Proceedings 20th NZ Geothermal Workshop 1998

PREDICTION OF THE FUTURE PERFORMANCE OF GEOTHERMAL RESERVOIRS USING THE CONCEPT OF DELIVERABILITY

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SUMMARY: One of the major aims of a geothermal reservoir engineer, or indeed any one with interest in reservoir studies in the geothermal business, is optimization of steam production fiom the geothermal reservoirs. Optimization is an important aspect of the overall development of a geothermal reservoir with maximum heat recovery. The concept of deliverability is one way that **may** be used in optimizing steam production. Deliverability of geothermal reservoirs has three components, namely, wellbore, inflow and reservoir performances. In this paper, we shall learn how each of these performances can be determined and also how prediction **of** the future production rates **of** wells can be calculated.

1. INTRODUCTION

Geothermal reservoir performance based **on** the concept of deliverability entails three aspects viz. wellbore performance, inflow performance and reservoir performance. Wellbore performance is the contribution of both the liner and the casing towards the transportation of fluids from the bottom to the top of the well when there is a pressure drop between the well bottom **and** the wellhead. Inflow performance is a function that describes the ability **of** the geothermal fluid to flow through a feed zone or the well bottom when there is a pressure drop between the reservoir and the feed zone or well bottom. Reservoir performance **on** the other hand is a dynamic variable which shows how the reservoir pressure has been changing with time. In this paper, we shall demonstrate in detail how each one of these performances interact and **how** they affect the production of steam in the overall system. We use data fiom a hypothetical well (from a hypothetical field) we code name HW to show the methodology used in working out these performances and conclusions dram.

2. WELLBORE PERFORMANCE

Wellbore performance describes fluid pressure behaviour in the casing and liner between the bottom or the main feed zone and the wellhead. This behaviour of the fluid depends **on** a number of factors such as fluid temperature, casing diameter, depth of well etc. Wellbore performance can be analyzed by curves relating the pressure and mass flowrate at the main feed zone **or** bottom **of** the well. Well flowing pressures at depth are not easy to measure in geothermal wells due to **high mass** flowrate. **A** single or two-phase wellbore simulator is normally used under these conditions. To illustrate the procedure we use in calculating the performance curves, we refer to our hypothetical well HW. Let HW have a depth **of** 1500m, this is a typical depth of a geothermal well. Wellbore performance curves are calculated for the well at different **mass** flowrates. The wellhead pressure is varied between ***0.5*** and 1.2Mpa. Table 1 shows the bottom hole pressure required to deliver the mass flowrate at a given wellhead pressure.

A graph of the performance curves with the data fiom Table 1 overleaf is as shown in Figure 1. One reason **why** we analyse wellbore performance using curves is that they can be easily combined with inflow performance curves to predict field deliverability.

3. INFLOW PERFORMANCE

Inflow performance is a function that describes the ability of the geotheml fluid to flow **through** a feed zone or well bottom when there is a pressure drop between the reservoir and the feed zone or the **well bottom.** The reservoir pressure provides the driving force to move fluid towards the well. Inflow performance can depend on a number **of** variables such as reservoir pressure, well **bottom** pressure, permeability, formation thickness etc.

Table 1 Results of wellbore simulator for well HW

W/head pre. (MPa)	0.5	0.6	1.0	1.1
M/flowrate (kg/s)	Well flowing bottom pressure (Mpa)			
50.0	1.36	1.50	3.68	8.02
75.0	1.83	2.02	4.28	7.74
100.0	2.41	2.80	5.21	7.92
125.0	2.82	4.27	6.08	8.29

3.1 Laminar and Turbulent flows

If the geothermal flow between the reservoir and the main feed zone or well bottom is laminar, it can be assumed that the inflow into a well is directly proportional to the pressure difference between the reservoir and the wellbore and that production is directly proportional to the drawdown. The constant of proportionality is the productivity index denoted P.I. This concept can be used in calculating output curves for geothermal wells with single-phase feed zones using a wellbore simulator. The equation that defines the productivity index for single-phase laminar flow is

$$P.I. = W/(P_r - P_{wf}) \qquad (1)$$

where w is the mass flowrate, P_r reservoir pressure and P_{wf} the well flowing pressure at the depth of the main feedzone or well bottom. A graph of mass flowrate versus the corresponding flowing pressure results in a straight line and the inverse of its slope gives the productivity index. This straight line is the inflow perfonnance for laminar flow.

To illustrate this phenomenon, values for flowing pressure are plotted against flowrate for well HW in Figure 2. It can be noted from the figure that inflow performance below the saturation pressure does not seem to be linear. Many geothermal wells do not present linear behaviour above the saturation pressure due to turbulent effects. The flow may be turbulent if the rate of flow from the reservoir into the wellbore is high, or the feed zone structure is narrow. Under these circumstances the linear productivity index can not be calculated. One way to describe turbulent effects is to use the two constant equation:

$$P_r - P_{wf} = Aw + Bw^2 \qquad (2)$$

where A is a laminar flow coefficient and B is a turbulent flow coefficient. Dividing through by w yields:

$$(P_r - P_{wf})/w = A + Bw \qquad (3)$$

which is the reciprocal of the productivity index described in Equation (1) above. When this is plotted against production rate w, a straight line results. The slope of this line is a measure of the degree of turbulence.

3.2 Two-phase flow

When a liquid only or a steam water mixture feed zone occurs in a reservoir, this may produce a two-phase geothermal well. When liquid water flows into the casing of a well, the water will remain liquid up the well until reaching a depth where the pressure is the same as the saturation pressure. At this stage, the liquid water starts to flash forming steam. Flashing continues until the mixture reaches the wellhead. A two-phase feed zone can result from the following scenarios. Liquid water could flash as it flows towards the wellbore or it could be that the overall fluid state in the reservoir is two-phase or the well may be having two feed zones, one with liquid water and the other with steam. It can be observed from Figure 2 that at a relatively high flowrate the relationship in the form of Equation (1) is likely to be non-linear. This problem has been investigated by a number of authors. The investigation by Marcou and Gudmundson (1986) is relevant in geothermal studies. They stated a relationship for the inflow performance below the saturation pressure when there are two-phases present and the effects of the turbulent flow as indicated in Equation (4) below.

$$\Delta w/\Delta w_{max} = 1.0 - 0.2P_{wf}/P_{sat} - 0.8(P_{wf}/P_{sat})^2 \qquad (4)$$

where Aw is the incremental mass flowrate achieved by lowering the well flowing pressure below the fluid saturation pressure. Ideally then Δw_{max} would be achieved if the well flowing pressure become negligible. The square term in the relationship takes into account the turbulent losses and other non-linear effects. How then can we evaluate Δw_{max} in Equation(4)? It can be shown through some mathematical presentation that:

$$\Delta w_{max} = -P_{sat}/1.8(1/(dP/dw)) \quad (5)$$

Therefore to determine the theoretical inflow performance for well HW, the productivity index (Equation 1) is used for the linear inflow performance. Below the saturation pressure, Equation *(5)* is used to determine Δw_{max} and Equation **(4)** is used to calculate the profile as shown in Figure 2. In Equation **(4)** dP/dw has to be known before hand. Equation (2) is then used to find:

$$dP/dw = A+2Bw \quad \textbf{(6)}$$

substituting this expression in Equation (6) into Equation *(5)* yields:

$$\Delta w_{max} = -P_{sat}/1.8(A+2B) \quad (7)$$

The w value is considered at the saturation pressure, A and B are constants that can be obtained fiom the best fit equation in the graph of $(P_r - P_{wf})/w$ vs.w

4. RESERVOIR PERFORMANCE

The reservoir performance describes the decrease in reservoir pressure with time as fluid is produced. If some production and pressure history of the field is known, it is possible to use a mathematical model to forecast the reservoir behaviour. The forecast can be connected with the wellbore and reservoir performances to determine field deliverability. As a first approximation, we use a lumped parameter model which is a material balance on a closed reservoir producing an amount of fluid which causes a pressure drop in the reservoir. Since a geothermal field is always connected to a supporting aquifer, an influx term is added to the material balance. When the drawdown history of a geothermal reservoir cannot be explained by simple mass removal, a water influx model is used to account for water influx or recharge into the reservoir. Recharge will maintain the pressure in the reservoir by replacing the produced fluid usually colder fluids. One such model due to Hurst (Drake, 1977) which assumes that the reservoir is radial and the supporting aquifer is also a radially symmetric layer, infinite in extent with the same properties as the reservoir, takes the form:

$$\Delta P = \underline{\mu_a}/2\Pi kh\rho_a \Sigma \Delta w_j[\sigma N(\sigma, t_D) - t_{Dj}] \quad (8)$$

where

$$\sigma = (2C_a\rho_a)/C_r\rho_r$$

and

$$N(\sigma, t_D - t_{Dj}) = L^{-1}\,[k_0(\surd s)/s^{3/2}[\sigma k_1(\surd s) + k_0(\surd s)$$

where $t_D = kt/\psi\mu_a C_a r^2$ for $t = t_n$

4.1 Field data preparation

The kind of data that is prepared from the field involves drawdown and flowrate. Pressure drawdowns at a fixed depth for a number of wells in the field are taken after a fixed or variable period of time e.g for our hypothetical well HW we may have the following:

Table 2. Pressure measures at 800m depth in well HW

Date	Pressure (at say 800m depth)
Year-Month-Day	(Mpa)
1990-11-27	5.17
1992-03-18	4.75
1995-12-11	4.19
1997-04-29	4.08

Initial pressure is chosen from the well that was the first to produce fluid in the field before the reservoir was exploited commercially. The pressure of each well is adjusted to this initial value to obtain drawdown with time. A best fit equation is then obtained connecting pressure and time. Cumulative mass production is olso obtained by considering the total production since exploitation started. The average flowrate for a given period is obtained by dividing the cumulative mass by the time. A FORTRAN 77 code exist from Brock (1986) which can be utilized to solve the equations in the Hurst model. The primary input data for running the program are the drawdown pressure, mass flowrate and time.

4.2 Forecast of the model

Production data for a given period of time can be used. A prediction for a similar period can then be done by the model. This will show either cumulative mass produced versus drawdown with real data and the best fit prediction or drawdown versus time for the real data and the best fit prediction by the model.

5. FIELD DELIVERABILITY

Deliverability is the overall effect of the three performances. When the wellbore performance and the inflow performance curves are plotted together, their intersection determines the production rate of a well. As production continues, the reservoir pressure will decrease. The water influx model i.e the Hurst model provides the new reservoir pressure. At these new conditions the wellbore performance curves look the same. Since the factors affecting wellbore performance remain unchanged. However, the inflow performance curve will change. As before, the inflow performance is constrained to pass through the new reservoir pressure. The productivity index, which is related to the slope of the inflow performance curve, does not depend upon the reservoir pressure. Consequently the inflow performance curve will shift downwards so that it is parallel to the old curve but passes through the new reservoir pressure. To estimate future productivity from a geothermal field using field deliverability consists of the following steps, namely,

(a) take the wellbore performance curve as a constant since the casing of the well does not change with time.

(b) the Hurst model gives the future drawdown. A new reservoir pressure may be obtained with

$$P_{nr} = P_{ir} - \Delta P \qquad (9)$$

where P_{nr} is the new reservoir pressure, P_{ir} is the initial reservoir pressure and ΔP is the drawdown pressure

(c) this new reservoir pressure can be used with linear inflow, turbulent flow or two-phase inflow performance equations to try and obtain the inflow perfonnance curves.

(d) the new curves can be plotted together with the wellbore performance curves and the future deliverability of the field determined. As an example of deliverability calculations, consider well HW. Wellbore performance curves for well HW were chosen (Figure 1). Inflow performance curve (Figure 2) for well HW was chosen. The other inflow performance curves are calculated assuming the same productivity index. This is shown in Figure 3.

The wellbore performance curve at 1.0MPa is taken as the reference. The points at which these curves intersect the inflow performance curve must be considered the future production rate of this well. From this figure, it can be noted that the deliverability of the well decreases with time which indicates that, using the predicted pressure of the reservoir we can calculate future output curves fiom wellhead pressure of each wellbore perfoxmance curve and the flowrate of the well determined.

6. CONCLUSIONS

It is important to have an idea of what changes a reservoir will undergo in the fbture in order to establish an exploration strategy. One method to achieve this is the deliverability concept.

7. REFERENCES

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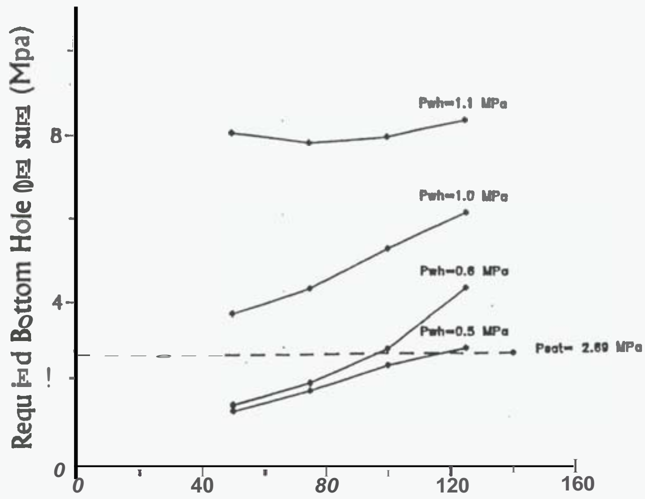

Figure 1. Wellbore performance curves for well HW at different wellhead pressures

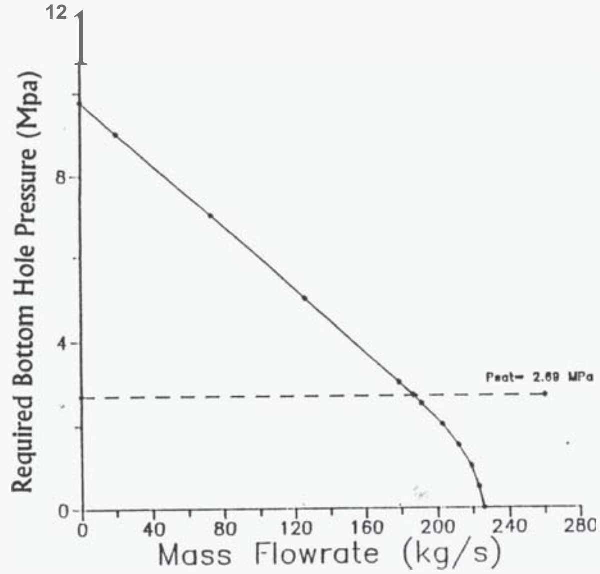

Figure 2. Inflow performance *curve* for well HW

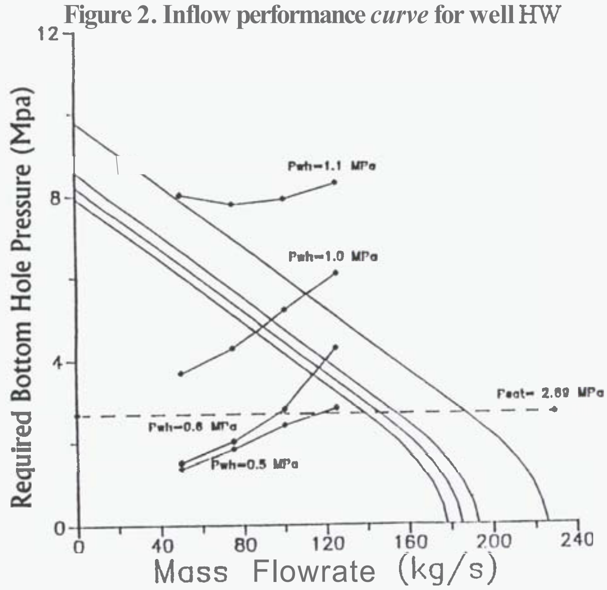

Figure 3 Deliverability of well HW