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CHARACTERISATION OF AQUIFERS FOR THE UTILISATION OF LOW-ENTHALPY GEOTHERMAL ENERGY DURING THE INDIVIDUAL STAGES OF SITE PLANNING AND OPERATION

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ABSTRACT

The understanding of the properties and behaviour of geothermal reservoirs is the essential condition for the dimensioning of subsurface installations on a geothermal site. In the course of the individual stages of site planning, any prognosis is based on geological models and mathematical-physical simulations. With the knowledge of the geological conditions increasing in the process of reservoir exploration, geological models and simulations will more and more reflect reality.
This paper describes the quantification of the main geological parameters, their sensitivity and effects on the simulation results for a Mesozoic sandstone aquifer which is used for geothermal energy exploitation on a site in Northern Germany. There are considered all stages ranging from initial planning to plant operation.

During operation, the injection of cooled thermal water has an effect on the temporal and spatial distribution of the hydraulic conductivity of the thermally influenced reservoir. The permanent recording of the pressure at the injection well head – which is the total of the pressure response of the aquifer, the loss due to tube friction and replenishment of the water column in the well – is to reflect this effect.

Although the paper deals with a specific reservoir in the North German Basin, conclusions with regard to the reliability of parameters, the interpretation of the operational data and the applied methodology may well be generalised.

1. INTRODUCTION

The prognoses of reservoir behaviour prove essential conditions for the assessment of technical feasibility and economic efficiency. These are based on geological parameters and conditions (such as rock and fluid parameters, depth, temperature, feasible flowrate, reservoir boundaries). The model quality is influenced by the increasing knowledge and reliability of the parameters concerned. Due to the lack of site specific data during the initial planning process, seismic reflection data and interpretations of deep drillings from the ± surrounding region have to be relied upon. Thus, finally having installed the necessary doublet, reliable knowledge on the site specific parameters will be obtained.
However, these can be understood only as representing coincidental results within a varying basic multitude, based on the common understanding, that young Mesozoic sandstones in the North German Basin (*Keuper – Lower Cretaceous*) were subjected to processes of facial differentiation in their genesis.

Most important prognostic assumptions for the dimensioning of a doublet are:

- Expected maximum head or pressure changes (aiming at the proof of the technical feasibility of the required production and injection flowrates)
- Moment of the beginning of temperature decline and its further behaviour in the production well to get certainty regarding its lifetime.

The depth of model-reality comparison assumed to be necessary does not depend only on the special task, but essentially on the knowledge concerning the reservoir. As regards the applied model, the (in reality most probable) heterogeneity of parameters is described by lumped parameters. The influence of averaging is investigated by variation of parameters within the range of uncertainties, respectively. From the relation of the relevant reservoir parameters in an uncertainty-impact diagram, conclusions can be drawn regarding the sensitivity of the parameters and the extent of parameter identification required for qualified prognoses.

The results as presented below were obtained in the course of the investigations carried out exemplarily for the Neustadt-Glewe Geothermal Plant which is situated in the North German Basin.
The main stages were

- Prognosis (primarily before drilling)
- Drilling, installation and investigation of the first well
- Completion of the doublet and final investigation.

The results of real operation will be discussed in Chapter 4.

2. BASIC GEOLOGICAL PARAMETERS

All parameters given (with the exception of depth) in Table 1 are essential for geohydraulic and thermodynamic simulations. The depth, however, controls both temperature and mineralization of the thermal water in this part of the North German Basin.

PARAME-TER	**DIMENSION**	**PROGNOSIS**	**1ST WELL**	**2ND WELL**	**RESERVOIR**
depth	m bg	2,300	2,245	2,284	2,250
effective thickness	m	30	52.5	46.5	52
Net porosity	%	25	21.6	20.7	21.5
average permeability	10^{-12} m²	0.9	0.64	0.3	0.5
k · H-product	10^{-12} m² · m	(27)	75	35	58
rock density (horizon)	kg/m³	not known	2,073	2,054	2,065
thermal conductivity (cap rocks)	W / m K	not known	not known	2.7	2.7
total minerali-zation	g/l	240	218.8	223.3	221.5
static hydraulic head	m bg	120	125	130	127.5
temperature of thermal water	°C	85	100	99.6	100

Table 1: Basic geological parameters for geothermal reservoir modelling in the individual stages of site evaluation referring to the example of Neustadt-Glewe (mean values for Contorta sandstone / Upper Rhaetian-Karnian)

Obviously, the prognosticated data are based on conservative estimates. Despite the good agreement of depth, head level and mineralization, effective thickness, kH-product and temperature of the thermal water were estimated seemingly rather carefully. However, the initially estimated permeability appears far too high. The calculated kH-product (based on the effective thickness and permeability parameters of the rocks) was too small and obviously not to be compared with the test results which were obtained later.

All parameters - except permeability and static water level - were definitely determined by well logging and core sampling. With regard to the kH-product, deviating results were obtained from different tests. The parameters given are mean values merely, without any statistic evidence.

The main differences between the two wells refer mainly to permeability and kH-product (Table 1). The less satisfying dynamic mineral conditions of the second well are due to the considerably more differentiated lithologic profile (despite similar mean pore radii).

CHARACTERISTICS	**1ST WELL**	**2ND WELL**
Profile	unstructured sandstone profile	sandstone interstratified by silt and clay and with internal fine structure
Lithology	fine sandy medium grained sandstone	silty fine to medium grained sandstone
Stratification	massive, unstratified	predominantly medium dimensional cross-bedding
percentage of grain size > 0.2 mm	76.4 %	54.6 %
percentage of grain size < 0.06 mm	6.6 %	9.2 %
Medium grain diameter	0.312 mm	0.224 mm
grain classification according to TRASK	good to medium	medium
percentage of large pores (> 5 000 nm)	68 %	65 %
mean pore radius	12,200 nm	12,615 nm

Table 2: Lithologic characterisation of Contorta sandstone on the Neustadt- Glewe site

Real *reservoir parameters* can be found by means of interference testing only. But, on the other hand, the two different profiles reflect the lithological differentiation of the reservoir already. It was assumed that both profiles - with due consideration of their specific uncertainties - cover the whole range of the relevant reservoir parameters, although being aware of the fact that it is not known to which extent they represent the reservoir actually. The deviations of the mean values according to Table 1 are given in Figure 1 for different stages. The considerable uncertainty of the prognosis will be reduced by the drilling results, particularly for the effective thickness and the kH-product.

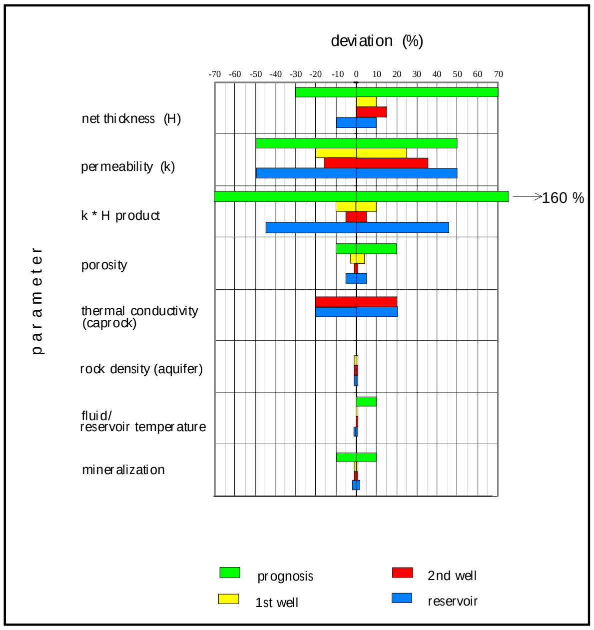

Figure 1: Deviations of basic geological parameters during the different stages

Especially, the determination of porosities, reservoir or fluid temperatures and mineralization seems to be rather easy, and the parameters apparently deviate little only. Rock density and thermal conductivity can be estimated based on the relevant technical literature.

Partly, the deviations are in the positive range, which seems to be indicated by the effective thickness. This is considered reasonable when limiting to "pure" sandstone layers. If the surrounding rocks, intermediate and mixed layers would be included, then the estimated thickness might increase only.

Upon completion of drilling, only deviations of the permeability from the mean value continue to be rather impressive. Apparently, the results are to be understood under the aspect of core losses (interpreted as layers of least cementation and highest permeability) or, possibly, of considerably higher standard deviations of the mean values when comparing them with porosities.

Therefore, the dynamic reservoir conditions (permeability, kH-product) are still very uncertain even after drilling and investigation of the reservoir. Here, necessity and significance of interference tests become obvious.

3. UNCERTAINTY AND IMPACT

With the help of analytic and semianalytic solutions and based on the range of the expected geological parameters, two characteristic values had to be calculated:

- the proper internal distance between production and injection well (preventing a significant breakthrough in the course of the expected lifetime of the doublet);
- the water drawdown in the production well (ensuring a sufficiently high water column above the submersible pump).

These two dimensioning values should be minimised for economic reasons, but must guarantee compliance with the safety criteria (no thermal breakthrough, no dry-running of the submersible pump).

The model assumptions are based on lumped parameters for the application of analytic solutions (assumed homogeneous distribution of parameters in the reservoir). In fact, a heterogeneous distribution of parameters can be modelled numerically, but the model lacks sufficient reservoir information, with the exception of the two single wells.

Therefore, the real heterogeneous distribution is considered by simulating geologically and, partly, statistically founded ranges of values to be expected.

In addition to the geological parameters, engineering and operating conditions (e.g., flowrate, injection temperature, annual load and expected lifetime) do affect the calculations. However, these will not be considered here and are assumed to be equal in any further calculation.

For evaluation of the sensitivity of the primary parameters with regard to the dimensioning of the well spacing, the impact of each parameter on the prognosis is related to its uncertainty within a range from 0 to 1 in a diagram (Fig. 2). It is clearly indicated, that the effective thickness has a major influence on the well spacing at this stage.

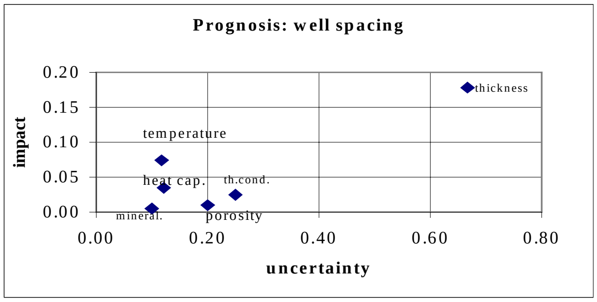

Figure 2: Uncertainty-impact diagram of well spacing calculation (prognosis) (heat cap.=heat capacity; th.cond.=thermal conductivity)

Analogously, the drawdown in the production well is calculated, being an important criterion for the dimensioning of the submersible pump, since it essentially influences the expenditures required on pumping. Accordingly, the distance between the two wells affects the steady-state head (or pressure) decline in the production well due to the dependency of well spacing on thermophysical properties, since the latter ones have an indirect impact on the calculated drawdowns, too. But, simulations for the above example showed clearly that this effect is neglectable.

The drawdown in the production well is influenced decisively by reservoir thickness and permeability. This effect is shown very clearly in the uncertainty-impact diagram (Fig. 3).

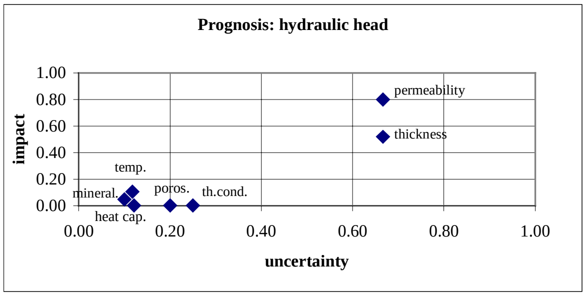

Figure 3: Uncertainty-impact diagram of drawdown calculation (prognosis)

In a similar way, the increased knowledge will be considered after drilling and investigation of the first well. Based both on mean and extreme values of the more precise geological parameters, new values for spacing and pressure (or head) drawdown have been calculated with the result that uncertainty as well as impact of parameters are clearly reduced in comparison with the prognosis (Fig. 4 and 5).

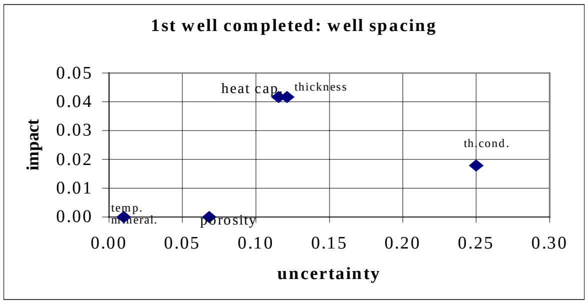

Figure 4: Uncertainty-impact diagram of well spacing calculations (upon drilling of 1^{st} well) (heat cap.=heat capacity; th.cond.=thermal conductivity)

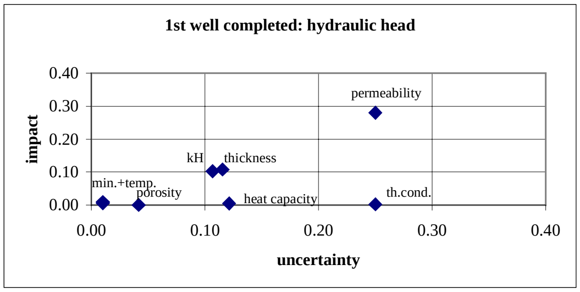

Figure 5: Uncertainty-impact diagram of drawdown calculation (upon drilling of 1^{st} well)

The thermophysical parameters (thermal conductivity and heat capacity) and the porosity were found to have a neglectable influence on the dimensioning.

The drawdown calculations are based on the effective thickness and permeability representing individual values obtained from well logging and core sampling as well as their kH product according to test results. This product, which was found to be determined by production or injection test results, characterises the reservoir and proves to be the essential basis for the calculation of head or pressure changes. However, for the thermodynamic calculations (well spacing) the effective thickness proves to be the dominating input, which cannot be measured directly by hydrodynamic testing. Therefore, the effective thickness, directly determined from well logging results or indirectly from the kH-product with local permeability, characterises the local well conditions only.

From the above calculated results, conclusions could be drawn for dimensioning. Having drilled the first well and investigated the reservoir, the proper distance of the second well is to be assessed. Furthermore, as part of the planning of the equipment the installation depth of the submersible pump is to be fixed.

For this specific example and based on conservative assumptions of all parameters, an internal distance of 900 m between the production and injection well would be found to be sufficient for a temperature decline in the production well of less than 3 % during the expected lifetime of the whole installation.

Considering this distance and based again on conservative assumptions, the drawdown in the well is expected to settle in a depth of 50 m below ground at a flowrate of 100 m^3/h.

But, having drilled the second well and completed the investigations, the geological conditions proved to differ much more than assumed originally.

Now, the distance of the second well cannot be changed anymore. However, the conclusions drawn are based on the prognosis and can be verified according to the enhanced knowledge and improved models upon drilling of the first well. The only parameter which is still characterised by a certain uncertainty and sensitivity is the effective thickness of the reservoir, ranging from 46 ... 58 m. According to the results obtained from the first well, an internal distance of 900 m between production and injection well is assumed to be sufficient.

With the upper limit of 58 m, no thermal breakthrough will occur within the lifetime of 30 years (the injected water would reach the production well on the direct streamline after 34 years at the earliest). Assuming the lower limit (46 m), the temperature decline in the production well would be about 1 K (1.4% decline with reference to the reservoir and injection temperature), after 30 years (Fig. 6). The distance chosen upon drilling of the first well proved to be completely sufficient.

Figure 6: Temperature decline in the production well (900 m spacing, conservative assumption: 46 m effective thickness)

For the installation depth of the submersible pump, a 50 m drawdown at a flowrate of 100 m³/h was calculated. Upon drilling of the second well and interpretation of the hydrodynamic tests, the kH-product of the reservoir was found to be within the range from 33 to 83 10^{-12} m²m. According to these values, the drawdown in the production well (at flowrates of 100 m³/h) is expected to vary between 21 ... 52 m. Only under most disadvantageous conditions, the prognosis would fail insignificantly. Any other parameters did not prove to be sensitive anymore.

Conclusively, these results confirm the methodology (describing the geological model by ranges of uncertainties, simulation with lumped parameters, evaluation of uncertainties and impacts on dimensioning) as well as the correctness of the decisions based hereon.

4. INTERPRETATION OF OPERATIONAL DATA

4.1 Theoretical background

Generally, only reservoir responses can be measured at the production and injection well heads.

The injection of cooled thermal water affects the temporal and spatial distribution of the hydraulic conductivity of the thermally influenced reservoir, due to the temperature dependency of fluid parameters. Therefore, cooled water injection has an immediate influence on the pressure response of the reservoir.

During the operation of a geothermal site, the well head pressure is permanently recorded, which is the total of the pressure response of the aquifer, the losses due to tube friction and the replenishment of the water column in the well. Thus, the well head pressure is related to the reservoir, borehole and operational parameters in a complex physical manner.

Following Benson et al. (1987), the pressure at $r=r_w$ (radius of the injection well) can be approximated under certain conditions by two terms:

$$\Delta p(r_w, t) = \Delta p_{ss}(r_w, t) + \Delta p_t(r_f, t) \qquad (1)$$

where Δp_{ss} is the steady-state pressure response of the thermally influenced region and Δp_t the transient pressure response of the thermally uninvaded region. The radial distance to the thermal front r_f can be calculated for a radial distribution according to (2) by

$$r_f = \sqrt{\frac{\rho c_i}{\rho c_a} \frac{\dot{V}t}{\pi H} + r_w^2} \qquad (2)$$

where there are

$(\rho c)_i$ heat capacity of the injected fluid

$$(\rho c)_a = (1 - \Phi) \cdot (\rho c_{a_m}) + \Phi \cdot (\rho c_{a_f}) \qquad (3)$$

heat capacity of the thermally unaffected aquifer

(ρc_{a_m}) heat capacity of the thermally unaffected rock matrix

(ρc_{a_f}) heat capacity of the thermally unaffected reservoir fluid

H effective thickness

$V \cdot t$ injected volume (flowrate * time).

The heat transfer from the cap rocks is not considered. It is assumed, that a sharp cold water front is radially distributed around the injection well affected only by the heat transfer within the horizon.

Considering the injection fluid parameters density ρ_i and viscosity η_i within the thermal front, Δp_{ss} is calculated by integration from r_w to r_f :

$$\Delta p_{ss}(r_w,t) = \frac{q\eta_i}{2\pi\rho_i \cdot kH} \ln\left(\frac{r_f}{r_w}\right) \tag{4}$$

q being the mass flowrate.

The transient term (1) of the thermally unaffected region including fluid density ρ_r and viscosity η_r can be calculated :

$$\Delta p_t(r_f,t) = \frac{q\eta_r}{4\pi\rho_r \cdot kH} \cdot Ei\left(\frac{r_f^{\,2}}{4at}\right) \tag{5}$$

with a representing diffusivity.

This solution of Benson et al. was extended to the doublet. In this case, production at a distance D results in an additional pressure decrease, so the total relation at the location of the injection well r_w is given by:

$$\Delta p(r_w,t) = \frac{q\eta_i}{2\pi\rho_i \cdot kH} \ln\left(\frac{r_f}{r_w}\right) + \frac{q\eta_r}{4\pi\rho_r \cdot kH} \cdot Ei\left(\frac{r_f^{\,2}}{4at}\right) - \frac{q\eta_r}{4\pi\rho_r \cdot kH} \cdot Ei\left(\frac{(D-r_w)^2}{4at}\right) \tag{6}$$

(This superposition is not totally exact. The non-radial distribution of the cold water front caused by the production well is neglected here. Also, the effect of the locally decreasing mobility on the production well pressure response [term 3 in equation (6)] is neglected. But these two neglections may be assumed to be correct for the first years of operation.)

Neglecting the compressibility and re-arranging equation (6), the pseudo steady-state pressure response depending on mass flowrate, temperature and rate of cooling (radius of the cold water front) is given by:

$$\Delta p(r_w,t) = \frac{q\eta_r}{2\pi\rho_r \cdot kH}\left[\ln\left(\frac{D-r_w}{r_w}\right) + \left(\frac{\eta_i\rho_r}{\eta_r\rho_i} - 1\right)\ln\left(\frac{r_f}{r_w}\right)\right], \tag{7}$$

with the first term being identical with the (isothermal) pressure response in the production well.

Due to technical reasons, the pressure response is measured at the well head only. Therefore, pressure reactions within the well have to be considered as well.

The well head pressure is the total of

$$\Delta p_{wellhead}(V,T,t) = \Delta p_{hor}(V,T,t) + \Delta p_{tf}(V,T) - \Delta p_{rep}(T)\,. \tag{8}$$

where Δp_{hor} is the pressure response at the sandface according to (7), Δp_{tf} the pressure loss due to tube friction within the well, and Δp_{rep} is equivalent with the missing water column in the well.

Losses due to tube friction depend on the installation, flowrate and, to a lesser extent, on the temperature. They can be calculated for sections of equal diameters by

$$\Delta p_{tf} = \lambda \cdot L \cdot w^2 \cdot \frac{\rho}{2d} \tag{9}$$

where there are

Δp_{tf}	tube friction losses
l	length of pipe
w	flow velocity
d	internal diameter of pipe
λ	tube friction coefficient.

The replenishment of the water column depends on the static water level, which settles after sufficient duration (one or several years) of the thermal equilibrium with the surrounding rocks. Generally, such long periods without any technical troubles in the well are rare. But, knowing the dependency of the density on temperature, this level can be calculated at any time using a temperature log.

The pressure which is equivalent with the replenishment of the water column is given by

$$\Delta p_{rep} = \rho(T_i) \cdot g \cdot \left(h - h_0 \frac{\rho(T_0)}{\rho(T_i)}\right) \tag{10}$$

where there are

h	depth of the upper limit of the aquifer
h_0	water column with density $\rho(T_0)$.

The equations given above presume isothermal conditions in the well during injection, i.e., heat transfer to the surrounding rocks is neglected. For the flowrates considered >35 m³/h, these well effects could be neglected, i.e., the temperature at the sandface is equal to the well head temperature.

With the help of equations (8), (7), (9) and (10), we are able to calculate well head pressures at the injection well with due consideration of the dependency on flowrate, injection temperature and rate of aquifer cooling.

4.2 Example

On the Neustadt-Glewe site, the thermally invaded region had a radius of about 117 m at the end of 1997 after the reinjection of 1.35 million m^3 of cooled thermal water in the course of three years. The mean injection temperature was 67°C. Therefore, the injectivities (well head pressure over flowrate) are presented for 60°C and 70°C at different times (Fig. 7).

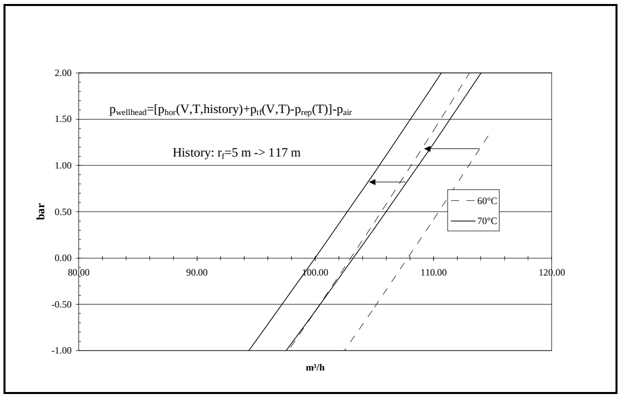

Figure 7: Calculated injectivities (well head pressure over flowrate) at two selected moments

The non-radial cold front effect as well as the heat transfer to cap rocks and its effect on the hydrodynamic diffusivity cannot completely be taken into account by analytic solutions. Furthermore, the solution is not practical considering temporally changing flowrates and injection temperatures. Therefore, a numerical Finite Element model (FEFLOW, Diersch 1991) was used for the interpretation of operational data. The model was calibrated by the analytical solution given above.

For numerical calculations with FEFLOW, the two-dimensional area of 49 km² was discretised into finite elements considering the discretisation in the near well region.

The finite element net implies varying element sizes, with their length differing between 1,300 m in the outer model areas and 0.1 m on the well locations due to the largest pressure gradients, pore flow velocities and temperature contrasts on the latter locations. The total number of finite elements was 15,500. For the task of discretisation, triangular elements were used which are most suitable to fit into the well approximations with ”Finite Element angular tubes”. The FE angular tubes with mean radii of 0.1 m fit well into the real well conditions. The heat transfer to the cap rocks is taken into account by a time depending “Cauchy type” boundary condition (heat transfer function).

Regrettably being limited by small numbers of physically interpretable positive well head pressure data during the operation (with the well head pressure being lower than the air pressure most of the time), only one example is given illustrating the effect of progressive aquifer cooling on the well head pressure response. Fig. 8 compares measured well head pressures with those calculated with due consideration as well as exclusion of any influences of cooling history effects. The effect of the increased pressure response, which characterises the three years period of injection, is clearly indicated.

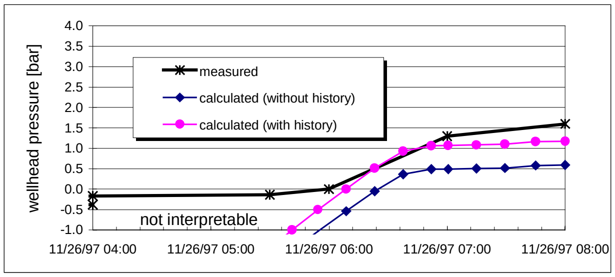

Figure 8: Comparison of measured and calculated well head pressures considering and neglecting the thermal history of the reservoir (11/26/97)

Due to the higher dynamic viscosity of the fluid compared to the uninvaded reservoir, the thermal invasion results in an evident increase of the injection pressure. Therefore, the influence quite suitably to reflects a mining control effect.

Moreover, the kH-product with 36 10^{-12} m²m was confirmed numerically (cf. range of values to be expected for the test results [paragraph 3]: 33...83 10^{-12} m²m).

5. CONCLUSIONS

The increasing accuracy of prognosis based on geological models applied from site planning (geological prognosis) to exploration (results from the first and second well) can be proven.

The expected range of variation can be confirmed by arguments and at least partially by means of statistics. In this way, representation and the range of values to be expected for the reservoir conditions proved to be quantifiable.

Instead of modelling the heterogeneity of the reservoir, models with lumped parameters considering their specific range of values to be expected were used to investigate their sensitivity to prognosis. By relating the impacts to uncertainties of the parameters, conclusions were drawn regarding their sensitivity and the necessity to improve their identification. So, e.g., effective thickness, permeability and, in this context, the kH-product were found to be the most sensitive ones. On the other hand, net porosity and thermophysical properties signalled only small impacts.

During the operation including reinjection of cooled thermal water, the progressive cooling of the reservoir is verified by the well head pressure response to quite a certain extent. This could be a new tool both for mining and operation control. For the latter one it was proven useful to distinguish potential mechanical damages from the thermally induced injectivity decline.

ACKNOWLEDGEMENTS

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