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A METHOD TO RECOVER USEFUL GEOTHERMAL-RESERVOIR PARAMETERS FROM PRODUCTION CHARACTERISTIC CURVES (1) STEAM RESERVOIRS.

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ABSTRACT

In this paper we develop and demonstrate a method to estimate the reservoir pressure and a productivity index for vertical steam wells, from its production characteristic (also called output) curves. In addition, the method allows to estimate the radius of influence of the well, provided that a value of the reservoir transmisivity is available. The basic structure of the present method is: first, the measured wellhead mass flowrates and pressures are transformed to downhole conditions by means of a numerical simulator; then, the computed downhole variables are fitted to a simple radial model that predicts the sandface flowrate in terms of the flowing pressure. For demonstration, the method was applied to several steam wells from the Los Azufres geothermal field. We found excellent agreement of the model with this ample set of field data. As a bonus, the processed data allowed several inferences about the steam -producing zone of the reservoir: that the wells considered produce from relatively isolated pockets of steam, which are probably fed by nearby inmobile water; and that these feed zones are in poor hydraulic communication with the field surface waters. The main advantages of our method are that it provides a way to retrieve important reservoir information from usually available production characteristic curves, and that the method works from easily and accurately taken wellhead measurements.

INTRODUCTION

Production characteristic curves, also called output curves, are routinely determined for most geothermal wells. These curves relate mass flowrate at the wellhead with the corresponding wellhead pressure. Their normal uses include gathering cualitative information about reservoir properties(e.g. relative values of reservoir pressure, temperature or gas content, reservoir permeability) and about effects of scaling in the wellbore (eg. Grant et. al., 1982); estimating discharge enthalpy from the maximum discharging pressure (James, 1970, 1980 a,b); and, of course, predicting mass flow rates for given wellhead pressures and vice versa.

Output curves contain mixed information about both the reservoir and the intervening wellbore. As pointed out, only qualitative information about the reservoir is ussually recovered from these curves. The sole exception to this, James' maximum discharging pressure method to estimate discharge enthalpy, is based on the fact that at low flowrates resistive wellbore effects are unimportant; that is, in this case the wellbore and reservoir information are already separated.

In this paper we develop and demonstrate, via field examples, a method to recover important cuantitative information about the reservoir from output characteristic curves of steam wells. In a companion paper (Iglesias et. al., these Proceedings), we describe and demonstrate a similar method for water-fed wells. The method is based on unscrambling the wellbore and reservoir contributions to the output curves, by means of a wellbore flow numerical simulator. The reservoir information retrievable with our method can alternatively be obtained from transient pressure tests. These tests are difficult to run in high temperature wells which, more often than not, contain corrosive fluids. Moreover, the method presented in this paper uses as input data characteristic curves that have to be determined, anyway, for other uses. Our method is, therefore, an efficient way for retrieving important reservoir information from usually available wellhead data, without resorting to more difficult bottomhole measurements. No previous similar work is known to the authors.

METHOD

As outlined in the previous section, the first step of the method presented here consists of using a wellbore flow numerical simulator to unscramble the reservoir and the wellbore information contained in the production characteristic curves. This provides the values of the bottomhole variables corresponding to the data points on the wellhead output curves. The second step is to fit the computed bottomhole data to simple models that predict the behavior of the sandface flowrate as a function of the bottomhole flowing pressure. The fit provides estimates of the reservoir pressure p_e, and of a productivity index J' of the well. If estimates of the reservoir transmissivity (kh/μ) are available, the radius of influence of the well can also be estimated.

Production characteristic curves are obtained measuring the stable or quasi-stable steam flowrates and acompanying wellhead pressures corresponding to different degrees of chocking of the well. Usually these measurements cover the range from fully open to nearly the maximum degree of chocking compatible with the existance of flow. The stable or quasi-stable state of the flow is important with regard to the types of wellbore and reservoir models appropriate for the present method.

The wellbore numerical model (WELFLO) used in this work is described by Goyal et. al. (1980) and references therein. WELFLO is a finite difference, one dimenssional, multiphase, steady-state geothermal wellbore flow simulator appropriate for vertical multidiameter wells. It has been extensively validated against field data (Goyal et. al., 1980,1981; Arellano, 1983). Two features of this code make it suitable for the problem at hand. First, the cappability to compute bottomhole conditions from wellhead input variables, as needed. Second, the assumtion of steady-state flow in the wellbore. This is required because, in order to obtain characteristic curves, wells are flown through the same orifice for several days, thus allowing transient wellbore effects to die out. The input variables of WELFLO are the geometry of the well (lengths, diameters, open or ranurated interval), mass flowrate, wellhead pressure, and wellhead flowing enthalpy. Conductive heat losses to the wellbore walls were neglected in our calculations. Our method requires to transform each and every measured data point of the characteristic curve to the corresponding bottomhole conditions. Of the complete set of bottomhole variables computed by means of WELFLO, we require only the flowing pressure and the mass flowrate (which equals the wellhead flowrate, due to the steady state conditions of the flow in the bore).

For the flow in the reservoir we chose a simple model suggested by experience: radial, horizontal, isothermal flow of steam through a porous, homogeneous, confined, cylindrical reservoir of constant thickness. If the outer boundary condition is constant pressure, then steady state can be achieved. In that case the mass flowrate is given by

$$W=\alpha \frac{kh}{\mu} \frac{(p_e^2 - p_{wf}^2)}{zT \ln (r_e/r_w)} , \qquad (1)$$

the well-known expression of Darcy's Law for steam flow in steady-state radial flow. Here α is a constant to accomodate different systems of units (nomenclature at the end of the paper). This steady-state model can approximately describe three situations of interest, with the restrictions commented below. (a) Infinite acting period, i.e. no boundary effects are felt during the time period Δt over which the output production data were collected; in this case Δt must be smaller than the time scale associated with the outward movement of the pressure perturbation in the reservoir, for (1) to be a valid approximation. (b) Constant pressure outer boundary condition, which may arise from the existence of a cylindrical boiling front some distance from the well; equation (1) is a valid approximation if Δt is smaller than the time scale associated with the outward movement of the boiling front. (c) Finite reservoir, no-flow condition at $r=r_e$; approximation (1) is valid when Δt is smaller than the time scale associated with the decrease of p_e.

If the reservoir flow model summarized by (1) is valid for a given set of output data (production characteristic curve), a plot of the computed sandface flowrate versus the corresponding squared flowing pressures should give a straight line. From (1) the intercept of this line is

$$a=\alpha \frac{kh}{\mu} \frac{p_e^2}{zT \ln (r_e/r_w)} , \qquad (2)$$

and its slope is

$$b= -\alpha \frac{kh}{\mu} \frac{1}{zT \ln (r_e/r_w)} . \qquad (3)$$

The reservoir pressure is then easily computed from

$$p_e = (-a/b)^{1/2} . \qquad (4)$$

A productivity index is naturally defined as

$$J' = W/(p_e^2 - p_{wf}^2) \qquad (5)$$

Then from (1), (3) and (5), the value of the productivity index is

$$J' = -b. \qquad (6)$$

Finally, if the transmisivity (kh/μ) of the reservoir is known, the radius of influence can be estimated from (6) as

$$r_e = r_w \exp (\alpha \frac{kh}{\mu}/ z TJ') \qquad (7)$$

FIELD VALIDATION

To demonstrate our method we present a number of examples in this section. The data correspond to five steam wells from the Los Azufres (Michoacán, México) geothermal field. These and other steam wells are clustered on a relatively ample zone bounded on its North, West and East sides by wells that produce water and steam (Fig. 1).

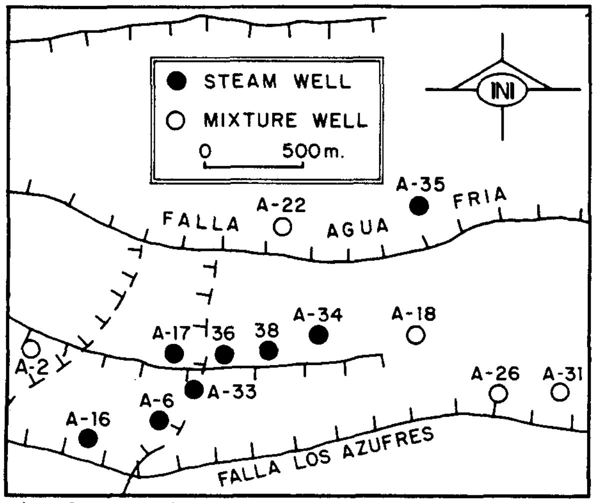

Fig. 1 Location of steam-producing wells in the Los Azufres geothermal field.

Figures 2 through 6 show the original production characteristic curves and their transformation to bottomhole conditions. Table 1 summarizes our results. The coefficients of correlation quoted in Table 1 correspond to the fit of the proposed reservoir flow model to the data -see also Figs. 2 through 6 (b)-. We conclude that the demonstrated excellent agreement with an ample set of field data constitutes strong evidence of the validity of our model.

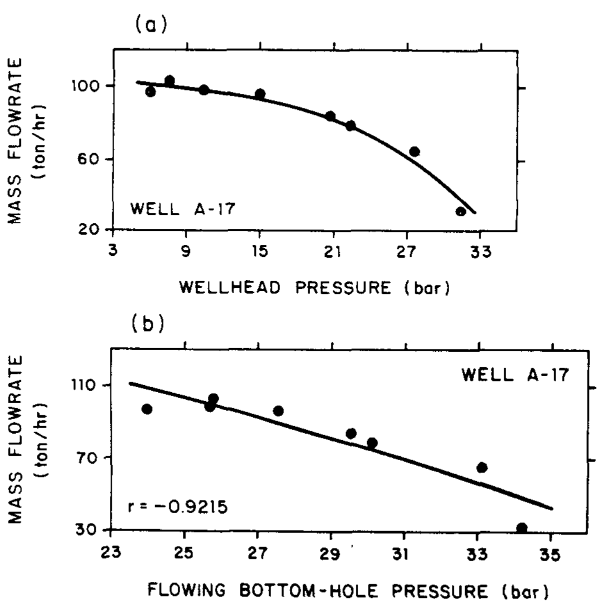

Fig. 2 (a) Characteristic curve of well A-17; (b) corresponding computed bottomhole variables, and fit of the steady-state radial steam flow model.

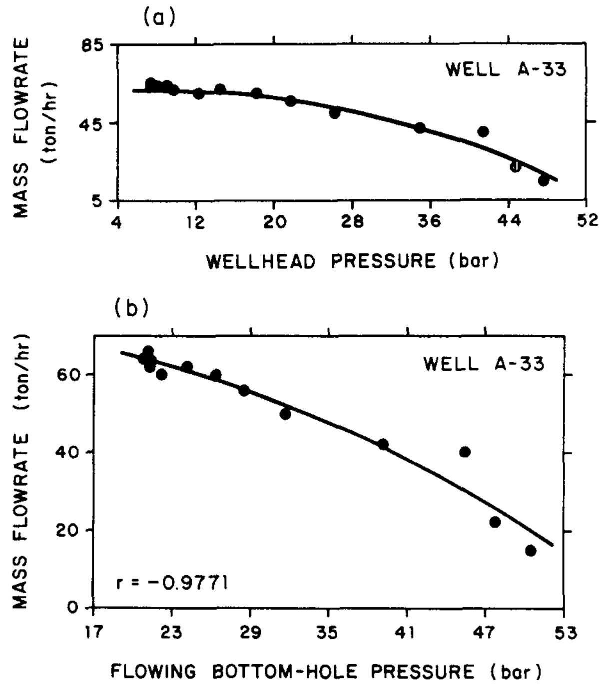

Fig. 3 (a) Characteristic curve of well A-33; (b) corresponding computed bottomhole variables, and fit of the steady-state radial steam flow model.

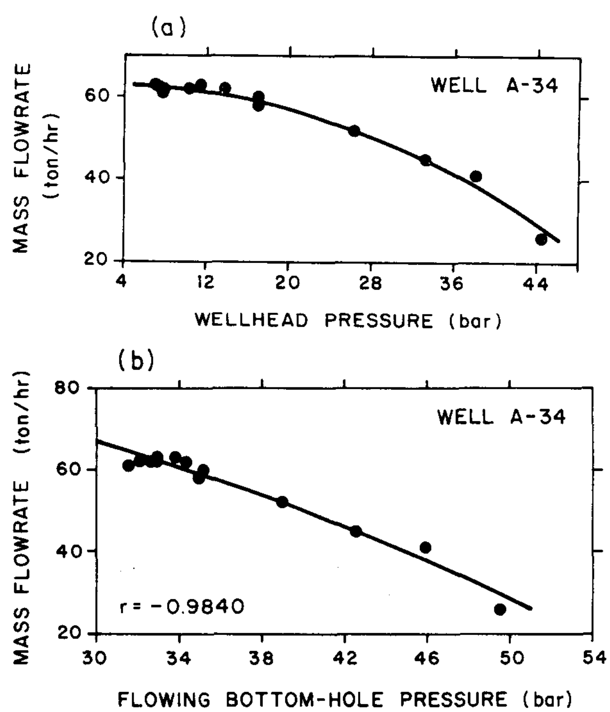

Fig. 4 (a) Characteristic curve of well A-34; (b) corresponding computed bottomhole variables, and fit of the steady-state radial steam flow model.

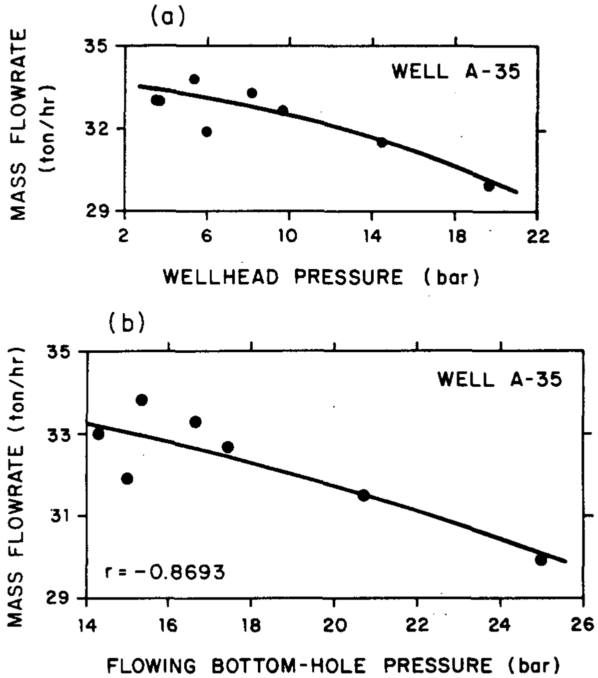

Fig. 5 (a) Characteristic curve of well A-35; (b) corresponding computed bottomhole variables, and fit of the steady-state radial steam flow model.

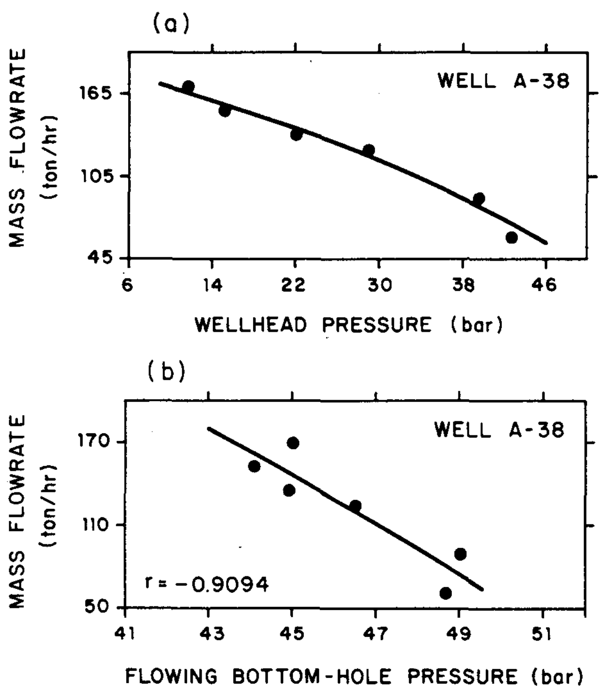

Fig. 6 (a) Characteristic curve of well A-38; (b) corresponding computed bottomhole variables, and fit of the steady-state radial steam flow model.

Table 1. Results of the method applied to wells from the Los Azufres geothermal field.

Well	Depth (m)	J' ($ton\ h^{-1}\ bar^{-2}$)	Pe (bar)	Correlation Coefficient
A-38	752	0.1915	52.8	-0.9094
A-17	627	0.1015	40.5	-0.9215
A-34	856	0.0241	60.6	-0.9840
A-33	683	0.0210	59.1	-0.9771
A-35	1240	0.0074	68.5	-0.8693

Another check on our results, it would appear, should be to compare the computed reservoir pressures with measured shut-in bottomhole pressures. However, such comparison is not necessarily granted in geothermal wells (Grant, 1979; Grant et. al., 1981). The reason is that geothermal reservoirs are in a dynamic state of equilibrium which promotes the existence of non-hydrostatic internal pressure gradients. Since geothermal wells ussually have more than one feed zone, even shut - in wells may sustain internal flows. Thus, downhole profiles do not necessarily reflect reservoir pressure, except at the depths corresponding to feed points. Table 2 shows a comparison of measured bottomhole pressures with computed reservoir pressures. The former were measured in wells that had been shut-in for relatively long periods of time after their completion. In the cases presented in Table 2

Table 2. Computed reservoir pressures vs. measured bottomhole pressures.

Well	Well Depth. (m)	Pe (bar)	Depth of measurement (m)	Measured pressure (bar)
A-17	627	40.5	617	46.0
A-33	683	59.1	683	52.9
A-34	856	60.6	850	54.9
A-35	1240	68.5	1240	67.6
A-38	752	52.8	745	52.0

there is a remarkable good agreement between observed and predicted values. The average deviation is less than 6%. This constitutes further, though somewhat circumstantial, evidence supporting the applicability of the present model.

APPLICATIONS

As stated, if an estimate of the transmisivity is available, our method provides a way to estimate the radius of influence of the well. As an example, we present here such calculation for well A-35. A transient pressure test indicated a value $(kh/\mu) = 33{,}390$ md. m/cp for that well. The other relevant parameters are $J' = 0.0074\ ton.\ h^{-1}/bar^{2}$ (from Table 1), $T = 473$ °K, $z = 0.87$, $\alpha = 2.3278 \times 10^{-4}$. Pluging these values into (7) we find $(r_e/r_w) = 12.84$, which implies a radius of influence of the order of lm. This result suggests the existence of a boiling front, and therefore of inmobile water, near the well.

As another application we plotted the computed reservoir pressures versus the corresponding depths (Fig. 7). The boiling point for depth curve is also indicated. The fact that well A-33 falls on the liquid region of the diagram was at first disturbing. However, this result was justified a-posteriori. Well A-33 was flown January 17 through March 24, 1983 to obtain the characteristic curve shown in Fig. 3 (a). During that period the well produced what appeared to be dry saturated steam. Consequently, a wellhead dryness fraction equal to unity was assumed in our calculations, with the result just noted. In early August the well was opened again, still apparently producing dry saturated steam. As time went by it was apparent that the steam produced became wetter. Finally, starting October 13, 1983, sizable amounts (few tons/hr) of separated water started to be recorded. In the authors' opinion, the accurate prediction that well A-33 should produce steam and water constitutes further evidence of the validity of the method presented in this work.

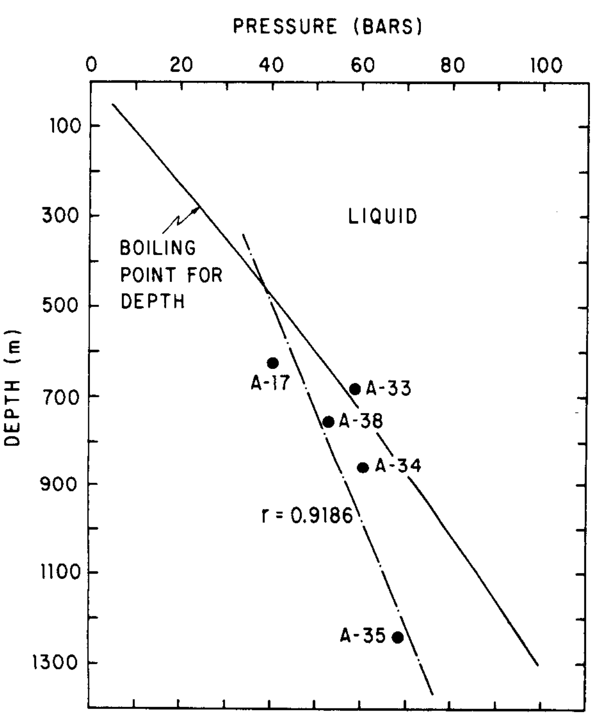

Fig. 7 Inferred reservoir pressures for steam wells vs. depth.

Other important inferences were drawn from Fig. 7. It has been assumed that a "steam dome" existed in the area defined by the steam wells of Fig. 1. The evidence summarized in Fig. 7 helps qualify that assumption. Excluding A-33 because of its status of a mixture producer, a straight line of slope 0.0414 bar/m and coefficient of correlation equal to 0.9186 can be fitted to the remaining steam wells. If a continuous steam phase existed interconecting these wells, the pressure profile should be nearly vertical. Therefore, we conclude that a steam dome constituted by a continuous steam phase does not exist in the area. Rather, the evidence points to the existence of relatively isolated pockets of steam, probably fed from nearby inmobile liquid water zones.

Another interesting inference from Fig. 7 is that the steam wells are underpressured with respect to the mean boiling for depth pressure profile, implying poor hydraulic communication of the feed zones with the field surface waters. Since the field is located in a highland, 300 to 500 meters above the neighboring valleys, this inference does not preclude recharge from the nearby lowlands.

SUMMARY AND CONCLUSIONS

We have developed and demonstrated a method to retrieve the reservoir pressure p_e and the productivity index J' corresponding to vertical steam wells from its production characteristic curves. If an estimate of the reservoir transmisivity (kh/μ) is available, our method provides a way to estimate the radius of influence of the well.
We found excellent agreement between predicted and observed values. This agreement provides strong evidence of the validity of our method.

The main advantages of the proposed method are as follows: It provides a way for retrieving important reservoir information from ussually available production characteristic curves; no extra measurements are needed. Unlike traditional methods that require significantly more difficult bottomhole measurements to evaluate the reservoir pressure and the productivity index, the present method works from easily taken wellhead measurements.

Concerning the steam producing zone of the Los Azufres geothermal field, we drawed the following inferences: The computed pressure profile of that zone indicates that a steam dome constituted by a continuous steam phase does not exist in the area. Rather, the evidence points to the existence of relatively isolated pockets of steam, probably fed by neighboring inmobile liquid water. Finally, the formations feeding the steam wells are underpressured with respect to the mean boiling for depth pressure profile, implying poor hydraulic communication with the field surface waters; however recharge from nearly lowlands is not precluded by our results.

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NOMENCLATURE

a: Intercept of straight line (ton hr^{-1})

b: Slope of straight line (ton hr^{-1}/bar^2)

h: Reservoir thicknes (m)

J': Productivity index (ton hr^{-1}/bar^2)

k: Permeability (md)

p_e: Reservoir pressure (bar)

p_{wf}: Sandface flowing pressure (bar)

r_e: Radius of influence of the well (m)

r_w: Wellbore radius (m)

T: Absolute temperature (°K)

W: Mass flowrate (ton hr^{-1})

z: Gas deviation factor

α: Constant to accomodate different systems of units

μ: Viscosity (cp)

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