A New Understanding of Deliverability of Dry Steam Wells

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ABSTRACT

A new deliverability function for steam wells is derived and proposed as an alternative to the empirical Equation commonly used for characterization of steam wells. This approach combines the effects of both the wellbore and formation making it possible to explain the characteristics of well deliverability curves in terms of Productivity Index and wellbore pressure loss. These parameters are much more intuitive and useful than the usually calculated *"C"* and *"n"* parameters commonly obtained for gas wells. A technique to graphically solve the unknowns is given as well as an example application.

Introduction

The empirical Equation normally used to analyze deliverability of dry steam wells, Equation (1), has been used with good success to quantify well decline in steam dominated reservoirs (Sanyal, S.K., *et. al.,* 1991; Sanyal, S. K., *et. al.,* 2000).

$$W = C(p_{si}^2 - p_f^2)^n \tag{1}$$

Where: p_{si} = static (shut-in) wellhead pressure
p_f = flowing wellhead pressure
C = a constant parameter
n = a constant exponent

However, the empirical nature of the terms in Equation (1) makes it very difficult to correlate them with measurable well parameters such as Productivity Index (PI) and friction loss in the wellbore. Moreover, it is not clear what the parameter "n" known as turbulent factor (Sanyal, S.K., *et. al.,* 1991; Sanyal, S.K., *et. al.,* 2000) means in terms of well characterization.

We set out to derive a new deliverability Equation for dry steam wells based on parameters that can be independently measured such as PI and wellbore pressure loss.

Derivation

To understand better a flowing steam well from formation to wellhead we proceed to separate the two components of the total pressure loss that takes place. First we start with wellbore pressure loss. For a horizontal pipe and provided that we neglect the thermal losses and the fluid velocity is not too high so we can neglect the kinematic term, the pressure drop is caused by friction. This friction loss can be expressed as follows

$$\Delta p = C'\frac{W^2}{\rho} \tag{2}$$

Where: Δp = pressure drop due to friction
C' = parameter that contains effect of friction factor and well geometry
ϱ = average density of the fluid

To make this formulation useful we have to assume that the friction factor is constant. The same assumption is used in very popular empirical formulas for steam pressure drop such as the Anwin and the Babcok formulas (Shashi Menon, E., 2005).

For application to geothermal wells, it has been further shown that a constant friction factor is a reasonable assumption as the Reynolds numbers of flowing geothermal wells are usually high enough to make the friction factor dependent only on relative pipe rugosity (Acuna J. and Arcedera B., 2005). However, for a vertical wellbore, we have to start by adding the gravity term to the left hand side of Equation (2). Neglecting the kinematic term and heat losses and rearranging we obtain

$$p_{wf} - \rho g h - p_f = C'\frac{W^2}{\rho} \tag{3}$$

Density can be approximated by making it proportional to average pressure.

If $\varrho \sim C(p_1 + p_2)$ then $(1\text{-}Cgh)\varrho \sim C(p_1 - \varrho gh + p_2)$. From here we obtain

$$(p_{wf} - \rho g h)^2 - p_f^2 = C_{WB}W^2 \tag{4}$$

Where C_{WB} = a new constant called wellbore coefficient [(bar^2-s^2)/kg^2]
ϱgh = vaporstatic correction from bottomhole elevation to wellhead [bar]
p_{wf} = bottomhole flowing pressure [bar]
p_f = flowing wellhead pressure [bar]

Equation 4 is surprisingly accurate for wellbore calculations. To test it we calculated output curves with Chevron's geothermal wellbore simulator (Geoflow) by setting the downhole pressure constant to isolate the effect of the wellbore. Figure 1 shows a comparison between wellbore simulated values and Equation (4) for typical large and small diameter wells. The Equation is less accurate at very low wellhead pressure because the kinematic term in the wellbore calculation may become significant and also for very low flow rates, close to Maximum Discharge Pressure (MDP), as the friction factor may not be constant due to lower fluid velocity and its effect in reducing the Reynolds number.

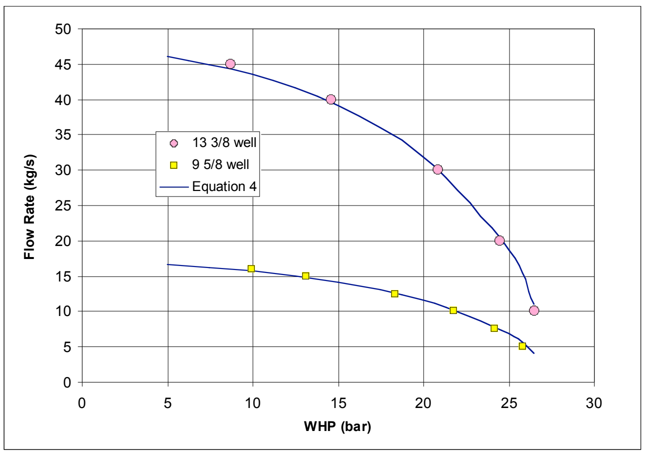

Figure 1. Wellbore only deliverability curves for two wells 2000 m depth assuming all production from bottom. To avoid effect of formation, bottomhole pressure held constant at 30 bar. Symbols are calculated with our wellbore simulator Geoflow. Lines are calculated with Equation (4) and C_{WB} = 0.34 and 2.6 for large and small diameters respectively.

The term $(p_{wf} - \varrho gh)$ in Equation (4) is downhole flowing pressure minus the vaporstatic correction commonly used to convert wellhead to bottomhole pressures in a static well. It is assumed that steam density in the wellbore does not change between producing and static conditions. Note that if a flowing pressure survey is available from the well, it is possible to calculate the value of the wellbore coefficient C_{WB} directly from Equation (4). Static pressure surveys, on the other hand are not always useful to get the vaporstatic correction as accumulated gas leads to an overestimation.

The selection of the bottomhole depth has to be made keeping in mind that friction losses will be neglected below that depth and the full flow rate of the well will be used for friction losses above that depth. The "centroid" of feed zone contributions should be a reasonable selection.

Turning now our attention to the reservoir side, the deliverability of a steam feed zone can be expressed as

$$\frac{PI}{\nu_s}(p_r - p_{wf}) = W \tag{5}$$

Where: PI = well productivity index [m^3]
ν_s = kinematic viscosity of steam defined as μ_s/ϱ_s [(bar-s-m^3)/kg]
p_r = reservoir pressure [bar]

We prefer this formulation to the p^2 formulation (Dake, L.P., 1978) normally used for gas inflow performance curves because it works equally well for our wells. Indeed the kinematic viscosity is inversely proportional to pressure therefore this formulation is not too different from the p^2 formulation.

The PI is dependent on reservoir conditions only and not on fluid properties. It can be expressed as

$$PI = \frac{2\pi kh}{\log(\frac{r_e}{r_w}) + S} \tag{6}$$

Where kh = permeability thickness product in [m^3]
r_e *and* r_w = radius of drainage area and of wellbore respectively [m].
S = skin factor [dimensionless]

The kinematic viscosity for saturated steam can be approximated by the following relationship

$$\frac{1}{\nu_s} = 2.6501687\text{x}10^9\text{p} + 8.8934068\text{x}10^9 \tag{7}$$

Where ν_s = kinematic viscosity of steam defined as μ_s/ρ_s [(bar-s-m^3)/kg]
p = pressure [bar]

Solving for p_{wf} from Equation (5), substituting in (4) and noting that the shut-in pressure p_{si} equals $p_r - \varrho gh$ we get

$$(p_{si} - \frac{W\nu_s}{PI})^2 - p_f^2 = C_{WB}W^2 \tag{8}$$

Equation (8) is the most important one in this paper and it is proposed as a replacement for Equation (1). If the density and viscosity are evaluated at p_{si}, which is usually a good approximation for steam wells, the entire Equation becomes dependent on parameters measurable at the surface with the exception of two: PI and C_{WB}. These two parameters are more insightful than *"C"* and *"n"* from Equation (1).

Equation (8) can also be written as an explicit expression for flow rate W as follows

$$W = (C_{WB}A^2p_{si}^2 - Ap_f^2)^{0.5} - A\frac{\nu_s}{PI}p_{si} \tag{9}$$

Where $$A = \frac{1}{C_{WB} - \left(\frac{\nu_s}{PI}\right)^2}$$

Application

The data required to solve the two unknowns PI and C_{WB} is contained in a typical well deliverability test. The left hand side of Equation (8) is a function of PI only. This means that plotting

W^2 derived from Equation (8) versus measured W with the correct value of PI and any value of C_{WB} should give an Equation with slope equal to 2 on log-log paper. The value of C_{WB} is then adjusted to make the line pass through the point (1,1).

An auxiliary plot may be required when the data is noisy. Plotting the right hand side of Equation (9) versus measured flow rate should give a graph with slope of 1 and also passing through the point (1,1) on log-log paper.

Table 1 shows four stabilized points from a deliverability test for a well in Darajat, a dry steam field in Indonesia operated by Chevron. It also shows the calculated values of W^2 and W calculated with the described values of PI and C_{WB}.

Figure 2 shows a plot of W^2 and W versus measured flow rate as well as the best fitting Equations. The corresponding value of PI/ν_s equals 16.7 kg/(s-bar), which is quite large for the well actual production. This is explained by the relatively large value of C_{WB} obtained for the wellbore. Wells with this depth and completion and no damage have C_{WB} on the order of 0.2. This well has been documented to have an obstruction and is scheduled for a workover.

Table 1. Measured points in deliverability tests as well as W^2 and W calculated using Equations (8) and (9) as explained for PI = $2.15\text{x}10^{-10}$ m^3 and C_{WB} = 0.55.

WHP(bar)	Q(kg/s)	W^2	W
12.73	27.8	777.6	27.88
18.93	21.3	455.5	21.33
19.81	20.0	400.6	20.01
21.49	17.0	290.6	17.04
25.95	0.0		

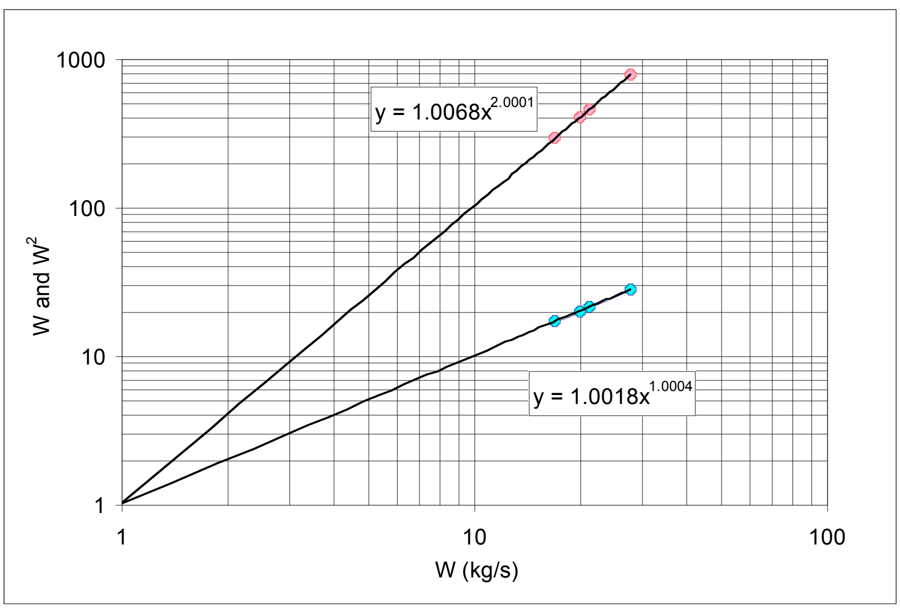

Figure 2. Diagnostic graph of W^2 from equation (8) versus measured flow rate once the correct values of PI = $2.15\text{x}10^{-10}$ and C_{WB} = 0.55 are selected. Best fitting equations as well as the auxiliary graph of W calculated with equation (9) versus measured flow rate are also shown.

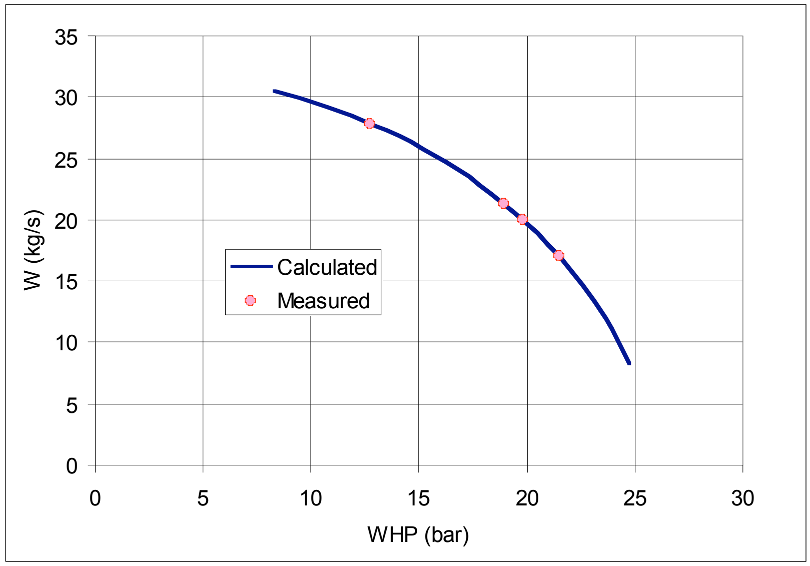

Figure 3. Measured values (symbols) and curve calculated with equation (9) using PI = $2.15\text{x}10^{-10}$ m^3 and C_{WB} = 0.55.

Figure 3 shows the measured output curve as well as the calculated curve obtained with the selected values of PI and C_{WB}. As can be seen the match is very good.

In order to compare the relative effects of wellbore and formation Equation (8) is rewritten as follows

$$p_{si}^2 - p_f^2 = \frac{1}{A}W^2 + \frac{2\nu_s p_{si}}{PI}W \tag{10}$$

Where A was defined in Equation (9).

The two terms in the right hand side of Equation (10) represent the wellbore loss (quadratic term) and the formation loss (linear term). By calculating these terms separately we can assess that for this well formation losses account for 17 to 25% of the total, depending on the point used for calculation, while wellbore losses account for 75 to 83% of the total pressure loss.

Discussion

The formulation presented here shows how the deliverability of a dry steam well relates to wellbore and formation behavior. The combined effect creates a typical shape in the well deliverability curve that can be quantitatively analyzed to obtain estimates of Productivity Index and wellbore friction. In terms of Equation (1), wellbore only behavior corresponds to a value of $n = 0.5$ while formation only behavior corresponds to a value of $n = 1$. A typical well behaves with a combination of both effects giving a value of "n" that ranges from 0.5 to 1.

If wellbore losses account for the largest part of the difference $(p_{si}^2 - p_{wf}^2)$ then the apparent value of n should be close to 0.5. This would be the case of wells with limited wellbore capacity or wells with scale or other wellbore restriction. If on the other hand, formation permeability is very small or the wellbore too large the apparent value of *"n"* should approach 1. Cases like these are observed in Darajat field and the interpretation is consistent with findings from independent data such as pressure transient tests, spinner surveys and other tests.

Equation (8) suggests that by selecting the correct value of *PI* the formation related linear effect may be subtracted. Well behavior can then be described as purely wellbore related losses with the known flow squared behavior. Thus it is possible to separate wellbore and formation effects from the surface well deliverability data. The value of this procedure as a way to assess wellbore damage or estimate productivity index cannot be overemphasized.

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