but also maximizing learnings that can only come from an industry-like approach to manufacturing such wells as is described in the Sandia GeoVision report[Error! Bookmark not defined.] for cost trends to 2050.

Project specifics	
Production	Electricity, Heat, CO2 Allowances
Reservoir depth	6'000 m
Maximum temperature of circulating heat exchanger fluid	139 °C
Length of horizontal lateral	2'000 m
Number of laterals	7
Production or Circulation Rate	21 kg/s
System capacity (electricity)	0.64 MW_{el}
System capacity (heat)	5.21 MW_{th}

Capex	Total
Total investments geothermal source (subsurface)	169'445'036 CHF
Total investments power plant (surface)	3'545'192 CHF
Total investments heat plant (surface)	1'000'000 CHF
Total	**173'990'228 CHF**

Net Present Value NPV (CHF)	*20 years*	*25 years*	*30 years*	*40 years*	*50 years*
NPV Real (without inflation)	-160'428'401	-158'097'953	-156'487'430	-154'303'425	-153'017'547
NPV Nominal (with inflation)	-161'307'879	-158'318'549	-156'149'878	-152'990'506	-150'935'750

Specific investment cost	
Specific capacity investment for power (CHF/kW_{el})	173'441
Specific capacity investment for heat (CHF/kW_{th})	11'840

Unit Technical Cost UTC (CHF/MWh)		*20 years*	*25 years*	*30 years*	*40 years*	*50 years*
Total UTC	Total UTC Electricity	1'831	2'576	2'391	2'182	2'076
	Total UTC Heat	262	607	562	511	485
Subsurface Unit Technical Cost	Subsurface UTC of Electricity	1'066	860	721	545	438
	Subsurface UTC of Heat	154	125	105	80	64

Project specifics	
Production	Electricity, Heat, CO2 Allowances
Reservoir depth	6'000 m
Maximum temperature of circulating heat exchanger fluid	139 °C
Length of horizontal lateral	2'000 m
Number of laterals	7
Production or Circulation Rate	21 kg/s
System capacity (electricity)	0.64 MW_{el}
System capacity (heat)	5.21 MW_{th}

Capex	Total
Total investments geothermal source (subsurface)	13'844'235 CHF
Total investments power plant (surface)	3'545'192 CHF
Total investments heat plant (surface)	1'000'000 CHF
Total	**18'389'427 CHF**

Net Present Value NPV (CHF)	*20 years*	*25 years*	*30 years*	*40 years*	*50 years*
NPV Real (without inflation)	2'614'612	7'020'283	9'904'684	13'816'175	16'119'146
NPV Nominal (with inflation)	5'081'411	10'729'535	14'613'564	20'271'908	23'951'919

Specific investment cost	
Specific capacity investment for power (CHF/kW_{el})	17'435
Specific capacity investment for heat (CHF/kW_{th})	1'031

Unit Technical Cost UTC (CHF/MWh)		*20 years*	*25 years*	*30 years*	*40 years*	*50 years*
Total Unit Technical Cost (CHF/MWh)	Total UTC of Electricity	302	271	252	230	219
	Total UTC of Heat	70	63	58	53	50
Subsurface Unit Technical Cost (CHF/MWh)	Subsurface UTC of Electricity	87	70	55	45	36
	Subsurface UTC of Heat	13	10	9	7	5

Figure 6 Variations on the Eavor commercial concept: in line with the aspirational Sandia GeoVision scenario, reducing the subsurface development cost by more than a factor 10 from about CHF 170 million (left table – capex total investment geothermal source subsurface) to CHF 14 million lowers the unit technical costs and the specific capacity investment for electricity/power and heat supply to a level that suggests potential commercial viability. For a commercially viable project, approximately 20 km (or 66'000 ft) of well and laterals need to be drilled which corresponds to an average per foot well and completion cost of CHF 210 per foot. The latter figure is in broad agreement with the results of Beckers and Johnston (2022) who suggest a well cost of USD 200-400 per foot for a commercially viable project.

3.4 GreenFire concept

The GreenFire concept[37,38] has recently experienced considerable interest after a 2019 demonstration of a closed-loop heat loop in an inactive well in the Coso Geothermal Field. A techno-economic analysis of the "field-scale application of closed-loop geothermal development" (page 41 of the report[37]) strongly suggests the technical viability of such a concept. The issue for commercial viability is naturally the cost of drilling and completing wells that can subsequently operate the GreenFire concept.

3.5 Concepts using complex geometries and/or complex civil engineering works: shafts with geothermal wells (MAGES, ehoch10, DTE, EAPOSYS)

Researchers, innovators, and project developers have conceptualized more complex ways to access geothermal heat. One approach rests on mine shaft-like access to significant depths such as developed by the "Man-Made Geothermal Energy Systems" (MAGES) Project (1978-1980) under the auspices of the IEA. Related concepts are due to DTE[39] and ehoch10[40] which, following the construction of a mineshaft and associated large subsurface infrastructures, proceed to drill a very large number of lateral wells at depths from 5-10 km, which are subsequently used as heat exchangers. Also related is a more recent concept promoted by EAPOSYS, a Swiss project company. Information on the geometry of the subsurface heat exchanger can be accessed via one of the company's patents[41].

All the concepts are at very early stages of their development and need to mature technologically. It is however essential that project developers also develop ideas around credible paths to commerciality. This discussion will invariably center on the major cost driver, drilling and completing wells. The development of a credible paths to commerciality involves early techno-economic analysis, identifying major cost drivers and developing concepts on how unit technical costs (CHF/MWh) can be lowered.

4 Conclusions

We draw the following conclusions:

1. Ramey's seminal 1962 paper on wellbore heat transmission readily enables parametric studies of the temperature evolution in a closed-loop geothermal system.
2. When coupled with additional technical parameters that describe energy conversion and when coupled with economic parameters, one can use Ramey's solution to develop a simplified techno-economic analysis tool using standard MS Office software (Excel).
3. The tool is suitable for assessing a range of single wellbore heat exchanger systems that are core to closed-loop geothermal systems. The tool informs early discussions on technical maturity and pathways to commercial maturity. In addition, stakeholders will be invited to discuss assumptions and inputs for a techno-economic analysis, arrive at points of common understanding and identify divergent opinions.
4. When the tool is applied to closed-loop concepts and systems that have been proposed for Switzerland, results for standard economic metrics such as unit technical cost or specific capacity investment strongly suggest that there is little hope for commercial viability.
5. Considering Switzerland's geology which is characterized by a relatively low geothermal gradient of approximately 30-35 ^{o}C per km and an expensive cost base for drilling and

completing wells suitable for close-loop wellbore heat exchangers, break-even price would have to be 10-100x higher than today for such systems to be successful in the marketplace.

6. A material lowering of the unit technical cost for geothermal heat and electricity supplied by such systems would require major investments in drilling and completion's research and innovation. Of secondary importance is research and innovation that will lead to an increase in the net thermal power of closed-loop wells.

5 Outlook and next steps

As we have suggested in our work, it is the specific technical cost (MW/CHF) of drilling and completing wells which requires special attention. This approach requires not only developing and implementing technologies that maximize the well's net power (MW_{th}) but, critically, lowering the cost of delivering wells.

For closed-loop systems the scope of maximizing a well's net power may involve, for example, the use of CO_2 or other tailor-made substances as a heat exchange fluids[3] or improving the heat transfer from the reservoir rock to the well (without breaching the hydraulic barrier).

However, substantial inroads must be made in lowering the cost of drilling and completing wells for closed-loop systems. A positive example is the Eavor concept which introduces not only the concept of "manufacturing" wells but also develops "casing-less" wells. Whether or when this technology will yield specific technical costs for heat and power that are cost-competitive remains to be seen. We show the potential impact of reduced well and completion cost in several worksheets "Summary GeoVision world" and "Cash-Flow Model GeoVision".

The European Horizon 2020 and Horizon Europe framework research programs and to a lesser degree the GEOTHERMICA ERA-NET have invested significantly into drilling research and innovation to meet a target of 30% reduction in the specific capacity cost of wells by 2030. Switzerland may leverage its own drilling research and innovation by encouraging research and innovation cooperation across Europe and North America. Whether or not the scale of cost reduction to make deep single wellbore heat exchangers commercially viable can be achieved, is very much an open question.

6 National and international cooperation

No activities were undertaken with national and international stakeholders.

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