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Accurate Prediction of Feed Enthalpy and Mass Flow using Flowing Survey Analysis Workflow by Combining Production Logging Analysis (PLA) and Wellbore Simulation

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ABSTRACT

Wellbore simulation is used to build a well model based on the flowing PTS logs. The solution is usually non-unique for multiple feed wells since feed parameters such as enthalpy and mass flow are assumed arbitrarily based on a broad range of values. A workflow that combines production logging analysis (PLA) and wellbore simulation using flowing PTS data was developed to derive a more accurate estimate of feed enthalpy and mass flow. PLA generates volumetric gas and liquid flow rates per feed using pressure, temperature, fluid velocity and pressure-derived density using multiphase flow correlation. Standard thermodynamic relationships are used to convert volume to mass flow rates and calculate enthalpy per feed. A well model is constructed using wellbore simulation by matching flowing pressure, temperature, fluid velocity and bore output curve. The workflow was tested and validated using multiple flowing survey data. The number of iterations in the simulation is significantly reduced with increased confidence in the well model. The well model will serve as a baseline for future intervention. Furthermore, these well model parameters are inputs to the reservoir model, analytics project and well design and therefore can increase prediction accuracy.

1. INTRODUCTION

Pressure, temperature and spinner (PTS) data obtained during well discharge are valuable information in diagnosing overall well performance. The result of the PTS interpretation can give insights into the characterization of the individual feed zones. Conceptual model of a well is created based on the flowing survey interpretation, which serves as a reference model. Operation of the well can be optimized based on feed performance as understood from the model. Effects of well intervention to the output of the well such as relining, zone's permeability enhancement through acidizing can be determined from the model. Output-affecting scenario such as blockage, feed impairment, pressure drawdown and cooling can also be run as diagnostics when well's output declines.

Therefore, an accurate conceptual model of the well can be a very valuable baseline reference throughout the whole well utilization. Crucial to creating a good conceptual well model is the accuracy of input parameters such as productivity index, mass flow and enthalpy of each feed zone. For a geothermal well, estimating these values is not straight forward due to the difficulty in two-phase flow measurement and analysis. Current interpretation involves trial and error wellbore simulation. Arbitrary estimates of these parameters are used to match measured downhole data and wellhead parameters. However the result of the simulation is a non-unique solution. Multiple combinations of feed parameters will match the measured data. Acuña and Arcedera (2005) evaluated the use of drift-flux and homogenous flow models for application in two-phase flow in geothermal wells.

Here, a workflow is developed to determine a more accurate mass flow and enthalpy, and create a reliable conceptual model of the well. The proposed workflow integrates production logging interpretation and a wellbore simulation to analyze a flowing survey data. The workflow is shown in Figure 1.

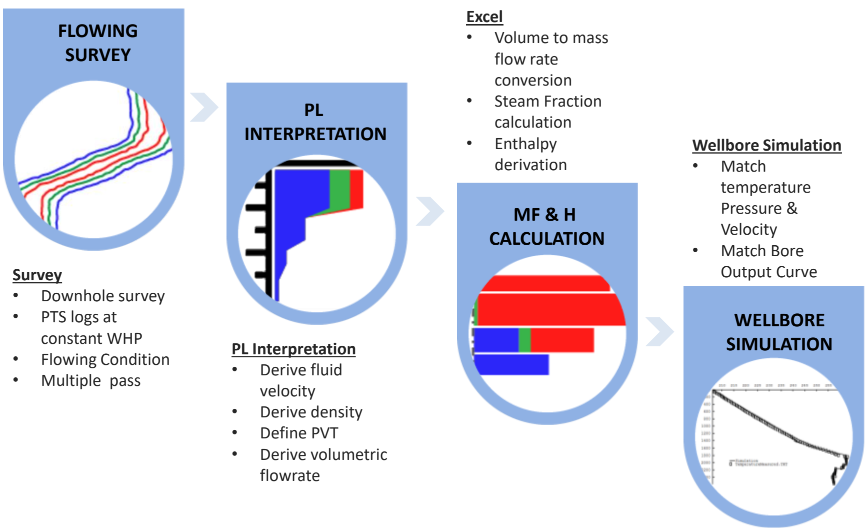


Figure 1. Proposed workflow by combining PL interpretation and wellbore simulation in analyzing PTS flowing survey data.

2. FLOWING SURVEY

Pressure, Temperature and Spinner (PTS) data with depth are recorded at constant discharge condition during flowing survey. A downhole PTS tool, capable of withstanding fluid temperature up to 300^{o}C is run in hole from surface down to the well's maximum cleared depth. Multiple passes are obtained to get spinner response at different logging speed. Figure 2 shows an example of PTS profiles obtained during a flowing survey.

Location of the permeable zones and flash depth is readily inferred from the raw data logs. Producing zones show increase in spinner response, signifying additional flow contribution. Due to the high velocity nature of the flow above flash point permeable zones are sometimes masked at this region. Therefore, records such as completion tests and drilling indicators should be correlated in the flowing survey. Changes in wellbore ID can also be reflected by the spinner response.

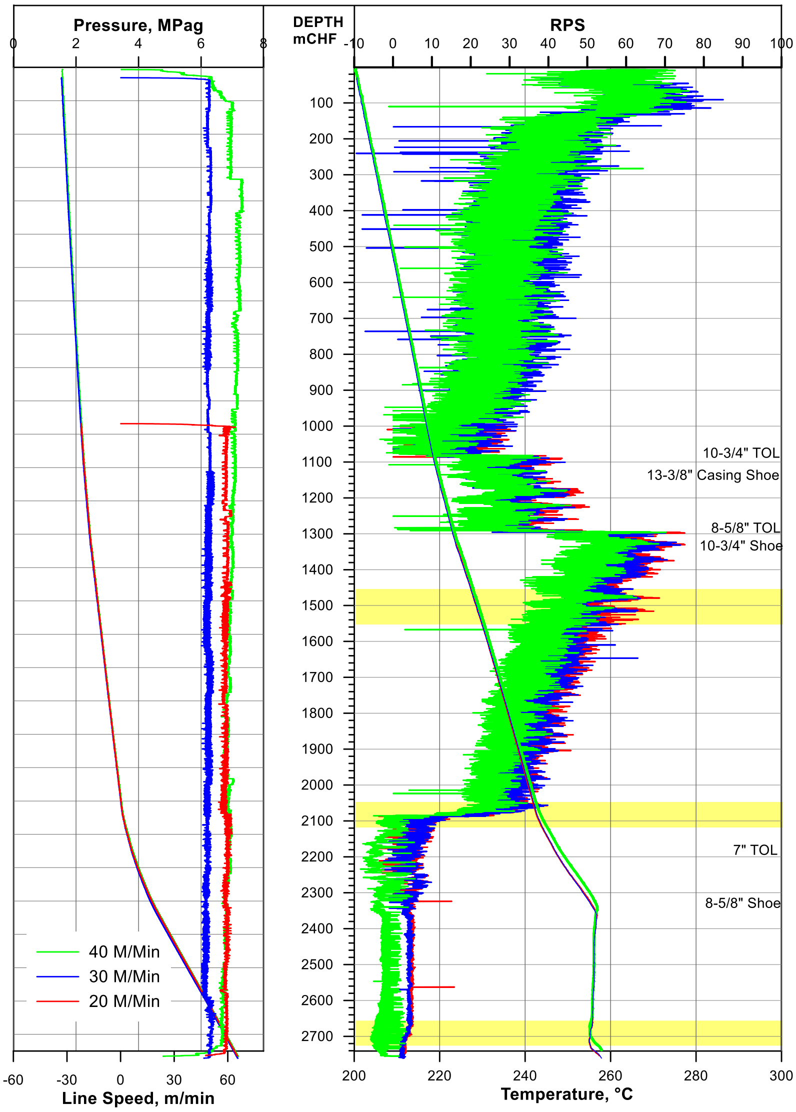


Figure 2. Flowing PTS logs at different line speed of Well 1 at constant discharge condition.

For the purpose of this paper, three (3) sets of flowing PTS data taken from different well are used as test cases for the proposed workflow. Discharge parameters of each well are listed in Table 1. Figure 2 is also the PTS profile of Well 1 at different line speed.

Table 1. Discharge parameters from different well that were surveyed using PTS.

Parameters	Well 1	Well 2	Well 3
WHP, MPa	1.6	1.2	0.6
Mass Flow, kg/s	31.3	29.5	28
Water Flow, kg/s	14.7	17.7	18.3
Steam Flow, kg/s	13.9	8.9	6.9
Enthalpy, kJ/kg	1608	1311	1202

3. PRODUCTION LOGGING INTERPRETATION

A detailed discussion in converting spinner into flow rate per feed is shown in the paper by Buscato, 2012. An automated production logging interpretation software called Emeraude was used to analyze the flowing PTS data. Production logging interpretation generally aims to characterize well performance through integrated analysis of production logs.

For PTS logs, a response curve is generated to calibrate spinner response at different line speed. This will result to a velocity profile representing fluid flow in the wellbore. For flowing survey, the velocity increases and phases shift as the fluid flashes. It is therefore recommended to calibrate spinner response at each of every zone to ensure that fluid property changes are captured.

The velocity profile generated using the spinner calibration represents the two-phase flow inside the wellbore. An automated process inherent to software is used to extract liquid and gas flow rates. Estimate on the density profile and the choice of flow correlations are two crucial components in deriving both components.

Density is derived using pressure derivative at depth interval using the formula in *equation 1*. To be able to calculate individual liquid and gas volumetric flow rate, each phase property are be defined separately.

$$\rho_{gr} = \frac{\Delta p_t}{g\Delta z} = \rho \cos(\theta) + \frac{\Delta p_f}{g\Delta z} + \frac{\Delta p_a}{g\Delta z} \qquad (1)$$

Where $\rho_{gr}, \Delta p_t, \Delta p_f, \Delta p_a, \rho, \theta$ and Δz are density from pressure derivative, local total pressure drop, friction component, acceleration component, fluid density, deviation angle and change in depth, respectively.

Multiphase flow correlations provide the values that cannot be measured. Based on mechanistic, experimental or a combination of both types of works, the authors proposed Slip models that are often a function of the flow regime. It is important to understand that the correlations are models, and none of them is an absolute truth. They have limitations and ranges of applicability, and therefore the accuracy of the interpretation will depend on the interpreter's choice, and the capacity of the correlation to model the downhole conditions.

Different flow correlations were considered in the analysis. But among the available models, Petalas and Aziz correlation were observed to arrive at the closest to the total surface value. Petalas and Aziz can capture a mechanistic model for all pipe inclinations, geometry, and fluid properties. The empirical correlation involved in the model were developed based on the Multiphase Flow Database of Stanford University gathering 20,000 laboratory measurements and 1800 measurements from actual wells (Petalas and Aziz, 1996).

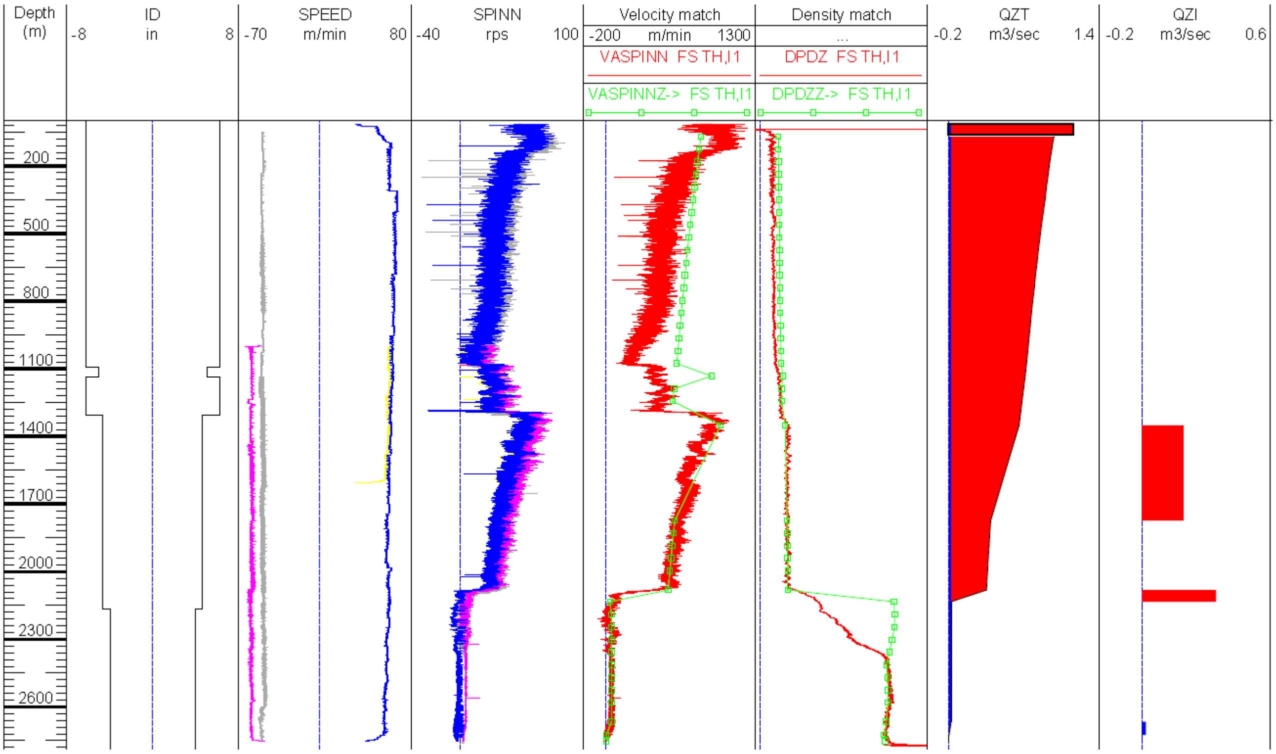


Figure 3. Emeraude illustration on visualization of velocity and density matching and generating flow contribution per feed.

Using the said flow correlation of liquid-gas model, simulated velocity and density are made to match the measured and or pressure derived values to generate a volumetric flow rate at different feed zones. Figure 3 illustrates the whole process described above for the case of well 1. QZT and QZI are the cumulative and individual feed contribution, respectively.

3.2 Mass Flow Rate, Steam Fraction and Enthalpy

The output of the production logging interpretation is volumetric flow rates for both liquid and gas of each feed zone. Using the respective gas and liquid density based on the flowing and temperature condition at each feed zone, volumetric flow rate can be converted to mass. Standard thermodynamic relationship shown in Equations 2 and 3 are used to derive the steam fraction *x* and mix enthalpy *Ht*, respectively.

$$x = \frac{SF}{SF+WF} \quad (2)$$

$$H_t = xh_g + (1-x)h_f \quad (3)$$

Where *SF*, *WF*, h_g and h_f are steam flow, water flow, gas enthalpy and liquid enthalpy, respectively.

Calculated mass flow steam fraction and enthalpy for each well are shown in Table 2. The total mass flow of the individual feed is not always exactly the same compared to the measured discharge output. One factor considered is that effective diameter is not entirely known since the measured flow is affected by the combination of slotted liner and annular space between the liner and hole. Therefore the derived value is corrected using ratio and proportion.

Table 2. Derived mass flow, steam fraction and enthalpy from the production logging interpretation result.

Well 1 Feed Zone	**Mass Flow**	**Steam Fraction**	**Enthalpy**
1	3.5	100%	2803.3
2	9.0	80%	2447.4
3	18.8	0%	1114.0
Well 2 Feed Zone	**Mass Flow**	**Steam Fraction**	**Enthalpy**
1	3.7	100%	2802.2
2	17.6	15%	1162.8
3	8.7	0%	1154
Well 3 Feed Zone	**Mass Flow**	**Steam Fraction**	**Enthalpy**
1	2.4300	100%	2800.1
2	1.1000	100%	2801.0
3	9.8400	7.9%	1176.7
4	10.180	0%	1017.8
5	4.4500	0%	899.51

4. WELLBORE SIMULATION

Wellbore simulation is conducted for each well with the calculated mass flow and enthalpy as input parameters. The simulated flowing pressure, temperature wellhead parameters and fluid velocity should be able to match the measured value. Other input parameters are reservoir pressure, casing profiles, feed location and discharge parameters, all of which can be directly measured.

Figure 4 to Figure 9 shows the simulation match between measured pressure, temperature, fluid velocity and bore output curve. A good match between predicted (simulated) and measured pressure, temperature, fluid velocity and bore output curve were obtained for all the modeled wells.

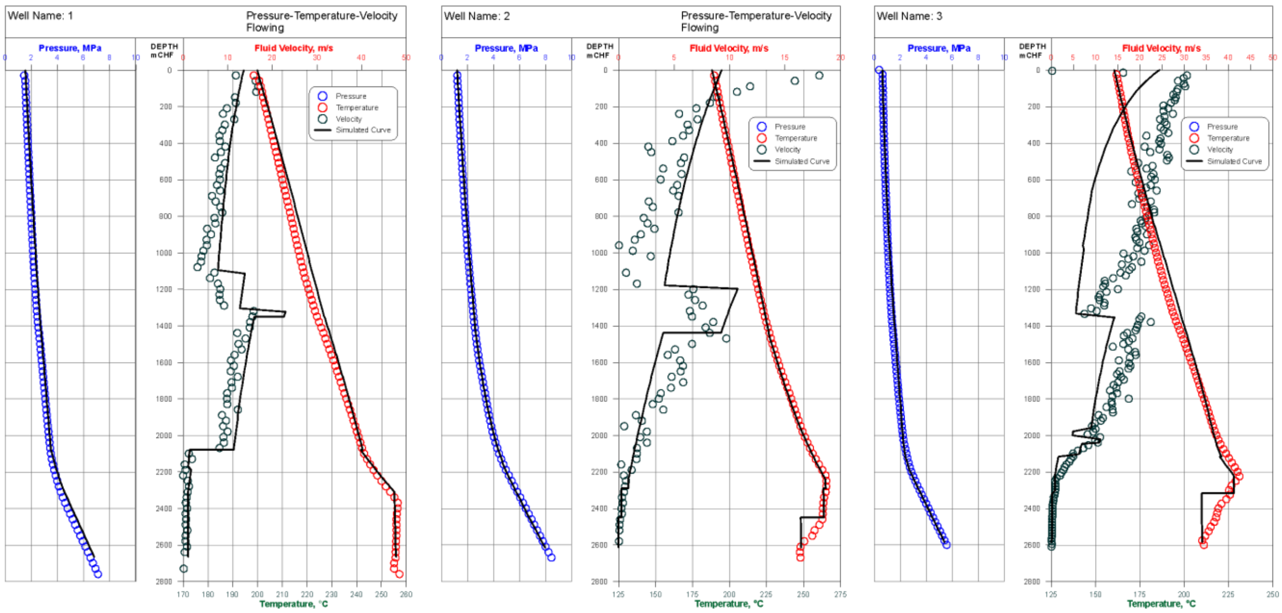
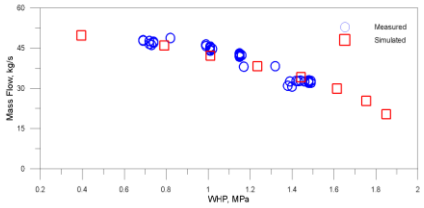


Figure 4. Wellbore simulation match on donwhole data for well 1 (left), well 2 (center) and well 3 (right)



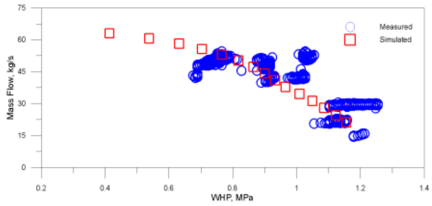


Figure 8. Simulated and measure bore output curve of well 2.

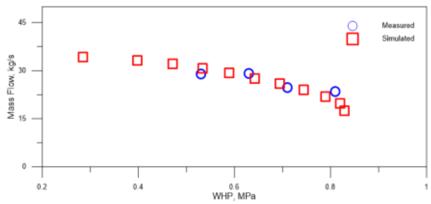


Figure 9. Simulated and measure bore output curve of well 3.

Figure .7 Simulated and measure bore output curve of well 1 (left), well 2 (center) and well 3 (right).

Wellbore model are very helpful in predicting well performance at different wellhead opening. These well model, created after drilling, will serve as baseline and will be useful in diagnosing well behavior during the course of well utilization. It can be used to determine the effects of reservoir processes such as pressure drawdown and cooling. Scenarios such as relining, feed enhancement from acidizing and wellbore blockage can be built from this model. It will be implemented in the model by tweaking the value of input parameters such as pressure, enthalpy and productivity index of individual feed.

5. CONCLUSION

Based on the result of the exercise, the following conclusions can be drawn:

1. Oil and gas production logging interpretation software can be used to estimate the flow contribution of each feed in terms of mass flow rate.
2. Standard thermodynamic relationship is used to convert volumetric flow rate to mass flow rate based on the measured flowing pressure and temperature.
3. Enthalpy is derived using the steam component calculated from the liquid and gas mass flow value.
4. The mass flow and enthalpy together with other measured parameters were used as input parameters in the wellbore simulation. The quality of the match between the simulated and the measured values validates that the derived value were likely accurate.

Throughout the course of well utilization, different cases can occur that will lead to the decline of the well. Being able to construct a more accurate baseline wellbore model is very helpful in diagnosing the likely cause of output decline. Scenario such as reservoir process such as cooling and pressure drawdown and blockage can incorporated in the model to match current output. Appropriate surveillance activities such as blockage, PTS, downhole video, etc. can be programmed to confirm the cause. Furthermore, the right well intervention can be implemented since the well has been properly diagnosed.

Another advantage of this can be applied to resource definition. A good well and feed characterization can always be a helpful insight to drilling new offset wells.

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