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Quantifying Risk in Geothermal Development – High Enthalpy and Low Enthalpy Cases

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ABSTRACT

Like most resource harnessing ventures, geothermal energy shares both exploration and exploitation risks. Resource discovery and confirmation is carried out mainly by activities, among which are drilling operations, which incur high initial costs. These activities display relatively high risks and are the major barrier to accelerated development worldwide. Once the resource is proven, it mobilizes important financial resources for geothermal production infrastructure development, power plant and transmission line construction. Both the risk and high upfront capital cost make geothermal ventures less attractive to conventional financing schemes.

To help accelerate geothermal development a number of national governments have created risk mitigation instruments such as loan guarantees, guaranteed cost sharing of unsuccessful drilling projects and insurance programs and incentive measures to help cover the upfront costs of exploration drilling and power plant construction, in addition to tax cuts, mandated power purchase programs and even feed in tariffs to provide a market for geothermal power and heat.

This paper presents two case studies. The first addresses the high enthalpy, power generation case, in the exploration phase where the main problems of quantifying success-failure risk of exploratory drilling are addressed and a numerical criterion to assess the well output from well testing figures proposed. The second study deals with a large geothermal district heating (GDH) scheme, where the drilling success ratio approached 100% (one recorded full and two partial failures out of around 100 wells) whereas exploitation of the low temperature deposits showed, in the early stages, severe technical and nontechnical shortcomings leading to frequent, prolonged well shutdowns and, ultimately, to their abandonment. A quantified risk prognosis was at a stage projected 15 years ahead which later proved relevant.

1. INTRODUCTION

Many of the countries with geothermal resources have not fully exploited their potential because of a variety of barriers (regulatory, policy, fiscal, technical, geographical, etc.). Geothermal risk mitigation can be achieved by the following key elements: establishment of reliable geological data developed by state-of-the-art geoscientific assessment methodologies, mobilization of the latest exploration and drilling technologies, and availability of a risk insurance product on the insurance market in combination with support from government, bilateral and multilateral financial resources.

Most of the existing geological risk mitigation instruments have been supported by government funding. The commercial insurance market, except for a few recent cases in Germany (e.g. Unterhaching project by Munich Re), is not yet prepared to fit the geothermal risk insurance business into a standard product line because of the lack of adequate size of market demand or nature of the unique risk element which may not be "commercially insurable" with conventional insurance methodologies. In order to bridge this gap, the World Bank has launched the GeoFund and ARGeo programs.

While risk assessment is a complex procedure, relying on surface exploration, and shallow drilling, it is necessary to set up a series of numerical criteria which could lead to the definition of the success or failure when proceeding to the phase of resource confirmation by drilling.

Risk assessment addresses both financial issues and reservoir management strategies.

As regards financial risks incurred at exploration level, the World Bank has produced a comprehensive overview summarised in Fig. 1 risk vs. expenditure chart. It shows quite clearly that, in the compiled project areas located chiefly in East Africa and Pacific Rim countries, the exploratory drilling risk could be minimised thanks to the filtering out of the less attractive, most risky, prospects identified in the preliminary reconnaissance stages, thus leading to a 80% drilling success ratio.

After project commissioning and start-up, the first years of exploitation provide the reservoir/production engineers and management with additional clues on future development alternatives.

The latter are usually investigated by integrating all pertinent data – reservoir characteristics, surface heat/power loads, well productivities, plant performance, make-up well drilling and plant production schedules, economic parameters – into reservoir and economic models to assess ultimately well/field productivities and project economic value.

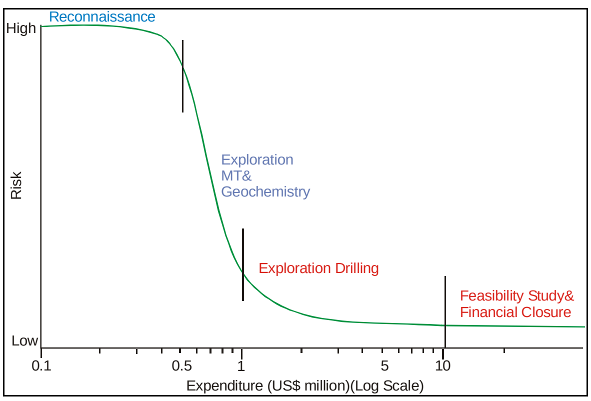

Figure 1: Expenditure and risk prior to geothermal development (source World Bank)

However, the decision making process is clouded by the many uncertainties affecting model inputs. A purely deterministic or probabilistic approach could be misleading. A thorough coupled deterministic-probabilistic approach could prove more relevant but by all means unrealistic considering the huge numbers of model runs involved, indeed a tedious and costly exercise if manageable ever, unless kept within reasonable limits by adequate constraints.

Acuna et al. (2002) review the case of a liquid-dominated field in the Philippines where a strategic decision is to be taken as to whether a deep, poorly produced reservoir underlying the presently exploited shallow seated reservoir should be developed or not.

In order to overcome the aforementioned limitations the authors suggest an interesting methodology outlined hereunder.

- up to ten different exploitation strategies were selected;
- the economic model calculates the project NPV (net present value) probability distribution. The uncertainty for each relevant parameter is described by the most likely (50% probability – P50); pessimistic (10% probability – P10) and optimistic (90% probability – P90) values, defining the parameter cumulative probability function;
- in order to reduce the number of reservoir simulation runs for the P10, P50, P90 uncertainties allocated to the parameters for each exploitation strategy, the model results were synthesised, after preliminary model tests, by using a polynomial approximation to key output data, and four cases reflecting changes in steam extraction rates and make up well drilling schedules constrained by existing well deliverabilities.

The polynomial approximation of reservoir performance (as well deliverability vs. cumulative produced steam) proved rewarding in that it enabled integration of this key uncertainty into the probabilistic economic model to assess the risk impact on project NPV.

2. THE HIGH ENTHALPY CASE

The resource confirmation phase is accomplished by a series of deep exploratory drill holes aiming at determining the potential of the resource which ultimately leads to the design capacity of the power plant.

After the drilling phase is completed, the wells are thoroughly tested.

2.1 Methodology

Drilling records and further downhole measurements in a closed well give a rough indication of the output to be expected, and therefore the method of flow measurement that is the most adequate.

The observation of the wellhead pressure over a period of time provides useful indication of any changes in either quantity or quality of flow.

The well measurement programme must comprise a full range of output testing at intervals of several days, linked together in time by wellhead pressure reading, preferably automatically recorded.

The geothermal well output test programme should record for *several values of wellhead pressure* the following parameters:

- total mass flow rate
- temperature of single phase and/or quality of flow (enthalpy or dryness)
- chemical composition (constituents) of the phases

In order to provide a good assessment of the well performance, it is also important to keep record of:

- extreme pressure values
- description of the test, reason for selecting a particular method
- history of the well (drilling records)
- correlation to other measurements, e.g. downhole pressure measurements, interference with wells nearby

Any method is used for testing; it is governed by the well characteristics, the resources available and the accuracy. It is recommended to carry out several measurements using the same method and check the results with another method.

Available methods for flow measurements are:

- Orifice plate (sharp-edged orifices in combination with a cyclone separator)
  - single phase measurements – pressure drop across the plate associated with temperature measurement
  - two phase measurements – phases must be separated
- Calorimeters – not very appropriate for superheated steam and hot water, most adequate for two-phase flow mixtures

The flow results observed directly are used to calculate from the steam tables, the mass and heat flow enthalpy and dryness fraction.

The isentropic power is equal to:

$$W_{is} = q_v \Delta h_{is} \qquad (1)$$

$$\Delta h_{is} = \left(h_v - h_c\right) - T_c\left(S_v - S_c\right) \qquad (2)$$

where q_w is the steam (vapour) mass flow rate, Δh_{is} is the isentropic enthalpy drop, h is the specific enthalpy, S is the entropy, T is the temperature and v, c are subscripts referring to inlet vapour and condenser respectively.

The steam mass flow is equal to:

$$q_v = \frac{q_t\left(h_t - h_f\right)}{h_v - h_f} \qquad (3)$$

where q_t is the total flowrate at wellhead, h is the specific enthalpy and the subscripts t, v and f refer to wellhead (total flow), vapour and separated liquid respectively.

There is an optimum flash temperature. If the latter decreases, vapour flow will increase but at the expense of the isentropic enthalpy drop, which will diminish.

The maximum useful work is given by:

$$W_{net}^{\max} = -\left(\Delta H - T_0 \Delta S\right)\Big]_{T_{gf}^{in}}^{T_{gf}^{out}} = -\Delta B \qquad (4)$$

where ΔB is commonly referred to as change in availability (Tester, 1976). For a given fluid and a fixed T_0 and a reinjection temperature T_{gf}^{out} which has a minimum value T_0, the maximum work (per unit weight of geothermal fluid or per unit heat transferred) possible from an ideal reversible process is a function of only T_{gf}^{in}, the geothermal source temperature. A plot of this value is given in fig. 2.

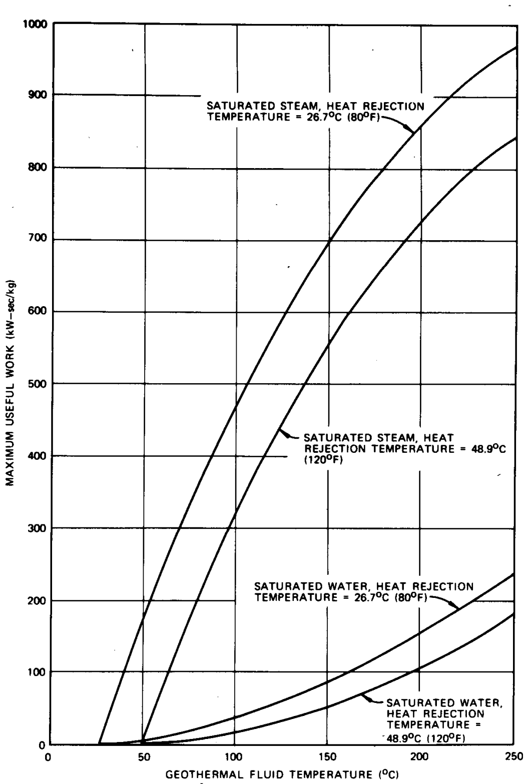

Figure 2: Maximum useful work (ΔB) plotted as a function of geothermal fluid temperature for saturated steam and saturated water sources (Tester, 1976)

2.2. Enthalpy measurements

In a paper issued in 1962 Russell James described an empirical method to measure flow rate from a discharging high-temperature well. James's experiment showed that "*the critical discharge pressure can be used to measure the mass flow or the energy flow of steam-water mixture passing through pipes*". Based on the experiment the following empirical equitation describes the relation between the various measured components:

$$\frac{M * H^{1.102}}{3600 * A * p_c^{0.96}} = 0.184 \qquad (5)$$

where M is the total flow (t/h), A is the cross-section area of the discharging pipe (cm^2) , p_c is the critical pressure (bar a) and H is the enthalpy (kJ/kg). To use this formula to calculate flow rate from discharging well, the enthalpy must be known. Downhole temperature measurements can yield accurate enthalpy figures if the boiling takes place within the well.

However in many geothermal fields boiling takes place outside the well. Therefore downhole temperature measurements or geothermometers do not give correct value of the enthalpy of the steam-water mixture entering the well. In such cases a modified version of the Russell-James method has to be applied. The modification is based on measuring the flow rate of 100°C geothermal water from the silencer after separation from the steam fraction. The total flow and enthalpy from the discharging well can be extracted by iteration from the Russell-James empirical formula.

2.3. Power potential estimate

The process described here (DiPippo, 2008) is a single flash cycle where the geothermal fluid is wet steam (mixture of water and steam) at the wellhead. The analysis presented here is based on fundamental thermodynamic principles, namely the principle of energy conservation (i.e. First Law of thermodynamics) and the principle of mass conservation. Figure 3 shows the basic operating principles of the single flash process.

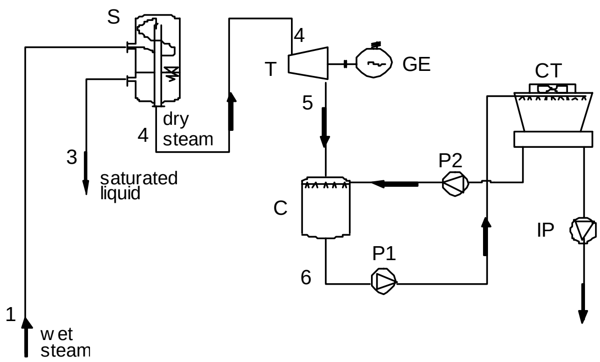

Figure 3: Single flash process schematics

The well (1) is producing wet steam which is separated via a separator (S). The saturated liquid phase is reinjected (waste heat disposal) and the dry steam flows directly to the turbine. After expansion in the turbine (T), the steam is condensed in the condenser (C) and reinjected together with the saturated liquid collected at the separator outlet.

The processes undergone by the geothermal fluid are best viewed in a thermodynamic state diagram in which the fluid temperature is plotted on the ordinate and the fluid specific entropy is plotted on the abscissa. A temperature-entropy diagram is presented in fig. 4.

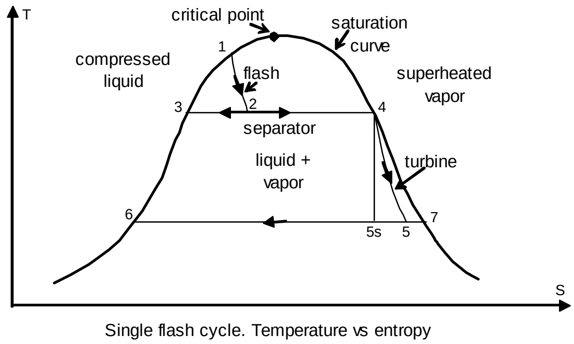

Figure 4: Temperature vs. entropy diagram of the single flash cycle (DiPippo, 2008).

The main processes undergone by the geothermal fluid are: flashing (1-2), separation (2-3 liquid; 2-4 steam), expansion in the turbine (4-5) and, condensing (5-6).

Flashing

The cycle of thermodynamic processes (DiPippo, 2008) begins with the geothermal fluid under pressure at state 1, close to the saturation curve. The flashing process is modelled as one at constant enthalpy, i.e. isenthalpic process, because it occurs steadily, spontaneously, essentially adiabatically, and with no work involvement. We also neglect any change in the kinetic or potential energy of the fluid that undergoes flash. Thus we may write:

$$h_1 = h_2$$

Separation

The separation process is modelled as one at constant pressure, i.e. isobaric process, once the flash has taken place. The quality or dryness fraction, *x*, of the mixture hat forms after the flash, state 2, can be found from:

$$x_2 = \frac{h_2 - h_3}{h_4 - h_3} \tag{6}$$

by using the so-called lever rule from thermodynamics. This gives the steam mass fraction of the mixture and is the amount of steam that goes to the turbine per unit total mass flow into the separator.

Turbine expansion

The work produced by the turbine per unit mass of steam flowing through it is given by:

$$w_t = h_4 - h_5 \tag{7}$$

assuming no heat loss from the turbine and neglecting the changes in kinetic and potential energy of the fluid entering and leaving the turbine. The maximum possible would be generated if the turbine operated adiabatically and reversibly, i.e. constant entropy or isentropically. The process shown in fig. 4 from 4-5s is the ideal process. The isentropic turbine efficiency, η_t, is defined as the ratio of the actual work and the isentropic work, namely:

$$\eta_t = \frac{h_4 - h_5}{h_4 - h_{5s}} \tag{8}$$

The power developed by the turbine is given by:

$$\dot{W}_t = \dot{m}_s\, w_t = x_2\, \dot{m}_{total}\, w_t \tag{9}$$

This represents the gross mechanical power developed by the turbine. The gross electrical power will be equal to the turbine power times the generator efficiency:

$$\dot{W}_e = n_g \dot{W}_t \tag{10}$$

All auxiliary power requirements for the plant must be subtracted from this to obtain the net, saleable power. These so-called parasitic loads include all pumping power, cooling tower fan power, and station lighting.

Before eq. 8 can be used computationally, it must be recognised that the isentropic efficiency of a turbine is affected by the amount of moisture that is present during the expansion process; the higher the moisture, the lower the efficiency. This effect can be quantified by using the so-called Baumann rule which says that a 1% average moisture causes a 1% drop in turbine efficiency. Since geothermal turbines generally operate in the wet region, we must account for the degradation in performance. Adopting the Baumann rule, the isentropic efficiency for a turbine operating with wet steam will be given by:

$$\eta_{tw} = \eta_{td} \times \left[\frac{x_4 + x_5}{2}\right] \tag{11}$$

Where the dry turbine efficiency, η_{td}, may be assumed constant, (85%):

$$\eta_{td}=0.850 \tag{12}$$

From fig. 4, it is clear that the quality at the turbine outlet, state 5, depends on turbine efficiency. State 5 is determined by solving eq. 8 using the turbine efficiency and the fluid properties at state 5s, the ideal turbine outlet state, which are easily calculated from the known pressure and entropy values at state 5s. The ideal outlet enthalpy is found from:

$$h_{5s} = h_6 + [h_7 - h_6] \times \left[\frac{s_4 - s_6}{s_7 - s_6}\right] \tag{13}$$

where the entropy term, by itself, gives the fluid outlet dryness fraction for an ideal turbine. When the Baumann rule is incorporated into the calculation, the following working equation emerges for the enthalpy at the actual turbine outlet state:

$$h_5 = \frac{h_4 - A\left[1 - \frac{h_6}{h_7 - h_6}\right]}{1 + \frac{A}{h_7 - h_6}} \tag{14}$$

where the factor *A* is given by:

$$A \equiv 0.425(h_4 - h_5) \tag{15}$$

The above equations are valid if it is assumed that the quality at the turbine inlet, x_4=1, i.e. the steam at the turbine inlet is saturated steam. If x_4<1 eq. 9 becomes:

$$h_5 = \frac{h_4 - A\left[x_4 - \frac{h_6}{h_7 - h_6}\right]}{1 + \frac{A}{h_7 - h_6}} \tag{16}$$

Based on the methodology described above, a spreadsheet was developed. In order to calculate enthalpies and entropies for the thermodynamic cycle, steam tables were implemented based on the IAPWS-IF97 (http://www.cheresources.com/iapwsif97.shtml).

After completion of the well drilling, at least three months must pass before necessary measurements can be carried out to deem if a well meets the predefined success criteria. Of these three months, one is reserved for thermal recovery of the well and for setting up wellhead and flow-test equipment. As soon as the well has heated up and the wellhead equipment is in place, discharge will be started to last for the remaining two months.

Chemical monitoring of geothermal wells is a standard practice. It is intended to operate a well at as low wellhead pressure as possible - for maximizing the output. A controlling factor for deciding on such a minimum "safe" wellhead pressure is the downhole scaling potential of the geothermal fluid. Low operating pressure may lead to precipitation and scaling in the borehole and surface pipelines. In slightly mineralized geothermal systems the precipitation of silica is the controlling factor. In this case the wells can be operated safely at wellhead pressures as low as 5 bars-a. In the case of highly saline geothermal fluid, operating well head pressure lower than 20 bars-a will lead to a rapid downhole scaling in the form of metal sulfide minerals and amorphous metal silica deposits. This will drastically reduce the well output. Scaling in the borehole can cause the reduction of total flow.

The predefined success criteria will be the minimum power potential of the well for which the project will be economic.

3. THE LOW ENTHALPY CASE

The Paris Basin geothermal district heating projects and accomplishments faced five levels of risks, exploration (mining, geological), exploitation (technical, managerial), economic/financial (market, institutional, managerial), environmental (regulatory, institutional) and social acceptance (image) respectively.

3.1 Exploration risk

The mining/geological risk could be minimized thanks to two favourable factors and incentives. First, the existence of a dependable hot water aquifer (Dogger limestones) of regional extent evidenced thanks to previous hydrocarbon exploration/step out/development drilling, which enabled to reliably assess the geothermal source reservoir prior to development. This resulted later in a 95 % geothermal drilling success ratio according to the success/failure criteria set forth by the ad-hoc geothermal steering committee. Second, the coverage by the State of the geological risk amounting to 80 % of the costs incurred by the first, assumed exploratory, drilling.

As a result of the high drilling success ratio, the so-called short-term provisional fund could be allocated, at a later stage, to the so-called long-term exploitation mutual insurance budget line.

3.2. Exploitation risks

Those could not be estimated from scratch. A (long-term) fund initially financed by the State was created in the 1980s to cope with the hazards induced by the exploitation of the geothermal fluid. Later this could be supplied by operators' subscriptions.

It soon became obvious that the, initially overlooked, hostile thermochemistry of the geothermal fluid provoked severe corrosion and scaling damage to casing and equipment integrities resulting in significant production losses. A prospective survey commissioned in 1995 aimed at assessing the exploitation risks and related restoration costs projected over a 15 year well life. This exercise was applied to thirty three doublets. The governing rationale, developed by Ungemach (2002), consisted of (i) listing potential and actual, technical and nontechnical, risks ranked and weighted as shown in table 4, and (ii) classifying risks according to three levels (1 : low, 2 : medium, 3 : high), each subdivided in three scenario colourings (A : pink, B : grey, C : dark) regarding projected workovers deadlines and expenditure. This analysis led to a symmetric distribution, i.e. eleven sampled sites per risk level, each split into three (A), five (B) and three (C) scenario colourings.

Table 1: Summary of risk factors

Risk description	***Nature weight***	***Ranking***	***Status***	***Remarks***
Last known casing status	Technical 1	1	Fine	Residual steel thickness >75% nominal WT before treatment
		2	Fair	Residual steel thickness >50% nominal WT before treatment
		3	Bad	Residual steel thickness <50% nominal WT before treatment
Damaging kinetics	Technical 1	1	Low	Corrosion rate <150µm/an before treatment
		2	Medium	Corrosion rate >150µm/an before treatment
		3	High	Corrosion rate >300µm/an before treatment
Chemical inhibition efficiency	Technical 1	1	High	Provisional statement
		2	Low	Provisional statement
Casing lining opportunities	Technical 1	1	Full	No diameter restrictions
		2	Partial	Some diameter restrictions
		3	None	Total diameter restrictions
New well drilling expectation	Technical 1	1	Long term	> 20 yrs
		2	Medium term	> 10 yrs
		3	Short term	< 10 yrs
Other	Non technical 3	1	favorable	
		2	hostile	

The next step applied the workover/repair unit costs to the concerned wells, required to forecast the workover types and relevant schedules, thus leading to the synthetic expenditure breakdown summarized in table 5. This evaluation illustrates the paradox between competing (if not conflicting) well heavy duty maintenance strategies, i.e. repeated repair of damaged infrastructures vs. re-drilling/re-completion of new wells reflected by scenarios 2 (A, B, C) and 3 (A, B, C). Here, the optimum, in terms of investments but not necessarily cash flows, is represented by scenarios 2B and 3B, case 2C displaying definitely the worst profile.

Table 2: Recapitulation of provisions (sinking funds) required by heavy-duty well workover/repair/redrilling over 15 years (cost per well/year, 10^3 EUR)

SCENARIO	A	B	C
Risk level		1	
Yearly provision	74	99	125
Risk level		2	
Yearly provision	203 (229)	193 (221)	255 (277)
Risk level		3	
Yearly provision	222 (241)	201 (213)	206 (277)
TOTAL (Weighted average)		173 (186)	

In conclusion, an average provision (fiscally deductible) of 0.19 million euros (around 186,000 €/yr) has been recommended to cope with future exploitation hazards resulting in a 12 % increase of initially anticipated OM costs. Loose management remaining the exception, managerial risks could be reliably regarded as minimized in year 2000. Surprisingly, the risk model matched expectations as of late 2002.

3.3. Economic/financial risks

They represent a major uncertainty owing to a somewhat unpredictable, if not chaotic, energy market and pricing context in which geothermal heat must prove competitive. This is indeed a difficult challenge bearing in mind that geothermal district heating grids are structurally, especially under Paris Basin conditions, strongly capital intensive and financially exposed, in case of low equity/high debt ratios, a distinctive attribute of Paris Basin loan policies.

At the time, in the wake of the second oil shock, most geothermal district heating doublets were commissioned, oil prices, dollar exchange and inflation rates stood high and accordingly feasibility projections shaped very optimistic, in spite of their fragile financial planning. A few years later, these trends were totally reversed. This, added to the dramatic technical, financial and managerial problems undergone by most geothermal doublets, endangered grid operation to a stage the abandonment of the geothermal district heating route was envisaged. These difficulties could be overcome at the expense of the shut in of technically irreparable/economically infeasible doublets and rationalizing exploitation technologies and management of the remaining 34 doublets operated to date.

The economic/financial risks were controlled thanks to debt renegotiation, technological/managerial improvements and stable heat selling prices agreed in long term and users subscription contracts. These contracts, passed in the mid 1980s, expired in the late 1990s/early 2000s. Negotiation of these contracts was clouded by depleted, downward trending, deregulated energy prices prevailing in years 1998 and 1999. This situation incited several operators to pass cogeneration contracts and public and private JV, a compromise deemed satisfactory to remain competitive and secure the survival of the geothermal heating grid regardless from any environmental considerations whatsoever.

In 2008, both a sharp increase of oil prices and natural gas tariffs and growing environmental concerns (global warming and related climatic disasters) modify again the energy panorama. Taxation of greenhouse gases becomes a realistic working hypothesis for the future, limiting the uncertainty margin of geothermal heating prices. In this perspective a 45 €/MWht selling price appears a reasonable threshold safeguarding the economic feasibility of most operating grids.

3.4. Environmental risks

Damages caused to the environment by casing leaks, uncontrolled well head blowouts and workover operations have been minimized. Limitation of the environmental risks is to be credited to the periodical (quarterly) doublet monitoring and casing inspection logging imposed by the competent mining/environmental authority (DRIRE) and blowout control/waste processing equipments currently operated by the industry.

3.5. Social acceptance

Geothermal energy, particularly direct uses of low-grade heat, has a structural image problem. The product and the recovery (heat exchange) process remain somewhat mysterious or esoteric to the public as opposed to obvious, visible, competing solar, wind and fuel sources. For many years indifference, at the best, was the prevailing attitude. In the early days of geothermal development (the infancy stage), it was regarded as a poorly reliable and costly, occasionally, environmentally hazardous technology. Nowadays mature engineering and management and growing environmental (clean air) concerns have gained wider acceptance by the public of the geothermal district heating alternative. Still, image building efforts need to be persued to popularize the technology.

3.6. Success/failure criteria of the SAF short term guarantee

An example of quantified risk occurrence and coverage criteria for a GDH deep drilling application, is illustrated in fig. 5. Here, the success/failure zones are delineated by two hyperbola Q(To-Ti)=C, with Q well discharge, To and Ti well head formation and grid rejection temperatures and C a constant defined by a given internal rate of return (success criteria) and zero net present value (failure threshold). The algorithm used to calculate are presented in eq. The points characteristic to the full success curve are described in eq. 17. Similarly those characterising failure are described by eq. 18.

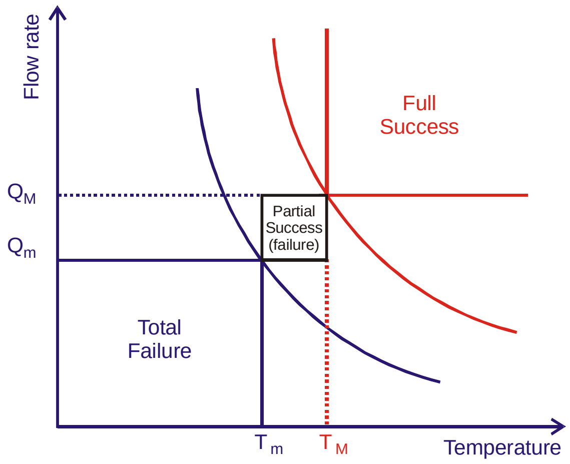

Figure 5. Success/failure curves

Full success:

$$Q\left(T_{wh} - T_i\right) = \frac{1}{1.161 \cdot nh \cdot c}\left[A \cdot INV + OMC + \frac{INV}{n}\right] \quad 17$$

Total failure:

$$Q'\left(T_{wh} - T_i\right) = \frac{1}{1.161 \cdot nh \cdot c}\left[A' \cdot INV + OMC + \frac{INV}{n}\right] \quad 18$$

Where:
Q, Q' = flowrate (yearly average) (m^3/h)
T_{wh} = production wellhead temperature (°C)
T_i = injection temperature (yearly average) (°C)

$$A = \frac{r(1+r)^n}{(1+r)^n - 1} \quad 19$$

$$A' = \frac{r'(1+r')^n}{(1+r')^n - 1} \quad 20$$

INV = capital investment (€)
OMC = operation and maintenance costs (€/yr)
c=heat selling price (€/MWh_t)
n = project lifetime (years)
nh = number of operating hours per year
r, r' = discount rates

Numerical application:

INV=12 10^6 €
OMC= 5 10^5 €
n=20 years
nh=8256 hr/yr
r=5% (total failure)
r=10% (total success)
Full equity (zero debt)
Subsidies=25% INV
c=35.45/MWt
T_i=45.4°C

Full success
Q=299 m3/h ; no subsidy, c=35 €/MWh_t
T_{wh}=70°C T_i=45°C
T_{wh}=65°C T_i=40°C
Q=200 m^3/h ; 25% subsidy, c=45 €/MWh_t
T_{wh} unchanged

Total failure
Q=246 m^3/h ; no subsidy, c=35 €/MWh_t
T_{wh}=70°C T_i=45°C
T_{wh}=65°C T_i=40°C
Q=155 m^3/h ; 25% subsidy, c=45 €/MWh_t
T_{wh} unchanged

CONCLUSIONS

Geothermal energy shares both exploration and exploitation risks.

Two case studies were presented. The first addresses the high enthalpy, power generation case, in the exploration phase where a numerical criterion to assess the well output from well testing figures was proposed. The second study dealt with a large geothermal district heating (GDH) scheme, where the drilling success ratio approached 100%. The success/failure curves and numerical criteria set out by SAF were presented. Exploitation of the low temperature deposits showed, in the early stages, severe technical and non technical shortcomings. A quantified risk prognosis was at a stage projected 15 years ahead which later proved relevant.

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