WELLBORE MODELLING OF DRY STEAM PRODUCTION FROM A MULTI-LATERAL GEOTHERMAL WELL

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ABSTRACT

Multi-lateral wells are commonly used in the oil and gas industry worldwide. A multi-lateral well has the same form as a standard well but has one or more fork holes from the same wellhead. By adopting the techniques from oil and gas the geothermal industry has recently been utilizing multi-lateral wells for their production and injection strategies. One of the ways to understand the fluid behavior inside a multi-lateral well is to carry out wellbore modeling. In this project, a multi-lateral dry steam production well is studied. The dry steam acts as a single-phase fluid in a homogeneous state, and the calculation of pressure drop can be made with a simple equation. The junction between the original hole and the forked hole is the crucial location in the wellbore as it is the point where steam from the original hole and the forked hole mix and flow up to the wellhead. A multi-lateral well will have an improved production capacity compared to a single well. Based on this study, a modified equation is given for the productivity capacity of a multi-lateral well, providing an improved method for predicting its performance.

1. INTRODUCTION

Geothermal developments are currently increasing in number, and knowledge for choosing the best development strategy plays an important role. One important part of the strategy is making a good decision about the type of production or injection wells that will be used. In the geothermal industry, there are two types of well that commonly chosen, namely: a standard-hole type and a big-hole type. The production capacity for a big-hole well is usually larger than that of a standard-hole well because of the difference in the geometry of the well. A geothermal development, from the perspective of an investor, should has the maximum production capacity with the lowest cost. Increasing the production capacity by considering the type of the well is not the only solution. Another alternative for increasing the production capacity is by introducing a multi-lateral system in a single well.

Multi-lateral wells are commonly used in the oil and gas industry. Multi-lateral wells require directional drilling technology (horizontal) that was first used in oil and gas resources which have a limited and narrow reservoir. Because of the reservoir conditions, precision is required in manoeuvring the course of drilling to the target area. Although, directional drilling also plays an important role in the geothermal industry, the main reason for utilization of multi-lateral wells is to increase production capacity. Careful planning is required for directional drilling in geothermal reservoirs in order to eliminate hazards such as wells becoming too close or inaccuracy the position of branches so that they do not reach geological targets.

A multi-lateral well is the same as an old well type. The only difference is there will be additional borehole(s) introduced by side-tracking from the original single well hole. Additional side-tracks in the well, will increase the production capacity without having to drill another hole from a new well pad. The use of multi-lateral wells may reduce the necessity of drilling make-up wells if the production zone is sufficient for running the power plant.

The production capacity of a well is closely related to the pressure inside the wellbore. The pressure inside the wellbore increases from top to bottom due to pressure losses or the pressure drop along the trajectory of the well. With knowledge of the pressure drop pattern in a multi-lateral well, the well performance can be thoroughly understood and it can be forecast for future production.

Currently the development of multi-lateral wells mostly happens in the oil and gas industry. The use of multi-lateral wells in geothermal projects is somewhat limited, especially in Indonesia. At least two wells are using the multi-lateral approach in Indonesia, located in the Awibengkok Geothermal Field (Stimac, Baroek, Pazziuagan, & Vicedo, 2010).

2. METHODOLOGY

Multi-lateral well data needs to be clear, including well geometry, pressure and temperature. From that data, a calculation can be made using a model based on the homogeneous phase equations. The calculation can be based on both top-down and bottom-up criteria depending on assumptions about parameters used in the calculation. Results from the model created are matched with actual well data and then an equation for determining the performance of a multi-lateral well is generated based on the model. A brief discussion regarding the economics of a multi-lateral well is given and comparison is made with a “traditional” hole to gain preliminary picture of the effectiveness of multi-lateral wells.

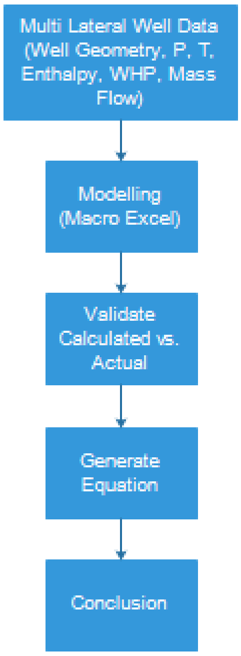

Figure 1. Work-flow for the study

3. MODELLING EQUATION

Modelling of single-phase, steam has its own characteristics. Compared to two-phase flow, modelling steam is simpler because the single-phase fluid acts as a homogeneous state. Thus, the homogeneous fluid flow equation will be used for creating the model.

We begin with the top-bottom option to solve the pre-calculation of the model. The parameters used include well geometry, mass flow rate, and wellhead pressure. To calculate the deliverability of a steam-phase well, the following simple equation can be used:

$$m = C(\bar{P}_r^2 - P_{wf}^2)^n \qquad (1)$$

Here

- m = mass flow rate (kg/s)
- C = is a constant matching the well performance (ton/day.bara^{2n})
- Pr = reservoir pressure (bara)
- Pwf = bottom hole pressure (bara)
- n = constant, represented by value of 0.5 for turbulent flow and 1 for laminar flow

Then we find the average pressure from wellhead pressure and a speculative ΔP (Pwf - Pwh). Then we can identify temperature, saturation, density of steam, and kinematic viscosity based on pressure gained from steam tables. Then we can calculate steam velocity (v_v), using:

$$v_v = \frac{m}{\rho_g((\frac{\pi}{4})d^2)} \qquad (2)$$

Where d is inside diameter of the casing and the rest are common or previously mentioned variables.

The model also requires the Reynold number (N_{re}) to differentiate between laminar flow and turbulent flow:

$$N_{Re} = \frac{\rho v d}{\mu} \qquad (3)$$

The transition condition is:

- $N_{re} < 2000$ = laminar flow
- $N_{re} > 4000$ = turbulent flow

The range between is transitional flow. Friction at the inside wall of the casing is also included in the calculation. The friction factor for laminar flow is:

$$f = \frac{64}{N_{Re}} \qquad (4)$$

For turbulent flow we differentiate between a smooth pipe (zero roughness value assumption) and a rough pipe (has roughness value). The friction factor for a smooth pipe, developed by Drew, Koo, and McAdams, is:

$$f = 0.0056 + 0.5\, N_{Re}^{-0.32} \qquad (5)$$

The friction factor for a rough pipe uses the Colebrook-White equation (1939):

$$f_c = \left[\frac{1}{1.74 - 2\log\left(\frac{2\varepsilon}{d} + \frac{18.7}{N_{Re}\sqrt{f_g}}\right)}\right]^2 \qquad (6)$$

Iteration is used to evaluate (6), starting with an assumed value of friction factor, where:

- fc = friction factor solution
- fg = assumed friction factor

The total pressure gradient equation is given by:

$$\frac{dp}{dz} = \frac{\frac{g}{g_c}\rho\cos\theta + \frac{f\rho v^2}{2g_c d}}{1 - \frac{\rho_g v^2}{g_c \bar{p}}} \qquad (7)$$

The equation can also be used for a bottom-up calculation and matching with measurement data.

Table 1. Top-down Approach

Data-1	Segment-1	Segment-2	Segment-3	Segment-4a	Segment-4b
Inclination	0.00	11.93	39.78	55.14	49.00
Pwh (bara)	11.50	11.62	12.24	16.91	16.91
M (ton/jam)	173.70	173.70	173.70	75	98.70
ΔPg (bara)	0.12	0.62	4.67	3.64	5.34
P rata2 (bara)	11.56	11.93	14.57	18.73	19.58
T.sat (C)	186.27	187.68	196.93	209.09	211.31
ρg (kg/m3)	5.91	6.09	7.38	9.42	9.84
µg (Pa.s)	2.15E-05	2.17E-05	2.32E-05	2.53E-05	2.58E-05
Vv (m/s)	44.64	43.32	82.34	45.83	57.75
Nre	5.91E+06	5.86E+06	8.34E+06	4.23E+06	5.47E+06
fg	0.012	0.01	0.01	0.01	0.01
fc	0.012	0.01	0.01	0.009	0.009
fg/fc	1.00	1.00	1.00	1.00	1.00
dp/dz	0.00208	0.00204	0.01116	0.00432	0.00676
ΔPc (bara)	0.12	0.62	4.67	3.64	5.34
ΔPg/ΔPc	1.00	1.00	1.00	1.00	1.00
Pwf (bara)	**11.62**	**12.24**	**16.91**	**20.55**	**22.25**

4. WELL GEOMETRY

In this study, the well geometry shown in Fig. 2 is used.

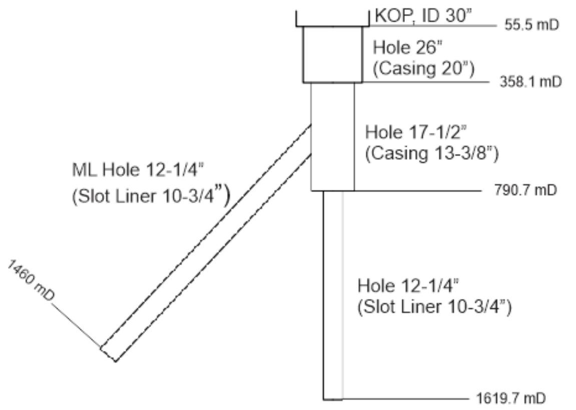

Figure 2. Simple well geometry (without scale)

The production well consists of five segments based on the casing geometry used. They are: Segment 1 (55.5 mD), Segment 2 (358.1 mD), Segment 3 (790.7 mD), Segment 4a (1619.7 mD), and Segment 4b (1460 mD) consisting of a multi-lateral/forked hole. There will be a different value of pressure drop on each segment. Based on the figure, the fluid flows from the bottom of each leg (original hole and forked hole) to the top. The junction in Segment 3 will become the mixing point of steam flow from Segment 4a and Segment 4b.

5. MODEL APPLICATION

The calculation of wellbore modelling for single-phase (steam) flow behavior is implemented in Macro Excel.

Segment 1, which is where the calculation is started, uses the known wellhead pressure for the system. The value is 11.5 bara (150 psia). From the baseline value of pressure, using mass flow rate based on actual deliverability data, we can continue to the next segment with the same equation, matching values continuously from one segment to the next. The mass flow rate is divided at the junction of Segment 3 based on actual data. The Pwf from Segment 3 is used as Pwh for both Segment 4a and Segment 4b. The values of assumed variables fg and ΔPg are determined by iteration until convergence with fg = fc and ΔPg = ΔPc. The results for bottom pressure of the original hole is 20.55 bara and 22.25 bara for the forked hole.

Table 2. Bottom-up Approach

Data-1	Segment-1	Segment-2	Segment-3	Segment-4a	Segment-4b
Inclination	0.00	11.93	39.78	55.14	49.00
Pwh (bara)	21.31	22.04	26.28	30.05	32.15
M (ton/jam)	225.00	225.00	225.00	75	150.00
ΔPg (bara)	0.13	0.73	4.24	2.70	6.93
P rata2 (bara)	21.38	22.40	28.41	31.40	35.61
T.sat (C)	215.79	218.19	230.85	236.41	243.56
ρg (kg/m3)	10.72	11.22	14.20	15.71	17.84
μg (Pa.s)	2.67E-05	2.72E-05	3.01E-05	3.15E-05	3.35E-05
Vv (m/s)	31.87	30.44	55.45	27.48	48.39
Nre	6.19E+06	6.07E+06	8.32E+06	3.39E+06	6.39E+06
fg	0.012	0.01	0.01	0.01	0.01
fc	0.012	0.01	0.01	0.010	0.009
fg/fc	1.00	1.00	1.00	1.00	1.00
dp/dz	0.00243	0.00240	0.01014	0.00321	0.00877
ΔPc (bara)	0.13	0.73	4.24	2.70	6.93
ΔPg/ΔPc	1.00	1.00	1.00	1.00	1.00
Pwf (bara)	**21.18**	**21.31**	**22.04**	**27.35**	**25.22**

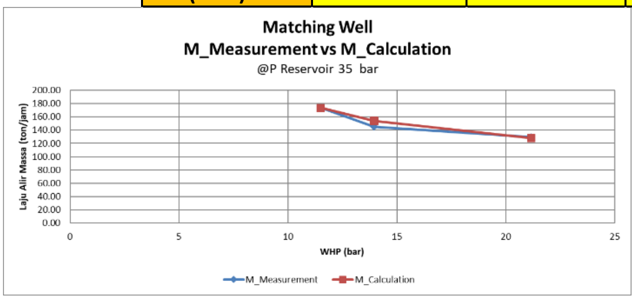

Figure 3. Validating Model Top-down

Validation by matching the measured mass flow rate and calculation mass flow rate, with a reservoir pressure of 35 bar, should give confidence in the well geometry data and proof that this equation can also be used for a multi-lateral well.

Calculation with a bottom-up method (from bottom of each leg of the well to the surface) is used to find a governing equation for geothermal multi-lateral well. In principle the method is the same as for the previous calculation. The difference is the calculation is done from Segment 4a and Segment 4b to the surface (Segment 1).

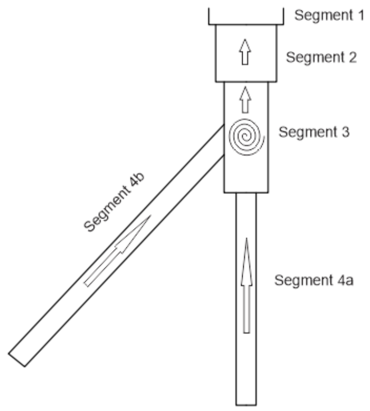

Figure 4. Illustration of fluid flow inside wellbore

As represented in Figure 3, steam flows from productive zones in Segment 4a and Segment 4b to the surface. Before reaching the surface, the steam mixes at the junction of Segment 3, creating a mixed mass flow rate and mixed pressure.

The characteristics of fluid flow inside the wellbore is determined initially by reservoir fluid flow into the wellbore, generally, at the bottom of the well. From the bottom of the well, fluid flows up due to the pressure gradient. In this bottom-up approach, the flow of the steam will be mapped inside wellbore. In Table 2, the variables and method are still the same as for the previous calculation, but now the initial step begins with Segment 4a and Segment 4b. Segment 4a and Segment 4b flows will be mixed in Segment 3. The assumption is made that Segment 4a and Segment 4b are acting without interfering with each other. The calculation is as follows:

- 1st Body, original hole: Segment 4a-Segment 3-Segment 2-Segment 1

- 2nd Body, forked hole: Segment 4b-Segment 3-Segment 2-Segment 1

The functions of Pwh and Pwf are switched as the calculation starts from the bottom. So, the value of Pwf will be used for wellhead pressure and the value of Pwh will be used for bottom (segment) well pressure. The value of the Pwh for Segment 3 will be average value of those from Segment 4a and Segment 4b.

Table 3. Original Hole Condition

P reservoir (bara)	Pwh (bara)	M measured (ton/jam)	ΔP (bara)	Pwf (bara)	p_r^2-p_{wf}^2 (bara^2)	n (log-log)	C	M calculated (ton/jam)
35	11.5	225.0	7.81	27.35	477.21	3.618	0.000000046	225.0
	13.95	205	6.87	27.58	464.24			203.7
	21.16	130	3.78	28.55	409.80			129.7

Table 4. Forked Hole Condition

P reservoir (bara)	Pwh (bara)	M measured (ton/jam)	ΔP (bara)	Pwf (bara)	p_r^2-p_{wf}^2 (bara^2)	n (log-log)	C	M calculated (ton/jam)
35	11.5	225.00	12.03	25.22	588.89	1.252	0.077	225.0
	13.95	205	10.30	26.26	535.58			199.8
	21.16	130	5.31	29.12	377.11			128.8

A value of 35 bara was set for the reservoir pressure (steam reservoir). From the equation used for the model, a value of n and can be determined as follow,

$$n = \frac{1}{m} \tag{8}$$

The constant n represents the slope of the function of (Pr^2-Pwf^2) on a log-log chart. In this study, the value of n for original hole and forked hole are 3.618 and 1.252 respectively.

The constant C can be found using:

$$C = \frac{m}{(\bar{P}_r^2 - P_{wf}^2)^n} \tag{9}$$

In this study, the constant C for the original hole and forked hole are 4.6 x 10^{-8} and 0.077, respectively

Using equation (1), the model equation can be generated as follows:

$$m = 3.618(\bar{P}_r^2 - P_{wf}^2)^{4.6x10^{-8}} \text{ for Original Hole} \tag{10}$$

$$m = 1.252(\bar{P}_r^2 - P_{wf}^2)^{0.077} \text{ for Forked Hole} \tag{11}$$

For the production capacity of the multi-lateral well, equation (10) and (11) can be combined as follow,

$$m = 3.618(\bar{P}_{roh}^2 - P_{wfoh}^2)^{4.6x10^{-8}} + 1.252(\bar{P}_{rfh}^2 - P_{wffh}^2)^{0.077} \tag{12}$$

As all the variables are the same, the only difference is the bottom hole pressure, because each leg has its own characteristics. The modified equation can be used for determining the production potential of a multi-lateral well, if well completion data has been supplied. These brief information can be achieved right away after a geothermal well has been completed and is ready for production to be initiated.

6. CONCLUSION

Studies of multi-lateral wells in the geothermal industry are few. Perhaps the reason for the scarcity of studies is the fact that geothermal developer are simply not using this kind of technology very often, especially in Indonesia. Despite having little information on geothermal multi-lateral wells, a study on one of the multi-lateral well has been conducted. For the first study, it was conducted for a simple single-phase steam reservoir because the governing equations are simpler than for two-phase flow modelling. Our study on single-phase steam flow can help with understanding the fluid behavior in a multi-lateral well, especially in the junction area, where fluid from each hole will mix. A modified flow equation has been achieved for a multi-lateral well.

More effort is required for studying the fluid behavior inside wellbore from bottom to the surface, and also in each leg of the well. The main issue with the model for a multi-lateral well is the junction between original hole and forked hole/leg. The problem lies in the possibility of interference with one another when both holes are producing.

For the next part of this study, more attention is required on the locations of each feed zone at the bottom of the well in each hole. Also, a study of the economics will have to be detailed for a “traditional” well and multi-lateral well in geothermal a context as it could help companies in balancing the benefits of an increased production rate against the extra financial investment in the mulita-lateral well itself.

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