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TWO-PHASE FLOW BEHAVIOR AND SPINNER DATA ANALYSIS IN GEOTHERMAL WELLS

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ABSTRACT

A method has been developed for interpretation of Pressure-Temperature-Spinner (PTS) surveys. Drift-flux and homogenous flow models are evaluated for application in two-phase flow in geothermal wells. It was found high fluid velocity makes possible simple assumptions regarding holdup and friction losses. The analysis method provides sufficient resolution to determine mass contribution and enthalpy of individual feed zones in geothermal wells. Technique is described and a field example provided.

INTRODUCTION

Pressure-temperature-spinner (PTS) surveys are a valuable surveillance tool for diagnosing performance problems with geothermal wells and evaluating changes in reservoir conditions.

Interpretation of PTS surveys typically relied heavily on wellbore simulation. To match a model to observations a trial and error procedure must be followed to determine location and individual feed zone contribution both in terms of mass and enthalpy in the two-phase part of the well. The contribution of individual feed zones is usually seen as increases in fluid velocity. An estimation of the feed zone enthalpy must be made in order to convert velocity changes to mass contributions. If a well has a particularly cold shallow feed zone or a thief zone, there is a decrease or no change in spinner velocity. In those circumstances the interpretation becomes difficult.

In the past we have used pressure gradient of the well to estimate minimum flowing enthalpy. As long as the friction losses are small and can be neglected this method provides an estimate of flowing enthalpy that agrees reasonably well with measured wellhead enthalpy. The assumption of small friction losses, however is only valid in the deeper part of the well where fluid velocity is small.

We set out to develop a simple method to estimate the mass and energy distribution in the wellbore so that we could calculate the location and contribution of the individual feed zones.

THEORETICAL BACKGROUND

In wellbore simulation for every section of the well there are two main unknowns: the liquid holdup and the friction loss. The liquid holdup is the ratio of the area of the pipe occupied by liquid to the total area. This ratio depends on the velocity of the individual phases. Steam is expected to flow faster than liquid. The difference between the two velocities is called slip velocity. Instead of liquid holdup (f_l), volumetric gas fraction (f_g) can be used, the two are related by equation (1).

$$f_g + f_l = 1 \tag{1}$$

Modern treatment of two-phase flow in vertical wells describes four different flow regimes: bubbly, slug, churn and annular. Some other regimes are also mentioned such as dispersed bubbly (Hasan and Kabir, 2002) and wispy annular (Collier and Thome, 1996). For each of those flow regimes holdup and friction loss expressions are available in Hasan and Kabir (2002).
For each section of the well the flow regime must be determined first in order to apply the corresponding equations of liquid holdup and friction loss. This requires knowing mass flow and enthalpy. For geothermal wells these variables are measured only at the surface, therefore the analysis must start by defining the feed zone locations and contributions that determine the mass flow and enthalpy variation along the well.

The homogenous and drift flux models

To determine liquid holdup two models are available: homogenous flow and separated flow. The homogeneous flow model provides a simple treatment of two-phase flow. It assumes that both phases can be treated as a single fluid moving at the same velocity with no slip velocity. Appropriate expressions for density and viscosity are used. The mixture density of the two-phase fluid is related to volumetric gas fraction (f_g) as

$$\rho_m = (f_g)\rho_g + (1 - f_g)\rho_l \tag{2}$$

where ρ is density and the subscripts *m*, *l* and *g* refer to mixture, liquid and gas. The same expression using viscosity instead of density can be applied to calculate average viscosity and corresponds to the Dukler formulation described in Hasan and Kabir, (2002). Under non-slip conditions, characteristic of homogeneous flow, the flowing fluid density or mixture density is equal to the static density or mass averaged density.

Contrary to the homogeneous flow model, separated flow models treat each phase separately. These models account for different velocity of the phases or slip velocity. One of the most common models used to describe two-phase flow is the drift flux model as described by Hasan and Kabir (2002). This model can be used without reference to any particular flow regime for high pressure steam-water mixtures according to Collier and Thome (1996).

The flowing gas volumetric fraction (f_g) according to the drift flux model can be expressed as follows.

$$f_g = \frac{v_{sg}}{C_o v_m + v_\infty (1 - f_g)^n} \tag{3}$$

where v_{sg}, v_m, C_0, v_∞ are gas superficial velocity (volumetric gas rate divided by total pipe area), total superficial velocity (total volumetric rate divided by pipe area), flow parameter and terminal-rise velocity respectively. The exponent *n* can range from 0 to 3 depending on flow regime (Kleinstreuer, 2003). Ansari et al. (1994) found that a value of 0.5 provided the best fit to their data.

The flow parameter C_0 , also called “concentration factor” is an empirical factor that accounts for the fact that the velocity profile and the void or “bubble concentration” profile across the pipe may vary independently of each other. If the void fraction profile is uniform across the pipe then the flow parameter C_0 is equal to 1 (Kleinstreuer, 2003). The recommended value of this parameter, however, is 1.2 based on experiments in 1- to 2-in diameter pipes. For steam-water flow at elevated pressures a value of 1.13 is recommended (Collier and Thome, 1996).

The terminal-rise velocity is the velocity of a single bubble rising in an infinite liquid medium. An expression for this velocity as recommended for high pressure steam-water mixtures (Collier and Thome, 1996) is the following.

$$v_\infty = 1.41\left[\frac{\sigma g(\rho_f - \rho_g)}{\rho_f^2}\right]^{0.25} \tag{4}$$

In this equation σ, g, ρ are surface tension, gravity constant and density respectively. The subscripts *f* and *g* refer to liquid and steam respectively. In two-phase flow gas and liquid density as well as surface tension are functions of pressure or temperature as they are related by saturation conditions. The terminal-rise velocity varies very little with pressure, it changes between 0.21 and 0.19 m/s for pressures between 6 and 30 bar.

According to Collier and Thome (1996), for the drift flux model to be applicable, the terminal-rise velocity must be significant with respect to the volumetric velocity ($v_\infty > 0.05\ v_m$). This is not the case for many geothermal wells.

Flow in a typical well occurs mostly in the high velocity flow regimes: churn and annular. Churn flow is sometimes also referred to as semi-annular, annular-slug or froth flow. It is characterized by the liquid phase being mainly displaced to the pipe wall with the vapor flowing in a chaotic manner through the liquid. Annular flow is characterized by the vapor phase flowing in the core of the pipe while the liquid phase is dragged along the pipe walls forming an annulus. A fraction of the liquid, sometimes most of it, flows as droplets entrained in the gas core (Hasan and Kabir, 2002).

A volumetric steam fraction of 0.52 is the criteria for transition from slug to churn flow (Hasan and Kabir, 2002). Figure 1 shows the pressure below which the volumetric steam fraction is larger than 0.52 as a function of enthalpy. Figure 1 also shows the flashing pressure for liquid at that enthalpy.

As can be seen in Figure 1 at low enthalpies there is very little difference between flashing pressure and the pressure required to reach churn flow. It can be shown that a volumetric gas fraction greater than 0.52 is reached less than 200 m above the flashing level for fluid enthalpy below 1100 kJ/kg. The criteria for transition from churn to annular flow is when the gas fraction is greater than 0.52 and the gas velocity exceeds that given by equation (5).

$$v_{gs} = 3.1\left[\frac{\sigma g(\rho_f - \rho_g)}{\rho_g^2}\right]^{0.25} \tag{5}$$

where the symbols have the same meaning of equation (4). As the flow gets dryer the terminal-rise velocity term disappears from equation (3) as f_g gets closer to 1. The flow parameter C_0 can be set to 1 in annular flow according to Kleinstreuer (2003). The assumption of homogeneous flow is made for the equivalent of annular flow, called "mist" flow, in the Duns and Ros two-phase flow correlation (Hasan and Kabir, 2002).

Depending on pressure and flow rate a well can transition directly from slug to annular flow without going through churn flow.

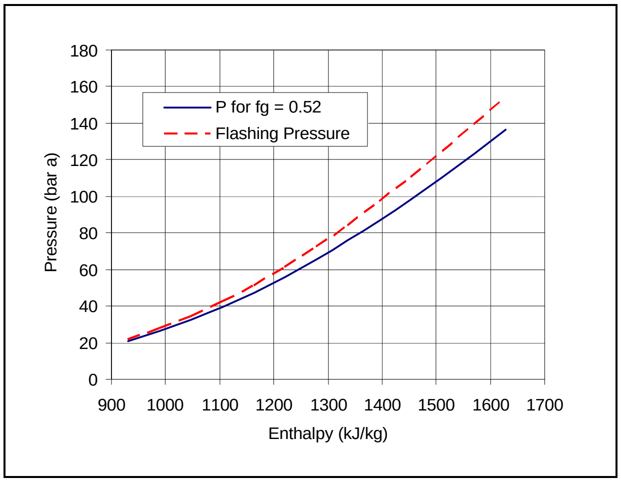

Figure 1: Pressure below which volumetric steam fraction is larger than 0.52 and flashing pressure for liquid at that enthalpy.

The gas velocity given by equation (5) is called "terminal velocity" in oil and gas literature. It has been described as the minimum velocity required by gas to carry liquid droplets in suspension (Coleman et al. 1991). In gas wells when the gas velocity is below the "terminal velocity" the well starts to "load up" or accumulate liquid in the wellbore and flow eventually stops. This usually leads operators to replace the production tubing with a smaller diameter in order to extend the well life.

Experimental results have shown that at high fluid velocity flow behavior evolves towards homogeneous flow. This is known as the "mass velocity" effect. Mass velocity is actually a velocity per unit area and it is defined as mass flow divided by pipe area. Experimental evidence suggests that at mass velocities larger than 1000 kg/m^{2}s fluid behavior approaches homogeneous flow and results match predictions of homogeneous flow at mass velocities of 2000 kg/m^{2}s (Collier and Thome, 1996).

Experimental results for large diameter pipes such as those used in geothermal wells, however, are not available. We expect that the transition should occur at lower mass velocities in large pipes. The reason is that the wall shear effect that creates the bubble concentration profile will affect a smaller fraction of the pipe area in a large diameter than in a small diameter pipe.

The working hypothesis for this paper is that flow velocity is large enough so that there is no slip velocity and the flow is homogenous. Our experience in matching PTS surveys shows that this assumption should be reasonable for volumetric gas fraction greater than 0.52 and fluid velocities greater than 3 m/s.

Friction factor considerations

The equation that describes the total pressure gradient in a well is composed by three terms: gravity term, friction losses and acceleration term as shown in equation (6)

$$\frac{dP}{dz} = \rho_m \frac{g}{g_c}\cos\theta + \rho_m \frac{f v_m^2}{2 g_c D} + \rho_m \frac{v_m}{g_c}\frac{dv_m}{dz} \qquad (6)$$

where z, dP/dZ, ρ_m, g, D, f, v_m, θ are measured depth, total pressure gradient, mixture density, gravity constant, pipe diameter, Moody friction factor, mixture velocity and angle with respect to vertical. g_c is a conversion factor equal to 1 for metric units and 32.17 for English units.

We can write equation (6) as follows

$$\rho_m = \frac{\dfrac{dP}{dz}}{\dfrac{g}{g_c}\cos\theta + \dfrac{f v_m^2}{2 g_c D} + \dfrac{v_m}{g_c}\dfrac{dv_m}{dz}} \qquad (7)$$

In a PTS survey the total pressure gradient (dP/dz) is known as well as all other variables in the right hand side of equation (7) with the exception of the Moody friction factor *f*.

For the estimation of the Moody friction factor we will take advantage of our assumption of large fluid velocity. In this condition Reynolds numbers are large. For large Reynolds number (Re > 10^6) the friction factor depends only on relative pipe rugosity. For example, in a 0.25 m diameter steel pipe with gas volumetric fraction of 0.52 the Moody friction factor will become dependent mostly on pipe relative rugosity when fluid velocity is greater than 1.1 m/s for pressure between 6 and 30 bar.

Relative rugosity changes along the well with diameter and absolute rugosity. To account for these variations the following approximate relationship derived from the Coolebrook-White equation can be applied.

$$f_1\left[\log(\frac{\varepsilon_1}{D_1})\right]^2 = f_2\left[\log(\frac{\varepsilon_2}{D_2})\right]^2 \qquad (8)$$

In this equation *f*, *ε* and *D* are Moody friction factor, absolute pipe rugosity and pipe diameter. Subscripts *1* and *2* refer to two different pipe sections. Obviously it cannot be used for smooth pipe sections. At lower fluid velocities the Reynolds number may not be large enough for the friction factor to be independent of fluid velocity. In this case, however friction losses may not be too important and errors in the friction factor will not affect too much the estimate of density.

Fluid velocity, mass flow and energy

For fluid velocity we use the spinner calculated fluid velocity. The spinner fluid velocity has been proven to be proportional to mass average velocity and not to mixture velocity (Gang et al., 1990). Both definitions of velocity in two phase flow, however, are equivalent for homogeneous flow.

By solving equation (7) for every section of the pipe we will end up with a profile of calculated fluid density as a function of measured depth. Since fluid velocity and pipe cross section are also known, a graph of mass flow versus depth can be constructed. Gas mass fraction or flash *x* can be calculated once density is known using the following relationship

$$x = \frac{V_m - V_f}{V_g - V_f} \qquad (9)$$

where V is the specific volume or inverse of density. Subscripts *m*, *f* and *g* refer to mixture, liquid and gas respectively. Liquid and gas specific volume are calculated at corresponding pressure of pipe section. Once flash is known enthalpy can be calculated using standard thermodynamic relationships.

Internal energy per unit mass for a section of the pipe with no feed zones is calculated by adding fluid enthalpy, heat losses, kinematic and potential energy components. The internal energy for a given point in the pipe is given by equation (10)

$$U = h + q + \frac{v_m^2}{2g_c} + \frac{g}{g_c}H \qquad (10)$$

where U, h, q, v_m , g and H are internal energy, enthalpy, heat loss, fluid velocity, gravity constant and elevation. g_c is set to 1 in metric units and 32.17 in English units. The units of the three terms must be consistent. The wellhead is a good reference point to set the elevation term to zero. The kinematic and elevation energy terms are small compared to enthalpy. The kinematic term for a fluid velocity of 50 m/s is only 1.25 kJ/kg. The elevation term is -9.81 kJ/kg 1000 m below wellhead elevation. Both terms decrease with well depth therefore the enthalpy increases slightly with depth.

Using this method, graphs of mass and internal energy versus depth can be constructed. The selection of the friction factor will change the shape of the curves. Ideally the mass flow rate and internal energy graphs should look like a sequence of straight lines with step changes at the feed zones. The size of the change in each curve makes it possible to calculate the mass and enthalpy of the feed zones.

Measured wellhead mass flow and enthalpy can also be used to constraint the friction factor even more. The wellhead values are used to calculate a curve of fluid velocity versus depth in the cased part of the well. This helps in constraining the spinner derived fluid velocity.

The calculated mass and internal energy curves are normalized by dividing them by the wellhead mass and internal energy. This produces two curves that when the correct friction factor is selected form two straight lines in the cased part of the well that coincide at the value of one.

This method in which homogenous flow is assumed and friction factor calculated to match observed total pressure gradient has been used before. It is called, not surprisingly, the “friction factor” model (Collier and Thome, 1996). The main difference with our application is that it will be applied to interpretation of PTS surveys and the shape of the mass and energy curves versus depth is used to determine the correct friction factor. A good matching friction factor should represent the proper balance between gravity and friction effects in the total pressure gradient.

APPLICATION OF THE METHOD

We will apply this method to well A in the Bulalo geothermal field in the Philippines. Well A is a directional well cased to 975 m measured depth with a 0.273 m (10 ¾”) tie back. The slotted liner diameter is also 0.273 m down to 2195 m and 0.219 m (8 5/8”) down to total depth at 2746 m.

Fluid velocity

We have to correct the fluid velocity obtained from the spinner to reflect a consistent set for the entire well. We have observed that in the vertical section of the well the spinner measures higher velocity than in the non-vertical section of the well. This is clearly seen at the directional kick-off of the well and we call it "kick-off" effect. It is believed that this is due to the spinner traveling close to the center of the pipe in vertical parts of the well where fluid velocity is larger. In non-vertical parts of the well the spinner travels close to the pipe wall and fluid velocity is smaller. Figure 2 shows the well angle in degrees as well as the uncorrected and angle effect corrected fluid velocities.

The upper part of the well is cased-off therefore the estimation of fluid velocity using wellhead pressure, enthalpy and mass flow should be reliable. The calculated fluid velocity in the upper part of the well is also plotted and it serves as a guide to make the angle correction. This velocity is shown as calculated in Figure 2. The lower velocity observed below 830 m is due to completion effects.

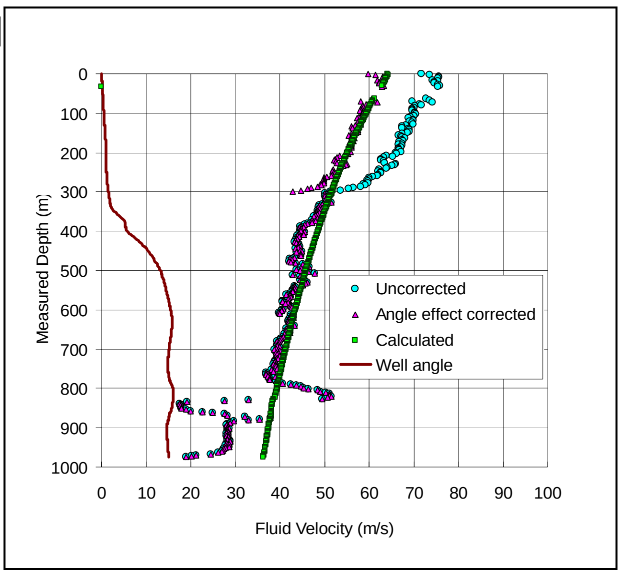

Figure 2: Comparison of fluid velocity from PTS survey uncorrected, corrected by angle effect and calculated using wellhead measured mass flow and enthalpy and survey pressure. Well angle is degrees also shown.

The angle correction is made by dividing the fluid velocity in the vertical part of the well by a factor (1.2 in this case). We have found that segments where the well angle is less than 1.5 degrees can be approximated as vertical. The angle effect shows clearly that PTS derived fluid velocities depend on the location of the tool with respect to the well center. It is expected that by doing the angle correction we will end up with a consistent set of velocities for the entire well. Matching calculated fluid velocities in the cased part of the well we expect the PTS velocity to reflect the average fluid velocity for the entire well.

Fluid density

The next step in the calculation is to apply equation (7) to calculate fluid density. Then calculate mass flow rate and internal energy as given by equation (10). The wellhead measured pressure for this wells is 18.7 bar a, mass flow is 52.9 kg/s. Wellhead enthalpy is 1839 kJ/kg and internal energy is 1840 kJ/kg. Calculated mass flow and internal energy are then normalized by dividing them by the wellhead values.

For this case we neglected heat losses. We also neglected the kinematic term in equation (7). This term was calculated after the solution was reached and it was confirmed that it represents only a small fraction of the total pressure gradient.

The process of estimating the friction factor by trial an error is illustrated in Figure 3. This figure shows the normalized curves that result from selecting too low a friction factor (0.005) and too high a friction factor (0.02).

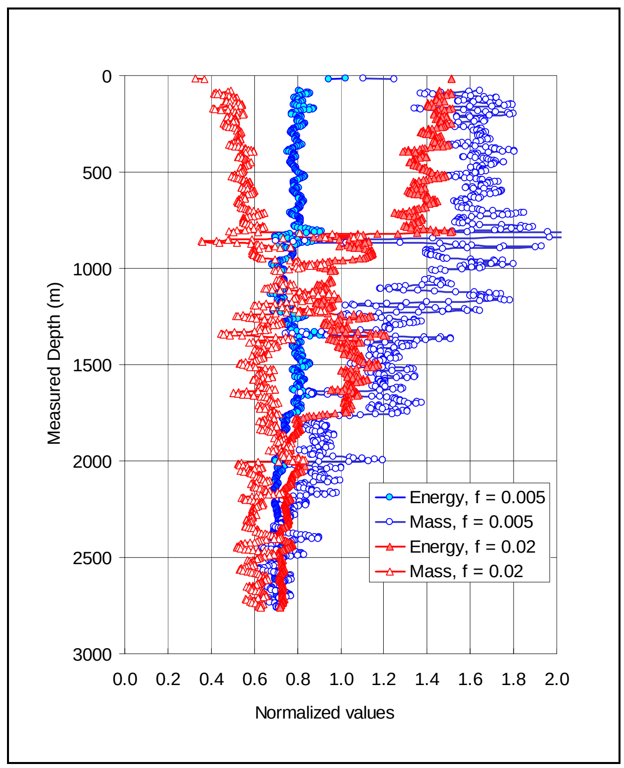

Figure 3: Normalized mass and energy curves for two selections of the Moody friction factor: 0.005 (circles) too low a value and 0.02 (triangles) too high a value.

Figure 3 shows how the selection of friction factor does not affect significantly the deepest part of the well. The reason is that fluid velocity is low enough for friction to be a small component of the total pressure gradient although fluid velocity at the deepest part of the well is still more than 6 m/s. The mass and energy curves move in opposite direction with variations of the Moody friction factor *f*. This makes selection of the correct friction factor easier. Another important feature is that curves are not straight when the friction value is not correct. This may be sometimes difficult to assess due to the noise characteristic of PTS surveys.

Figure 4 show the normalized curves for a friction factor on 0.0097. This selection of the Moody friction factor produces two curves that are composed of straight segments. The mass curve should increase in steps from bottom to top of the well unless there is a "thief" zone, with the steps corresponding to feed zone locations. The enthalpy may increase, decrease or remain the same depending on the enthalpies of the feed zones. The upper cased part of the well should show two straight lines coinciding at the value of 1. This means that the wellhead measured values are being honored. The possibility of errors in the wellhead measurements should always be kept in mind when a match is difficult to achieve.
For the calculation of the slotted liner part of the well it was assumed that the well diameter is the diameter of the slotted liner and the pipe rugosity equals that of the normal steel pipe (0.046 mm) used in the cased part of the well. We justify this selection by noting that the absolute pipe rugosity (ε) should be higher than that of the non-slotted pipe but the diameter should also be larger than the one used. Therefore relative pipe rugosity (ε/D) should not change too much. This assumption may not work as well for mass flow calculations. Those depend on using actual pipe area with fluid velocity and density to obtain mass flow. This aspect of the calculation can cause discontinuities at the contact between casing and slotted liner as well as at different diameter contacts and it is being revised at this time.

Once the friction factor is selected some additional interpretation must be done. Feed zones must be located and their contribution in terms of mass and enthalpy must be determined to match the flowing profiles.

Table 1 shows our interpretation of the location and contribution of each feed zone for well A. A feed zone at the top of the 10 ¾" liner at 831 m was added to improve the match. To corroborate the thief zone at 1116 m, the flowing wellbore pressure was compared to reservoir pressure and it was found that wellbore pressure is indeed larger than reservoir pressure at this elevation.

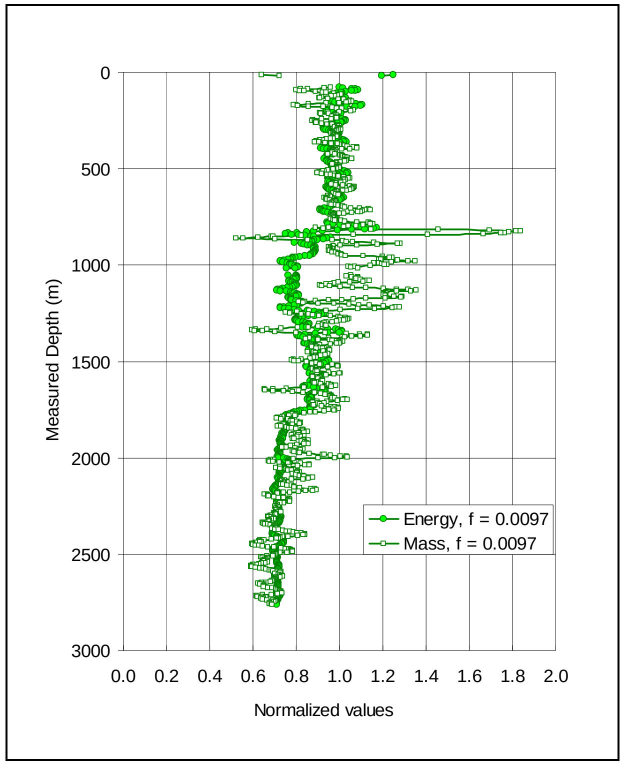

Figure 4: Normalized mass and energy graphs for correct selection of Moody friction factor: 0.0097.

Depth (m)	Flow (kg/s)	Enthalpy (kJ/kg)
831	5	2791
975	9	2791
1116	-28	N/A
1250	19	977
1768	8	2791
2134	5	1861
2775	38	1326

Table 1. Depth and contribution of feed zones in well A

Figure 5 shows the final calculated mass flow and enthalpy variation with depth compared to the expected variation assuming the mass and enthalpy contributions of the feed zones described in Table 1.

This figure shows that assuming constant enthalpy between feed zones is a good approximation. The entire well can be matched reasonably well.

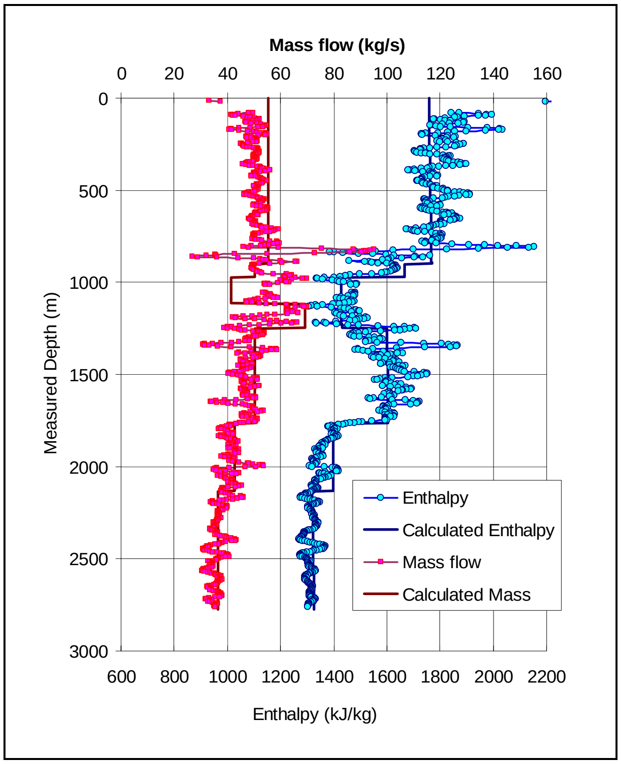

Figure 5: Interpretation of variation of mass flow and enthalpy with depth. Feed zone depths and contributions are shown in Table 1.

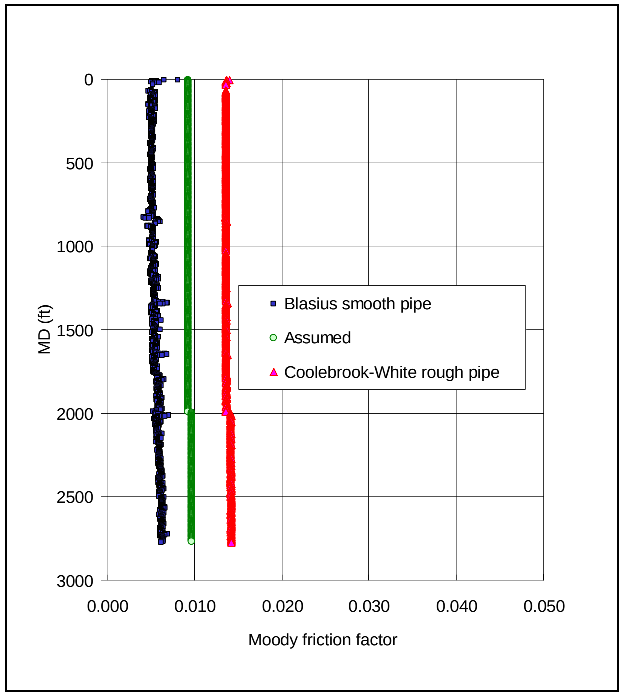

Figure 6: Comparison of assumed Moody friction factor obtained from this analysis with values for smooth pipe (Blasius) and rough pipe (Coolebrook-White).

Consistency of results

A very valid question is how consistent is the obtained friction factor with respect to more conventional ways of calculating it. Figure 6 shows the comparison of the friction factor calculated using Blasius smooth pipe friction factor formula, Colebrook-White equation for rough pipe and the assumed value obtained with this method. Interestingly enough the results fall in between the two values. The absolute rugosity required by the Colebrook-White equation to match the observed results is 0.0064 mm.

In order to check independently the consistency of the results with a different method, the feed zone contributions shown in Table 1 were simulated in our wellbore simulator using the Duns and Ros correlation (Hasan and Kabir, 2002) and also the Orkiszewski correlation (Brill and Beggs, 1991). Both correlations use the same formulation (Duns and Ros) for the "mist" flow regime. The measured and calculated temperature pressure and mixture velocity are shown in Figure 7.

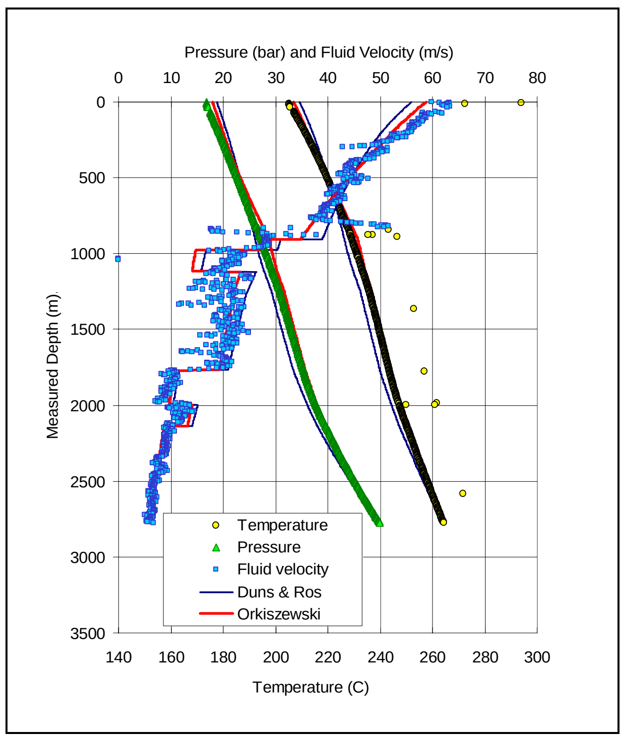

Figure 7: Wellbore simulator match of pressure, temperature and mixture velocity using Duns & Ros (blue) and Orkiszewski (red) correlations.

As expected the results are different because the holdup and friction loss treatment in the correlations may be different from the one used here. The Orkiszewski correlation shows a better agreement than Duns and Ros.

CONCLUSIONS

The method for PTS survey interpretation presented in this work has been applied to more than 10 wells in Unocal. In most cases it has shown results that are consistent with our previous interpretations. Sometimes, however it shows unexpected results that offer alternative and interesting interpretations.

Contrary to normal methods of solution in two-phase flow in which the holdup is calculated separately from friction losses, this method offers the possibility of balancing the gravity and friction components of the total pressure gradient by selecting the friction factor that makes the profiles of mass and internal energy consistent.

Including reliable wellhead measurements of mass and enthalpy improves the precision of the method. These measurements, however are not strictly required. It is possible to determine a friction factor that provides the correct shape of mass and energy curves with depth without wellhead measured values.

The main limitation of the method is that assumptions made for its derivation require fluid velocity to be large enough so homogeneous flow can be assumed. We have found that as long as the fluid velocity is larger than 3 m/s the method works well. In lower enthalpy high diameter wells we found some inconsistencies possibly related to low flow velocity.

This method has provided an alternative way to check consistency of feed zone location, enthalpy and mass flow rate contributions found with our conventional trial and error wellbore simulator based method. It has also provided an unprecedented level of resolution in the interpretation of two-phase sections in flowing geothermal wells.

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