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Improved Method for Decline Analysis of Dry Steam Wells

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ABSTRACT

This paper describes the application of a new method developed by Acuna (2008) to calculate production decline in dry steam wells. It provides an alternative way to reconstruct the reservoir pressure history of wells using flow rate and wellhead pressure variation with time. The formulation presented here can be used to predict well decline and normalized well deliverability over time. Given that the method accounts for well PI and wellbore friction losses, it is possible to calculate variations of these parameters with time. The analysis can help diagnose problems in wells. An example of a well in the Darajat field, Indonesia is used to demonstrate this technique.

1. INTRODUCTION

Deliverability of dry steam wells has been analyzed for several decades according to Equation 1:

$$W = C_0 (p_{si}^2 - p_f^2)^n \tag{1}$$

where W is mass flow rate, p_{si} is static (shut-in) wellhead pressure, p_f is flowing wellhead pressure, C_0 is a constant parameter and n is a constant exponent. The shape of the output curve reflects the value of the exponent n and has been associated to predominance of either pressure drop proportional to the square of flow such as that caused by wellbore scaling or pressure drop proportional to flow such as in low permeability wells (Grant et al, 1982). This equation has also been applied to quantify well decline, in which case it has been observed that the coefficient C_0 changes with time (Faulder, 1997; Sanyal et al., 2000).

The empirical nature of this equation makes it difficult to understand the physical meaning of their parameters or correlate their changes to wellbore or reservoir processes. It is not clear how these parameters relate to other measurable well parameters such as Productivity Index (PI) and friction loss in the wellbore. It was intended to derive a new deliverability equation for dry steam wells based on parameters that can be independently measured.

2. DERIVATION

To better understand the flow of steam from formation to wellhead, it was planned to separate the two components of the total pressure loss that takes place. First, wellbore pressure loss was focused upon. Provided that the thermal losses and kinematic term can be neglected (the latter because the fluid velocity is not too high), the pressure drop through a horizontal pipe is caused by friction. This friction loss can be expressed by Equation 2:

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

where Δp is pressure drop due to friction, C' is a parameter that contains the friction factor and well geometry and ρ is average density of the fluid.

To make this formulation useful, it must be assumed that the friction factor is constant. This assumption is used in popular empirical formulas for steam pressure drop such as the Unwin and the Babcock formulas (Shashi Menon, E., 2005). For application to geothermal wells, Acuna and Arcedera (2005) showed 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.

For a vertical wellbore, the gravity term is added to Equation 2, and neglecting the kinematic term and heat losses, the new relationship is expressed in Equation 3:

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

where ρgH is the gravity component of the total pressure difference from bottomhole to wellhead, g is the gravitational constant, H is vertical depth, p_{wf} is bottomhole flowing pressure, and p_f is flowing wellhead pressure.

Steam density can be approximated as proportional to pressure ($\rho \sim Cp$). For average pressure, it follows that $2\rho \sim C(p_{wf} + p_f)$ and $(2-CgH)\rho \sim C(p_{wf} - \rho gH + p_f)$. Therefore, $\rho \sim (C/(2-CgH))(p_{wf} - \rho gH + p_f)$. From this, one can obtain Equation 4:

$$W = C_{WB}\left(p_{wfg}^2 - p_f^2\right)^{0.5} \tag{4}$$

With $$p_{wfg} = p_{wf} - \frac{CgH}{2}(p_{wf} + p_f)$$

where p_{wfg} is the gravity corrected wellbore flowing pressure, and the CgH term is dimensionless, with the value of C given in the Appendix.

C_{WB} is a new constant called the wellbore coefficient [kg/(s-bar)]. The definition of C_{WB} is different from what was published in Acuna (2008). C_{WB} in this paper is equivalent to $C_{WB}^{-0.5}$ using the definition in Acuna (2008). This change was made to make C_{WB} more physically intuitive.

Equation 4 is quite accurate for wellbore calculations. To test it, output curves were calculated using an in-house geothermal wellbore simulator. A comparison between wellbore simulated values and those calculated according to Equation 4 is shown in Figure 1 for a 2000 m deep typical large and small diameter wells. A constant pressure of 30 bara was specified at the bottom in order to calculate only the wellbore pressure loss. If a flowing pressure profile survey is available for the well, it is possible to calculate the value of the wellbore coefficient C_{WB} from Equation 4. The selection of the bottomhole depth has to be made keeping in mind that friction losses are neglected below that depth and the full flow rate of the well will be assumed for friction losses above that depth. The "centroid" of feed zone contributions seems to be a reasonable choice.

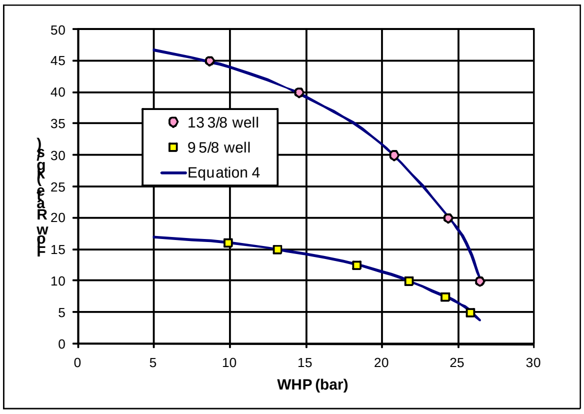

Figure 1. Deliverability points for typical wells calculated with wellbore simulator and Equation 4. Match obtained with C_{WB} = 1.68 and 0.61 respectively.

With respect to the reservoir side, the deliverability of a steam feed zone can be expressed as

$$W = \frac{PI}{2\nu_{rg} p_{rg}}(p_{rg}^2 - p_{wfg}^2) \qquad (5)$$

with

$$p_{rg} = p_r - \frac{CgH}{2}(p_r + p_f) \quad \text{and} \quad \nu_{rg} = \nu_r(1 - \frac{CgH}{2}).$$

where PI is the well productivity index, p_{rg} is the gravity corrected reservoir pressure, p_{wfg} is the gravity corrected wellbore flowing pressure as defined in Equation 4, ν_{rg} is kinematic viscosity calculated at reservoir pressure (ν_r) multiplied by the correction factor shown above. In Equation 5 average pressure between reservoir and wellbore are used to calculate fluid properties. Acuna (2008) calculated fluid properties at average reservoir pressure, leading to a different solution. Using gravity corrected values as opposed to actual downhole values is not exact, but it is a very good approximation.

Equation 5 neglects the effect of non-Darcy flow usually expressed as a flow dependent skin factor (Dake, 1978). This is a reasonable assumption for geothermal wells because they have usually large permeability and large diameter as compared to gas wells. They also have hundreds of feet of slotted liner or open hole as opposed to perforations. They also have open fractures as opposed to porous permeability. All these features reduce the near-wellbore pressure drop making non-Darcy flow less likely to occur. If non-Darcy flow occur then its effect simply adds to the wellbore effect.

The PI value is dependent on reservoir conditions only and not on fluid properties. It can be expressed as Equation 6:

$$PI = \frac{2\pi kh}{\ln(\frac{r_e}{r_w}) - 0.5 + S} \qquad (6)$$

where kh is the permeability thickness product in, r_e and r_w are the drainage area radius and wellbore radius, respectively, and S is the skin factor.

Solving for p_{wfg} in Equation 5 and substituting it into Equation 4, Equation 7 is obtained.

$$W = C_{WB}\left(p_{rg}^2 - \frac{2\nu_{rg} p_{rg} W}{PI} - p_f^2\right)^{0.5} \qquad (7)$$

Equation 7 is the most important one in this paper, and it is proposed as an alternative to Equation 1. When the well is shut-in, p_{rg} corresponds to wellhead pressure, but when the well is flowing, the gravity correction is smaller due to the lower average fluid density in a flowing well. Acuna (2008) assumed that the difference was negligible, but this assumption introduces unnecessary error to the formulation. Equation 7 is considered an improvement, as it deals explicitly with the dynamic gravity term in the wellbore. The exact expression derived using with downhole values in Equation 5 is shown in the Appendix.

Equation 7 can also be written as an explicit expression for flow rate W, as shown in Equation 8:

$$W = C_{WB}^2\left(\left(\frac{p_{rg}^2}{A} - \frac{p_f^2}{C_{wb}^2}\right)^{0.5} - \frac{\nu_{rg}}{PI}p_{rg}\right) \qquad (8)$$

with

$$A = \frac{1}{\left(\frac{1}{C_{WB}}\right)^2 + \left(\frac{\nu_{rg}}{PI}\right)^2}$$

where p_{rg} and ν_{rg} are defined in Equation 5.

3. APPLICATION

Data from well deliverability tests or from records of wellhead pressure and flow can be used to calculate the two unknowns (PI and C_{WB}). An example with a well deliverability test is shown in Acuna (2008). Historic records were used for the example shown here.

Production records have been taken for a well in Darajat with since 2000, with only a few occasional shut-in periods.

The first step in this analysis is to simulate an approximate reservoir pressure record by converting shut-in pressures to reservoir pressures with a vaporstatic correction (see Appendix) and joining the reservoir pressure points, as shown in Figure 2.

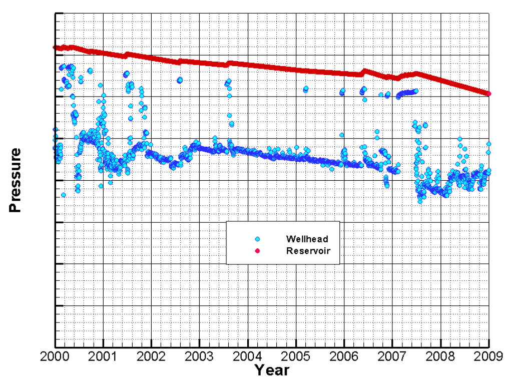

Figure 2. Wellhead pressure records of well A in Darajat and preliminary reservoir pressure obtained by joining the vaporstatic corrected shut-in pressures.

Using the definitions in Equation 5, gravity corrected reservoir pressure p_{rg} and kinematic viscosity ν_{rg} were calculated. C_{WB} was initially specified as 1. Equation 7 was then used to calculate flow rate using measured flow rate in the right hand side. The calculated flow rate was plotted against measured flow rate in log-log scale. The value of PI was adjusted by trial and error until the log-log slope equaled 1. The value of C_{WB} was then adjusted until the curve passed through the point (1,1).

The result of matching theoretical flowrate data with data measured between 2001 and 2002 is shown in Figure 3. The points that deviated from the linear trend by more than ±30% were removed. The previously described process depends on best fitting of measured data and is therefore subject to error. A best fitting line algorithm was used to evaluate the slope. Methods based on non-linear regression might offer a better alternative.

The best match was obtained with *PI* equal to $1.39*10^{-10}$ m^3 and C_{WB} equal to 1.92 kg/(s-bar). *PI* values of $1.24*10^{-10}$ and $1.88*10^{-10}$ m^3 made the slope equal to 1.05 and 0.95, respectively. Two points were selected as guides to facilitate matching: the maximum flow point and the three points located close to 10 kg/s. This is also subjective, but once the slope is obtained and the value of C_{WB} is adjusted to pass through (1,1), it is clear when a fit is good or not.

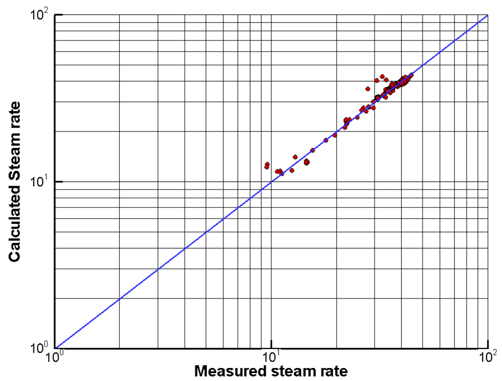

Figure 3. Matching data from 2001-2002 with PI = $1.39*10^{-10}$ m^3 and C_{WB} = 1.92 kg/(s-bar).

The value of PI can be independently measured via a pressure transient test or a flowing spinner. For high permeability wells, spinners are performed at a relatively low flow rate to prevent problems with the logging tool. For a spinner survey done in 2000 at 21 kg/s, the difference between static and dynamic pressures was approximately 1.7 bar. The value of PI for this case was $1.20*10^{-10}$ m^3.

The pressure buildup test performed in 2001 shown in Figure 4 was used instead. Steam pseudo pressures were used as defined by Grant et al. (1982).

The test showed the existence of an inner area with a flow dimension of 2.65. This produced the declining pressure derivative before 1.4 hours (~5000 s). After that time, the test reached a region with radial flow. The existence of this inner area caused a pseudo-skin effect for the outer radial flow area. The value of this pseudo-skin is 9.24. A PI value of $1.34*10^{-10}$ m^3 was calculated using Equation 6 and assuming a drainage radius r_e of 500 m. The sensitivity to this parameter was found to be relatively small. A radius of 1000 m resulted in a PI of $1.28*10^{-10}$ m^3. The agreement with the value estimated using the graphical technique of Figure 3 is good.

The value of C_{WB} was also independently calculated using a flowing spinner survey performed in 2000. The flowing downhole pressure was 34.1 bara at the centroid of the feed zones at a 1346 m vertical depth. The wellhead pressure was 30 bara, and the flow rate was 21 kg/s. Equation 4 was used to obtain a C_{WB} value of 1.90 kg/(s-bar). This value also agrees well with the one obtained using the graphic technique in Figure 3.

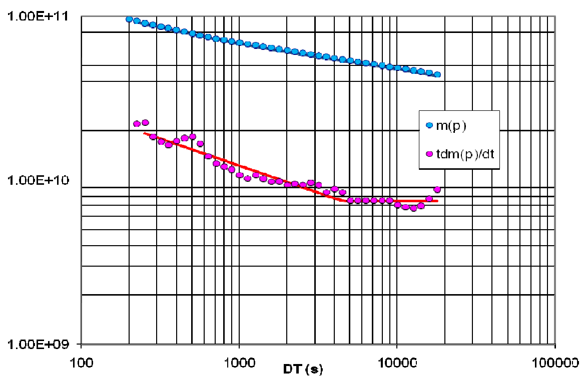

Figure 4. Pressure transient test with an estimated kh for the radial flow region of $3.61*10^{-10}$ m^3 and a pseudo skin factor of 9.24. PI is $1.34*10^{-10}$ m^3.

The parameters *PI* and C_{WB} should not change with time unless there is a variation in permeability, wellbore geometry, or fluid quality. Such changes can be caused by wellbore or formation scaling, casing collapse, evolution from saturated to superheated steam, etc.

The entire flow record calculated with the same parameters of 2001 is shown in Figure 5. The match is not as good as the 2001 data. Changes in C_{WB} should appear as parallel lines, while changes in PI should appear as changes of slope. Continual yearly data analysis can be used to diagnose changes in wellbore parameters. Once values of *PI* and C_{WB} were defined, it was possible to calculate the flow rate using Equation 8 using the measured wellhead pressure and assumed reservoir pressure.

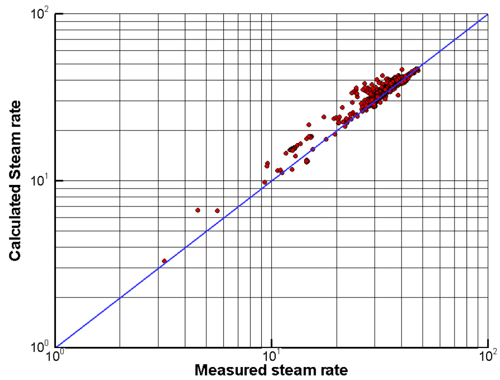

Figure 5. Matching data for the entire production record (2000-2009) shown with fit for 2001.

Figure 6 shows the match of the entire historic series with the 2001 parameters. As expected, the match for 2001-2002 is good, but there is a mismatch soon after. The calculated flow rate is larger than the measured one. These periods were evaluated, and it was found that the permeability can be kept at the same value, but the wellbore coefficient should be reduced in 2002 and 2007.

The match for the entire record with reduced C_{WB} is shown in Figure 7. Changes in this parameter or PI can be used to time the occurrence of events that affect well deliverability. Equation 7 can also be used to calculate reservoir pressure once *PI* and C_{WB} are known. This has to be done iteratively, because the kinematic viscosity is a function of reservoir pressure, but a few iterations are enough.

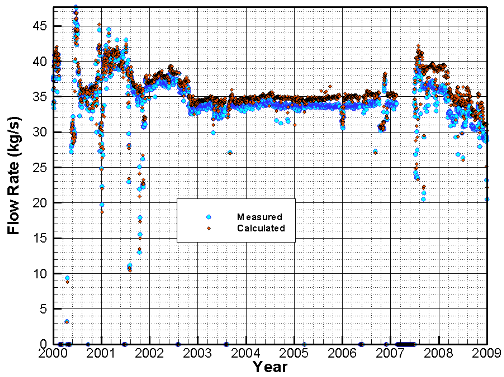

Figure 6. Matching flow rate with assumed shut-in pressure from Figure 2 using parameters *PI* and C_{WB} from 2001-2002.

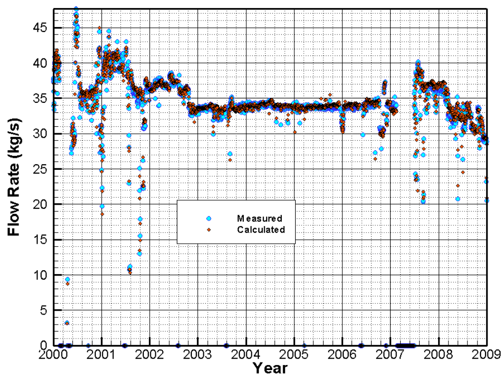

Figure 7. Matching flow rate with shut-in pressure from Figure 2. *PI* and C_{WB} for 2001 used for period before 2002, C_{WB} reduced to 1.90 for 2002-2007 and to 1.85 kg/(s-bar) for 2007-2009.

The calculated reservoir pressure is shown in Figure 8 and compared to the preliminary estimation shown in Figure 2. The calculated shut in pressure shows a level of detail that is not available from the actual shut-in pressure. An example of this is the period after mid 2007, when the drop in reservoir pressure caused by start up of Unit III is clearly depicted.

A great deal of the dispersion found in the matching process is due to using an approximated reservoir pressure as a starting point. This is evident when observing how the mismatch in the period close to 2008 in Figure 7 is caused by the mismatch in pressure evident in Figure 8.

Sometimes, there are not enough points to generate a preliminary shut-in pressure record. In this case, it is tempting to use the available shut-in points as a calibration parameter to obtain *PI* and C_{WB}. However, this leads to error, because a bad selection of *PI* can be offset by a bad selection in C_{WB}. This should only be done if one of the two parameters is known. In this case, Equation 7 is used to solve for reservoir pressure by changing the missing parameter until a good match is obtained with the available reservoir pressures derived from shut-in pressure values.

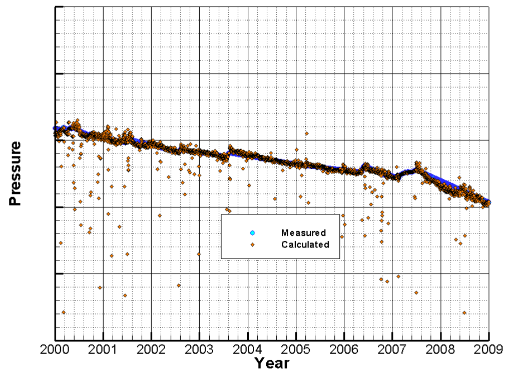

Figure 8. Reservoir pressure calculated using the parameters described in Figure 7 compared to the initial estimation in Figure 2.

One of the objectives of a well calibration is to calculate production rate (also known as normalized production rate) at constant wellhead pressure. A comparison between the normalized flow rate and the actual flow rate is shown in Figure 9. The normalized flow rate makes possible to determine the actual well decline in cases when wells have been operated at variable wellhead pressures. The correct selection of *PI* and C_{WB} is needed to obtain an accurate estimate.

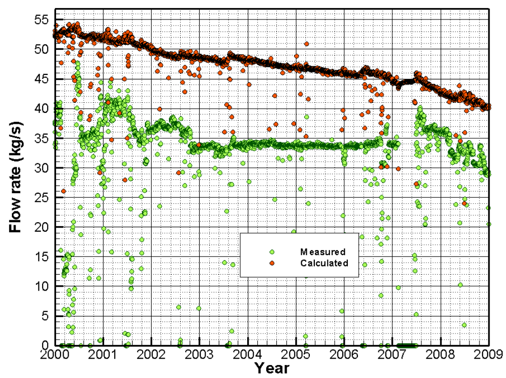

Figure 9. Normalized flow rate at 13 bara (calculated) versus actual flow rate (measured).

4. DISCUSSION

The formulation presented here shows how the deliverability of a dry steam well relates to wellbore and formation behavior. In order to compare relative effects, Equation 7 can be rewritten as Equation 9:

$$p_{rg}^2 - p_f^2 = \frac{1}{C_{WB}^2} W^2 + \frac{2\nu_{rg} p_{rg}}{PI} W \qquad (9)$$

The left hand side of Equation 9 represents the available pressure difference, and the right hand side represents the effects of the wellbore (quadratic in W) and formation (linear in W). The predominance of one term over the other influences the shape of the output curve of a particular well. In terms of Equation 1, the apparent value of *n* ranges from 0.5 to 1 when the quadratic or linear term predominates, respectively. The shape of the output curves as described qualitatively by Grant et al. (1982) can then be explained quantitatively.

The quadratic term dominates well behavior in cases of wells with limited wellbore capacity for the formation permeability (large *PI* relative to C_{WB}) or wellbore scaling or other wellbore restriction (small C_{WB}). The linear term dominates when formation permeability is low (small PI) or the wellbore too large for the prevailing permeability (large C_{WB}). By selecting the correct value of *PI*, wellbore and formation effects can be separated in the surface well deliverability data.

Values of *PI* and C_{WB} found with this analysis have been compared to independent measurements. It has been observed that PI values calculated using pressure transient test data and wellbore friction factors obtained from flowing spinners have good correlation with values found using this method.

All wells in Darajat have been analyzed. Reconstruction of reservoir pressure variation when there are few shut-in pressures or during the latest flow period when no shut-in values are yet available has been a major application. Causes of flow impairment have been diagnosed as they develop over time.

This technique has been applied to output curves as well as historic data and has become a tool of choice to evaluate well decline and document well changes using production data. The value of this procedure as a means to assess wellbore damage or estimate productivity index cannot be overemphasized.

NOMENCLATURE

C = steam density pressure proportionality constant equal to 5.017*10^{-6} [s^2/m^2]
C_0 = constant in empirical Equation 1
C' = constant in friction Equation 3
C_{WB} = wellbore coefficient [kg/s-bar]
g = gravitational constant 9.806 [m/s^2]
H = elevation difference [m]
kh = permeability thickness product [m^3]
n = constant exponent in Equation 1
p_f = wellhead pressure [bara]
p_r = reservoir pressure [bara]
p_{rg} = gravity corrected reservoir pressure defined in Equation 5 [bara]
p_{si} = shut-in pressure in Equation 1 [bara]
p_{wf} = bottomhole flowing pressure [bara]
p_{wfg} = gravity corrected bottomhole flowing pressure defined in Equation 4 [bara]
PI = productivity index of well [m^3]
r_e = drainage radius of well [m]
r_w = wellbore radius [m]
S = skin value [dimensionless]
W = mass flow rate [kg/s]
ρ = fluid density [kg/m^3]
ν_r = kinematic viscosity (viscosity divided by density) at reservoir pressure [m^2/s^2]
ν_{rg} = kinematic viscosity corrected for consistency with gravity corrected pressure defined in Equation 5 [m^2/s^2]

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APPENDIX

The gravity correction *CgH* [dimensionless] for elevation difference *H* [m] assuming that steam density is proportional to pressure can be approximated as follows

$$CgH = 4.920 * 10^{-5} * \mathrm{H}$$

The kinematic viscosity ν_s [m^2/s^2] for saturated steam can be approximated as a function of pressure [bara] by the following relationship

$$\nu_s = (2.6501687 * 10^9 \mathrm{p} + 8.8934068 * 10^9)^{-1}$$

Pressure p_2 [bara] at some elevation z_2 [m] in a shut-in well with saturated steam where the pressure p_1 at another elevation z_1 is known can be expressed as follows.

$$p_2 = p_1 \exp(-4.94178 * 10^{-5} * (z_2 - z_1))$$

The exact expression for Equation 7 using downhole values in Equation5 is the following

$$W = C_{WB}\left(\left(\left(p_{rc}^2 - \frac{2\nu_{rg}\, p_{rc}}{PI} W\right)^{0.5} - \frac{CgH}{2}\, p_f\right)^2 - p_f^2\right)^{0.5}$$

where

$$p_{rc} = p_r\left(1 - \frac{CgH}{2}\right) \quad \text{and} \quad \nu_{rg} = \nu_r\left(1 - \frac{CgH}{2}\right)$$